SEPTEMBER FILINGS

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Date: September 6, 2023

Witness: Brian Shuey

PREPARED DIRECT TESTIMONY OF BRIAN SHUEY
ON BEHALF OF
THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION
IN PACIFIC GAS AND ELECTRIC COMPANY'S
2024 ERRA FORECAST PROCEEDING

PUBLIC

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Attachments

I. INTRODUCTION AND SUMMARY OF TESTIMONY

The California Community Choice Association (**CalCCA**) presents this direct testimony in the *Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2024 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation* (**Application**). This testimony has been prepared on behalf of CalCCA by Brian Shuey, Senior Manager, NewGen Strategies and Solutions, LLC. Mr. Shuey's qualifications are set forth in Attachment A.

CalCCA has a particular interest in the Power Charge Indifference Adjustment (**PCIA**) and the Portfolio Allocation Balancing Account (**PABA**), both of which are charged to customers of the eleven community choice aggregators (**CCAs**) that CalCCA represents through the PCIA rates for which Pacific Gas & Electric Company (**PG&E**) seeks approval in this proceeding. This testimony focuses on the following issues in Commissioner Reynolds' August 3, 2023 Scoping Ruling:[1]

1. PG&E's forecasted 2024 energy procurement revenue requirements to become effective in rates on January 1, 2024, including:
    a. disposition of PG&E's forecast December 31, 2023 year-end balancing account balances, subject to adjustments in the Annual Electric True-up process, except for disposition of balances recorded to the Modified Cost Allocation Mechanism Balancing Account (MCAMBA);
    b. disposition of recorded Voluntary Allocation Market Offer Memorandum Account (VAMOMA) balances; and
    c. approval of PG&E's methodology to include pre-2024 renewable energy credits (RECs) toward the 2024 PCIA revenue requirement calculation and to allocate the value of such RECs to benefit bundled and departing load customers responsible for applicable PABA vintage costs;

5. PG&E's rate design proposals associated with its proposed total electric procurement revenue requirements to be effective in rates on January 1, 2024, including Green Tariff Shared Renewables (GTSR) rates.

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[1] *See* Application (**A.**) 23-05-012, *Assigned Commissioner's Scoping Memo and Ruling*, pp. 2-5 (August 3, 2023) (2023 Scoping Ruling).

8. [T]hat PG&E has not demonstrated the relief it requests is just and reasonable, is in compliance with rules, regulations, resolutions and decisions for all customer classes, including but not limited to D.18-10-019, D.19-10-001, D.20-12-038, and D.23-06-066, and prevents illegal cost shifts between bundled and unbundled rate payers.

9a. Whether PG&E's proposal to change the approved methodology for allocating Electric Supply Administration (ESA) costs, and allocate those costs based on gross generation authorized costs (as opposed to allocation on net authorized revenue requirements), is reasonable and in compliance with rules, regulations, resolutions, and decisions;

9b. Whether PG&E's proposal to include pre-2024 RECs—including RECs generated prior to the current (2021-2024) Renewables Portfolio Standard (RPS) compliance period—toward the 2023 PCIA revenue requirement calculation; its proposal to use a "last-in first-out" approach to meet REC deficits after applying 2021 and 2022 RECs towards its forecasted shortfall; its decision not to apply over 4 million MWh in Unsold RPS in 2023 towards its forecasted shortfall; and its proposal to allocate the value of pre-2024 RECs to benefit customers responsible for the applicable PABA vintage is reasonable and in compliance with all applicable rules, regulations, resolutions and decisions;

9c. Whether PG&E's proposal to amortize any year-end 2023 residual balance in the PCIA Undercollection Balancing Account (PUBA) in 2024 rates (through PUBA rate adders) is reasonable;

9d. Whether PG&E is correctly calculating the reduction in its PCIA revenue requirement resulting from the removal of Diablo Canyon Power Plant (DCPP) Unit 1 from the PCIA (upon that Unit's retirement on November 2, 2024);

9e. Whether PG&E is correctly implementing D.19-11-016 and D.22-05-015 to ensure appropriate accounting treatment for both bundled and unbundled customers related to the forecasted cost recovery of system reliability Modified CAM contracts;

9f. Whether PG&E's Indifference Calculation inputs and sources are appropriate and comply with D.18-10-019 and D.21-03-051;

9g. Whether PG&E's proposed accounting for Local Resource Adequacy resources forecasted to be shown or sold to the Central Procurement Entity in 2024 is reasonable and in compliance with prior Commission decisions;

9h. whether PG&E's forecast of Retained RPS, Excess RPS, Sold RPS, and Unsold RPS energy is reasonable and in compliance with prior Commission decisions;

9i. Whether PG&E's funding set asides for the Disadvantaged Community Green Tariff (DAC-GT) program and the Community Solar – Green Tariff (CS-GT) programs are consistent with the budgets requested by the particular Community Choice Aggregators.

Based on my review of PG&E's application, supporting workpapers, and responses to discovery, I make the following recommendations to bring PG&E's request in line with prior Commission rules, regulations, resolutions, and decisions, and with just and reasonable ratemaking:

- PG&E's proposal to apply excess RPS credits from prior years to meet their RPS obligations for the 2024 forecast year should be approved, but with modifications. CalCCA's recommended method of accounting for these banked RECs should be applied to actual PABA accounting as well as future ERRA forecast proceedings. (Section III of this testimony)
- In light of the investor-owned utilities' (**IOU**) respective responses to the Administrative Law Judge's Ruling Directing Parties to Comment Regarding Fixed Generation Costs issued in each of the IOUs' 2024 ERRA Forecast cases on August 1, 2023, in which each IOU described a different approach to ESA cost recovery, CalCCA recommends the Commission consider PG&E's proposal to modify its methodology for allocating ESA common costs as part of the evaluation of fixed generation cost recovery in Phase 2 of this proceeding or in a separate application. However, if the Commission considers PG&E's proposal in this phase, the allocation factors PG&E uses for 2024 should be adjusted to reflect the removal of Diablo Canyon Unit 1 from the PCIA resource portfolio. (Section IV of this testimony)

- PG&E's proposal to extend the PCIA Under-collection Balancing Account (**PUBA**) rate adder an additional year should be approved, with modifications. (Section V of this testimony)
- PG&E should reduce the General Rate Case (**GRC**) revenue requirement included in the Indifference Amount because it is based on PG&E's 2020 GRC and does not reflect the San Francisco General Office (**SFGO**) sale. (Section VI.A. of this testimony)
- PG&E should adjust the market value of capacity in the Indifference Amount to remove Diablo Canyon Unit 1 November 2024 Resource Adequacy (**RA**). (Section VI.B. of this testimony)

Table 1 provides the impact of the above recommendations on PG&E's proposed PCIA revenue requirement.

Table 1: Recommended Adjustments to PCIA Revenue Requirement

Description	Adjustment
SFGO Gain on Sale	($17 million)
Diablo Canyon Unit 1 November 2024 RA	[redacted]

Lastly, in Section VII of this testimony, I provide an update on the status of the true-up of 2023 forecasted above-market costs with actual above-market costs recorded to date and the market factors driving that true-up. This true-up manifests in the forecasted year-end 2023 PABA balance, which will be updated with additional actual monthly activity in PG&E's October Update.

II. THE PCIA, THE PABA, AND THE PUBA

In this section of my testimony, I provide an overview of the PCIA, the PABA, and the PUBA, each of which are key concepts relevant to PG&E's Application and this testimony.

CCA customers receive generation services from their local CCA, and receive transmission, distribution, billing, and other services from the incumbent for-profit utility. CCA customers pay CCA-specific generation rates. CCA rates are partially influenced by local mandates to procure and maintain clean electricity portfolios that in many cases exceed state requirements for renewable generation. In addition, CCA and other unbundled customers are subject to several non-bypassable charges (**NBCs**), including the PCIA and the CAM, the 2024 levels of which will be determined in this proceeding.

The Commission adopted the PCIA to ensure that when customers of IOUs depart from bundled service and receive their electricity from a non-IOU provider, such as a CCA, "those customers remain responsible for costs previously incurred on their behalf by the IOUs — but only those costs."[2]

The PCIA is derived from the utility's Indifference Amount, which is updated annually in each IOU's ERRA Forecast proceeding. The Indifference Amount is the difference in the target year between the cost of the IOU's supply portfolio and the market value of the IOU's supply portfolio.

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2 *See also* Rulemaking (**R.**) 17-06-026, *Scoping Memo and Ruling of Assigned Commissioner*, p. 2 (September 25, 2017), Decision (**D.**) 18-10-019, p. 3 (October 11, 2018).

Total Portfolio Cost includes capital investment recovery and fixed maintenance costs determined in a GRC for utility owned generation, purchased power such as that from power purchase agreements (**PPAs**), fuel costs for UOG and PPAs with tolling agreements, and California Independent System Operator (**CAISO**) grid charges and revenues, net of any sales.[3]

Portfolio Market Value is derived from total eligible resource output multiplied by the Market Price Benchmarks (**MPBs**), an administratively determined set of proxy values that represents the market value of the IOU's resource portfolio.[4] Portfolio Market Value consists of three principal components: Energy Value, RPS Value, and Resource Adequacy Value.

- Energy Value is the estimated financial value, measured in dollars, that is attributed to the generation component of a utility portfolio for a given year.[5]

- RPS Value is the estimated financial value, measured in dollars, that is attributed to the renewable energy component of a utility portfolio for a given year above and beyond the Energy Value.[6]

- RA Value is the estimated financial value, measured in dollars, that is attributed to the resource adequacy component of a utility portfolio for a given year.[7]

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[3] D.11-12-018, pp. 8-9 (December 1, 2011).

[4] D.19-10-001, p. 6 (October 10, 2019) ("Market Value is the estimated financial value, measured in dollars, that is attributed to a utility portfolio of energy resources for the purpose of calculating the Power Charge Indifference Adjustment for a given year.").

[5] *Id.*

[6] *Id.*

[7] *Id.*

MPBs are estimates of the value per unit (not total portfolio value) associated with the three principal sources of value in utility portfolios (non-RPS energy, RPS, and RA capacity).[8] Each MPB must be multiplied by the relevant portfolio volume as part of the overall calculation of Portfolio Market Value:[9]

- Energy Index is the MPB that reflects the estimated market value of each unit of energy in a utility portfolio, in dollar value per megawatt hour ($/MWh). It is sometimes referred to as "Brown Power Index", "Brown Power component", "Brown Power Adder", or "Brown Power benchmark."[10] Energy Index multiplied by non-RPS energy output produces the Energy Value.

- RPS Adder is the MPB that reflects the estimated incremental value of each unit of RPS-eligible energy in $/MWh.[11] RPS Adder multiplied by RPS output produces the RPS Value.

- RA Adder is the MPB that reflects the estimated value of each unit of capacity in a utility portfolio that can be used to satisfy Resource Adequacy obligations, in dollar value per kilowatt ($/kW-month). The RA Adder has three subcomponents, reflecting each type of RA product required for compliance with the RA program: system, local and flexible.[12] RA Adder multiplied by RA capacity produces the RA Value.

Finally, each generation resource and departing customer is assigned a "vintage." A distinct portfolio of generation resources is identified for each vintage year based on when a commitment to procure each resource was made. Customers are assigned to vintage years according to the date departing bundled IOU service.[13] Customers continuing to receive bundled service from the IOU are included in the latest vintage (e.g.

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8 *Id*.
9 *Id*.
10 *Id*., p. 7.
11 *Id*.
12 *Id*.
13 Unlike portfolio resources, customers are assigned to vintages using a July to June calendar period. For example, customers departing bundled service between July 2019 and June 2020 are assigned to the 2019 vintage.

vintage 2024 in the current application). Each vintage is assigned a separate Indifference Amount[14] and customers are responsible for the cumulative PCIA rates for their vintage.

Prior to D.18-10-019, the PCIA rate was set only on a forecast basis with no after-the-fact true-up for unbundled customers. Decision 18-10-019 approved a true-up for the PCIA using actual recorded net costs for PCIA-eligible resources and billed revenues from both bundled and departing load customers. This true-up now occurs via the PABA, a rolling true-up between the forecasted costs and revenues used to determine the Indifference Amount and the actual costs and revenues PG&E realizes during the year related to its PCIA eligible resource portfolio.

PG&E's PCIA rates for 2024 will be set in this proceeding based on two key components: (1) the forecasted Indifference Amount, *i.e.*, the difference between the forecasted cost of PG&E's generation portfolio in 2024 and the forecasted market value of PG&E's generation portfolio in 2024; and (2) the 2023 year-end balance in the PABA.[15] The Indifference Amount and the year-end PABA balance are added together to form the revenue requirement underlying PCIA rates. In addition, consistent with D.22-05-029, PG&E will transfer the 2023 year-end balance in the ERRA balancing account to the 2023 vintage subaccount of the PABA, allowing the balance to be recovered from bundled customers and unbundled customers that depart on or after July 1, 2023.

The PCIA revenue requirement is allocated among both bundled and unbundled customers based on their vintage, *i.e.*, the year unbundled customers left PG&E's

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[14] D.11-12-018, p. 9 (December 1, 2011).

[15] Because rates are determined during 2023, including the true-up for 2023, this true-up is developed using (1) actual values that are available to date and (2) a forecast of actual values for the remainder of the year. PG&E's May Application includes an estimate of the 2023 year-end PABA balance comprising a combination of actual entries from January through March 2023 and a projection of activity from April through December 2023.

service,[16] and their rate class using the allocation factors from PG&E's most recently approved GRC.[17]

Decision 18-10-019 limited "the change of the PCIA from one year to the next. Starting with forecast year 2020, the cap level of the PCIA rate should be set at $0.005/kWh more than the prior year's PCIA, differentiated by vintage."[18] If the year-over-year increase in departing load PCIA rates exceeded the rate cap in a given year, bundled customers rates were increased instead to "finance" the amount above the cap. A separate balancing account, the PCIA Under-collection Balancing Account, was also established to record the shortfall in revenue charged to departing load customers due to PCIA rates being limited by the $0.005/kWh cap in annual rate changes. PG&E also established the PCIA Financing Subaccount, a subaccount of the ERRA balancing account, to record the amount paid by bundled customers to cover the PUBA shortfall. Unbundled customers are responsible to pay for the shortfall recorded to PUBA, plus interest, to compensate bundled customers for having paid for the amount in excess of the cap. The final disposition of the residual PUBA undercollection is an issue in this proceeding.

On May 24, 2021, the Commission issued D.21-05-030 which discontinued the PCIA cap and trigger mechanism.[19] In D.20-12-038, the Commission approved a PCIA Adder to amortize the 2020 PUBA year-end balances over a three-year period beginning in 2021.

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[16] D.11-12-018, p. 9 (December 1, 2011).
[17] D.18-10-019, p. 122 and Ordering Paragraph (**OP**) 4 (October 11, 2018).
[18] *Id.*, Conclusions of Law 19-20, OP 9(a)-(c).
[19] D.21-05-030, OP 1 (May 24, 2021).

III. PG&E'S PROPOSAL TO APPLY BANKED RPS CREDITS TO MEET ITS RPS OBLIGATIONS FOR THE 2024 FORECAST YEAR SHOULD BE APPROVED WITH MODIFICATIONS.

In its Prepared Testimony PG&E explains that due to the RPS energy allocation and/or sale expected to take place through the Voluntary Allocation and Market Offer (**VAMO**) process, its net RPS position (i.e., forecast RPS-eligible generation less allocation and/or market offer activity) will be less than its annual RPS compliance target for 2024.[20] This means PG&E forecasts it will not have sufficient RPS-eligible energy to meet its annual RPS compliance target in 2024.

In D.20-02-047 addressing PG&E's 2020 ERRA Forecast application, the Commission established that the annual RPS targets used to calculate the IOU's RPS compliance period requirement are the minimum quantity that should be counted as Retained RPS in the PCIA.[21] Consequently, PG&E proposes to make up for the RPS shortfall in 2024 by applying RECs generated in prior years but in excess of annual RPS targets (*i.e.*, banked RECs) toward the bundled customer RPS compliance target in 2024.[22] Specifically, PG&E proposes to transfer banked RECs from 2022, 2021, 2020, and 2018 to cover the forecasted Retained RPS shortfall in 2024. PG&E proposes to apply those banked RECs toward its 2024 shortfall in a Last-in/First-out (**LIFO**) manner—which means PG&E would start by applying 2022 banked RECs, then move to 2021 banked RECs, and so on and so forth until PG&E has covered its 2024 shortfall. Recognizing that some of the bundled customer base that paid for those banked RECs in prior years may now be unbundled customers, PG&E proposes to credit PCIA vintages

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[20] PG&E Prepared Testimony, Chapter 9, page 9-17, lines 15-20.
[21] *Id.*, Chapter 9, pages 9-17, line 30 through 9-17, line 1.
[22] *Id.*, Chapter 9, Table 9-6.

2022, 2021, 2020, and 2018 for the value of the needed RECs and charge current bundled customers for those RECs in 2024. The REC transfer will be priced at the RPS Adder for 2024; PG&E's initial filing is based on the 2023 Forecast RPS Adder of $12.63/MWh as a placeholder until the 2024 RPS Adder is available in the October Update.[23]

Table 2 below details the REC quantities involved with PG&E's proposal. Based on PG&E's initial filing, PG&E needs 5,416 GWh of banked RECs to eliminate the forecasted Retained RPS shortfall in 2024.

Table 2: Proposed Excess REC Transfer

	2018	2019	2020	2021	2022	2023	2024
PG&E Bundled Sales (MWh)	48,832,111	35,956,100	35,838,070	33,149,379	28,776,746	30,544,937	28,831,236
Annual RPS Compliance Target	29.0%	31.0%	33.0%	35.8%	38.5%	41.3%	44.0%
RPS Compliance Requirement (MWh)	14,161,312	11,146,391	11,826,563	11,850,903	11,079,047	12,599,787	12,685,744
Retained RPS (MWh)	18,934,717	10,444,565	12,271,881	17,250,635	13,737,610	10,003,832	7,269,735
Unsold RPS	-	-	-	-	-	4,090,485	-
Excess/(Defecit)	4,773,405	(701,826)	445,318	5,399,732	2,658,563	(6,686,439)	(5,416,009)
REC Transfer (MWh) 2023				(4,480,474)	(2,205,965)	6,686,439	
REC Transfer (MWh) 2024	(3,598,835)		(445,318)	(919,258)	(452,598)		5,416,009
Remaining Excess/(Defecit)	1,174,570	(701,826)	-	-	-	-	-

Table 3 below details the calculation of the proposed dollar credit applied to PCIA vintages 2022, 2021, 2020, and 2018, with an offsetting charge included in bundled generation rates for 2024.

Table 3: Proposed REC Transfer Value

	2018 Vintage	2019 Vintage	2020 Vintage	2021 Vintage	2022 Vintage	2023 Vintage	2024 Bundled Customers
REC Transfer (MWh)	(3,598,835)	-	(445,318)	(919,258)	(452,598)	-	5,416,009
2024 RPS Adder ($/MWh)							$12.63
Transfer Value ($)	($45,453,286)	$0	($5,624,366)	($11,610,229)	($5,716,313)	$0	$68,404,194

CalCCA does not oppose PG&E's proposal to use banked RECs to meet its minimum Retained RPS requirements in 2024 or future years. However, CalCCA does

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[23] *Id.*, Chapter 9, page 9-28, lines 1-3.

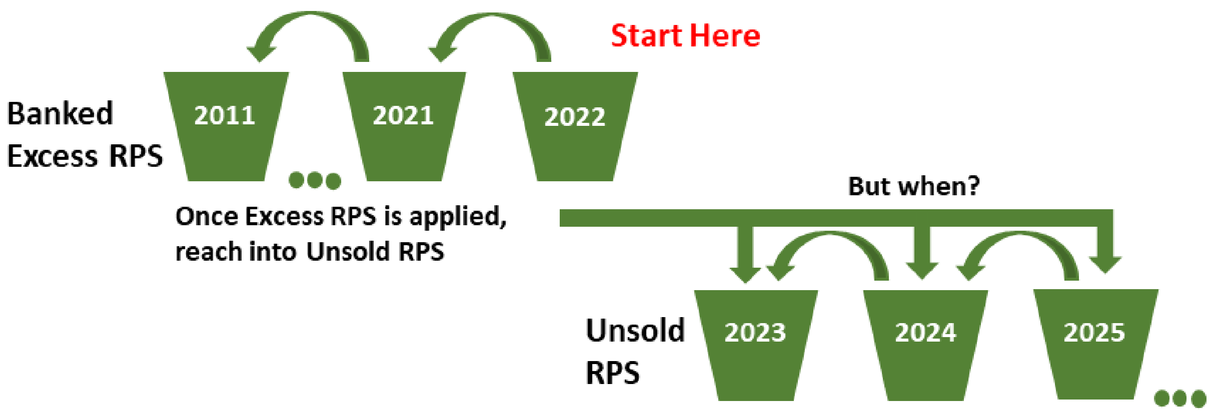
not support PG&E's proposed LIFO method of applying banked RECs. The LIFO method favors recently departed customers over those that departed earlier but also paid for excess RECs prior to departing. Withdrawing banked RECs on a LIFO basis causes customers who paid for excess RECs in earlier years to wait longer to receive a credit until PG&E ultimately needs the excess RECs for which those customers paid. For example, under PG&E's proposed methodology, vintage 2013 customers would receive no benefit from PG&E's application of banked RECs until PG&E reaches back to the 2013 excess RECs after exhausting all surplus RECs from years 2014 and beyond. In contrast, under a First-In/First-Out (**FIFO**) methodology as discussed later, vintage 2013 customers, who paid for RECs before vintage 2014-and-later customers, would appropriately receive a credit for PG&E's use of banked RECs *before* vintage 2014-and-later customers receive a similar credit.

PG&E's LIFO proposal is also internally inconsistent with its proposed treatment of an unexpected quantity of Unsold RPS recorded in 2023. In 2023, PG&E will be left with 4,090 GWh of Unsold RPS[24] due to a delay in the approval and initial delivery dates of the Short-Term and Long-Term Market Offer contracts.[25] PG&E indicated that "Unsold RPS will be eligible to count towards the minimum RPS quantity for the PCIA in a future period once all of the past, previously retained excess RPS volumes have been drawn upon."[26] While CalCCA does not oppose using Unsold RPS for future compliance, PG&E's proposal to delay using the 2023 Unsold RPS until prior years' banked RECs are used up is not consistent with the LIFO method, because Unsold RPS amounts would be

[24] *Id.*, Chapter 9, Table 9-4.
[25] *See* PG&E's response to CalCCA data request 2.21.
[26] *See* PG&E's response to CalCCA data request 2.22.

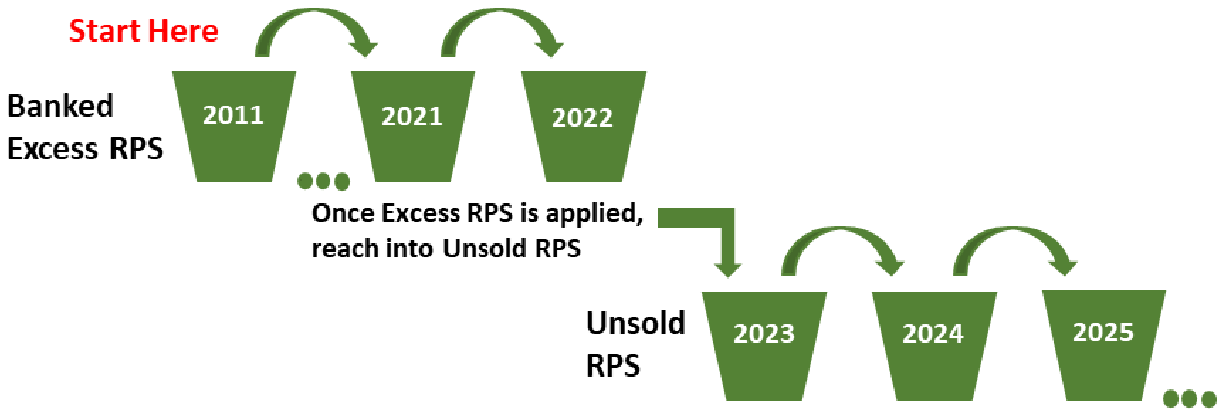
applied only *after* RECs previously generated were applied. A visual representation of PG&E proposed methodology is included below in Figure 1. Beginning with 2022 RECs PG&E will use up the remaining excess each year until all excess banked RECs are applied. Once that occurs, they will begin to reach into the Unsold RPS which PG&E first recorded in 2023, but it is unknown when PG&E will run out of excess banked RECs from earlier years therefore it is unknown when it will begin using Unsold RPS.

Figure 1: PG&E Proposed Methodology



Rather than adopt PG&E's LIFO method, CalCCA recommends the Commission direct PG&E to utilize a FIFO method to withdraw RECs from the bank, so that PG&E credits customers in the order they paid for the excess RECs. Using a FIFO method also allows a more natural transition to using PG&E's 2023 Unsold RPS after all previously banked excess RECs have been applied. See Figure 2 below for an illustration.

Figure 2: Recommended RPS Tracking Methodology



In response to discovery, PG&E provided an inventory of banked RECs quantifying excess RECs by year going back to 2011, the beginning of RPS Compliance Period 1. PG&E confirmed in discovery it does not have any net available RPS generation prior to 2011.[27] Beginning in 2011 and 2012, PG&E had under-procured the required RECs to meet the annual RPS target; however, they were able to procure enough in 2013 to meet compliance for the compliance period. After 2013, PG&E began banking excess RECs in each year until 2023, with the exception of 2019 when they had to make an adjustment to comply with Commission decision D.20-02-047. At the end of 2022, PG&E had a net excess REC balance of 31.1 million MWh. See Table 4 below which summarizes the REC balance by year.

[27] *See* PG&E's response to CalCCA's data request 5.01.

Table 4: PG&E Banked REC Balance by Year

Year	Annual Surplus/ (Deficit) MWh	Cumulative Balance MWh
2011	(139,673)	(139,673)
2012	(727,915)	(867,588)
2013	1,928,480	1,060,892
2014	3,980,017	5,040,909
2015	4,482,478	9,523,387
2016	5,379,424	14,902,811
2017	3,704,274	18,607,085
2018	4,773,405	23,380,490
2019	(701,826)	22,678,664
2020	445,318	23,123,982
2021	5,399,732	28,523,714
2022	2,658,563	31,182,277
2023	(6,686,440)	24,495,837
2024	(5,416,009)	19,079,828

As shown in Table 4, PG&E has been consistently short of its annual RPS compliance target beginning with VAMO implementation in 2023. Based on PG&E's banked REC inventory, and using the FIFO methodology illustrated in Figure 2, PG&E should begin by crediting customers who paid for excess RECs in 2013 to meet the minimum Retained RPS targets in later years.[28] Per the FIFO methodology CalCCA recommends, PG&E should apply banked RECs from years 2013, 2014, and 2015 to cover the entire 2023 shortfall. Doing so will require PG&E to make a correcting entry to the 2023 PABA to move the value of banked RECs needed for 2023 out of the 2021 and 2022 vintages (used under a LIFO method) and into the 2013, 2014 and 2015 vintages (used under a FIFO method). This correcting entry is required before determining the vintages that should be credited for the 2024 REC transfers. Because PG&E projects that 5,416 GWh of RECs are needed in 2024, PG&E would need to apply banked RECs from years 2015 and 2016 to cover the shortfall in 2024. Table 5 below details the REC quantities required if PG&E were to switch to a FIFO model as CalCCA recommends.

[28] Note that excess RECs don't begin until 2013 due to initial REC deficits in 2011 and 2012.

Table 5: Banked REC Utilization – FIFO Method

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Compliance Period 1			Compliance Period 2			Compliance Period 3							
PG&E Bundled Sales (MWh)	74,863,941	76,205,120	75,705,039	74,546,865	72,112,848	68,440,794	61,397,214	48,832,111	35,956,100	35,838,070	33,149,379	28,776,746	30,544,937	28,831,236
Annual RPS Compliance Target	20.0%	20.0%	20.0%	21.7%	23.3%	25.0%	27.0%	29 0%	31.0%	33.0%	35.8%	38.5%	41.3%	44.0%
RPS Compliance Requirement (MWh)	14,972,788	15,241,024	15,141,008	16,176,670	16,802,294	17,110,199	16,577,248	14,161,312	11,146,391	11,826,563	11,850,903	11,079,047	12,599,787	12,685,744
Retained RPS (MWh)	14,833,115	14,513,109	17,069,488	20,156,687	21,284,772	22,489,623	20,281,522	18,934,717	10,444,565	12,271,881	17,250,635	13,737,610	10,003,832	7,269,735
Unsold RPS	-	-	-	-	-	-	-	-	-	-	-	-	4,090,485	-
Excess/(Defecit) Before Portfolio Compliance	(139,673)	(727,915)	1,928,480	3,980,017	4,482,478	5,379,424	3,704,274	4,773,405	(701,826)	445,318	5,399,732	2,658,563	(6,686,440)	(5,416,009)
Retained for Compliance (MWh)	139,673	727,915	(867,588)					(701,826)	701,826					
Excess/(Defecit) Available For Use	-	-	1,060,892	3,980,017	4,482,478	5,379,424	3,704,274	4,071,579	-	445,318	5,399,732	2,658,563	(6,686,440)	(5,416,009)
REC Transfer (MWh) 2023			(1,060,892)	(3,980,017)	(1,645,531)								6,686,440	
REC Transfer (MWh) 2024					(2,836,947)	(2,579,062)								5,416,009
Net Excess/(Defecit)	-	-	-	-	-	2,800,362	3,704,274	4,071,579	-	445,318	5,399,732	2,658,563	-	-

Utilizing a FIFO rather than LIFO method does not affect the total $68.4 million value of banked RECs needed for the 2024 ERRA Forecast because the banked RECs are still valued using the 2024 RPS Adder MPB. The change in method simply alters the PCIA vintages that receive the credit for the use of banked RECs. The FIFO method should be applied to actual PCIA accounting as well as future ERRA forecast proceedings. Table 6 below details the application of the proposed dollar credits to PCIA vintages 2013-2016. Separate columns are used to summarize the 2023 REC transfer (in the PABA) and 2024 REC transfer (in the PCIA forecast).

Table 6: REC Transfer Value – FIFO Method

PCIA Vintage	2023 REC Transfer (MWh)	2023 RPS Adder ($/MWh)	2023 Transfer Value ($)	2024 REC Transfer (MWh)	2024 RPS Adder ($/MWh)	2024 Transfer Value ($)
2011	-	-	$ -	-	-	$ -
2012	-	-	$ -	-	-	$ -
2013	(1,060,892)	$ 12.63	$ (13,399,066)	-	-	$ -
2014	(3,980,017)	$ 12.63	$ (50,267,615)	-	-	$ -
2015	(1,645,531)	$ 12.63	$ (20,783,057)	(2,836,947)	$ 12.63	$ (35,830,641)
2016	-	-	$ -	(2,579,062)	$ 12.63	$ (32,573,553)
2017	-	-	$ -	-	-	$ -
2018	-	-	$ -	-	-	$ -
2019	-	-	$ -	-	-	$ -
2020	-	-	$ -	-	-	$ -
2021	-	-	$ -	-	-	$ -
2022	-	-	$ -	-	-	$ -
2023	6,686,440	$ 12.63	$ 84,449,737	-	-	$ -
2024	-	-	$ -	5,416,009	$ 12.63	$ 68,404,194

PG&E proposes the LIFO method for the 2024 forecast proceeding and indicated in discovery that it plans to propose the same methodology in subsequent ERRA forecast filings but reserves the right to propose an alternate methodology in future proceedings.[29]

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[29] *See* PG&E's response to CalCCA's data request 2.20.

It is important to establish long-term consistency with an inventory accounting methodology; therefore, the Commission should require the REC tracking method adopted in this proceeding to be applied in subsequent ERRA proceedings.

IV. PG&E'S PROPOSAL TO MODIFY ITS ENERGY SUPPLY ADMINISTRATION COMMON COST ALLOCATION METHODOLOGY SHOULD BE DELAYED UNTIL THE ISSUE OF FIXED GENERATION COST RECOVERY CAN BE ADDRESSED.

In its Prepared Testimony, PG&E proposes to change the approved methodology for allocating ESA costs between ERRA, PABA, and NSGBA. Under the net revenue requirement method, which was approved via Advice Letter 5440-E, authorized gross procurement costs are offset by the market value of generation resource attributes (*i.e.*, market value of energy, RA, and RPS) when calculating the allocation rates applicable to ERRA, PABA, and NSGBA.[30] PG&E states:

> Since implementing PABA in 2019 and making modifications to other associated generation-related balancing accounts, ESA costs have been allocated to ERRA and PABA based on the net authorized revenue requirements, i.e., authorized generation resource costs less the market value of the supply portfolio. As a result, the ESA allocations have been suboptimal in aligning ESA costs with cost causation and, if left unchanged, would result in almost all of the 2024 ESA costs being charged to PG&E's bundled customers.[31]

PG&E now proposes to allocate ESA expenses to ERRA, PABA, and NSGBA based on the gross authorized revenue requirements associated with each balancing account rather than the net authorized revenue requirements, as it has done in the past. Under the gross authorized revenue requirement approach PG&E now proposes, allocation rates would be calculated based only on the gross procurement cost component of each balancing account's revenue requirement, without any reduction for the market

[30] *See* PG&E's response to CalCCA data request 2.08.

[31] PG&E Prepared Testimony, Chapter 9, page 9-10, lines 21-29.

value of resource attributes. Table 7 and Table 8 below demonstrate the Common Cost Allocation Factors using both the current and proposed allocation methodologies.

Table 7: Common Cost Allocation Factors

Common Cost Allocation Factors			
Cost Recovery		Current Methodology	Proposed Methodology
ERRA	ERRA	96.48%	37.56%
CAM	NSGBA	4.30%	3.30%
PCIA	UOG Legacy	-12.02%	22.86%
PCIA	Vin 2009	12.00%	25.64%
PCIA	Vin 2010	3.58%	5.22%
PCIA	Vin 2011	0.25%	1.57%
PCIA	Vin 2012	-0.33%	1.94%
PCIA	Vin 2013	-0.68%	0.71%
PCIA	Vin 2014	-0.08%	0.07%
PCIA	Vin 2015	-0.14%	0.15%
PCIA	Vin 2016	-0.05%	0.03%
PCIA	Vin 2017	-0.28%	0.11%
PCIA	Vin 2018	0.00%	0.00%
PCIA	Vin 2019	-0.61%	0.57%
PCIA	Vin 2020	0.00%	0.01%
PCIA	Vin 2021	-1.91%	0.27%
PCIA	Vin 2022	-0.50%	0.00%
	Total	100.00%	100.00%

Table 8: Common Cost Allocation Factors Summary

Common Cost Allocation Factors		
	Current Methodology	Proposed Methodology
ERRA	96.48%	37.56%
CAM	4.30%	3.30%
PCIA	-0.77%	59.14%
	100%	100%

On August 1, 2023, the ALJ issued a Ruling Directing Parties to Comment Regarding Fixed Generation Costs.[32] The Administrative Law Judges assigned to Southern California Edison's (**SCE**) and San Diego Gas and Electric Company's (**SDG&E**) respective 2024 ERRA Forecast applications issued substantially similar rulings on the same day. Those rulings asked the IOUs to describe each of the "Fixed Generation Costs" in their respective 2024 ERRA Forecast proceedings, the balancing account used for tracking those costs, the estimated 2023 cost, and the estimated 2023 cost associated with a hypothetical "last remaining bundled customer."[33]

In opening comments on the ALJ Ruling, PG&E estimated it incurs [redacted] in ESA costs annually and estimated [redacted] of those costs would be borne by a hypothetical "last remaining bundled customer." In sharp contrast, SCE estimated $0 ESA costs in 2023,[34] and SDG&E stated it recovers its ESA costs through distribution rates.[35] Based on their opening comments on the ALJ Ruling, CalCCA observed each IOU appears to approach ESA cost recovery in a different manner.[36] CalCCA therefore recommended the Commission move the issue of PG&E's allocation of ESA costs (currently Scoping Issue 9(a)) and other common costs[37] to a Phase II of this proceeding, such that the Commission addresses allocation of common costs consistently and comprehensively (across common cost categories, but also across the three IOU service territories, assuming the Commission consolidates each IOU's Phase II).[38] I agree that approach would be reasonable and most efficient.

To the extent the Commission does not move PG&E's proposed modification to its ESA cost allocation methodology to a Phase II of this proceeding, I recommend one modification to PG&E's proposed methodology. Because Diablo Canyon Unit 1 will no longer be a PCIA-eligible resource effective on November 2, 2024, I recommend removing two months of Diablo Canyon Unit 1 costs from the calculation Common Cost Allocation Factors. Adjusting the allocations factors now is appropriate for two reasons: 1) it is known that Diablo Canyon Unit 1 will no longer be a PCIA-eligible resource beginning November 2024, and 2) PG&E adjusted the projected PCIA portfolio costs to exclude Diablo Canyon Unit 1 for two months of the 2024 forecast. PG&E agrees that removing the Diablo Canyon Unit 1 costs is reasonable and plans to do so once authorized.[39] Removing Diablo Canyon Unit 1 costs would appropriately reduce the allocation of ESA costs to the UOG Legacy PCIA vintage. Table 9 below shows the impact of removing two months of Diablo Canyon Unit 1 costs from the calculation of the Common Cost Allocation Factor. The reduced allocation of ESA costs to the PCIA will reduce the 2024 Indifference Amount by [redacted].

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32 Administrative Law Judge's Ruling Directing Parties to Comment Regarding Fixed Generation Costs (August 1, 2023) (ALJ Ruling).

33 *Id*. at 1-2.

34 SCE Opening Comments on ALJ Ruling at 3.

35 SDG&E Response on ALJ Ruling at 3.

36 CalCCA Reply Comments on ALJ Ruling at 9-10.

37 In its opening comments on the ALJ Ruling, PG&E stated it allocates its collateral costs, like its ESA costs, to balancing accounts based on net authorized revenue requirements, and now seeks to modify that allocation approach such that Collateral Costs are allocated based on gross authorized revenue requirements. PG&E Opening Comments on ALJ Ruling at 6-7.

38 CalCCA Reply Comments on ALJ Ruling at 9-10.

39 *See* PG&E's response to CalCCA data request 2.11.

Table 9: Common Cost Allocation Factors without 2 Months of Diablo Canyon

	Proposed w/o 2 Months DCPP Unit 1
ERRA	37.56%
CAM	3.30%
PCIA	57.87%
DCPP	1.27%
	100%

CalCCA notes that although Diablo Canyon will no longer be a PCIA-eligible resource after the original intended retirement dates, if PG&E continues to operate the plant during a period of extended operations, it is appropriate that an allocated share of ESA costs follow other Diablo Canyon costs for recovery from customers responsible for the cost of extended operations. Currently the extended operation of Diablo Canyon is being addressed in a separate proceeding.[40] CalCCA believes it is reasonable to recover an allocated share of ESA costs through the Diablo Canyon extended operations balancing accounts.

V. PG&E'S PROPOSAL TO EXTEND THE PUBA RATE ADDER AN ADDITIONAL YEAR SHOULD BE APPROVED, WITH MODIFICATIONS.

As described above, the Commission approved a PCIA Adder to amortize the 2020 PUBA year-end balances over a three-year period beginning in 2021. The PUBA was targeted to be fully amortized in 2023; however, in PG&E's Prepared Testimony PG&E indicated that it projects approximately $7.4 million[41] remaining unamortized in the PUBA at the end of 2023. PG&E proposes to amortize the residual balance in the PUBA in rates for 2024 through the continued implementation of PUBA rate adders.

[40] R.23-01-007.

[41] PG&E's Prepared Testimony, Chapter 14, page 14-23, lines 27-30.

Once the balance in the PUBA is closer to zero, PG&E plans to submit an Advice Letter to close the PUBA.[42]

CalCCA does not oppose extending the PUBA rate adder for an additional year provided PG&E terminates the rate adder and handles the final residual PUBA balance appropriately. Due to the inherent nature of rates, billing cycles, and unpredictable customer usage it is impossible to terminate a rate immediately once a balance reaches zero, therefore it will be necessary for PG&E to manage a residual balance.

In response to a CalCCA discovery request, PG&E indicated it believes a balance of less than $1 million would be an acceptable threshold to consider closing the PUBA.[43] PG&E also proposed to close the PUBA account through a Tier 2 Advice Letter and then roll the final residual balance into the PABA.[44]

CalCCA does not oppose the $1 million threshold for closing the PUBA rate or rolling the final residual balance into the PABA. However, the Commission should direct PG&E to close the PUBA rate through the use of a Tier 1 Advice letter once the $1 million threshold is reached so that PG&E can immediately stop charging the PUBA rate to customers and avoid overcollections rather than waiting for approval through a Tier 2 Advice Letter. Furthermore, if the $1 million threshold is not reached by the end of 2024 PG&E should be required to close the PUBA and present a proposal in its 2025 ERRA Forecast proceeding to dispose of the final residual balance without continuing the PUBA surcharge. PG&E was originally supposed to collect the PUBA balance by the end of 2023, there should be no issue collecting the remaining balance by the end of 2024. I

42 PG&E Prepared Testimony, Chapter 19, page 19-4, lines 9-12.
43 *See* PG&E's response to CalCCA data request 2.36.
44 *See* PG&E's response to CalCCA data requests 2.37 and 2.34.

would note that in its pending 2024 ERRA Forecast proceedings, San Diego Gas & Electric Company and Southern California Edison have proposed to close out their respective PUBA accounts, and transfer the residual balance to PABA ($1.3 million balance for SDG&E and $1.5 million balance for SCE).[45]

VI. CALCULATION OF THE 2024 PCIA REVENUE REQUIREMENT.

PG&E's proposed PCIA revenue requirement is a net credit of $289 million, shown for each vintage in Table 10 below.

Table 10: PCIA Revenue Requirement by Vintage ($millions)

Vintage	Legacy UOG	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Total
2024 Indifference Amount	$ (529)	$ 330	$ 161	$ 12	$ (16)	$ (29)	$ (3)	$ (6)	$ (2)	$ (15)	$ (46)	$ (26)	$ (6)	$ (141)	$ (6)	$ (1)	$ (321)
2024 PUBA Amortization	$ -	$ 0	$ 1	$ 0	$ 0	$ 0	$ 0	$ 0	$ 1	$ 3	$ 2	$ 0	$ (0)	$ -	$ -	$ -	$ 7
2023 PABA Balance	$ (943)	$ 464	$ 62	$ 26	$ 13	$ 9	$ 0	$ (1)	$ 2	$ 5	$ (0)	$ 27	$ (5)	$ (18)	$ 156	$ (0)	$ (203)
2023 ERRA Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (0)	$ -	$ -	$ 228	$ 228
Vamo Balances	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ -	$ -	$ -	$ -	$ -	$ -	$ 1
Total PCIA RRQ	**$ (1,473)**	**$ 795**	**$ 224**	**$ 39**	**$ (3)**	**$ (19)**	**$ (3)**	**$ (7)**	**$ 1**	**$ (8)**	**$ (45)**	**$ 1**	**$ (10)**	**$ (159)**	**$ 151**	**$ 227**	**$ (289)**

Based on my review of PG&E's testimony, workpapers, and discovery responses, my testimony concludes PG&E made the following errors related to the 2024 Indifference Amount:

- PG&E did not remove the cost of its old SFGO headquarters, which has been sold, from the GRC revenue requirement included in the 2024 Indifference Amount.
- PG&E did not remove Diablo Canyon Unit 1 RA capacity from the PCIA for the forecast month of November 2024.

[45] *See* A.23-05-013, SDG&E Witness Hua testimony, page BH-14; A.23-06-001, SCE-01, Chapter IX, page 133.

A. PG&E should correct two errors related to the gain on sale of its SFGO headquarters, each of which incorrectly inflate the 2024 Indifference Amount.

In D.21-08-027 the Commission authorized PG&E to credit customers the gain on the sale of its SFGO headquarters over a five-year period from 2022 through 2026. Because a portion of the costs to own and operate SFGO is allocated to PG&E's electric generation revenue requirement and included in the GRC-related electric generation costs recovered through PCIA rates, a portion of the benefits related to the sale are also allocated to electric generation and included as a credit to the Indifference Amount. Those benefits include the gain on sale of the SFGO headquarters and a reduction in GRC-related revenue requirement due to a lower rate base and reduced expenses such as depreciation, property taxes, and operation and maintenance costs.

PG&E's Application includes a $22 million credit for the electric generation portion of the estimated net gain on sale of its SFGO headquarters, reflecting year 3 of the amortization of the gain.[46] Through my review of PG&E's workpapers I found two errors related to PG&E's treatment of the SFGO sale included in the 2024 Indifference Amount. First, PG&E did not include Revenue Franchise Fees and Uncollectibles (**RF&U**) in the calculation of the credit before including the credit in the Indifference Amount calculation. This error overstates the indifference amount. PG&E corrected this error in its supplemental testimony submitted on August 15, 2023.[47]

Second, PG&E did not remove the cost of the SFGO headquarters from the GRC-related revenue requirement included in the 2024 Indifference Amount.[48] Through discovery PG&E confirmed that the GRC-related costs in its Application are based on the

46 PG&E Prepared Testimony, Chapter 9, Table 9-1.
47 PG&E Supplemental Testimony, pages 3, line 15 through 2, line 5.
48 *See* Workpapers to PG&E's response to CalCCA data request 2.16.

authorized 2020 GRC revenue requirement plus attrition for 2021 and 2022.[49] The cost to own and operate the SFGO was included in the 2020 GRC because, at the time, PG&E was using SFGO as their headquarters. Now that PG&E has sold SFGO, PG&E should have removed the cost of SFGO from the GRC-related costs in its Application.

CalCCA identified the same issue in PG&E's 2023 ERRA Forecast proceeding. In that case, PG&E agreed that an adjustment was required to remove SFGO costs from the GRC-related revenue requirement until the pending 2023 GRC Phase 1 is implemented.[50] PG&E's 2023 GRC remains pending before the Commission, and resolution is not expected prior to finalizing the 2024 ERRA Forecast. Consequently PG&E should again remove SFGO costs from its GRC-related costs in this Application, until the GRC is reflected in rates.

Extending the GRC-related cost reductions through at least the end of 2023 results in an incremental credit of $17.4 million allocated to electric generation. Of the $17.4 million credit, $17 million is allocated to the PCIA and will reduce the 2024 Indifference Amount.

B. PG&E should adjust the Indifference Amount Forecast to remove Diablo Canyon Unit 1 RA effective November 2024.

The Diablo Canyon Power Plant will soon be retired or enter extended operations. Diablo Canyon Unit 1 will retire or enter extended operations on November 2, 2024, and Unit 2 will retire or enter extended operations in 2025. While PG&E currently recovers the above-market costs associated with Diablo Canyon through the PCIA, it will no

49 *See* PG&E's response to CalCCA data request 3.04.

50 *See* A.22-05-029, PG&E's 2023 ERRA Rebuttal Testimony, Exhibit No. PGE-3 at 9-11.

longer recover those costs through the PCIA once each Unit retires or enters extended operations.

PG&E proposes to remove Diablo Canyon Unit 1 GRC-related revenue requirement from the PCIA calculation effective November 2, 2024.[51] Through my review of PG&E's supporting workpapers, I confirmed that PG&E removed the fuel costs and generation output of Diablo Canyon Unit 1 for November and December of 2024. However, as demonstrated in Table 4-6 of PG&E's Prepared Testimony, PG&E only removed the RA capacity associated with Diablo Canyon Unit 1 for December 2024.

PG&E should make an adjustment to remove an additional month of Diablo Canyon Unit 1 RA capacity from the calculation of the 2024 Indifference Amount. Removing an additional month of RA reduces Diablo Canyon Unit 1 annual average Retained RA by 95 MW, with a corresponding reduction of [redacted] to the market value of capacity included in the Indifference Amount. This adjustment increases the 2024 Indifference Amount by [redacted]. PG&E has agreed to make this adjustment in the October Update.[52]

VII. REVIEW OF PG&E'S 2023 YEAR-END PABA BALANCE.

As described earlier, the PABA is a rolling true-up of the actual above-market costs of PG&E's PCIA-eligible resource portfolio and the amount collected from customers through PCIA rates to recover such above-market costs. PG&E's Prepared Testimony presents a projection of the 2023 year-end PABA balance that assumes the account will be over-collected by $272 million.[53] An over-collected PABA balancing

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51 PG&E Prepared Testimony, Chapter 9, pages 9-12, line 11 through 9-13, line 1.

52 *See* PG&E's response to CalCCA data request 2.06.

53 PG&E Prepared Testimony, Chapter 14, Table 14-3. The 2023 year-end PABA balance of $272 excludes proposed transfers from other balancing accounts.

account can be the result of many different factors, including higher than expected customer revenues, lower than expected procurement costs, or higher than expected market revenue from resource generation. Evaluating the reasonableness of PG&E's projection that the 2023 PABA will be over-collected by over a quarter of a billion dollars requires a comparison of the initial PCIA forecast for 2023 with the latest combination of actual results and projected activity in 2023.

Since its inception in 2019, the PABA has been a major contributor to PG&E's total PCIA revenue requirement. The PABA balance has also proven to be volatile, fluctuating by hundreds of millions of dollars through the year, or even the pendency of the ERRA application process. For example, at the end of November 2022, PG&E's PABA balance was undercollected by $109.2 million, but due to an unanticipated upward spike in CAISO market prices during December the 2022 year-end balance was overcollected by $333.8 million – *a $443 million swing in one month*. In theory, if PCIA rates are implemented on January 1 and everything went according to forecast during 2023, the PABA balance would be reduced to $0 by the end of the year. In reality, in its Application (filed in May 2023), PG&E's projection of the 2023 year-end PABA balance (based on actual results through March 2023 and projections for April through December 2023) indicated that by the end of 2023 the PABA will be overcollected by $271.6 million[54] – a decrease of only $62 million in one year.

In D.20-12-038, the Commission "recognize[d] that it is essential for CCAs to access more PG&E information on a routine basis ahead of annual November Updates."[55] The Commission required PG&E to provide a Master Data Request (**MDR**) in its ERRA

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54 Before account transfers.

55 D.20-12-038, p. 31.

Forecast proceedings, including monthly ERRA/PABA/PUBA activity reports and supporting detail of the costs and revenues along with volumetric quantities underlying the recorded dollar amounts. Pursuant to D.22-02-002 PG&E was also required to provide access to confidential workpapers supporting the derivation of final 2023 PCIA rates.[56]

PG&E provided the required workpapers and monthly activity reports. This reduced the discovery that CalCCA needed to issue and provided timely insight into the actual amounts recorded to PABA each month. These data are critical because they facilitate a high-level review of the actual costs recorded each month prior to such costs being included in customers' rates. More concretely, by comparing the details of PG&E's 2023 PCIA forecast to the actual 2023 results the Commission, CalCCA, and other parties are better able to determine the causes of the projected over-collection and whether stakeholders can reasonably expect that the October Update will also reflect a large credit balance.

Using data from the 2023 ERRA Forecast and the PABA data provided in the MDR, I was able to prepare the below Table 11 comparing the 2023 PCIA forecast to the 2023 PABA.

[56] D.20-02-002, OP 7.

Table 11: 2023 PCIA Forecast Versus 2023 PABA

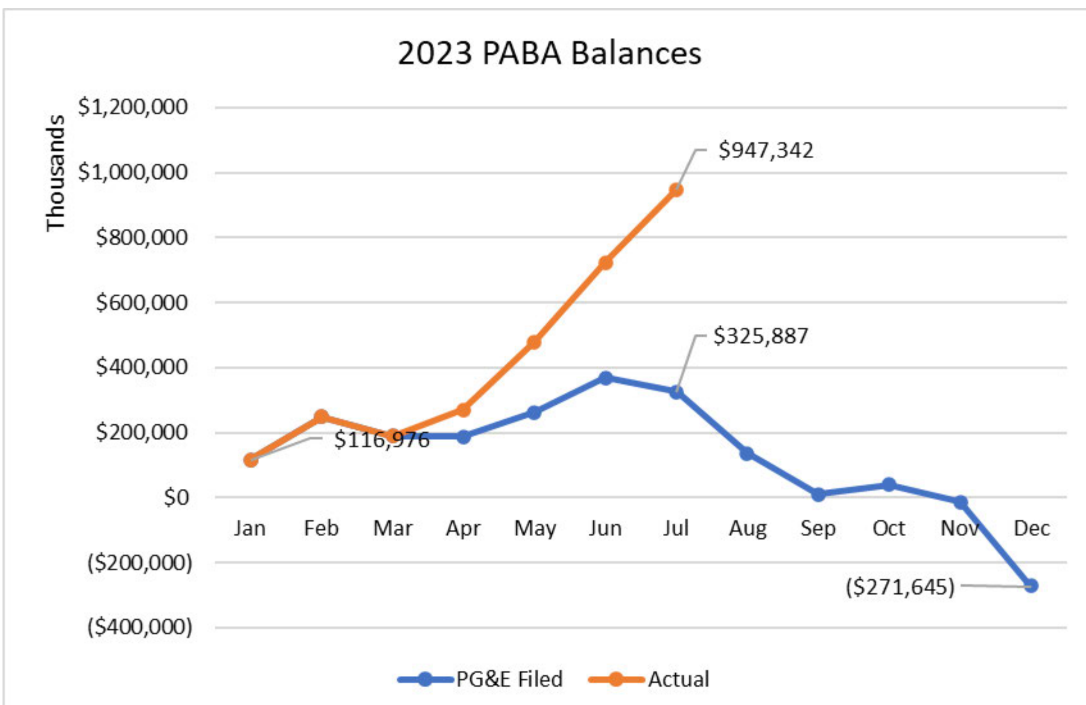
Line	Category	2023 PCIA Forecast ($000)	2023 PABA Projection ($000)	Variance ($000)	Variance %
1	UOG (GRC) Costs	2,208,224	[redacted]		
2	Fuel, Purchased Power, Other Costs	3,142,948			
3	**Total Portfolio Costs**	**5,351,172**			
4	Brown Power Market Value[1]	(4,282,767)			
5	RPS Market Value[2]	(281,584)			
6	RA Market Value[3]	(820,385)			
7	**Total Market Value**	**(5,384,735)**			
8	**Indifference Amount**	**(33,563)**			
9	Adjustments/Transfers	-			
10	Interest				
11	**Adjusted PCIA Revenue Requirement**	**(33,563)**			
12	Customer Revenue	(382,003)			
13	**Subtotal Under/(Over) Recovery**	**(415,566)**			
14	2022 PABA in Rates	(30,246)			
15	2022 ERRA YE Balance	445,366			
16	Misc	446			
17	**Total Under/(Over) Recovery**	**0**			
18	**2023 PABA**				
19	Beginning Balance		(333,829)		
20	Activity		62,184		
21	**Ending Balance**		**(271,645)**		

Notes
1 Includes brown power value of RPS sales
2 Includes Retained RPS
3 Includes Retained RA

PG&E's testimony includes a description of the drivers it identified as causing the large projected overcollection in the 2023 PABA. My analysis shows that there is [redacted] of additional market value driven by higher market prices and higher than expected generation volume. This is offset by higher procurement costs of [redacted] driven by higher average prices and higher than expected volumes procured. PG&E described the variance in its prepared testimony.[57] PG&E's description is directionally consistent with my testimony as presented in Table 12.

Thus far, however, PG&E's actual 2023 PABA balance has remained higher than expected. At the time this testimony was prepared the latest detailed results available to CalCCA—actual results through July 2023—showed that the PABA balance was now undercollected by $947.3 million, $621.5 million higher than PG&E projected for July 2023. Figure 3 illustrates the variability in the monthly PABA balance in 2023 and the deviation of the actual balance from the forecast included in PG&E's Application.

Figure 3: PG&E Monthly PABA Balances



Because the actual year-end PABA balance will be rolled into PCIA rates in 2024, the large swings in the recorded PABA balance versus the projection PG&E included in

[57] *See* PG&E Prepared Testimony, pages 14-16, lines 3-6 and 14-17, lines 15-17.

its Application will have a significant impact on the PCIA rates that bundled and unbundled customers ultimately pay. It remains to be seen whether the summer months of 2023 will reduce the year-to-date undercollected PABA balance in a manner consistent with PG&E's initial expectations.

This concludes my testimony.

Attachment A

Curriculum Vitae of Brian Shuey

NewGen Strategies & Solutions

Brian T. Shuey

SENIOR MANAGER
BSHUEY@NEWGENSTRATEGIES.NET

Mr. Brian Shuey joined NewGen as a Senior Manager in May 2022, with over 15 years of experience in consulting and the utility industry. Mr. Shuey has audited specialized financial statements and reviewed adjustment clause rate filings for electric, gas, water, and steam utility companies. Additionally, Mr. Shuey participated in various special projects regarding utility rate-making issues. He also has significant Big 4 internal audit, enterprise risk management, regulatory compliance, IT consulting, and process improvement experience.

EDUCATION

Bachelor of Science in Accounting, The Pennsylvania State University

PROFESSIONAL CERTIFICATIONS

Certified Internal Auditor; Institute of Internal Auditors

KEY EXPERTISE

Adjustment Clause Rate Filing Review
Cost Recovery
Enterprise Risk Management
Financial Statement Audits
IT Consulting
Management Consulting
Process Improvement
Project Management
Regulatory Compliance
Utility Rate Design

RELEVANT EXPERIENCE

Litigation Support

Mr. Shuey provides litigation support related to utility revenue requirements, rate design, and other ratemaking issues before state and local regulatory bodies. He has evaluated utility stranded costs and exit fees for retail customer choice, including on behalf of approximately a dozen Community Choice Aggregators in California.

A sample of Mr. Shuey's clients includes the following:

- California Community Choice Association, CA
- Clean Power Alliance, CA

Brian Shuey

SENIOR MANAGER

PRIOR RELEVANT EXPERIENCE

Below is a small sample of Mr. Shuey's work within the energy utility industry.

PA Public Utility Commission Auditor & Supervisor

- Experience reviewing and auditing Electric Default Service, Transmission Service, Competitive Transition Charges, and Infrastructure Improvement Charges.
- Developed and maintained a training program for new and current employees to complete the review of adjustment clause rate filings.
- Assigned and supervised the review of over 300 adjustment clause filings per year for conformity to Commission directives and State statutes.
- Led discussions with utility personnel to revise or update filings as needed.
- Supervised the preparation of all audit work papers and reports for a team of seven auditors.
- Reviewed the work of Audit Team Leaders to ensure the audits were in accordance with generally accepted auditing standards.

Enterprise Risk Management/Internal Audit

- Directed and supervised up to 15 staff while completing multi-year internal control assessments over multiple large and small state agencies.
- Participated in risk assessments and control testing in multiple organizations over five years, utilizing COSO 13 and Green Book internal control frameworks.
- Facilitated the documentation of over 35 key processes and over 500 controls for a single client and assisted in developing and executing a risk-based monitoring plan for these controls.
- Participated in executing a risk-based audit plan, including process/control documentation and control testing.

Attachment B

Select PG&E Responses to CalCCA Data Requests

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2024 Forecast
Application 23-05-012
Data Response

PG&E Data Request No.:	CalCCA_002-Q006		
PG&E File Name:	ERRA-2024-Forecast_DR_CalCCA_002-Q006		
Request Date:	June 7, 2023	Requester DR No.:	002
Date Sent:	June 21, 2023	Requesting Party:	California Community Choice Association
PG&E Witness:	George Clavier	Requester:	Nikhil Vijaykar

QUESTION 006

Referring to PG&E's prepared testimony, Page 4-18, Table 4-6 line 14: Please explain why the full amount of RA is included in November if Diablo Canyon Unit 1 is set to be removed from the PCIA on November 2, 2024.

ANSWER 006

PG&E's modeling framework included Diablo Canyon Unit 1 because the assumed end date was in November 2024. However, because the termination is scheduled to occur very early in the month, PG&E recognizes that for position modeling purposes, removing the unit from the November RA supply stack is appropriate. PG&E will make the change in the Fall update.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2024 Forecast
Application 23-05-012
Data Response

PG&E Data Request No.:	CalCCA_002-Q008		
PG&E File Name:	ERRA-2024-Forecast_DR_CalCCA_002-Q008		
Request Date:	June 7, 2023	Requester DR No.:	002
Date Sent:	June 21, 2023	Requesting Party:	California Community Choice Association
PG&E Witness:	Jessica Hilgart	Requester:	Nikhil Vijaykar

QUESTION 008

CalCCA to PG&E 01.08. Referring to PG&E's prepared testimony, Page 9-10 lines 19-29: Provide the following:

a) Please provide a citation to the Commission directive, statute, or other authority for the "approved methodology for allocating ESA costs".

b) Please provide a citation to the Commission directive, statute or other authority which PG&E is using to support its proposal to change the allocation of ESA costs.

ANSWER 008

a) AL 5440-E implemented changes to the PCIA approved in D.18-10-019 and was approved on May 3, 2019 and includes authority for PG&E to allocate ESA costs between PABA, ERRA, and NSGBA based on the authorized revenue requirement in each account.

   https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_5440-E.pdf

   For NSGBA costs, AL 6933-E became effective as of June 1, 2023, and provides the update to the NSGBA that was approved via AL 5440-E.

   https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_6933-E.pdf

   Following adoption of AL 5440-E, PG&E's ERRA Forecast decisions annually approved PG&E's methodology for allocating ESA costs through the establishment of revenue requirements applicable to PABA and ERRA that allocated such ESA costs.

b) See above.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2024 Forecast
Application 23-05-012
Data Response

PG&E Data Request No.:	CalCCA_002-Q011		
PG&E File Name:	ERRA-2024-Forecast_DR_CalCCA_002-Q011		
Request Date:	June 7, 2023	Requester DR No.:	002
Date Sent:	June 21, 2023	Requesting Party:	California Community Choice Association
PG&E Witness:	Jessica Hilgart	Requester:	Nikhil Vijaykar

QUESTION 011

Referring to PG&E's prepared testimony Page 9-11, lines 3-11: Please explain how PG&E's proposal would work in future ERRA forecasts when Diablo Canyon is entirely removed from the PCIA portfolio.

ANSWER 011

As stated in Prepared Testimony, page 9-11, lines 14-19, PG&E's proposed allocation of the Energy Supply Administration (ESA) costs is calculated based on the portfolio cost authorized by the Commission in the latest ERRA Forecast decision. This methodology is consistent with that adopted in Advice 5440-E.

Accordingly, when the Diablo Canyon related costs are authorized to be excluded in any ERRA Forecast decisions, they will automatically be removed from the Common Cost Allocation Factors of the PCIA portfolio.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2024 Forecast
Application 23-05-012
Data Response

PG&E Data Request No.:	CalCCA_002-Q016		
PG&E File Name:	ERRA-2024-Forecast_DR_CalCCA_002-Q016		
Request Date:	June 7, 2023	Requester DR No.:	002
Date Sent:	June 21, 2023	Requesting Party:	California Community Choice Association
PG&E Witness:	Angelia Lim/ Mia Gilbert	Requester:	Nikhil Vijaykar

QUESTION 016

Referring to PG&E's prepared testimony Page 9-13, lines 14-17: Please provide all workpapers supporting the amortization of the gain on sale of PG&E's San Francisco General Office.

ANSWER 016

Please see attachment 01 to this data response.

GO Sale Gain Amortization Schedule - Electric

Pacific Gas and Electric Company
Sale of San Francisco General Office
Interest on After Tax Gain
(Thousands of Dollars)

		Before Tax Gain			Deferred Tax Asset			After Tax Gain								
Amortization Months	Calendar Month	Beginning Balance	Amortization (Credit to Customers)	Ending Balance	Beginning Balance	Amortization	Ending Balance	Beginning Balance	Amortization	Ending Balance	Average Balance	Monthly Interest at 4.17% / 12	RRQ Reduction - Electric	Average Balance - Electric	Interest - Electric	Interest -Electric
	September 2021	-	-	(259,351,179.49)	-		72,576,834.07	-	-	(186,774,345.42)	(93,387,172.71)	(151,442.87)	(1,534,573.57)	(767,286.78)	(1,244.28)	(152,687.15)
	October 2021	(259,351,179.49)	-	(259,351,179.49)	72,576,834.07		72,576,834.07	(186,774,345.42)	-	(186,774,345.42)	(186,774,345.42)	(649,040.85)	(3,288,371.93)	(2,487,816.32)	(8,645.16)	(657,686.01)
	November 2021	(259,351,179.49)	-	(259,351,179.49)	72,576,834.07		72,576,834.07	(186,774,345.42)	-	(186,774,345.42)	(186,774,345.42)	(649,040.85)	(3,288,371.93)	(4,460,845.29)	(15,501.44)	(664,542.29)
	December 2021	(259,351,179.49)	-	(259,351,179.49)	72,576,834.07		72,576,834.07	(186,774,345.42)	-	(186,774,345.42)	(186,774,345.42)	(649,040.85)	(3,288,371.93)	(6,437,302.40)	(22,369.63)	(671,410.48)
1	January 2022	(259,351,179.49)	(4,322,519.66)	(255,028,659.83)	72,576,834.07	1,209,613.90	71,367,220.17	(186,774,345.42)	(3,112,905.76)	(183,661,439.66)	(185,217,892.54)	(643,632.18)	(3,360,068.25)	(8,453,041.76)	(29,374.32)	(673,006.50)
2	February 2022	(255,028,659.83)	(4,322,519.66)	(250,706,140.17)	71,367,220.17	1,209,613.90	70,157,606.27	(183,661,439.66)	(3,112,905.76)	(180,548,533.91)	(182,104,986.79)	(632,814.83)	(3,360,068.25)	(10,469,579.14)	(36,381.79)	(669,196.62)
3	March 2022	(250,706,140.17)	(4,322,519.66)	(246,383,620.52)	70,157,606.27	1,209,613.90	68,947,992.37	(180,548,533.91)	(3,112,905.76)	(177,435,628.15)	(178,992,081.03)	(621,997.48)	(3,360,068.25)	(12,484,211.57)	(43,382.64)	(665,380.12)
4	April 2022	(246,383,620.52)	(4,322,519.66)	(242,061,100.86)	68,947,992.37	1,209,613.90	67,738,378.46	(177,435,628.15)	(3,112,905.76)	(174,322,722.39)	(175,879,175.27)	(611,180.13)	(3,360,068.25)	(14,496,935.75)	(50,376.85)	(661,556.99)
5	May 2022	(242,061,100.86)	(4,322,519.66)	(237,738,581.20)	67,738,378.46	1,209,613.90	66,528,764.56	(174,322,722.39)	(3,112,905.76)	(171,209,816.64)	(172,766,269.51)	(600,362.79)	(3,360,068.25)	(16,507,748.37)	(57,364.43)	(657,727.21)
6	June 2022	(237,738,581.20)	(4,322,519.66)	(233,416,061.54)	66,528,764.56	1,209,613.90	65,319,150.66	(171,209,816.64)	(3,112,905.76)	(168,096,910.88)	(169,653,363.76)	(589,545.44)	(3,360,068.25)	(18,516,646.10)	(64,345.35)	(653,890.78)
7	July 2022	(233,416,061.54)	(4,322,519.66)	(229,093,541.88)	65,319,150.66	1,209,613.90	64,109,536.76	(168,096,910.88)	(3,112,905.76)	(164,984,005.12)	(166,540,458.00)	(578,728.09)	(3,360,068.25)	(20,523,625.61)	(71,319.60)	(650,047.69)
8	August 2022	(229,093,541.88)	(4,322,519.66)	(224,771,022.22)	64,109,536.76	1,209,613.90	62,899,922.86	(164,984,005.12)	(3,112,905.76)	(161,871,099.37)	(163,427,552.24)	(567,910.74)	(3,360,068.25)	(22,528,683.58)	(78,287.18)	(646,197.92)
9	September 2022	(224,771,022.22)	(4,322,519.66)	(220,448,502.57)	62,899,922.86	1,209,613.90	61,690,308.96	(161,871,099.37)	(3,112,905.76)	(158,758,193.61)	(160,314,646.49)	(557,093.40)	(3,360,068.25)	(24,531,816.67)	(85,248.06)	(642,341.46)
10	October 2022	(220,448,502.57)	(4,322,519.66)	(216,125,982.91)	61,690,308.96	1,209,613.90	60,480,695.06	(158,758,193.61)	(3,112,905.76)	(155,645,287.85)	(157,201,740.73)	(546,276.05)	(3,360,068.25)	(26,533,021.52)	(92,202.25)	(638,478.30)
11	November 2022	(216,125,982.91)	(4,322,519.66)	(211,803,463.25)	60,480,695.06	1,209,613.90	59,271,081.16	(155,645,287.85)	(3,112,905.76)	(152,532,382.09)	(154,088,834.97)	(535,458.70)	(3,360,068.25)	(28,532,294.79)	(99,149.72)	(634,608.43)
12	December 2022	(211,803,463.25)	(4,322,519.66)	(207,480,943.59)	59,271,081.16	1,209,613.90	58,061,467.25	(152,532,382.09)	(3,112,905.76)	(149,419,476.34)	(150,975,929.22)	(524,641.35)	(3,360,068.25)	(30,529,633.13)	(106,090.48)	(630,731.83)
13	January 2023	(207,480,943.59)	(4,322,519.66)	(203,158,423.93)	58,061,467.25	1,209,613.90	56,851,853.35	(149,419,476.34)	(3,112,905.76)	(146,306,570.58)	(147,863,023.46)	(513,824.01)				(513,824.01)
14	February 2023	(203,158,423.93)	(4,322,519.66)	(198,835,904.28)	56,851,853.35	1,209,613.90	55,642,239.45	(146,306,570.58)	(3,112,905.76)	(143,193,664.82)	(144,750,117.70)	(503,006.66)				(503,006.66)
15	March 2023	(198,835,904.28)	(4,322,519.66)	(194,513,384.62)	55,642,239.45	1,209,613.90	54,432,625.55	(143,193,664.82)	(3,112,905.76)	(140,080,759.07)	(141,637,211.94)	(492,189.31)				(492,189.31)
16	April 2023	(194,513,384.62)	(4,322,519.66)	(190,190,864.96)	54,432,625.55	1,209,613.90	53,223,011.65	(140,080,759.07)	(3,112,905.76)	(136,967,853.31)	(138,524,306.19)	(481,371.96)				(481,371.96)
17	May 2023	(190,190,864.96)	(4,322,519.66)	(185,868,345.30)	53,223,011.65	1,209,613.90	52,013,397.75	(136,967,853.31)	(3,112,905.76)	(133,854,947.55)	(135,411,400.43)	(470,554.62)				(470,554.62)
18	June 2023	(185,868,345.30)	(4,322,519.66)	(181,545,825.64)	52,013,397.75	1,209,613.90	50,803,783.85	(133,854,947.55)	(3,112,905.76)	(130,742,041.80)	(132,298,494.67)	(459,737.27)				(459,737.27)
19	July 2023	(181,545,825.64)	(4,322,519.66)	(177,223,305.98)	50,803,783.85	1,209,613.90	49,594,169.95	(130,742,041.80)	(3,112,905.76)	(127,629,136.04)	(129,185,588.92)	(448,919.92)				(448,919.92)
20	August 2023	(177,223,305.98)	(4,322,519.66)	(172,900,786.33)	49,594,169.95	1,209,613.90	48,384,556.05	(127,629,136.04)	(3,112,905.76)	(124,516,230.28)	(126,072,683.16)	(438,102.57)				(438,102.57)
21	September 2023	(172,900,786.33)	(4,322,519.66)	(168,578,266.67)	48,384,556.05	1,209,613.90	47,174,942.14	(124,516,230.28)	(3,112,905.76)	(121,403,324.52)	(122,959,777.40)	(427,285.23)				(427,285.23)
22	October 2023	(168,578,266.67)	(4,322,519.66)	(164,255,747.01)	47,174,942.14	1,209,613.90	45,965,328.24	(121,403,324.52)	(3,112,905.76)	(118,290,418.77)	(119,846,871.65)	(416,467.88)				(416,467.88)
23	November 2023	(164,255,747.01)	(4,322,519.66)	(159,933,227.35)	45,965,328.24	1,209,613.90	44,755,714.34	(118,290,418.77)	(3,112,905.76)	(115,177,513.01)	(116,733,965.89)	(405,650.53)				(405,650.53)
24	December 2023	(159,933,227.35)	(4,322,519.66)	(155,610,707.69)	44,755,714.34	1,209,613.90	43,546,100.44	(115,177,513.01)	(3,112,905.76)	(112,064,607.25)	(113,621,060.13)	(394,833.18)				(394,833.18)
25	January 2024	(155,610,707.69)	(4,322,519.66)	(151,288,188.04)	43,546,100.44	1,209,613.90	42,336,486.54	(112,064,607.25)	(3,112,905.76)	(108,951,701.50)	(110,508,154.37)	(384,015.84)				(384,015.84)
26	February 2024	(151,288,188.04)	(4,322,519.66)	(146,965,668.38)	42,336,486.54	1,209,613.90	41,126,872.64	(108,951,701.50)	(3,112,905.76)	(105,838,795.74)	(107,395,248.62)	(373,198.49)				(373,198.49)
27	March 2024	(146,965,668.38)	(4,322,519.66)	(142,643,148.72)	41,126,872.64	1,209,613.90	39,917,258.74	(105,838,795.74)	(3,112,905.76)	(102,725,889.98)	(104,282,342.86)	(362,381.14)				(362,381.14)
28	April 2024	(142,643,148.72)	(4,322,519.66)	(138,320,629.06)	39,917,258.74	1,209,613.90	38,707,644.84	(102,725,889.98)	(3,112,905.76)	(99,612,984.22)	(101,169,437.10)	(351,563.79)				(351,563.79)
29	May 2024	(138,320,629.06)	(4,322,519.66)	(133,998,109.40)	38,707,644.84	1,209,613.90	37,498,030.94	(99,612,984.22)	(3,112,905.76)	(96,500,078.47)	(98,056,531.35)	(340,746.45)				(340,746.45)
30	June 2024	(133,998,109.40)	(4,322,519.66)	(129,675,589.75)	37,498,030.94	1,209,613.90	36,288,417.03	(96,500,078.47)	(3,112,905.76)	(93,387,172.71)	(94,943,625.59)	(329,929.10)				(329,929.10)
31	July 2024	(129,675,589.75)	(4,322,519.66)	(125,353,070.09)	36,288,417.03	1,209,613.90	35,078,803.13	(93,387,172.71)	(3,112,905.76)	(90,274,266.95)	(91,830,719.83)	(319,111.75)				(319,111.75)
32	August 2024	(125,353,070.09)	(4,322,519.66)	(121,030,550.43)	35,078,803.13	1,209,613.90	33,869,189.23	(90,274,266.95)	(3,112,905.76)	(87,161,361.20)	(88,717,814.08)	(308,294.40)				(308,294.40)
33	September 2024	(121,030,550.43)	(4,322,519.66)	(116,708,030.77)	33,869,189.23	1,209,613.90	32,659,575.33	(87,161,361.20)	(3,112,905.76)	(84,048,455.44)	(85,604,908.32)	(297,477.06)				(297,477.06)
34	October 2024	(116,708,030.77)	(4,322,519.66)	(112,385,511.11)	32,659,575.33	1,209,613.90	31,449,961.43	(84,048,455.44)	(3,112,905.76)	(80,935,549.68)	(82,492,002.56)	(286,659.71)				(286,659.71)
35	November 2024	(112,385,511.11)	(4,322,519.66)	(108,062,991.45)	31,449,961.43	1,209,613.90	30,240,347.53	(80,935,549.68)	(3,112,905.76)	(77,822,643.93)	(79,379,096.80)	(275,842.36)				(275,842.36)
36	December 2024	(108,062,991.45)	(4,322,519.66)	(103,740,471.80)	30,240,347.53	1,209,613.90	29,030,733.63	(77,822,643.93)	(3,112,905.76)	(74,709,738.17)	(76,266,191.05)	(265,025.01)				(265,025.01)
37	January 2025	(103,740,471.80)	(4,322,519.66)	(99,417,952.14)	29,030,733.63	1,209,613.90	27,821,119.73	(74,709,738.17)	(3,112,905.76)	(71,596,832.41)	(73,153,285.29)	(254,207.67)				(254,207.67)
38	February 2025	(99,417,952.14)	(4,322,519.66)	(95,095,432.48)	27,821,119.73	1,209,613.90	26,611,505.83	(71,596,832.41)	(3,112,905.76)	(68,483,926.65)	(70,040,379.53)	(243,390.32)				(243,390.32)
39	March 2025	(95,095,432.48)	(4,322,519.66)	(90,772,912.82)	26,611,505.83	1,209,613.90	25,401,891.92	(68,483,926.65)	(3,112,905.76)	(65,371,020.90)	(66,927,473.78)	(232,572.97)				(232,572.97)
40	April 2025	(90,772,912.82)	(4,322,519.66)	(86,450,393.16)	25,401,891.92	1,209,613.90	24,192,278.02	(65,371,020.90)	(3,112,905.76)	(62,258,115.14)	(63,814,568.02)	(221,755.62)				(221,755.62)
41	May 2025	(86,450,393.16)	(4,322,519.66)	(82,127,873.51)	24,192,278.02	1,209,613.90	22,982,664.12	(62,258,115.14)	(3,112,905.76)	(59,145,209.38)	(60,701,662.26)	(210,938.28)				(210,938.28)
42	June 2025	(82,127,873.51)	(4,322,519.66)	(77,805,353.85)	22,982,664.12	1,209,613.90	21,773,050.22	(59,145,209.38)	(3,112,905.76)	(56,032,303.63)	(57,588,756.50)	(200,120.93)				(200,120.93)
43	July 2025	(77,805,353.85)	(4,322,519.66)	(73,482,834.19)	21,773,050.22	1,209,613.90	20,563,436.32	(56,032,303.63)	(3,112,905.76)	(52,919,397.87)	(54,475,850.75)	(189,303.58)				(189,303.58)
44	August 2025	(73,482,834.19)	(4,322,519.66)	(69,160,314.53)	20,563,436.32	1,209,613.90	19,353,822.42	(52,919,397.87)	(3,112,905.76)	(49,806,492.11)	(51,362,944.99)	(178,486.23)				(178,486.23)
45	September 2025	(69,160,314.53)	(4,322,519.66)	(64,837,794.87)	19,353,822.42	1,209,613.90	18,144,208.52	(49,806,492.11)	(3,112,905.76)	(46,693,586.36)	(48,250,039.23)	(167,668.89)				(167,668.89)
46	October 2025	(64,837,794.87)	(4,322,519.66)	(60,515,275.21)	18,144,208.52	1,209,613.90	16,934,594.62	(46,693,586.36)	(3,112,905.76)	(43,580,680.60)	(45,137,133.48)	(156,851.54)				(156,851.54)
47	November 2025	(60,515,275.21)	(4,322,519.66)	(56,192,755.56)	16,934,594.62	1,209,613.90	15,724,980.71	(43,580,680.60)	(3,112,905.76)	(40,467,774.84)	(42,024,227.72)	(146,034.19)				(146,034.19)
48	December 2025	(56,192,755.56)	(4,322,519.66)	(51,870,235.90)	15,724,980.71	1,209,613.90	14,515,366.81	(40,467,774.84)	(3,112,905.76)	(37,354,869.08)	(38,911,321.96)	(135,216.84)				(135,216.84)
49	January 2026	(51,870,235.90)	(4,322,519.66)	(47,547,716.24)	14,515,366.81	1,209,613.90	13,305,752.91	(37,354,869.08)	(3,112,905.76)	(34,241,963.33)	(35,798,416.21)	(124,399.50)				(124,399.50)
50	February 2026	(47,547,716.24)	(4,322,519.66)	(43,225,196.58)	13,305,752.91	1,209,613.90	12,096,139.01	(34,241,963.33)	(3,112,905.76)	(31,129,057.57)	(32,685,510.45)	(113,582.15)				(113,582.15)
51	March 2026	(43,225,196.58)	(4,322,519.66)	(38,902,676.92)	12,096,139.01	1,209,613.90	10,886,525.11	(31,129,057.57)	(3,112,905.76)	(28,016,151.81)	(29,572,604.69)	(102,764.80)				(102,764.80)
52	April 2026	(38,902,676.92)	(4,322,519.66)	(34,580,157.27)	10,886,525.11	1,209,613.90	9,676,911.21	(28,016,151.81)	(3,112,905.76)	(24,903,246.06)	(26,459,698.93)	(91,947.45)				(91,947.45)
53	May 2026	(34,580,157.27)	(4,322,519.66)	(30,257,637.61)	9,676,911.21	1,209,613.90	8,467,297.31	(24,903,246.06)	(3,112,905.76)	(21,790,340.30)	(23,346,793.18)	(81,130.11)				(81,130.11)
54	June 2026	(30,257,637.61)	(4,322,519.66)	(25,935,117.95)	8,467,297.31	1,209,613.90	7,257,683.41	(21,790,340.30)	(3,112,905.76)	(18,677,434.54)	(20,233,887.42)	(70,312.76)				(70,312.76)
55	July 2026	(25,935,117.95)	(4,322,519.66)	(21,612,598.29)	7,257,683.41	1,209,613.90	6,048,069.51	(18,677,434.54)	(3,112,905.76)	(15,564,528.79)	(17,120,981.66)	(59,495.41)				(59,495.41)
56	August 2026	(21,612,598.29)	(4,322,519.66)	(17,290,078.63)	6,048,069.51	1,209,613.90	4,838,455.60	(15,564,528.79)	(3,112,905.76)	(12,451,623.03)	(14,008,075.91)	(48,678.06)				(48,678.06)
57	September 2026	(17,290,078.63)	(4,322,519.66)	(12,967,558.97)	4,838,455.60	1,209,613.90	3,628,841.70	(12,451,623.03)	(3,112,905.76)	(9,338,717.27)	(10,895,170.15)	(37,860.72)				(37,860.72)
58	October 2026	(12,967,558.97)	(4,322,519.66)	(8,645,039.32)	3,628,841.70	1,209,613.90	2,419,227.80	(9,338,717.27)	(3,112,905.76)	(6,225,811.51)	(7,782,264.39)	(27,043.37)				(27,043.37)
59	November 2026	(8,645,039.32)	(4,322,519.66)	(4,322,519.66)	2,419,227.80	1,209,613.90	1,209,613.90	(6,225,811.51)	(3,112,905.76)	(3,112,905.76)	(4,669,358.64)	(16,226.02)				(16,226.02)
60	December 2026	(4,322,519.66)	(4,322,519.66)	0.00	1,209,613.90	1,209,613.90	(0.00)	(3,112,905.76)	(3,112,905.76)	0.00	(1,556,452.88)	(5,408.67)				(5,408.67)
	TOTAL INTEREST ACCRUED											(21,569,790.93)				(22,431,074.09)

2024 Credit to Customers

(51,870,235.90)	Amortization of Gain
(3,894,245.10)	Interest
(55,764,481.00)	Total Electric Credit to Customers
39.45%	Generation Allocation Factor
(21,997,250.11)	Generation Credit to Customers

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2024 Forecast
Application 23-05-012
Data Response

PG&E Data Request No.:	CalCCA_002-Q020		
PG&E File Name:	ERRA-2024-Forecast_DR_CalCCA_002-Q020		
Request Date:	June 7, 2023	Requester DR No.:	002
Date Sent:	June 21, 2023	Requesting Party:	California Community Choice Association
PG&E Witness:	Christa Hoffman	Requester:	Nikhil Vijaykar

QUESTION 020

Referring to PG&E's prepared testimony Page 9-19 Note 35: Is PG&E proposing the last in first out as the permanent REC tracking framework, or just for purposes of the current ERRA Forecast?

ANSWER 020

As the ERRA Forecast proceeding is meant to address the forecast year, PG&E's 'last in first out' proposal for the minimum retained RPS methodology once excess RECs retained from the current RPS compliance period have been exhausted is presented as part of PG&E's Application for the current 2024 ERRA Forecast.

While at this time PG&E intends to propose this same methodology in subsequent ERRA Forecasts when the minimum retained RPS requirement applies, PG&E reserve the right to pursue an alternative methodology in future proceedings.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2024 Forecast
Application 23-05-012
Data Response

PG&E Data Request No.:	CalCCA_002-Q021		
PG&E File Name:	ERRA-2024-Forecast_DR_CalCCA_002-Q021		
Request Date:	June 7, 2023	Requester DR No.:	002
Date Sent:	June 21, 2023	Requesting Party:	California Community Choice Association
PG&E Witness:	Christa Hoffman	Requester:	Nikhil Vijaykar

QUESTION 021

Referring to PG&E's prepared testimony Page 9-22, Table 9-4: Please confirm that PG&E's 2023 ERRA Forecast assumed that all RPS generation would be retained or sold. If confirmed, please explain the nature of the 4,090,485 MWh of Unsold RPS for 2023. If not confirmed, please explain.

ANSWER 021

PG&E objects to Question 21 to the extent that CalCCA seeks to relitigate revenue requirements and other outcomes approved in A. 22-05-029 on the basis of scope. Subject to and without waiving such objection, PG&E responds as follows: Confirmed. PG&E's 2023 ERRA forecast proceeding (A. 22-05-029) assumed all eligible RPS volumes would be allocated or sold through the Voluntary Allocation Market Offer process.

In PG&E's 2024 ERRA Forecast proceeding (A. 23-05-012), the Unsold RPS volume for 2023 represents the volumes forecasted to be Unsold in 2023 as a result of the delayed approval and initial delivery dates of the Short-Term and Long-Term Market Offer contracts. The Unsold volume forecast assumes contracts executed from PG&E's Short-Term Market Offer Solicitation begin deliveries in May 2023, and contracts resulting from PG&E's Long-Term Market Offer solicitation begin deliveries in December 2023.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2024 Forecast
Application 23-05-012
Data Response

PG&E Data Request No.:	CalCCA_002-Q022		
PG&E File Name:	ERRA-2024-Forecast_DR_CalCCA_002-Q022		
Request Date:	June 7, 2023	Requester DR No.:	002
Date Sent:	June 21, 2023	Requesting Party:	California Community Choice Association
PG&E Witness:	Christa Hoffman	Requester:	Nikhil Vijaykar

QUESTION 022

Referring to PG&E's prepared testimony Page 9-22, Table 9-4: If some quantity of RPS generation is counted as Unsold RPS during a delivery year (e.g., Unsold RPS shown for 2023), are the related RECs eligible to count toward the minimum Retained RPS quantity for the PCIA in a future period (e.g., 2024 forecast Retained RPS)? If no, please explain why not.

ANSWER 022

Yes. Unsold RPS volumes will be eligible to count towards the minimum Retained RPS quantity for the PCIA in a future period once all of the past, previously retained excess RSP volumes have been 'drawn upon' for the purposes of meeting the Minimum Retained RPS requirement.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2024 Forecast
Application 23-05-012
Data Response

PG&E Data Request No.:	CalCCA_002-Q034		
PG&E File Name:	ERRA-2024-Forecast_DR_CalCCA_002-Q034		
Request Date:	June 7, 2023	Requester DR No.:	002
Date Sent:	June 21, 2023	Requesting Party:	California Community Choice Association
PG&E Witness:	Ryan Stanley/ Ben Kolnowski	Requester:	Nikhil Vijaykar

QUESTION 034

Referring to PG&E's prepared testimony, Page 14-23 lines 27-31: Please explain how PG&E has treated closing out similar rate surcharges in the past (including, for example, the DWR Bond Charge).

ANSWER 034

PG&E amortized the recorded residual balance of the Power Charge Collection Balancing Account (PCCBA) in rates until the balance was closer to zero. Subsequently, the utility submitted Tier 2 Advice 6764-E and requested Commission authorization to retire the PCCBA by transferring the final remaining balance to the Energy Resource Recovery Account (ERRA). Advice 6764-E was accepted by the Commission on December 15, 2022.

The above is consistent with PG&E's proposal on page 19-4, lines 9 to 15.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2024 Forecast
Application 23-05-012
Data Response

PG&E Data Request No.:	CalCCA_002-Q036		
PG&E File Name:	ERRA-2024-Forecast_DR_CalCCA_002-Q036		
Request Date:	June 7, 2023	Requester DR No.:	002
Date Sent:	June 21, 2023	Requesting Party:	California Community Choice Association
PG&E Witness:	Ben Kolnowski	Requester:	Nikhil Vijaykar

QUESTION 036

Referring to PG&E's prepared testimony, Page 19-4 lines 9-15: How close would the PUBA balance need to be to zero such that PG&E would propose to close the account?

ANSWER 036

PG&E anticipates that a balance lower than $1 million would be an acceptable threshold to consider closing the PCIA Undercollection Balancing Account (PUBA).

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2024 Forecast
Application 23-05-012
Data Response

PG&E Data Request No.:	CalCCA_002-Q037		
PG&E File Name:	ERRA-2023-Forecast_DR_CalCCA_002-Q037		
Request Date:	June 7, 2023	Requester DR No.:	002
Date Sent:	June 21, 2023	Requesting Party:	California Community Choice Association
PG&E Witness:	Ben Kolnowski/ Angelia Vega	Requester:	Nikhil Vijaykar

QUESTION 037

Referring to PG&E's prepared testimony, Page 19-4 lines 9-15: If the PUBA balance is not exactly zero when PG&E proposes to close the account, how would PG&E propose to account for the final residual balance?

ANSWER 037

As stated in Page 19-4, lines 9 to 15, if the PCIA Undercollection Balancing Account (PUBA) balance is closer to zero, PG&E will submit a proposal to close the PUBA through a Tier 2 Advice Letter. Similar to the mechanism discussed in PG&E's Question 34 response (regarding the Power Charge Collection Balancing Account), PG&E will propose to transfer the final remaining unamortized balance[1] to the Portfolio Allocation Balancing Account (PABA).

[1] The unamortized balance that is not sufficient to be amortized through the PUBA rate adders.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2024 Forecast
Application 23-05-012
Data Response

PG&E Data Request No.:	CalCCA_003-Q004		
PG&E File Name:	ERRA-2024-Forecast_DR_CalCCA_003-Q004		
Request Date:	July 11, 2023	Requester DR No.:	003
Date Sent:	July 25, 2023	Requesting Party:	California Community Choice Association
PG&E Witness:	Angelia Vega/ Mia Gilbert	Requester:	Alicia Zaloga

QUESTION 004

Referring to PG&E's response to CalCCA DR 1.16 Attachment 1:

a. Please confirm the column 'RRQ Reduction – Electric' was calculated for 2021 and 2022 because the sale of SFGO is not reflected in generation revenue requirement from the 2020 GRC. If not confirmed, please explain.

b. Please confirm that the generation revenue requirement in the pending GRC reflects a reduction related to the sale of SFGO. If not confirmed, please explain.

c. Please explain when PG&E expect new GRC rates to take effect?

d. Should the reduction in RRQ for the GRC be reflected in the 2024 Forecast case up to the point the GRC is approved? If not, please explain.

ANSWER 004

a. PG&E confirms.

b. PG&E confirms the pending 2023 General Rate Case (GRC) Application (A.) 21-06-021 reflects a reduction in revenue requirement related to the San Francisco General Office (SFGO) sale by way of removing the associated costs and accumulated depreciation from rate base. Please see enclosed PG&E's 2023 GRC Exhibit (PGE-10), page 10-10, Lines 21 to 27, page 10-11, Lines 1 to 28 and page 10-12, Line 1 to 4, attached to this data response.

c. PG&E currently does not have the information available because the 2023 GRC Application is still pending before the Commission.

d. Yes, PG&E's May Prepared Testimony is calculated based on the currently authorized 2020 GRC, including the 2021 and 2022 attrition (2020 GRC + attrition) Revenue Requirement (RRQ). [1] Since the gain on sale of SFGO is not

[1] See Prepared Testimony Page 9-8, Line 5 to 10

reflected in the 2020 GRC + attrition, PG&E should include it in this application request until the 2023 GRC is determined by the Commission.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2024 Forecast
Application 23-05-012
Data Response

PG&E Data Request No.:	CalCCA_005-Q001		
PG&E File Name:	ERRA-2024-Forecast_DR_CalCCA_005-Q001		
Request Date:	August 18, 2023	Requester DR No.:	005
Date Sent:	August 28, 2023	Requesting Party:	California Community Choice Association
PG&E Witness:	Christa Hoffman / John Pappas	Requester:	Nikhil Vijaykar

SUBJECT: A.23-05-012: CALCCA'S FOURTH DATA REQUEST TO PG&E

QUESTION 001

See PG&E's supplemental response to CalCCA 3.07. Please confirm PG&E did not have any Net Available RPS generation in years prior to 2011. If not confirmed, please either expand Table 9-4 for each year through the inception of California's RPS program, or explain why PG&E cannot expand Table 9-4 to cover years prior to 2011.

ANSWER 001

Per PG&E's 2015 Annual 33% RPS Compliance Report and Final Verified 2011-2013 Report Public Version, dated September 1, 2016, PG&E had zero net surplus generation from its 20% RPS Closing Report. The 20% RPS Closing Report covered the period from the inception of California's RPS program through the end of 2010. Please refer to the 20% RPS Closing Report entry in the upper left box in the Accounting Tab on Page A-8 of the above referenced report. Therefore, PG&E did not have any net available RPS generation in years prior to 2011.

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U 39 E) and Pacific Generation LLC for Approval to Transfer Certain Generation Assets, for a Certificate of Public Convenience and Necessity, for Authorization to File Tariffs and to Issue Debt, and for Related Determinations.	Application No. 22-09-018

OPENING BRIEF OF THE
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

Public Version

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On behalf of
California Community Choice Association

September 18, 2023

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SUMMARY OF RECOMMENDATIONS

1. The Commission should reject the Application in its entirety on the grounds that the Proposed Transaction is not in the public interest under Public Utilities Code sections 854 and 851 because it would result in net harm to customers and would subject customers to incremental and unforeseeable risks.

2. In rejecting the Application in its entirety, the Commission should specifically deny the Applicants' requests that:

    i. The Commission authorize the contribution of assets from PG&E to Pacific Generation LLC.

    ii. The Commission grant Pacific Generation LLC a Certificate of Public Convenience and Necessity.

    iii. The Commission grant the requested financing authorizations.

    iv. The Commission approve the contemplated minority sale process.

    v. The Commission approve the contemplated minority governance rights.

    vi. The Commission approve the contemplated post-signing Advice Letter process.

3. In rejecting the Application in its entirety, the Commission should deny each specific requested determination and authorization set forth in Section XIV of the Application.

4. If, in the alternative, the Commission grants all or some of the requests in the Application, the Commission should adopt CalCCA's Transaction conditions set forth in Section IV.B.3 herein to partially mitigate the ratepayer harms and other risks of the Transaction.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U 39 E) and Pacific Generation LLC for Approval to Transfer Certain Generation Assets, for a Certificate of Public Convenience and Necessity, for Authorization to File Tariffs and to Issue Debt, and for Related Determinations.	Application No. 22-09-018

OPENING BRIEF OF THE
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

Pursuant to Rule 13.12 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission), the California Community Choice Association[1] (CalCCA) submits this Opening Brief within the above-captioned *Application of Pacific Gas and Electric Company (U 39 E)* (PG&E) *and Pacific Generation LLC* (PacGen) *for Approval to Transfer Certain Generation Assets, for a Certificate of Public Convenience and Necessity, for Authorization to File Tariffs and to Issue Debt, and for Related Determinations*[2] (collectively, along with the contemplated Minority Sale, the "Transaction" or "Proposed Transaction").[3]

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[1] California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Energy For Palmdale's Independent Choice, Lancaster Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

[2] Application (A.) 22-09-018, *Application of Pacific Gas and Electric Company (U 39 E) and Pacific Generation LLC for Approval to Transfer Certain Generation Assets, for a Certificate of Public Convenience and Necessity, for Authorization to File Tariffs and to Issue Debt, and for Related Determinations* (Sep. 28, 2022) (Application).

[3] All capitalized terms herein have the meanings assigned in PG&E's Application and Testimony, unless otherwise noted.

I. INTRODUCTION

The proposal to transfer substantially all of PG&E's non-nuclear generation assets to PacGen, a new PG&E subsidiary, is unprecedented. It would create a brand-new type of utility—a generation-only investor-owned utility (IOU) with the same service territory as an existing vertically integrated retail utility. The Proposed Transaction contemplates the Commission regulating two IOUs providing simultaneous service to the same retail customers in the same service territory without clear delineation of compliance obligations between the two entities.

This has never been done before. While PG&E cites to a few "precedent transactions" to suggest this is a tried-and-true method of raising equity capital, none of these referenced transactions involved the separation of a pre-existing utility into multiple regulated entities.[4] None of them resulted in the creation of a new regulated utility providing overlapping service with the pre-existing company. And none of them necessitated the creation of duplicative rate tariffs, ongoing joint commission filings, or joint billing to the same set of customers.

PG&E also attempts to minimize the novelty and complexity of this Application by suggesting the Transaction is akin to a sale of equity.[5] This is *not* an apt comparison; the issuance of common stock does not involve any of the significant policy questions or implications raised by the Proposed Transaction. As PG&E Witness Williams admitted on the stand, when PG&E issues common stock, it does not form a new company; convey to investors rights such as the ability to designate a board member; give investors a say in major company decisions or capital expenditures based on the percentage of shares they own; transfer and change title of assets from

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4 *See* Exh. CALCCA-01 at 10:11 to 12:10. The two additional transactions cited in PG&E's Rebuttal Testimony are also distinguishable on these metrics, like the transactions cited in PG&E's Opening Testimony. *See* Exh. PGE-17-E at 5-2:26 to 5-4:5.

5 *See* Exh. PGE-13 at 1-9:21 to 1-10:3.

PG&E to a new company; receive a new Certificate of Public Convenience and Necessity (CPCN) for a newly created public utility; or increase regulatory burdens for the Commission.[6]

The Commission should weigh the complexity of this fundamental restructuring of PG&E against the small fraction of PG&E's future capital needs the Proposed Transaction will raise. As CalCCA Witness Dickman demonstrated in testimony, the amount of capital likely to be raised is a drop in the bucket in the context of PG&E's capital needs—$1.1 to $2.5 billion in proceeds compared to PG&E's capital needs of approximately $63 billion from 2023 through 2027.[7] PG&E has not disputed this estimate. It has also acknowledged that pursuing this fundamental restructuring is not its only option. PG&E admitted it has not put forward evidence that it cannot meet its 2024 capital needs without the Proposed Transaction.[8] In addition, PG&E admitted that there are viable alternatives to this Transaction, but that it has not undertaken any analysis to quantify or otherwise compare the costs and benefits of this Transaction to such alternatives.

The Scoping Ruling sets forth one overarching issue to be determined: "whether the Commission should approve applicants' requests set forth in Section XIV of the application, which include requests for authorization for PG&E to transfer its right, title, and interest in substantially all of PG&E's non-nuclear generation assets as specified in the application; issuance of a CPCN to Pacific Generation as an electrical corporation; and authorization for Pacific Generation to issue short-term and long-term debt securities."[9] CalCCA's recommendation is unequivocal: the Commission should deny the Application in its entirety.

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[6] 1 Tr. 23:16-27:13 (Aug. 21, 2023 – Williams).
[7] Exh. CalCCA-01 at 6:13 to 10:10.
[8] 1 Tr. 63:5-9 (Aug. 21, 2023 – Williams).
[9] A.22-09-018, *Assigned Commissioner's Scoping Memo and Ruling*, at 2 (Jan. 20, 2023) (Scoping Ruling).

An evaluation of many of the specific issues listed in the Scoping Ruling as relevant to the Commission's consideration of the Applicants' requests informs CalCCA's determination that the Application should be rejected in its entirety. These specific issues include:

1. Whether the requests comply with applicable statutes, Commission decisions, and other legal requirements;

2. Whether the requests are adequately justified, reasonable, and in the public interest;

3. Whether there are alternative sources of funding available to PG&E to address its capital needs and the relative merits of such alternative sources of equity capital;

4. Potential impacts on ratepayers and rates over time, including potential revenue requirement impacts;

7. Whether the proposed transaction will result in dyssynergies and increases in billing, service, and other costs, and if so, who should bear responsibility for the increased costs;

8. The transaction costs and fees that will be incurred in connection with the proposed transaction and who should bear responsibility for such transaction costs and fees;

9. The estimated amount of benefits associated with the proposed transaction, the circumstances under which such benefits would no longer be realized (e.g., low sale price or higher share price), and whether any of the benefits should be shared with ratepayers;

10. Impacts of the proposed transaction on the future financial condition of PG&E and Pacific Generation, including any potential impacts on the aggregate amount of debt associated with the assets, credit metrics of each utility, risk profile of each utility, and cost of debt and cost of equity of each utility;

11. Whether there are adequate minority investor governance controls to protect against conflicts of interest and undue control, and whether there should be conditions or limitations placed on such controls (e.g., establishing a lower maximum percentage of Pacific Generation that should be available to be sold);

12. Potential impacts on the Commission's jurisdiction and existing regulatory proceedings, processes, and requirements;

13. Whether the proposed uses of transaction proceeds are appropriate and if there should be any conditions or restrictions on how proceeds from the proposed transaction are used;

16. Potential implications for California energy and capacity markets and market structure; and

17. Whether the proposed multi-stage regulatory approval process, including the use of Advice Letters to fully implement the proposed transaction and associated ratemaking and tariff changes, is reasonable.[10]

The Commission must reject the Proposed Transaction under Public Utilities Code sections 854 and 851[11] because PG&E has failed to demonstrate that the Transaction will result in concrete customer benefits, and has confirmed that it will result in concrete customer harms and subject customers to incremental and unforeseeable risks.[12] A transaction that results in net harm to customers is not in the public interest under the review standards of either section 854 or 851. The purported benefits of the Proposed Transaction—accelerated contributions to the Customer Credit Trust and avoided harm to the Fire Victim Trust (FVT)—are either uncertain or not even customer benefits at all. In fact, PG&E has designed the Transaction so as to avoid sharing any of the resulting economic benefits with ratepayers.[13] At the same time, PG&E has admitted that the Transaction will result in increased ratepayer costs but has declined to estimate those costs or to compare the various costs arising out of the Transaction to those of an alternative financing method.[14]

The Proposed Transaction also poses significant risks to the Commission and ratepayers beyond these incremental costs—risks that have been specifically identified as ones that are of concern to this Commission in the Scoping Ruling. These new risks include the potential market impacts arising out of conflicts of interest that are left unaddressed in PG&E's draft Transaction Documents;[15] increased administrative burdens for the Commission and stakeholders in

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10 Scoping Ruling at 2-4 (original numbering from the Scoping Ruling retained in this list).

11 Cal. Pub. Util. Code §§ 854, 851. All subsequent code sections cited herein are references to the California Public Utilities Code unless otherwise specified.

12 *See* Scoping Ruling at 2-4 (scoping issues 1, 2, 4).

13 *See id*. (scoping issue 9).

14 *See id*. (scoping issues 3, 7, and 8).

15 *See id*. (scoping issues 11 and 16). "Transaction Documents" as used throughout this Opening Brief, includes all of the documents put forward by PG&E in its Application and Testimony, and

ratemaking and enforcing PG&E's compliance obligations;[16] novel jurisdictional issues that could result in gaps in the Commission's regulatory authority;[17] a multi-stage regulatory approval process that would defer consideration of fundamental aspects of the Transaction until a later Advice Letter process;[18] the possibility that PG&E will use the Transaction proceeds for the benefit of shareholders rather than ratepayers;[19] and the largely unaddressed risk of negative impacts to PG&E's credit rating.[20]

Time and time again, the Commission and stakeholders have raised concerns about this Proposed Transaction, and PG&E's response has been: "The Commission can deal with this later." PG&E declined to estimate the additional administrative costs and other rate impacts arising out of the Proposed Transaction; did not compare the costs of this Transaction to any other alternatives; left the new compliance structure for the two entities unaddressed; proposed to leave critical approvals and review up to the expedited, 20-day Advice Letter process that has no formal discovery rights; relied on a code of conduct that does not exist yet to address market impacts; and opted not to seek an opinion from any credit rating agency before drawing conclusions on the potential impacts on PG&E's credit rating. In its rush to meet the arbitrary deadlines it has set for itself in this case, PG&E asks the Commission to make a decision that will permanently alter the

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specifically includes the following: the Minority Sale Agreement; the Amended and Restated Limited Liability Agreement of Pacific Generation; the "Intercompany Service Agreements" including the Operations and Services Agreement, Billing Services Agreement, Generation Facility Operations, Scheduling and Dispatch Agreement, and Fuel Procurement Agreement; the Legal and Regulatory Matters Agreement; the Benefits Agreement; the Interconnection Agreements; the Forecast Realization Adjustment Agreement; the Wildfire Indemnification Agreement, and the Separation Agreement. In its Rebuttal Testimony, PG&E attempted to limit the term "Transaction Documents" to only the Minority Sale Agreement and the Amended and Restated LLC Agreement. *See* Exh. PGE-13 at 1-AtchA-4. CalCCA does not agree to this limitation or definition.

[16] *See Scoping Ruling* at 2-4 (scoping issue 12).

[17] *See id*.

[18] *See id*. (scoping issue 17).

[19] *See id*. (scoping issue 13).

[20] *See id*. (scoping issue 10).

regulatory fabric of California based on a record that largely keeps the Commission and parties in the dark on key justifications and details.

For all these reasons, regardless of the stringency of the section 854 or 851 standard imposed, PG&E's Application fails to meet the standard because the Proposed Transaction will result in net harm to ratepayers and therefore is not in the public interest. If, notwithstanding all these considerations, the Commission finds that the Transaction meets these applicable legal standards, it should adopt CalCCA's Transaction conditions to mitigate the ratepayer risks associated with the Transaction, and it should reject the majority of PG&E's proposed edits to those conditions.

III. LEGAL STANDARD

A. Public Utilities Code Section 854 Requires Commission Review of the Proposed Transaction Under an Affirmative "Ratepayer Benefit" Standard

The Proposed Transaction triggers review under Public Utilities Code section 854 because it would result in PG&E having control over a new public utility operating in California. Section 854(a) provides, in part:

> A person or corporation, whether or not organized under the laws of this state, *shall not directly or indirectly* merge, acquire, or *control*, including pursuant to a change in control as described in subparagraphs (D) or (E) of paragraph (1) of subdivision (b) of Section 854.2, *any public utility organized and doing business in this state without first securing authorization to do so from the commission*.[21]

PG&E newly establishing control of PacGen, a public utility, as a result of the Proposed Transaction is a "control activity" subject to this Public Utilities Code section. PG&E

[21] Cal. Pub. Util. Code § 854(a) (emphasis added).

mischaracterizes this statute as only applying to *changes in control*.[22] However, this interpretation is contrary to both the plain language of the statute and Commission precedent.

The plain language of the statute provides that a corporation "shall not . . . control . . . any public utility organized and doing business in this state without first securing authorization."[23] Thus, regardless of whether there is a "change in control" of the underlying generation assets being transferred from PG&E to PacGen, if a corporation newly assumes control of a public utility doing business in California, section 854 review applies. While a "control activity" is not explicitly defined in the statute, section 854 grants the Commission the authority to "establish, by order or rule, the definitions of what constitutes a merger, acquisition, or control activity . . . subject to this section."[24]

In prior cases interpreting this statute, the Commission has emphasized the importance of reviewing the specific facts and potential impacts at issue to determine whether a transaction necessitates review under section 854. Instead of adopting a "bright line" test or "promulgat[ing] regulations to define 'control' in terms of clearly identifiable characteristics applicable to all cases . . . the Commission has relied on a fact-specific, case-by-case analysis."[25] In fact, the Commission has explicitly "rejected the concept that Section 854 does not require our advance review of a transfer of a utility when the transaction will not change the utility's underlying operations and day-to-day management."[26] In addition, the Commission has "decline[d] to apply only a control-based test[,]" noting, "we can imagine acquisitions not involving any change in control in which

22 Exh. PGE-13 at 1-2:20 to 1-3:2.
23 Cal. Pub. Util. Code § 854(a).
24 *Id*.
25 D.08-12-021, *Decision Granting Motion to Dismiss Application for Approval of Indirect Transfer of Control*, A.07-09-012 (Dec. 4, 2008) (D.08-12-021), at 11: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/94737.PDF.
26 D.08-12-021 at 11.

we well might wish to apply PU Code [section] 854[,]" and that "[i]f the degree to which a change in control was the only criterion that we used to determine whether an acquisition should be subject to PU Code [section] 854, we might preclude ourselves in situations where we should scrutinize a transaction more closely."[27]

Applying a more flexible case-by-case analysis, the Commission has instead focused on whether a proposed transaction impacting "control arrangements" will have an impact on the public interest, with the goal of ensuring "that changes which have the potential to involve public policy implications are brought to our attention."[28] In this review, the Commission has "consistently noted that . . . the degree to which issues of ownership and control have registered concern[] all turn on the specific facts at issue."[29]

The facts at issue here necessitate a review under section 854. The Proposed Transaction involves the separation of a pre-existing utility into multiple entities; the creation of a new regulated public utility providing overlapping service with the pre-existing company; the transfer of substantially all of PG&E's non-nuclear generation assets; the assumption by PG&E of control of the newly created public utility; and the creation of duplicative rate tariffs, ongoing joint Commission filings, and joint billing to the same set of customers. This reorganization is unprecedented and raises novel issues and concerns, as discussed in Section IV.B.2 herein. As such, the Commission should conduct a close review of the public interest and broader policy implications of this Proposed Transaction under section 854.

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[27] D.95-05-021, *In the Matter of the Application of SDG&E for Authorization to Implement a Plan of Reorganization Which Will Result in a Holding Company Structure*, A.94-11-013, 1995 Cal. PUC LEXIS 440 (May 10, 1995), at **3-4 and Conclusion of Law 2.

[28] D.08-12-021 at 11-14 (citing D.96-02-061).

[29] *Id*. at 12 (citing D.03-06-069 at 8).

Because PG&E's gross annual California revenues exceed five hundred million dollars, the Commission must find under section 854 that the Proposed Transaction does all of the following before granting the Application:

(1) ***Provide short-term and long-term economic benefits to ratepayers***.

(2) Equitably allocate, where the commission has ratemaking authority, the total short-term and long-term forecasted economic benefits, as determined by the commission, of the proposed merger, acquisition, or control, between shareholders and ratepayers. ***Ratepayers shall receive not less than 50 percent of those benefits***.

(3) ***Not adversely affect competition***. In making this finding, the commission shall request an advisory opinion from the Attorney General regarding whether competition will be adversely affected and what mitigation measures could be adopted to avoid this result.

(4) For an electrical or gas corporation, ensure the corporation will have an adequate workforce to maintain the safe and reliable operation of the utility assets.[30]

Further, the Commission must consider the following criteria and find, on balance, that the proposal is in the public interest:

(1) Maintain or improve the financial condition of the resulting public utility doing business in the state.

(2) Maintain or improve the quality of service to public utility ratepayers in the state.

(3) Maintain or improve the quality of management of the resulting public utility doing business in the state.

(4) Be fair and reasonable to affected public utility employees, including both union and nonunion employees.

(5) Be fair and reasonable to the majority of all affected public utility shareholders.

(6) Be beneficial on an overall basis to state and local economies and to the communities in the area served by the resulting public utility.

(7) Preserve the jurisdiction of the commission and the capacity of the commission to effectively regulate and audit public utility operations in the state.

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30 Cal. Pub. Util. Code § 854(b) (emphasis added).

(8) Provide mitigation measures to prevent significant adverse consequences that may result.[31]

PG&E, as the applicant, has the burden of proving by a preponderance of the evidence that these requirements of section 854(b) and (c) are met.[32]

B. Public Utilities Code Section 851 Requires Commission Review of the Proposed Transaction Under a "Public Interest" Standard

The Proposed Transaction also triggers review under Public Utilities Code section 851 because it would result in a transfer of substantially all of PG&E's generation assets to a newly created subsidiary, and the sale of a minority interest in that subsidiary. Under section 851, a public utility "shall not sell, lease, assign, mortgage, or otherwise dispose of, or encumber the whole or any part of its . . . property necessary or useful in the performance of its duties to the public . . . without first having . . . secured an order from the commission authorizing it to do so."[33] Both the contemplated transfer of PG&E's generation assets to PacGen and the minority sale of equity interests in PacGen trigger section 851 review.

In its decisions ruling on section 851 transactions, the Commission has consistently looked to the impact of the proposed transaction on the public interest, and has imposed varying iterations of the "public interest" review standard to evaluate different transactions.[34] For instance, at times

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[31] Cal. Pub. Util. Code § 854(c).

[32] Cal. Pub. Util. Code § 854(f).

[33] Cal. Pub. Util. Code § 851(a).

[34] *See* D.11-12-007, *Decision Conditionally Approving the Application for Authority for Western Water Holdings, LLC, Carlyle Infrastructure Partners Western Water L.P., and Carlyle Infrastructure Partners L.P. to Acquire and Control Park Water Company and Apple Valley Ranchos Water Company*, A.11-01-019 (Dec. 1, 2011) (D.11-12-007), at 5-6: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/154603.PDF ("In order to determine whether the proposed transaction is in the public interest, we note that the Commission has used both the 'ratepayer indifference standard' (i.e., a showing that no negative effects result from the change of control), and a net benefit standard (i.e., a showing that the transaction offers ratepayers some equitable share of the benefits the transaction will generate).").

the Commission has adopted a "ratepayer indifference" standard,[35] at times it has held that a transaction cannot be adverse to the public interest and should be explicitly encouraged when it is affirmatively in the public interest,[36] and at times it has required a showing of a "tangible ratepayer benefit."[37] When the transaction at issue triggers both section 851 and section 854 review, the

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[35] D.11-12-007 at 5-7; D.15-11-012, *Decision Authorizing California-American Water Company To Purchase the Public Utility Assets of Dunnigan Water Works*, A.14-07-005 (Nov. 5, 2015), at 7-8: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M155/K818/155818887.PDF.

[36] D.09-07-035, *Decision Granting Approval to PG&E and Lamar Central Outdoor, LLC to Enter Into a Master Signboard Agreement Pursuant to Public Utilities Code Section 851 and Denying the Requested Approval of Proposed Related Process*, A.08-10-014 (Jul. 30, 2009), at 13-15: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/105114.PDF ("In reviewing Section 851 applications, the Commission historically looked to public interest as its guiding post. While the minimal standard we consider in our review is that the transaction being proposed in a particular application is 'not adverse to the public interest', we do foster and encourage transactions such as the one being proposed by PG&E here where the transaction is also 'in the public interest.'"); D.09-04-013, *Decision Granting Approval Pursuant to Public Utilities Code Section 851 to Transfer 4.38 Acres of Right of Way by SDG&E to the Irvine Company, LLC*, A.08-10-022 (Apr. 16, 2009), at 5-6: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/100013.PDF ("The primary question for the Commission in Section 851 proceedings is whether the proposed transaction serves the public interest: 'The public interest is served when utility property is used for other productive purposes without interfering with the utility's operation or affecting service to utility customers.'"); D.11-05-048, *Decision Granting Approval of Lease of Transfer Capability Rights from SDG&E to Citizens Energy Corporation*, A.09-10-010 (May 26, 2011) (D.11-05-048), at 6-9: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/136211.PDF ("the Section 851 review standard stated in D.09-07-035 and D.09-04-013 should be applied, i.e., that the subject transaction should not be adverse to the public interest and that transactions that are in the public interest are to be encouraged.").

[37] D.19-12-038, *Decision Authorizing the Purchase of Water Utility Assets by California-American Water Company*, A.17-10-016 (Dec. 19, 2019), at 7-10: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M322/K796/322796350.PDF ("In evaluating whether an acquisition is in the public interest, the Commission will consider whether there is a tangible benefit to the ratepayer by determining whether the transaction will improve the financial condition of the public utility, will maintain or improve the management of the utility and the quality of service to the utility's ratepayers, will be fair to employees of the utility, and will be generally beneficial to the community served by the public utility."); D.21-08-027, *Decision Authorizing PG&E's Sale of its San Francisco General Office Complex and Related Matters*, A.20-09-018 (Aug. 19, 2021), at 11-13: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M401/K564/401564287.PDF (approving the sale of PG&E's headquarters building as consistent with the public interest under Section 851 because, among other showings, PG&E demonstrated the sale would be cost-effective for ratepayers in that it would result in a net benefit of $752 million as compared to the status quo).

higher "ratepayer benefit" standard and the specific requirements and considerations laid out in section 854 generally guide the analysis.[38]

As discussed above, the Commission should recognize this Proposed Transaction implicates section 854 and hold PG&E to the more stringent requirements of that statute, including the requirement that the Transaction provide short-term and long-term economic benefits to ratepayers.[39] However, in the event that the Commission declines to apply section 854, it has broad discretion to evaluate the Proposed Transaction under any of the previously endorsed section 851 "public interest" standards. Commission precedent does not clearly dictate the use of one of these standards in the evaluation of this kind of novel transaction because the Commission has never been presented with this type of transaction.

Given the risks inherent in approving a first-of-its kind transaction, and the fact that some of the attendant risks are unforeseeable, CalCCA urges a review under the higher "tangible ratepayer benefit" section 851 standard previously endorsed by the Commission in some cases. Notably, the Commission has recently made clear that it "sets a high bar for determining that *novel transactions* . . . meet the . . . 'public interest' and 'tangible benefits' standards" of sections 851 and 854.[40] Thus, the Commission should recognize the novelty of this Proposed Transaction and exercise its discretion to apply the higher "tangible benefits" standard of review in this case, even if it determines that it is not required by statute to do so. Further, the Commission should recognize

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38 *See, e.g.*, D.22-12-032, *Decision Denying Joint Application for a Change of Control of the Crimson Pipeline, L.P. and the San Pablo Bay Pipeline Company, LLC*, A.21-02-013 (Dec. 15, 2022) (D.22-12-032), at 12-14, 17: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M500/K044/500044605.PDF.

39 Cal. Pub. Util. Code § 854(b)(1).

40 D.22-12-032 at 33 (emphasis added).

its discretion to consider the criteria set forth in section 854 in its review, even if it determines that it is not mandated by law to adopt these criteria.[41]

C. The Commission Has Discretion Under Public Utilities Code Sections 854 and 851 to Order Utilities to Share the Economic Benefits of Proposed Transactions With Ratepayers

Public Utilities Code sections 854 and 851 provide the Commission with discretion to equitably allocate the economic benefits of proposed transactions as it sees fit. Sharing the economic benefits of the Proposed Transaction is required under section 854, and it is within the Commission's discretion under section 851. While PG&E requests the Commission share *none* of the economic benefits of the Proposed Transaction with ratepayers, and appears to have specifically tailored the Transaction to have the best possible case against sharing any proceeds, the Commission should not be swayed by any legal argument that the Commission does not have the authority to allocate transaction benefits as it sees fit.

Pursuant to section 854, the Commission is required to "[e]quitably allocate . . . the total short-term and long-term forecasted economic benefits . . . between shareholders and ratepayers[,]" with ratepayers receiving "not less than 50 percent of those benefits."[42] As discussed above, the Proposed Transaction triggers section 854 review, and therefore, the Commission is bound by this benefit sharing provision.

If the Commission determines that section 854 is not triggered by this Proposed Transaction, it still has broad discretion under section 851 to allocate the benefits of the Proposed Transaction as it deems appropriate. This is a first-of-its-kind transaction that raises novel policy

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41 D.22-12-032 at 12 ("In D.16-06-014, a change of control decision for the Wild Goose Gas Storage facility, the Commission expressly affirmed that it had 'discretion to consider the criteria set forth in §§ 854(b) and (c), that is, criteria included in the 'in the public interest' standard, if … inclined to do so', and it required the Joint Applicants there to 'show that the [change of control] is in the public interest.'").

42 Cal. Pub. Util. Code § 854(b) (emphasis added).

implications and risks for ratepayers.[43] As such, there is no prior Commission precedent on section 851 transactions that dictates how the Commission must allocate transaction benefits as between shareholders and ratepayers for this proposal. The fact that this is an unprecedented proposal does not mean, as PG&E suggests, that there cannot or should not be any sharing of economic benefits with ratepayers.[44] It simply means the Commission has not ruled on this question yet in the context of a similar transaction, and the Commission can therefore exercise its discretion regarding the appropriate allocation of benefits. Indeed, the Commission has explicitly confirmed that, regardless of whether an allocation of the gain on sale to ratepayers is required under the Commission's gain-on-sale precedent, the Commission has the discretion to allocate other economic benefits from a transaction to ratepayers.[45]

Notably, while PG&E suggests the Commission should treat the sale of equity in PacGen the same as a normal sale of equity—*i.e.*, without sharing proceeds with customers[46]—this argument is flawed for at least two reasons. First, the precedent PG&E relies on to conclude that there is no proceed sharing for traditional equity sales did not even come out of a proceeding where the sharing of proceeds was a contested issue addressed by the Commission,[47] therefore limiting

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[43] *See infra* Section IV.B.2 herein.

[44] Exh. PGE-13 at 1-5:15 to 1-11:7.

[45] D.05-05-014, *Decision Granting Conditional Authority for Lynch Interactive Corporation to Acquire Indirect Control of Cal-Ore Telephone Co. and Cal-Ore Long Distance, Inc.*, A.04-05-039 (May 5, 2005), at 11-12: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/46226.PDF ("The approach that the Commission has taken in allocating gain-on-sale should not be confused with the allocation of other benefits from a transaction. With respect to certain transactions (not including this one), § 854(b)(2) requires that ratepayers receive an equitable allocation of the transaction's benefits. Even in transactions not explicitly covered by § 854(b)(2) the Commission has sometimes allocated a portion of the transaction benefits to ratepayers. However, those cases did not involve an allocation of any gain on sale. They involved a quantification of economic benefits of a transaction and an allocation of an equitable share of those benefits to ratepayers").

[46] Exh. PGE-13 at 1-9:21-30.

[47] *See* D.15-06-051, *Decision Authorizing Southwest Gas Corporation to Issue up to $315 Million of New Debt Securities and up to 113,800 Shares of Common Stock*, A.14-07-012 (Jun. 25, 2015): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M152/K903/152903601.pdf (cited by PG&E at Exh. PGE-13 at 1-9 n. 37).

its precedential value on this point. More fundamentally, the Proposed Transaction comes with significantly more ratepayer risk than a traditional equity sale, conveying substantial rights to the Minority Investors that common stock shareholders do not possess. Consistent with Commission precedent, the benefits of a transaction involving such risks should accrue to the parties taking or assigned those risks.[48]

The Commission has consistently held that, in determining the fair allocation of proceeds resulting from a sale of utility assets, the Commission should be guided by its analysis of risk and should generally allocate the gains to the parties that assume the attendant risks of the transaction.[49] As the Commission made clear in the primary decision cited by PG&E on this issue, the "allocation of gain depends in general on the explicit and implicit risks taken by ratepayers and shareholders at the time an investment is made . . . The rewards and losses induced by sale of assets should accrue to the parties taking or assigned the risks."[50] Further, the Commission has acknowledged "[t]here are many . . . types of risk in utility service" the Commission may find appropriate to consider in such cases, including the risk of a reduced level or quality of service (to ratepayers), risks of rate increases (to ratepayers), and more general financial risks (to shareholders and/or ratepayers).[51] In line with this precedent, the Commission should generally allocate the economic benefits of utility asset sales and similar section 851 transactions based on a holistic analysis of the risks involved in the proposed transaction. Given the risks involved here, discussed in detail in

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[48] D.89-07-016, *Order Instituting Rulemaking Concerning the Ratemaking Treatment of Capital Gains Derived from the Sale of a Public Utility Distribution System Serving an Area Annexed by a Municipality or Public Entity*, R.88-11-041, 1989 Cal. PUC LEXIS 587 (Jul. 6, 1989) (D.89-07-016), at **5, **24-25.

[49] *Id*. at **5.

[50] *Id*. at **24-25.

[51] *Id*. at **5, 24-25.

Section IV.B.2 herein, it is appropriate for the Commission to allocate a significant portion of the economic benefits of the Transaction to ratepayers.

IV. WHETHER THE APPLICANTS' REQUESTS ARE ADEQUATELY JUSTIFIED REASONABLE AND IN THE PUBLIC INTEREST

Regardless of the stringency of the Public Utilities Code section 854 or 851 standard imposed, the Commission must deny PG&E's Application because the Proposed Transaction will result in net harm to ratepayers. PG&E has failed to identify any concrete customer benefits flowing from the Proposed Transaction, and it has admitted the Transaction will result in increased ratepayer costs—which it dismisses as insignificant, without providing any actual estimate. The Transaction also introduces many risks beyond these incremental net costs, including risks of competitive impacts, additional administrative burdens, new gaps in the Commission's regulatory authority, and the potential for the Transaction gains to benefit shareholders rather than ratepayers. There is no "public interest" review standard under which the Commission could conclude that, on balance, this Transaction—with these attendant impacts—will serve the public interest.

A. Whether the Transaction Benefits Customers (Scoping Ruling Issues 3, 9, and 13)

1. Accelerated Contributions to the Customer Credit Trust Are Not a Material Ratepayer Benefit (Scoping Ruling Issue 9)

One of the few ratepayer benefits PG&E claims will result from the Proposed Transaction is accelerated contributions to the Customer Credit Trust, but PG&E repeatedly failed to demonstrate these contributions will result in a material ratepayer benefit. Authorized in Decision (D.) 21-04-030, the Customer Credit Trust is intended to fund customer rate credits equal to the fixed recovery charge (Recovery Bond Charge) customers are paying following PG&E's

emergence from Chapter 11 bankruptcy.[52] The Customer Credit Trust is funded in part by shareholder contributions generated by tax deductions derived primarily from wildfire-related payments.[53] The maximum amount of contributions from these shareholder tax benefits is $7.59 billion, and these contributions are only required until the Recovery Bonds are repaid in full.[54] Customers currently get a rate credit (Recovery Bond Credit) funded by the Customer Credit Trust equal to, and offsetting, the Recovery Bond Charge on their electric bill.[55]

PG&E argues that because proceeds from the Proposed Transaction will increase PG&E's taxable income, PG&E Corporation will be able to recognize more of the shareholder tax deductions on its tax return earlier than previously expected, thus accelerating shareholder contributions to the Customer Credit Trust.[56] PG&E claims this directly benefits customers by reducing the probability of a deficit in the Customer Credit Trust and by increasing the probability of a surplus that customers would share.[57]

However, the Customer Credit Trust is structured such that the timing of contributions will not impact ratepayers in the near-term and will be unlikely to impact ratepayers in the long-term in any significant amount. On the first point, the Recovery Bond Credit on customers' bills will not change as a result of the Proposed Transaction.[58] PG&E does not dispute this.

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[52] D.21-04-030, *Decision Approving the Application of Stress Test Methodology to PG&E*, A.20-04-023 (Apr. 22, 2021) (D.21-04-030), at 72-73: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M379/K953/379953866.PDF.

[53] Exh. CalCCA-01 at 13:6-12.

[54] *Id*.

[55] *Id*.

[56] Exh. PG&E-08 at 8-7:10-13.

[57] Exh. PG&E-13 at 1-4:1-4.

[58] Exh. CalCCA-01 at 13:16-19; Exh. CalCCA-01, Attach. C (PG&E response to CalCCA data requests 3.12 and 3.13).

Any benefit to ratepayers in the long-term is uncertain, and unlikely to be significant. The total shareholder contribution over time will not increase above the original $7.59 billion.[59] As CalCCA Witness Dickman explained during evidentiary hearings, D.21-04-030 provides that there will be an evaluation of the amounts in the trust *in 2040*, and the Commission will at that time "evaluate whether the funds in the trust were sufficient to offset the cost of the recovery bonds that they were intended to offset."[60] The Commission will have the opportunity during this evaluation to ensure the trust is sufficiently funded and also determine whether there is any remaining economic benefit that should be returned to ratepayers.[61] Even if there is a surplus balance in 2040, only 25 percent of it will be shared with customers at that time.[62]

The potential "benefit" to ratepayers from the accelerated contributions to the Customer Credit Trust is therefore uncertain and immaterial. The contributions to the Customer Credit Trust will not change, the Recovery Bond Credit will not change, the Commission can address any deficit in 2040, and, if a surplus does exist, customers will only see 25 percent of it—*in 2040*.[63]

2. The Proposed Transaction is Unlikely to Impact the FVT, and if it Did, This Would be a Shareholder Benefit Rather Than a Customer Benefit (Scoping Ruling Issue 9)

PG&E also attempts to justify the Proposed Transaction by warning that its alternative—issuing common stock—would dilute the value of existing shares and cause "particular harm to the Fire Victim Trust[,]" while the Proposed Transaction would raise equity "in a manner that is

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59 *Id*.
60 2 Tr. 180:2-7 (Aug. 22, 2023 – Dickman).
61 2 Tr. 205:3-7 (Aug. 22, 2023 – Dickman).
62 Exh. CalCCA-01 at 13:19 to 14:3; Exh. CalCCA-01, Attach. C (PG&E response to CalCCA data request 3.13).
63 Exh. CalCCA-01 at 14:1-3; 2. Tr. 181:13 to 182:11 (Aug. 22, 2023 – Dickman).

supportive of the Fire Victim Trust."[64] The Commission should not be swayed by this purported transaction "benefit."

The FVT was established in 2020 for the purpose of administering and paying claims for damages sustained as a result of several different wildfires from 2015 through 2018.[65] The FVT was funded by PG&E through a combination of cash and PG&E Corporation common stock contributions.[66] Pursuant to PG&E's Plan of Reorganization, the FVT was allocated 22.19 percent (477,743,590 shares) of the total PG&E Corporation common stock when PG&E emerged from bankruptcy.[67]

"Preserving value for the FVT" by avoiding share dilution is just another way of stating that the Transaction preserves value for existing shareholders, relative to a common stock issuance. While the FVT beneficiaries are particularly deserving shareholders, preserving value for them should not be conflated with benefitting customers or the public interest more generally. PG&E contends in Rebuttal Testimony that the Commission has not limited its evaluation of the public interest to "customer interests,"[68] but the decision PG&E cites for this proposition does not support its broader argument. In D.11-05-048, the Commission found that while the public interest includes ratepayers, it is not limited to that portion of the public, as "[m]embers of the public may be affected by, and therefore interested in, a utility's facilities even if they are not served by that utility."[69] The Commission's prior recognition that benefits to the *general public* can be construed as benefits to "the public interest" in no way supports PG&E's contention that benefits to a *subset of PG&E shareholders* should be construed as benefits to the public interest.

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64 Exh. PGE-01 at 1-4:25 to 1-5:2.
65 Exh. CalCCA-01 at 14:8-10.
66 *Id*. at 14:10-11.
67 *Id*. at 14:11-13 (PG&E response to CalCCA data request 2.26).
68 Exh. PGE-13 at 1-5 n. 18.
69 D.11-05-048 at 9.

Regardless of whether any benefit to the FVT can or should be construed as a benefit to customers or the public interest, the FVT intends to complete sales of PG&E stock by the end of 2023, before the anticipated closing of the Proposed Transaction.[70] PG&E does not refute this fact.[71] In fact, between the time of PG&E's Rebuttal Testimony on July 7, 2023 and today, the FVT sold an additional 60 million shares, leaving only 67.7 million shares outstanding out of the original 477 million shares, or about 14 percent of those original shares.[72]

PG&E Witness Williams admitted during evidentiary hearings that if all of the shares are sold, the Proposed Transaction no longer needs to be completed in order to provide the FVT benefits PG&E has highlighted.[73] While PG&E emphasizes in Rebuttal Testimony that share price increases benefit its shareholders,[74] including the dwindling FVT shares, this obvious statement in no way undermines the fact the consummation of the Proposed Transaction is unlikely to benefit the FVT. If the FVT completes its sales of stock by the end of 2023, the Commission's decision to approve or deny the Transaction—a decision which is likely to occur in 2024—will not impact the FVT.

3. PG&E Has Structured the Transaction so as to Avoid Sharing Economic Benefits with Ratepayers (Scoping Ruling Issues 9 and 13)

While PG&E touts these dubious Customer Credit Trust and FVT "public interest benefits" of the Proposed Transaction, it at the same time has taken deliberate steps to design the Transaction such that it can avoid sharing any tangible economic benefits with ratepayers. This structure weakens any argument that the Proposed Transaction is in the public interest under Public Utilities

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70 Exh. CalCCA-01 at 14:18 to 15:8.

71 Exh. PGE-13 at 1-5:1-14.

72 1 Tr. 10:5 to 13:19 (Aug. 21, 2023 – Williams); Exh. CalCCA-02; Exh. TURN-03.

73 1 Tr. 10:14 to 15:11 (Aug. 21, 2023 – Williams) (admitting that "If the Fire Victims' Trust does not hold any shares, then there wouldn't be any shares for them to have an adverse impact on moving forward.").

74 Exh. PGE-13 at 1-5:1-14.

Code sections 854 and 851, and in fact directly contravenes the benefit sharing provision of section 854.[75]

Section 854 requires PG&E to "[e]quitably allocate . . . the total short-term and long-term forecasted economic benefits . . . between shareholders and ratepayers[,]" with ratepayers receiving "not less than 50 percent of those benefits."[76] Even if the Commission concludes that section 854's requirements do not apply to this Application and that PG&E is not *legally required* to share economic benefits with customers, if the Commission approves the Transaction it should still exercise its discretion to equitably allocate Transaction benefits to ratepayers under section 851. Requiring PG&E to estimate and equitably share any resulting economic benefits of the Transaction with ratepayers is warranted given the ratepayer risks inherent in the consummation of this novel Transaction and the new regulatory structure that would result.[77]

Dismissing the idea that the Transaction comes with substantial risk, PG&E argues the Transaction is in the public interest while remaining firm there should be no sharing of sale proceeds with customers.[78] PG&E drafted the Transaction Documents such that, if a regulatory body were to require a sharing of sale proceeds with customers, this would constitute a "Burdensome Condition" that would allow PG&E to avoid proceeding with the Transaction.[79] During hearing, when given *three opportunities* to clarify whether PG&E purposefully structured the Transaction to avoid sharing any proceeds with ratepayers, PG&E Witness Williams did not say no. Instead, she stated she "can't comment on the scope of that question" and then discussed PG&E's need to fund its infrastructure investments and insisted the Transaction should be treated

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75 Cal. Pub. Util. Code § 854(b).

76 *Id*.

77 *See supra* Section III.C herein.

78 Exh. PGE-13 at 1-5:15 to 1-11:7.

79 Exh. PGE-05 at 5-10:32 to 5-11:6.

like a sale of equity.[80] It is clear that PG&E has taken deliberate efforts to avoid sharing economic benefits of the Transaction with ratepayers, and it is telling PG&E's witness was unwilling to deny that fact on the stand.

Similarly, PG&E has been clear it does not intend to immediately share lower debt costs with customers. PG&E expects PacGen will receive credit ratings on its debt that are either equivalent to or better than PG&E's, and that a debt issuance by PacGen would result in debt costs that are the same, if not lower.[81] However, if PacGen's initial cost of debt is in fact lower than the currently authorized cost of debt, customers will not share in that benefit until the next cost of capital case.[82] PG&E proposes to apply the authorized cost of capital from Application (A.) 22-04-008, including the cost of debt, to PacGen when initially setting rates, and a full analysis of the cost of capital for the separated entities would not occur until a jointly filed cost of capital application in 2026.[83] Therefore, these lower costs that may, according to PG&E, result from the Transaction would not be shared with ratepayers for years.[84]

PG&E's deliberate structuring of the Transaction to avoid sharing these economic benefits with customers undermines its argument that the Transaction is in the public interest. If the Commission nonetheless approves the Transaction, it should order PG&E to estimate and equitably allocate a share of the economic benefits of the Proposed Transaction to customers, consistent with Public Utilities Code sections 854 and 851.

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80 1 Tr. 31:2-6 (Aug. 21, 2023 – Williams).
81 Exh. CalCCA-01 at 15:9-16.
82 *Id*.
83 *Id*. at 15:9-18.
84 *Id*. at 15:18 to 16:2; *id*., Attach. C (PG&E response to CalCCA data request 1.37).

4. PG&E Touts the Proposed Transaction as the Best Alternative But Admits It Has Done No Analysis to Substantiate This Claim (Scoping Ruling Issue 3)

Not only has PG&E failed to demonstrate any concrete customer benefits from its proposal, but it has also failed to show that the Proposed Transaction is, on balance, the best funding source available to PG&E. Scoping Issue three expressly states that the Commission will consider "[w]hether there are alternative sources of funding available to PG&E to address its capital needs and the relative merits of such alternative sources of equity capital."[85] Despite this clear direction, PG&E has admitted that it has not attempted to quantify or otherwise analyze the relative costs and benefits of this Transaction as compared to other available alternatives.[86]

The Commission should not approve the Transaction based on PG&E's assurances that it "expect[s] that the Proposed Transaction will be a superior alternative" when it has done no substantive analysis to support that claim. The only evidentiary support for the relative benefit of the Transaction PG&E has cited is what it describes as a positive reaction from equity research analysts to PG&E's announcement of the Transaction, and to other minority sales in the utility sector.[87] PG&E also admits its conclusion that this Transaction is the best alternative is uncertain and dependent on certain factors that are unknown at this time.[88]

Even assuming that PG&E is correct that this Proposed Transaction will generate a premium as compared to a common stock issuance, to meaningfully assess the Transaction as compared to other alternatives, PG&E would need to evaluate both the projected benefits *and costs* of the available options. PG&E has provided no such analysis here,[89] though it has admitted [redacted]

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85 Scoping Ruling at 3.
86 Exh. CalCCA-01 at 17:5 to 18:16 (citing PG&E responses to CalCCA data requests 1.34, 2.27, 3.04).
87 Exh. PGE-13 at 1-14:4-12.
88 *Id*. at 1-14:14-22.
89 Exh. CalCCA-01 at 16:5 to 18:16.

[redacted].[90] In fact, PG&E Witness Williams admitted during evidentiary hearings that an important issue in this case is whether there are alternative sources of funding available to PG&E to address its capital needs,[91] and that a comparison of the Proposed Transaction's transaction costs to those of any identified alternative funding source should inform the Commission's decision.[92] The only alternative to the Proposed Transaction that Witness Williams identified is the sale of common stock by PG&E.[93] Despite acknowledging that this kind of cost comparison is important to the Commission's decision here, Witness Williams admitted that the Commission does not know the transaction costs of the identified alternative of issuing common stock.

PG&E's explanation for this failure to estimate and compare transaction costs is not convincing. When asked in discovery to compare the expected transaction costs of the Proposed Transaction to the transaction costs that would be required to raise an equivalent amount of funds through the sale of common stock, PG&E stated it was unable to do so due to issues like changing market conditions.[94] During evidentiary hearings, Witness Williams admitted that PG&E is in fact able to estimate the transaction costs of the Proposed Transaction—a first of its kind transaction—but at the same time she maintained that it is *not* able to estimate the transaction costs from issuing common stock—a transaction the utility has completed many times.[95] The Commission should be skeptical of this claim, given that PG&E has issued common stock previously, and knows the transaction costs from those issuances.[96]

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90 1 Tr. 144:11 to 145:7 (Aug. 21, 2023 – Williams – Confidential Session).
91 1 Tr. 15:21 to 16:1 (Aug. 21, 2023 – Williams).
92 1 Tr. 17:24 to 18:3 (Aug. 21, 2023 – Williams).
93 Exh. PGE-13 at 1-9:28-29; 1 Tr. 16:10-20 (Aug. 21, 2023 – Williams).
94 Exh. CalCCA-01, Attach. C (PG&E response to CalCCA data request 3.04).
95 1 Tr. 18:4-24, 20:14-19 (Aug. 21, 2023 – Williams).
96 1 Tr. 18:4-24 (Aug. 21, 2023 – Williams).

Further, during cross examination, PG&E Witness Williams also admitted that PG&E has provided estimates of transaction costs in the face of similar such challenges (like, for example, changing market conditions), and that in fact, it has done so in a recent proceeding concerning the issuance of wildfire hardening recovery bonds pursuant to Assembly Bill 1054.[97] While PG&E is not *statutorily required* to do this comparison in the instant case, as it was in this other proceeding, PG&E clearly has the *capability* to make such estimates. PG&E's claims otherwise are disingenuous. As even PG&E has admitted that the Commission cannot meaningfully answer Scoping Issue three[98] without an analysis comparing the costs of the Transaction to those of alternative funding options,[99] the Commission should not accept PG&E's lack of analysis here.

B. Whether the Transaction Harms Customers (Scoping Ruling Issues 1, 2, 4, 7, 8, 9, 10, 11, 12, 13, 16, and 17)

In addition to the fact that PG&E has failed to demonstrate that customers will benefit from the Proposed Transaction or that the Proposed Transaction is the best way of raising capital, PG&E also admits that it would result in increased ratepayer costs. The Commission should not authorize a funding approach with no demonstrated customer benefits but clearly documented incremental costs—especially when other alternative approaches have not been meaningfully evaluated in terms of their relative benefits and costs. Aside from this cost-benefit analysis weighing against Commission approval, another factor crucial to the Commission's public interest analysis is the fact that the Proposed Transaction comes with substantial and unquantifiable risks—some foreseeable, and others unknown. These risks could result in additional ratepayer harm beyond just

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[97] Exh. CalCCA-03; 1 Tr. 21:20 to 23:10.

[98] Scoping Ruling at 3.

[99] 1 Tr. 17:24 to 18:3 (Aug. 21, 2023 – Williams).

the incremental costs CalCCA has identified. In light of all these considerations, the Commission cannot approve this Transaction under any of the relevant "public interest" review standards.[100]

1. PG&E Has Admitted That the Proposed Transaction Will Raise Customer Costs and Rates (Scoping Ruling Issues 4 and 7)

i. The Transaction Will Result In Increased Administrative Costs (Scoping Ruling Issues 4 and 7)

It is undisputed that the Proposed Transaction will raise administrative costs. PG&E has admitted in discovery that it expects ongoing administrative costs will increase due to the Transaction and that it plans to hire additional employees and/or contractors due to its expected increase in administrative workload.[101] PG&E's expectations for incremental work and personnel are shown in the Table below, reproduced from CalCCA's Testimony:[102]

Table 1

Activity	Existing Employee(s)	New Employee(s)	Contractor(s)	Incremental Work?
Financial Statement Preparation	x	x		Yes
Financial Statement Audit	x		x	Yes
Investor Relations	x	x		Yes
Monitoring Intercompany Agreements	x	x	x	Yes
Legal Representation	x	x	x	Yes
Tariff Preparation	x			Yes
Bill Preparation	x			No
Revenue and Cost Accounting		x		Yes

While it admits to the need for additional workforce, PG&E was not specific about the number of new employees or contractors it intends to employ.[103] To arrive at a reasonable estimate

100 Cal. Pub. Util. Code §§ 854, 851.
101 Exh. CalCCA-01 at 19:21 to 21:3.
102 *Id.* at 20:10-11.
103 *Id.* at 19:21 to 21:3.

of the incremental costs associated with these increased labor needs, CalCCA assumed two full time equivalent employees would be needed for each item requiring incremental work, resulting in an increase of approximately $3 million in annual labor costs.[104] Further, PG&E also admitted it expects some modifications would be required to its accounting system that calculates bill amounts and would determine the allocation between PG&E and PacGen, but it was unable to quantify the incremental costs associated with these modifications.[105] So, while $3 million represents one reasonable estimate of the added administrative costs per year in light of the information CalCCA was able to glean through discovery, it is quite possible the added costs will be higher than this. PG&E disagrees, stating in a few lines of Rebuttal Testimony that it expects the total increase in ongoing administrative costs will be "less" than CalCCA's estimate.[106] However, PG&E fails to provide any estimate of its own or any supporting evidence for that contention.[107] The Commission should afford no weight to PG&E's opinions that are not based on any analysis or record evidence.

PG&E's failure to consider and quantify the incremental costs likely to result from its Proposed Transaction in any of its testimony in this proceeding deprives the Commission of information crucial to its assessment of whether this Transaction is in the public interest. Simply put, the Commission cannot assess whether a proposal is in the public interest without a reasonable estimate of both the benefits and the costs of that proposal. PG&E seems to disagree, suggesting that the Commission should be satisfied with beginning to understand and review the incremental costs of operating PacGen as a subsidiary company starting in 2027, when PG&E and PacGen will

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104 *Id*.
105 *Id*.
106 Exh. PGE-20 at 9-3:24 to 9-4:5.
107 *Id*.

jointly file their general rate case (GRC).[108] PG&E has provided no recommendation, however, on how the Commission should track or limit recovery of such incremental costs in the future. The Commission should not approve this kind of novel proposal without a showing of (1) the likely costs to ratepayers, and (2) how the utility proposes to separately track incremental costs to allow the Commission the option to disallow ratepayer recovery of such costs.

ii. The Transaction Will Result In Increased PCIA Rates (Scoping Ruling Issues 4 and 7)

The Proposed Transaction contemplates a structure in which PG&E would bill PacGen for services provided by PG&E via the Intercompany Service Agreements. Instead of providing an estimate of any associated cost increase or developing the details of the cost allocation structure for such costs, PG&E again proposes to delay consideration of these issues until the 2027 GRC. Thus, this is another bucket of cost and rate impacts that PG&E simply asks the Commission to ignore while it is determining whether the Transaction is in the public interest. But the Commission cannot meaningfully assess whether this proposal is in the public interest without considering these kinds of impacts.

While initially PacGen's revenue requirement would be determined by carving out the non-nuclear electric generation portion of PG&E's 2023 GRC, going forward, PacGen's revenue requirement would reflect all the costs to operate as a separate generation utility.[109] This would necessarily include payments to PG&E for services provided pursuant to the various Intercompany Service Agreements required to enable PG&E to support PacGen's day-to-day operations.[110] Many

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108 *Id*. at 9-4:5.

109 Exh. CalCCA-01 at 21:6-11.

110 *Id*. at 21:6-16. As used by PG&E, the "Intercompany Service Agreements" include the Operations and Services Agreement, Billing Services Agreement, Generation Facility Operations Agreement, the Scheduling and Dispatch Agreement, and the Fuel Procurement Agreement. Exh. PGE-04-A at 4-AtchA-9.

of these support services are common utility costs, not generation-specific expenses. For example, PG&E admits that customer billing and wildfire liability insurance costs, which are not currently charged to PG&E's Power Generation line of business, will be billed to PacGen in the future.[111] While PG&E acknowledges certain disparities in this cost allocation approach as compared to the status quo, PG&E has not set forth a clear proposal for how these various costs billed from PG&E to PacGen will be allocated in the future and how that allocation may differ from the status quo cost allocation policy.

PG&E maintains these cost allocation issues need not be addressed until the 2027 GRC.[112] When asked to specifically identify each type of cost currently not allocated to Power Generation that will be charged to PacGen, PG&E responded that it would not charge PacGen such costs until the Commission authorized it in a future GRC.[113] Thus, PG&E requests Commission approval of Intercompany Service Agreements that contemplate billing PacGen for services provided by PG&E, but proposes to delay developing the details of the cost-sharing structure that would impact customer rates until the 2027 GRC.

These costs are not currently considered generation costs or recovered through generation-related rates, but they will be as a result of the Proposed Transaction unless and until PG&E develops a different cost allocation proposal in a future GRC filing. PG&E currently recovers the net cost of the generation resources at issue in this proceeding through Power Charge Indifference Adjustment (PCIA) and Cost Allocation Mechanism (CAM) surcharges.[114] In fact, all but one of the resources to be transferred to PacGen are recovered through PCIA rates.[115] The Commission

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111 Exh. CalCCA-01 at 21:6-16.
112 *Id*. at 21:6 to 22:7.
113 *Id*. at 21:17 to 22:1.
114 *Id*. at 22:8-10.
115 *Id*. at 22:8-11.

adopted the PCIA to ensure that when customers of IOUs depart from bundled service and receive their electricity from a non-IOU provider, such as a community choice aggregator (CCA), "those customers remain responsible for costs previously incurred on their behalf by the IOUs—but only those costs."[116] The PCIA is derived from the utility's Indifference Amount, representing the difference between the cost of the IOU's supply portfolio and its corresponding market value of its generation output, capacity, and other attributes.[117] Total portfolio costs for utility owned generation include capital investment recovery, fixed maintenance costs, and allocated administrative costs determined in a GRC.[118] Therefore, shifting additional administrative costs into electric generation—which is the default cost treatment contemplated by this Transaction—will increase PCIA rates relative to the status quo.[119]

Given that the Proposed Transaction will result in both an increase in ongoing administrative costs and the allocation of additional costs to the generation function for recovery via the PCIA, PG&E is asking the Commission to approve a proposal that will result in customers paying more to receive, at best, the same benefits. PG&E's customers—particularly departed customers no longer taking service from the assets in question—should not be required to pay incrementally higher costs for PG&E to oversee the same resource portfolio producing the same economic benefits. As PG&E has not shown that there will be any economic benefits flowing to customers as a result of this Transaction, and it has conceded that the Transaction will result in

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116 *Id*. at 22:11-15 (citing R.17-06-026, *Scoping Memo and Ruling of Assigned Commissioner*, at 2 (Sep. 25, 2017); D.18-10-019, *Decision Modifying the Power Charge Indifference Adjustment Methodology*, R.17-06-026 (Oct. 11, 2018), at 3: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M232/K687/232687030.PDF).

117 Exh. CalCCA-01 at 22:17-19.

118 *Id*. at 22:19 to 23:2.

119 *Id*. at 22:15-16 (citing PG&E response to CalCCA data requests 2.18 and 3.21).

these incremental costs and rate increases, the Commission cannot find that the Proposed Transaction is in the public interest under Public Utilities Code section 854 or 851.

2. The Transaction Will Result in Incremental and Unforeseeable Risks (Scoping Ruling Issues 10, 11, 12, 13, 16, and 17)

In its evaluation of whether this Proposed Transaction is in the public interest under Public Utilities Code sections 854 and 851, the Commission should consider not only the quantifiable costs of the Transaction, but also any other material risks that it presents. CalCCA has identified many such risks:

- The Transaction Documents do not impose sufficient guardrails on the identity, affiliations, or business dealings of the Minority Investors, opening the door to additional ratepayer harms.
- The Transaction will result in increased administrative burdens to develop and monitor PG&E's rates.
- The Transaction introduces novel questions regarding how compliance obligations for the resulting two regulated utilities should be handled but provides no answers to those questions.
- Under the Transaction structure, PacGen may be able to evade regulation as a public utility in the future.
- The Transaction Documents and underlying terms of this deal may change substantially after Commission approval.
- There is nothing preventing PG&E from paying gains from the Transaction out as dividends instead of using those gains for capital expenditures.
- The Transaction introduces risk that PG&E's credit rating will decline.

These risks introduced by the Transaction are relevant both to some of the specific elements the Commission must consider under section 854,[120] and to the Commission's broader, holistic consideration of whether the proposal is in the public interest under both sections 854 and 851. While CalCCA has identified these risks in its review of the Transaction as proposed thus far, the Commission should recognize that given the novelty of this Transaction, and the fact that the Transaction Documents and identities of the Minority Investor(s) are not finalized at this time, there are inevitably additional risks that are unknown or unforeseeable at this time.

i. The Transaction Documents Do Not Impose Sufficient Guardrails On the Identity, Affiliations, Or Business Dealings Of the Minority Investors and Thus Open the Door To Significant Ratepayer Harms (Scoping Ruling Issues 11, 16, and 17)

The Transaction Documents contain insufficient restrictions on the entities that can serve as the original Minority Investors, and these limited guardrails on the Minority Investors—as well as on any transfer of the Minority Investors' interests—become even more lenient post-Closing.[121] The implications of this structure should be of significant concern to the Commission. The new structure would generally allow the Minority Investor and its affiliates to operate as market participants, public utilities, or in other competing business ventures, opening the door to risks of competitive impacts that are ultimately felt by ratepayers.

An analysis of the market impacts of the Proposed Transaction is crucial to the Commission's decision on this Application. Under Public Utilities Code section 854, the Commission is specifically required to assess competitive impacts of the Proposed Transaction,[122]

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[120] *See* Cal. Pub. Util. Code § 854(b)(1); *id.* § 854(b)(3); *id.* § 854(c)(1); *id.* § 854(c)(2); *id.* § 854(c)(3); *id.* § 854(c)(5); *id.* § 854(c)(7); *id.* § 854(c)(8).

[121] *See* Exh. PGE-05, Attach. B at 5-AtchB-17 (Section 2.2 of the MSA defines "Closing" as the sale of the interests to the Minority Investor).

[122] Cal. Pub. Util. Code § 854(b)(3) (section 854 specifically requires that the Commission find that the Proposed Transaction does "[n]ot adversely affect competition").

whereas under the section 851 standard, the Commission should assess competitive impacts if it determines those impacts are relevant to its holistic determination of whether the Transaction is in the "public interest." Under either standard, the Commission should closely review these market impact issues.

The potential conflicts discussed in this Section may impact the public interest by giving a market player an undue advantage via access to confidential PacGen information, or undermining the integrity of PacGen's operations to the detriment of ratepayers. These kinds of harms to California's energy markets and to California ratepayers should be understood as harm to the "public interest." In fact, the Commission has already determined in its Scoping Ruling that it will examine both "[w]hether there are adequate minority investor governance controls to protect against conflicts of interest and undue control" and "[p]otential implications for California energy and capacity markets and market structure."[123] The Commission should not accept PG&E's arguments that it should essentially ignore these scoped issues, deferring to other regulatory review processes or to codes of conduct to be developed at some unspecified future date. These potential harms discussed throughout this Section should be another factor that weighs heavily against the Commission's approval of the Proposed Transaction.

a. The Transaction Documents Do Not Contain Sufficient Restrictions On the Entity That Can Serve as the Original Minority Investor

The Minority Sale Agreement (MSA) and the Amended and Restated LLC Agreement of Pacific Generation (LLC Agreement) contain very few limits on which kinds of entities may purchase the Minority Interest in PacGen. This lack of oversight exposes ratepayers to substantial risk that the Transaction will result in adverse competitive impacts or other ratepayer harms.

[123] Scoping Ruling at 2-4.

The limited restrictions that do exist in the MSA and LLC Agreement on the affiliations and identity of the original Minority Investor include the following:[124]

- The Investor must represent that it is and will remain a "United States person" within the meaning of Section 7701(a)(30) of the Internal Revenue Code, and is not and will not become a Tax-Exempt Entity.[125]

- To obtain full "Regulatory Approval" for the transaction to close, the parties must obtain approval from the U.S. Committee on Foreign Investment in the United States (CFIUS) that it has determined that the issuance and sale of the Acquired PacGen Interests is not a "covered transaction" pursuant to the CFIUS statute, or otherwise satisfy the "CFIUS Approval" provision of the MSA (to the extent such statutory provisions are applicable to the selected Investor).[126]

- At Closing, the Investor must represent that neither it nor any of its "affiliates" is a "public utility" as defined in the Federal Power Act (FPA) or a "public-utility company" as defined in the Public Utility Holding Company Act (PUHCA), or subject to the jurisdiction of the Commission.[127]

- Until Closing, neither Investor nor any of its affiliates shall take any action to acquire direct or indirect control over an electric generation facility or its output or a public utility operating, in each case, in the California Independent System Operator (CAISO) market, "if such action would reasonably be expected to materially impair or delay the consummation of the Transactions for any reason or result in the failure to satisfy any condition to the consummation of the Transactions."[128]

This narrow set of restrictions does not impose adequate guardrails on the business affiliations or identity of the entity to be selected as the original Minority Investor. For example, though the MSA includes a time-limited restriction on the Investor and its affiliates taking action to *newly acquire control* of certain CAISO market participants, there is no broader restriction in the Transaction Documents on the Minority Investor or its affiliates *already being* active CAISO market participants. Similarly, the Transaction Documents do not prohibit the Minority Investor from

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[124] *See* Exh. CalCCA-01, Attach. C (PG&E responses to data requests 5.01 through 5.05).

[125] Exh. PGE-05, Attach. A at 5-AtchA-50 (Section 13.1(e) of the LLC Agreement).

[126] *Id.*, Attach. B at 5-AtchB-37 (Sections 8.2(c) and 8.3(c) of the MSA); *see also id.*, Attach. B at 5-AtchB-8 (Section 1.1 of the MSA ("CFIUS Approval" definition)).

[127] *Id.*, Attach. B at 5-AtchB-26 (Section 6.9 of the MSA). The MSA defines "affiliate" in this section as that term is defined in 18 C.F.R. § 35.43.

[128] *Id.*, Attach. B at 5-AtchB-30 (Section 7.3(a) of the MSA).

having business interests in or affiliations with entities that provide inputs to generation facilities (such as natural gas, transmission, or fuel). The Transaction Documents therefore do very little to limit the potential for conflicts of interest arising as a result of the identity or affiliations of the selected Minority Investor at the time of Closing.

Simple examples illustrate how this setup could easily result in ratepayer harm. For instance, if a large power marketer or broker purchased the Minority Interests—which would be permissible under PG&E's proposed structure[129]—conflicts of interest may arise. The Minority Investor, and various types of Representatives[130] of the Minority Investor, will have access to confidential information of PacGen[131] and may have an incentive to use that information to benefit the Investor's business as a power broker. The Minority Investor may, for example, have an incentive to use information concerning PacGen's net short or net long position on Resource Adequacy (RA) to inform its predictions of market prices in its capacity as and for the benefit of its power broker business.[132] PG&E Witness Rogers even confirmed during evidentiary hearings that, in this kind of scenario, the Minority Investor may have access to confidential PacGen information relevant to their business interests as a power marketer or broker.[133] Witness Rogers

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[129] 2 Tr. 222:13-25 (Aug. 22, 2023 – Rogers).

[130] The LLC Agreement defines Representatives as follows: "'Representatives' means, with respect to any Person, such Person's shareholders or members, and its and their respective officers, directors, managers, employees, accountants, consultants, legal counsel, financial advisors, current and prospective financing sources and other representatives and agents." Exh. PGE-05, Attach. A at 5-AtchA-76.

[131] Note PG&E has admitted that the Minority Investor—including various types of Representatives of the Minority Investor—will have access to confidential information of PacGen. 2 Tr. 213:3 to 216:2 (Aug. 22, 2023 – Rogers).

[132] *See* Exh. PGE-05, Attach. A at 5-AtchA-54 (Section 15.10(b) of the LLC Agreement) (prohibiting the use of confidential information in a manner that's detrimental to PacGen or any Member and prohibiting certain disclosures of confidential information, but not imposing any restrictions on the Minority Investor's use of the confidential information of PacGen in a manner that does not harm PacGen or any Member. Thus, this provision does *not* categorically prohibit the Minority Investor from using PacGen's confidential information to benefit its own separate business interests). *See also infra* Sections IV.B.2.i.d and IV.B.2.i.e herein, addressing PG&E's explanations of why the Commission should not be concerned regarding the use of information in this manner.

[133] 2 Tr. 223:5 to 225:17 (Aug. 22, 2023 – Rogers).

also confirmed during hearings that there are not any terms in the Transaction Documents that would categorically prohibit the Minority Investor from using such confidential information in such a manner to benefit its own separate business interests.[134] The only limitations on the record on the use of that information by the Minority Investor are that the Investor (1) may not disclose that information to others, and (2) may not use that information in a way that is deemed as "detrimental" to PacGen or any Member of PacGen.[135]

As another example, if the selected Minority Investor happens to own a natural gas drilling business or a solar panel manufacturing business—both permissible under PG&E's proposed structure[136]—then it would have a clear conflict of interest: an incentive to expand the generation fleet of PacGen to benefit its separate business, or to stop the sale or retirement of PacGen's existing assets that may use inputs from its other business, regardless of whether this would be the most beneficial course of action for PacGen's business.[137] Ratepayers would be on the hook for

[134] 2 Tr. 216:9 to 219:1 (Aug. 22, 2023 – Rogers) (confirming that, while the LLC Agreement prohibits the use of confidential information in a manner that is detrimental to PacGen or any Member of PacGen, and it prohibits certain disclosures of confidential information, so long as the use of the confidential information does not cause harm to PacGen or any of its Members, the Minority Investor can use the confidential information to benefit its own separate business interests).

[135] *See* Exh. PGE-05, Attach. A at 5-AtchA-55 (Section 15.10(b) of the LLC Agreement); *id*., Attach. A at 5-AtchA-33 (Section 9.4 of the LLC Agreement). *See also infra* Sections IV.B.2.i.d and IV.B.2.i.e herein, addressing PG&E's explanations of why the Commission should not be concerned regarding the use of information in this manner.

[136] 2 Tr. 216:3-8 (Aug. 22, 2023 – Rogers); Exh. PGE-05, Attach. A at 5-AtchA-12 (Section 3.6(a) of the LLC Agreement).

[137] Note that any Minority Investor with at least a 20 percent interest in PacGen will have certain consent rights regarding certain asset sales and purchases. Exh. PGE-05 at 5-17:25 to 5-18:5; 2 Tr. 226:9 to 227:2 (Aug. 22, 2023 – Rogers).

PG&E Witness Rogers admitted that if PacGen faces a decision of whether to sell a large solar project, as opposed to continuing to maintain and invest in that project, a Minority Investor could have consent rights for that decision. 2 Tr. 227:3-10 (Aug. 22, 2023 – Rogers). She also confirmed that it is possible that a Minority Investor with a business interest in solar panels could benefit from a decision by PacGen to continue to maintain a utility-scale solar project instead of selling it. 2 Tr. 227:11 to 228:14 (Aug. 22, 2023 – Rogers).

all of PacGen's business decisions, even those unduly influenced by the Investor's other business ventures.

Without any contractual restrictions addressing these kinds of conflicts of interest, it is unclear if or how the Commission will have the ability to prevent the competitive impacts that may be associated with executing this Transaction with certain kinds of Minority Investors.

b. There Is No Continuing Obligation Preventing Minority Investors Or Their Affiliates From Acquiring Market Participants Or Being Involved In Competitive Business Ventures

In general, obligations under the MSA terminate at the Closing—*i.e.*, the sale of the interests to the Minority Investor.[138] Ongoing obligations of the Minority Investor are laid out in the LLC Agreement, which governs the relationship between the Minority Investor and PG&E in the ownership and management of PacGen. While the MSA includes provisions, discussed above, which impose restrictions on the Investor and its affiliates being public utilities, or newly acquiring control of generation facilities or public utilities operating in the CAISO market,[139] the LLC Agreement does not carry forward any of these restrictions after Closing. Therefore, after Closing, the Minority Investor and its affiliates would be free to acquire assets, or even other public utilities, operating in the CAISO market.

In fact, the LLC Agreement makes clear that the Members of PacGen (including the Minority Investor) and their Related Parties[140] are specifically permitted to engage, invest, or

138 *See* Exh. PGE-05, Attach. B at 5-AtchB-39 (Section 10.1 of the MSA).

139 *See id.*, Attach. B (Sections 6.9 and 7.3(a) of the MSA).

140 "'Related Party' means, with respect to any Person or group of Persons, a Person that directly, or indirectly through one (1) or more intermediaries, Controls, is Controlled by, or is under common Control with such Person or group of Persons. Notwithstanding the foregoing, for purposes of this Agreement, (a) none of the Members nor their Related Parties, by virtue of being a member of the Company or a party, shall be considered a Related Party of the other Member or the other Member's Related Parties and (b) no Investor Member, by virtue of being a member of the Company or a party, shall be considered a Related

otherwise be involved in "other business ventures of any nature or description . . . similar or dissimilar to the business [of PacGen,]" even those that are competitive with PacGen.[141] The one exception to this general rule is that, in the event that PG&E identifies an opportunity that is within the scope of PacGen's business (and that is available to both PG&E and PacGen), PG&E must first follow a prescribed process to present the opportunity to the PacGen Board for pursuit by PacGen before it may pursue the opportunity itself.[142]

The lack of any long-term limitation on the Investor and its affiliates' operations as market participants, public utilities, or in other competing business ventures introduces significant and ongoing risks of anti-competitive behavior and impacts of the kinds discussed above.

c. The LLC Agreement's Limited Restrictions on Transfers of Interests Are Insufficient

The LLC Agreement also contains insufficient guardrails with respect to whom the initial Minority Investors may transfer their interests in PacGen. This raises questions regarding whether the Commission is willing to open minority ownership of a significant portion of the state's regulated generation assets to virtually any entity, and what attendant ratepayer risks may come with such a setup.

Immediately post-Closing and then at any time going forward, the Minority Investor can transfer its interests to any of its wholly owned Related Parties without even the consent of the other Members—*i.e.*, PG&E and any other Minority Investor—provided those parties have at least

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Party of the Company or any of its Subsidiaries." *Id.*, Attach. A at 5-AtchA-76 (definition of "Related Party" in the LLC Agreement).

141 *Id.*, Attach. A at 5-AtchA-12 to 5-AtchA-13 (Section 3.6 of the LLC Agreement).

142 *Id*.

equal creditworthiness.[143] After three years, the Minority Investor can generally transfer its interests to *any third party*, although the remaining Members have certain rights of first offer.[144]

There are only two major ongoing restrictions on the identity of the third-party entities eligible to be transferred PacGen interests.[145] First, Minority Investors cannot transfer their interests to certain "Prohibited Transferees" or to persons to whom transfers would result in a violation of law or contractual, governmental, or regulatory arrangements.[146] The definition of "Prohibited Transferee" carves out a very narrow set of potential investors and sets a low bar for entities that may become Minority Investors in the future. The restriction only applies to:

> (i) any Person that appears on any list issued by a United States, Canadian or European Union governmental authority, the World Bank or the United Nations with respect to money laundering, terrorism financing, drug trafficking, or economic or arms embargoes, (ii) any Person who within the last five (5) years has been held liable by, or entered into a formal settlement agreement with, a United States, Canadian or European Union governmental authority for violations of anti-bribery, money laundering, terrorism financing or drug trafficking laws, or for criminal violations of economic or arms embargo laws or (iii) any Person for which the true Beneficial Owner of the Person is not known or identifiable and is not reasonably apparent.[147]

Second, Minority Investors are also prohibited from transferring any units to any person (or any Related Party thereof) set forth on a schedule to be provided by PG&E and updated annually, and not to exceed 14 persons.[148] This schedule has not been provided for stakeholder review, and PG&E also admitted in discovery that this list has not even been developed internally

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143 *See id*., Attach. A at 5-AtchA-41 to 5-AtchA-48 (Sections 12.2-12.10 of the LLC Agreement). *See also id*., Attach. A at 5-AtchA-76 (definition of "Related Party" in the LLC Agreement).

144 *See id*., Attach. A at 5-AtchA-42 to 5-AtchA-43 (Section 12.4 of the LLC Agreement).

145 *See id*., Attach. A at 5-AtchA-46 to 5-AtchA-47 (Section 12.8 of the LLC Agreement).

146 *See id*.

147 Exh. *id*., Attach. A at 5-AtchA-75 (LLC Agreement definition of "Prohibited Transferee").

148 Exh. *id*., Attach. A at 5-AtchA-47 (Section 12.8(b) of the LLC Agreement).

yet—currently, PG&E has not identified any persons for inclusion on this list.[149] PG&E has not provided any indication of the kinds of entities that might be included on this list or why the list is limited to 14.

These contractual restrictions, as currently drafted, do not meaningfully limit future transfers of PacGen interests. The restrictions are minimal, largely in PG&E's discretion, and subject to change.[150] Approving this structure would grant the Minority Investor considerable discretion to transfer its interests to virtually any entity providing the right price, with very limited carveouts. This could include new investors already participating substantially in the CAISO market or related upstream markets, or a large power marketer or broker with a significant interest in gaining access to PacGen's confidential information to inform its own separate business interests.

PG&E's suggested compromise that PacGen file a Tier 1 Advice Letter in the event any Minority Investor sells or transfers an equity interest in PacGen of at least ten percent is inadequate,[151] as such a review process is only appropriate for non-substantive changes or changes arising directly from statute or Commission order.[152] Further, given that significant market impacts could arise out of the use of PacGen confidential information by Minority Investors that are market participants, the ten percent threshold makes no sense; these issues would arise regardless of the percent interest that is transferred, and thus any transfer merits Commission review. The Commission should not approve a transaction that essentially writes a blank check for almost any entity to buy minority ownership of PacGen and thereby gain access to substantial information and influence over state-regulated generation assets.

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[149] Exh. CalCCA-01 at 31:6-9 (citing PG&E response to CalCCA data request 4.19).
[150] Exh. PGE-17-E at 5-12:4-19.
[151] *Id*. at 5-13:20-23.
[152] General Order 96-B, Section 5.1.

d. Nothing in the Record Addresses If Or How Conflicts Of Interest That May Arise for the Minority Investors In Their Ownership Of PacGen Will Be Mitigated Through Any Code Of Conduct

PG&E has not put forward a code of conduct provision that mitigates any of these concerns regarding the Minority Investor's other involvements with or as market participants. As discussed above, the potential for conflicts of interest in the course of the Minority Investor's ownership of PacGen is significant. The Minority Investor—including various types of Representatives[153] of the Minority Investor—could use their access to confidential PacGen information[154] to benefit the Minority Investor's separate business interests. Similarly, actions of PacGen that require the consent of a percentage of the Minority Investors may depend on the votes of Minority Investors with interests in other upstream market inputs;[155] instead of weighing solely the costs and benefits to PacGen of the particular action, the Minority Investor will have an incentive to consider the relative size and importance of each of its holdings, and the impact of the action on the Minority Investor's overall position. These kinds of conflicts could give a market player an undue advantage via access to confidential information, or undermine the integrity of PacGen's operations.

Neither PG&E's Testimony nor the Transaction Documents adequately address how such conflicts of interest will be avoided through any code of conduct. While the LLC Agreement provides that PacGen "shall establish and maintain a code of conduct that incorporates elements typical or advisable for a regulated utility," the one-sentence description of this code of conduct

[153] The LLC Agreement defines Representatives as follows: "'Representatives' means, with respect to any Person, such Person's shareholders or members, and its and their respective officers, directors, managers, employees, accountants, consultants, legal counsel, financial advisors, current and prospective financing sources and other representatives and agents." Exh. PGE-05 at 5-AtchA-76.

[154] 2 Tr. 213:3 to 216:2 (Aug. 22, 2023 – Rogers).

[155] 2 Tr. 225:18 to 228:14 (Aug. 22, 2023 – Rogers).

does not clarify *if or how* it might address or mitigate conflicts of interest for the Minority Investors that may arise due to their other business interests.[156]

During re-direct of PG&E Witness Rogers during evidentiary hearings, PG&E's counsel pointed out that this provision states that the code of conduct will include "provisions preventing a Member from disclosing confidential information to its Related Parties who are market participants", and seemed to suggest that this provision effectively solved the problem CalCCA was raising with respect to all conflicts of interest.[157] But while this code of conduct provision may address a particular subset of the conflicts that could arise (*i.e.*, those arising from the *disclosure of confidential information to Related Parties*), it does nothing to address many other types of conflicts that CalCCA has identified. For instance, this provision does not do anything to limit the use of this confidential information by the Minority Investor *itself*; under this provision, therefore, Representatives[158] of the Investor—including officers, directors, managers, employees, accountants, consultants, legal counsel, financial advisors, etc.—could use confidential PacGen information to benefit their own business interests.[159]

PG&E Witness Rogers made clear during cross examination that this code of conduct has not been developed yet, that PG&E cannot speculate as to what it will include, and that consequently, PG&E has not put any details of it on the record for Commission and stakeholder

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[156] Exh. PGE-05, Attach. A at 5-AtchA-33 (Section 9.4 of the LLC Agreement). The fact that this code of conduct will include "provisions preventing a Member from disclosing confidential information to its Related Parties who are market participants" does not address the bulk of the conflicts that could arise.

[157] 2 Tr. 286:20 to 287:5 (Aug. 22, 2023 – Rogers).

[158] Exh. PGE-05, Attach. A at 5-AtchA-76 ("'Representatives' means, with respect to any Person, such Person's shareholders or members, and its and their respective officers, directors, managers, employees, accountants, consultants, legal counsel, financial advisors, current and prospective financing sources and other representatives and agents.").

[159] Again, so long as that use is not detrimental to PacGen or any Member, per Section 15.10(b) of the LLC Agreement. *See id*., Attach. A at 5-AtchA-55.

review.[160] Witness Rogers initially even admitted that this code of conduct, as currently contemplated, would not prohibit the Minority Investor from using confidential PacGen information to benefit its own separate business interests.[161] In re-direct examination by PG&E's counsel, however, Witness Rogers went back on this testimony and stated that she was able to "look into the status" of the code of conduct during the break that day and learn that PG&E now expects to include a provision that would require the Minority Investor to only use PacGen confidential information in its governance of PacGen and in its capacity as an investor in PacGen.[162] The Commission should not accept this last minute change in testimony on the stand as a satisfactory solution to the issues CalCCA has identified that may arise from the Minority Investor's access to PacGen confidential information.

This purported new provision of the yet-to-be drafted code of conduct has not been provided for stakeholder review and the details of it are not on the record anywhere.[163] As Witness Rogers admitted on re-cross on this topic, this means the Commission and stakeholders have no way of verifying how that term would operate or how it would be enforced.[164] It is clear that PG&E *itself* has not meaningfully considered how it would enforce such a provision in depth either—during re-cross, when asked about enforcement, Witness Rogers admitted that this "is all still under development" and PG&E doesn't have "anything specific to . . . highlight there [regarding enforcement]."[165]

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160 2 Tr. 219:2 to 221:20 (Aug. 22, 2023 – Rogers).

161 2 Tr. 220:12 to 221:20 (Aug. 22, 2023 – Rogers) (confirming that, while PG&E cannot speculate at this time about what would ultimately be included in the yet to be drafted code of conduct, PG&E has not indicated anywhere on the record that the code of conduct will prohibit *the Representatives* of the Minority Investor from using confidential PacGen information to benefit its own separate business interests).

162 2 Tr. 268:2-18 (Aug. 22, 2023 – Rogers).

163 2 Tr. 275:14 to 276:8 (Aug. 22, 2023 – Rogers).

164 2 Tr. 276:9-24 (Aug. 22, 2023 – Rogers).

165 2 Tr. 277:4-16 (Aug. 22, 2023 – Rogers).

Enforcement would certainly be difficult—if not impossible—if this provision were to apply to *all Representatives* of the Minority Investor, as Witness Rogers initially stated during re-cross.[166] When Witness Rogers was reminded that "Representatives" per the LLC Agreement includes all officers, managers, directors, employees, etc. of the Minority Investor—individuals who PG&E has confirmed will have access to PacGen confidential information[167]—Witness Rogers backtracked, admitting that PG&E has not decided the "specific wording" on the applicability of this provision.[168] Based on this conversation and the totality of the record evidence concerning the code of conduct, the Commission should not be convinced that PG&E has any concrete plan for limiting the use of PacGen confidential information by the Minority Investor Representatives. As PG&E has not provided a proposed date for when this code of conduct or this specific newly contemplated provision would be made available, the Commission has no assurance that any such plan will materialize.[169]

Given the absence of any material contractual limitations on the affiliations or business interests of the Minority Investors, PG&E's failure to address how conflicts of interest will be mitigated through some form of code of conduct is striking, and should not be acceptable to the Commission.

e. PG&E's Other Explanations Regarding How Conflicts Of Interest Will Be Mitigated Are Also Insufficient and Unsupported

Aside from the code of conduct, PG&E has offered a few other explanations for its position that the Commission need not be concerned about the lack of guardrails on the identity and affiliations of the Minority Investor, but these explanations are insufficient and unsupported.

166 2 Tr. 278:6-13 (Aug. 22, 2023 – Rogers).
167 2 Tr. 213:7 to 216:2 (Aug. 22, 2023 – Rogers).
168 2 Tr. 278:14-25 (Aug. 22, 2023 – Rogers).
169 2 Tr. 276:25 to 277:3 (Aug. 22, 2023 – Rogers).

First, PG&E contends that its own internal incentives will sufficiently serve as these guardrails. PG&E explains that CalCCA's concerns regarding the entities that can participate as Minority Investors are unfounded because PG&E is itself motivated to seek out "investors seeking a regulated revenue stream, not market power."[170] The Commission should not rely on this statement, however, as PG&E has not elaborated on it or provided any evidence to support it. In fact, given that PG&E has fully rejected any binding selection criteria or contractual requirements that would impose guardrails on the identity or affiliations of the Minority Investor,[171] the Commission has no assurances that PG&E's intentions and incentives are as stated. Even taking PG&E's statements regarding its incentives at face value, an incentive is not a guarantee, it is not binding, and it is not enforceable. The Commission should impose guardrails that are binding and enforceable to prevent competitive impacts, rather than resting on PG&E's unsupported statements concerning its incentives.

Second, PG&E has pointed to a provision in the LLC Agreement that would prohibit the use of confidential information in a manner that is detrimental to PacGen.[172] Again, while this provision may prevent certain kinds of conflicts that would otherwise arise, it would do nothing to mitigate conflicts that may have an impact on the broader market *without harming PacGen itself*. For instance, referring again to one of the examples discussed throughout this Section, the use of confidential PacGen information to inform a Minority Investor's market forecasts for purposes of benefitting its own power broker business is unlikely to harm PacGen as an entity. However, this

[170] Exh. PGE-17-E at 5-10:15-19.
[171] *See* Exh. PGE-13, Attach. A (deleting, in its entirety, CalCCA's proposed Transaction condition 10 that would prohibit the Minority Investor and its Related Parties and Affiliates from being Market Participants (and declining to provide any revised or alternate condition on this issue)).
[172] 2 Tr. 216:9 to 219:1 (Aug. 22, 2023 – Rogers) (pointing to the LLC Agreement provision that prohibits the use of confidential information in a manner that is detrimental to PacGen or any Member of PacGen); Exh. PGE-05, Attach. A at 5-AtchA-55 (Section 15.10(b) of the LLC Agreement).

would still be an improper use of confidential PacGen information that would give an undue advantage to the Minority Investor's separate business. The Commission should not rely on this provision of the LLC Agreement to fully address market impact issues.

Third, PG&E has also suggested that the proposed Advice Letter process—to occur *after* the selection of the Minority Investor and execution of MSA—will provide sufficient "transparency to parties and the Commission regarding the identity of the Minority Investor(s)."[173] However, while it may in fact provide *transparency*, a Tier 2 Advice Letter process would be insufficient for stakeholders to meaningfully evaluate the identity of the Minority Investor and any additions/changes to the underlying Transaction Documents. New information on the selected Minority Investor, its market interests and affiliations, and the finalized contracts governing the operation and management of PacGen are not ministerial changes appropriate to Tier 2 review.[174] These proposals will likely necessitate discovery and further record development concerning the extent of the Investor's market participation and affiliations, as well as any new contract terms or code of conduct that would mitigate the corresponding risks to ratepayers. These new elements of the Proposed Transaction should therefore be subject to disposition by the Commission itself.

Finally, PG&E seems to suggest that the Commission need not review competitive impacts in this proceeding because the Federal Energy Regulatory Commission (FERC) will separately be conducting a review of the Transaction under FPA Section 203. This argument falls flat for a few reasons. As an initial matter, PG&E does not deny that the Commission has jurisdiction to review these issues;[175] instead, PG&E seems to suggest the FERC process will be adequate on its own. But while FERC's review will consider the effect of the Transaction on competition, the scope of

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[173] Exh. PGE-13 at 1-16:21 to 1-17:2.
[174] General Order 96-B, Section 5.2.
[175] *See* Exh. CalCCA-12.

FERC's "public interest" review under FPA Section 203 is limited—particular factors are generally considered, while others are often deemed out of scope and/or better suited to state-level review.[176] For instance, in its review of horizontal competitive effects in particular, the first step of FERC's approach[177] is a Competitive Analysis Screen, which "is intended to provide a standard, generally conservative check to allow [FERC] . . . to quickly identify [proposed transactions] that are unlikely to present competitive problems."[178] That screen evaluates the change in market concentration as a result of the transaction,[179] and generally, if the change in market concentration does not meet certain designated thresholds, it would not flag the transaction as problematic in

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[176] *See Order Authorizing Disposition and Acquisition of Jurisdictional Facilities*, 176 FERC ¶ 61,123, at PP 17, 19 (Aug. 24, 2021). *See also Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, 77 FERC ¶ 61,263, 1996 FERC LEXIS 2367, at *76 (Dec. 18, 1996) ("Where the affected state commissions have authority to act on the transaction, the Commission will not set for hearing whether the transaction would impair effective regulation by the state commission."); *id.* at *73 ("We clarify that the three factors discussed in this Policy Statement are not necessarily the only factors that make up the public interest, and, if appropriate, we will consider other matters that are under our jurisdiction. However, we believe such matters as the need for service to all households are more appropriately the concern of the states").

[177] *Analysis of Horizontal Market Power under the Federal Power Act*, 138 FERC ¶ 61,109, at P 34 (Feb. 16, 2012) (retaining its existing approach for analyzing horizontal market power under section 203 of the FPA, and specifically, "the five-step framework for assessing the competitive effects of a proposed transaction, with the first step consisting of the Competitive Analysis Screen, because we find that the approach remains useful in determining whether a merger will have an adverse impact on competition").

[178] *Analysis of Horizontal Market Power under the Federal Power Act*, 138 FERC ¶ 61,109, at P 35 (Feb. 16, 2012). *See also Panda Stonewall LLC*, 177 FERC ¶ 61,048, at P 20, n. 22 (Oct. 21, 2021) ("In the Merger Policy Statement, the Commission adopted the 1992 Federal Trade Commission/Department of Justice Horizontal Merger Guidelines, which state that in a horizontal merger, an increase of more than 50 HHI points in a highly concentrated market or an increase of 100 HHI points in a moderately concentrated market fails its screen and warrants further review. *See also Analysis of Horizontal Market Power under the Federal Power Act*, 138 FERC ¶ 61,109 (2012) (affirming the Commission's use of the thresholds adopted in the Merger Policy Statement).").

[179] *Analysis of Horizontal Market Power*, 138 FERC ¶ 61,109, at P 4 (Feb. 16, 2012) ("The Commission also adopted an analytic screen (Competitive Analysis Screen), based on the 1992 Guidelines and outlined in Appendix A of the Merger Policy Statement, which focuses on the first step in the analysis: whether the merger would significantly increase concentration in relevant markets. The components to a screen analysis are as follows: (1) identify the relevant products; (2) identify customers who may be affected by the merger; (3) identify potential suppliers to each identified customer (includes a delivered price test (DPT) analysis, consideration of transmission capability, and a check against actual trade data); and (4) analyze market concentration using the Herfindahl-Hirschman Index (HHI) thresholds from the 1992 Guidelines").

terms of horizontal competitive impacts.[180] However, many of the horizontal competitive impacts likely to result from the Proposed Transaction here are unrelated to market concentration issues; instead, they arise out of the use of PacGen confidential information to serve the Investor's own business interests. Therefore, while the FERC's review of horizontal competitive impacts is necessary, it is not sufficient. Additionally, not only is FERC's FPA Section 203 review limited in scope, but it is also only triggered in particular circumstances, and as a result, not all transfers of Minority Interests will trigger these reviews.[181] The Commission should not operate under a mistaken assumption that FERC's review will cover all the market impact issues that may be relevant to a determination of whether this Transaction is in the public interest pursuant to Public Utilities Code sections 854 and 851.

ii. The Commission's Administrative Burden To Regulate PG&E Will Increase (Scoping Ruling Issue 12)

In evaluating whether the Proposed Transaction is in the public interest, the Commission must also consider the impacts on the Commission's capacity to effectively regulate public utility operations in the state.[182] On this point, the record demonstrates the Commission's administrative burdens will increase significantly—both in terms of its obligations to develop and monitor rates, and its obligations to enforce various utility compliance obligations.

PG&E's testimony on ratemaking and compliance obligations reads like the fox telling the farmer not to worry, the henhouse is well-guarded. The Applicants rely on witnesses with no experience as regulators to assert regulators will not see an increase in difficulty regulating two

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[180] *Panda Stonewall LLC*, 177 FERC ¶ 61,048, at P 20, n. 22 (Oct. 21, 2021) ("in a horizontal merger, an increase of more than 50 HHI points in a highly concentrated market or an increase of 100 HHI points in a moderately concentrated market fails its screen and warrants further review").

[181] Exh. PGE-17-E at 5-11 n. 36.

[182] Cal. Pub. Util. Code § 854(c)(7).

utilities where currently there is only one.[183] PG&E's compliance witness, for example, admitted she has never had to deal with a utility objecting to an issue being out of scope, a utility deflecting questions between its witnesses, or convincing a utility—one that is reluctant to answer and adept at avoiding direct questions on its practices—to hand over data and pay penalties regarding its compliance obligations.[184]

It is no wonder PG&E's witnesses concluded that CalCCA's concerns over the Commission's ability to set rates and ensure compliance are "misguided" or "overstated"—they are lifetime PG&E employees with little understanding of the challenges an outside entity already faces in regulating PG&E. Those challenges will only increase with the addition of an entirely new public utility added to the mix, initially managed by PG&E and a board comprised of yet-to-be determined investors with their own agendas.

a. The Administrative Burden to Develop and Monitor PG&E's Rates Will Increase

PG&E's proposal that PG&E and PacGen submit joint applications in a wide range of proceedings—including in the Energy Resource Recovery Account (ERRA) forecast and compliance proceedings, GRCs, and cost of capital proceedings—will necessarily complicate those proceedings.[185] PG&E's testimony lists 29 different preliminary statements that would be impacted by the Proposed Transaction, with most requiring duplicative accounts established for PacGen and PG&E.[186] Some of the consequences of this new structure can be anticipated, while others will only present in future proceedings as they arise. The Commission should be cognizant

183 Exh. PG&E-12-E at DCT-1; Exh. CalCCA-16; 4 Tr. 517:4 to 518:9 (Aug. 25, 2023 – Toy) (admitting Witness Toy has only worked in the private sector her entire career and has never worked for a regulator); *see also* Exh. CalCCA-05 and Exh. PG&E-12-E at SAM-1 (demonstrating Witness Maggard has worked her entire career at PG&E).

184 *See* 4 Tr. 517:13 to 523:6 (Aug. 25, 2023 – Toy).

185 Exh. CalCCA-01 at 32:15-17.

186 *Id*. at 32:17-19.

of these impacts and the associated regulatory burdens on the Commission and other stakeholders as it analyzes whether this Transaction is in the public interest.

The incremental effort to examine joint filings will depend on the docket, but some of the administrative impacts are already clear. The proposed joint structure would increase the complexity of the ERRA proceedings at least twofold. Under this new structure, there would be two resource portfolios with their own costs and revenues, two Portfolio Allocation Balancing Accounts (PABAs), two ERRA balancing accounts, two New System Generation Balancing Accounts (NSGBAs), and two separate calculations for PCIA, CAM, and generation rates.[187] A further layer of complexity is added by the Forecast Realization Adjustment Agreement (FRAA) contemplated between PG&E and PacGen to transfer the market price risk of PacGen's assets to PG&E. PG&E proposes that payments made and received pursuant to this contract be recorded as transfer payments between the PABA accounts for each company.[188]

There will inevitably be further implementation details that have not been anticipated or explained in PG&E's Application. As just one example, PG&E's ERRA balancing account is subject to a trigger that requires PG&E to make a filing to adjust generation rates if the balance in the account reaches a certain threshold.[189] As proposed by PG&E, PacGen would also have an ERRA balancing account, and would presumably be subject to the same trigger mechanism.[190] But the details of how to operationalize this new structure have not been presented for Commission review as part of this proceeding. So if, for instance, the ERRA balance is triggered by one company but not the other, it is yet to be determined whether this will be addressed on a stand-

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187 *Id*. at 33:8-13.
188 *Id*. at 33:13-16.
189 *Id*. at 32:21 to 33:2.
190 *Id*. at 33:2-4.

alone basis or as a joint filing, or whether perhaps the combined ERRA balances should be considered when determining whether a trigger has been reached.[191]

While PG&E represents that its proposed joint filing approach "will ensure a seamless customer experience"[192] it fails to recognize the significant additional complexity that will be introduced into the process of determining and monitoring rates charged to customers or the fact that customers will not receive any benefit from the changes. The additional complexity not only increases the burden on the Commission and stakeholders who participate in the ratemaking process, but it will increase administrative expenses incurred by PG&E as it manages two separate entities. Simply put: the Proposed Transaction cuts an already complicated PG&E ratemaking puzzle into more pieces without improving the picture for customers. This is not in the public interest.

b. PG&E Provides No Proposal for How Compliance Obligations for Two Regulated Utilities Sharing the Same Service Territory Should Be Handled

Despite creating a structure where two separate regulated utilities will share the same service territory, PG&E puts forth no suggestions for how the Commission should assess each entity's compliance obligations. This will all be new for California: PG&E's witness could not point to an example where the Commission regulates joint compliance related to two electric utilities sharing the same service territory and having the same obligations.[193] But the complexity of what PG&E is proposing is apparently of little to no concern to PG&E. Instead of providing details, PG&E continues to rely on its refrain that the issue should be of no concern because the

191 *Id*. at 33:4-6.
192 *Id*. at 33:17-20.
193 4 Tr. 524:9-13 (Aug. 25, 2023 – Toy).

two entities will submit their compliance filings "jointly."[194] What that would mean in practice is simply not addressed.

According to their own witness, PG&E submits at least 100 compliance filings each year.[195] Again, according to their own witness, if the Proposed Transaction goes forward, PG&E and PacGen will be required to identify, and the Commission will be required to verify, the ownership of a compliance obligation—as between PG&E and PacGen—for each individual compliance filing.[196]

PG&E has put forward no proposal other than to confirm that the Commission will have the authority to decide to which entity the obligation belongs,[197] and to assert that as required, the two entities will make "joint" filings.[198] But the details of exactly how a "joint" penalty would be assessed or enforced are simply left up to the Commission to decide.

Highlighting the lack of a considered approach to this issue, PG&E's witness wavered between two frameworks when asked for specifics on how the Commission would determine which party would be liable for non-compliance penalties. As its witness originally described it, the Commission would need to determine "the ownership and origination of the non-compliance issue" for each non-compliance event in order to determine whether the "consequences will be assigned to Pacific Generation and/or PG&E."[199] When asked in hearing how the Commission would do so, she stated the Commission could do so as part of its existing citation program or it might have to initiate a new order instituting investigation in order to do so.[200] However, later in

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194 4 Tr. 519:11 to 520:21 (Aug. 25, 2023 – Toy).
195 4 Tr. 531:3-10 (Aug. 25, 2023 – Toy).
196 4 Tr. 531:3-23 (Aug. 25, 2023 – Toy).
197 Exh. PGE-11 at 11-2:5 to 11-3:10.
198 4 Tr. 519:11 to 520:21 (Aug. 25, 2023 – Toy).
199 Exh. CalCCA-15.
200 *Id.*; 4 Tr. 528:8 to 530:18 (Aug. 25, 2023 – Toy).

her testimony on the stand, the witness changed her original answer to suggest the Commission could just hold both PacGen and PG&E jointly liable, or it could determine whether one utility is responsible or the other is responsible.[201] But the issue is not whether the Commission has *authority* to hold one or the other utility responsible for compliance; the issue is what mechanism or rubric would have to be in place for the Commission to make the appropriate determination so that all of both utilities' obligations are fulfilled.

In the end, PG&E demonstrates it has no clear vision on how the Commission would assess compliance and determine the requisite penalties between the two utilities for over 100 compliance filings each year. The onus is simply on the Commission to figure it out each time. In ruling on the Application, the Commission should understand that if it approves the Proposed Transaction, it will be taking on these additional regulatory burdens and will need to establish a new compliance framework from scratch.

In addition to establishing and overseeing this new compliance framework for the utilities' compliance filings, the Commission and stakeholders may also find it necessary to review PG&E's compliance with its contractual duties under the Operations and Services Agreement (OSA) within Commission proceedings.[202] Because the draft OSA specifically excludes third-party beneficiaries, unless PacGen is incentivized to enforce PG&E's compliance with the OSA, meaningful review of PG&E's performance of its duties to PacGen will only be possible to the extent the Commission and stakeholders are able to scope such compliance issues into Commission proceedings.[203] Under this setup, the Commission and any involved Commission stakeholders may be the only entities to review PG&E's performance of these contractual duties,

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[201] 4 Tr. 527:8 to 528:21, 544:14-21, and 545:12-24 (Aug. 25, 2023 – Toy).

[202] Exh. CalCCA-01 at 34 n. 101 (citing PG&E responses to CalCCA data requests 5.08 and 5.09).

[203] *Id.*, Attach. C (PG&E responses to CalCCA data requests 5.08 and 5.09).

on a significantly delayed basis. Such a structure would add complexity to already complex regulatory proceedings—which will have recently been further complicated by the addition of PacGen as a regulated entity with its own tariffs, accounts, and workpapers. The added complexity of this setup put in place by the Transaction Documents should be another factor weighing against approval of the Application.

iii. The Commission and Ratepayers Face the Risk That PacGen Will Be Able to Evade Regulation as a Public Utility In the Future (Scoping Ruling Issue 12)

Given the practical realities of how PacGen will operate—*i.e.*, it will own generation assets that will be dispatched into the wholesale market, but will not actually sell electricity to retail customers—there is also a risk that PacGen will be able to evade regulation as a public utility. This risk should inform the Commission's determination of whether the Transaction is in the public interest under Public Utilities Code Sections 854 and 851. Under Section 854 in particular, the Commission must examine whether the Proposed Transaction will effectively "[p]reserve the jurisdiction of the commission and the capacity of the commission to effectively regulate and audit public utility operations in the state."[204] Further, the Commission has also already established in the Scoping Ruling that it will consider the "[p]otential impacts on the Commission's jurisdiction"[205] under Scoping Issue 12.

An entity is a "public utility" if it is an "electrical corporation [*i.e.*, a corporation owning any electric plant for compensation within California[206]] . . . where . . . the commodity is delivered

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204 Cal. Pub. Util. Code § 854(c)(7).

205 Scoping Ruling at 4.

206 Cal. Pub. Util. Code § 218(a) ("'Electrical corporation' includes every *corporation* or person *owning*, controlling, operating, or managing *any electric plant for compensation within this state*, except where electricity is generated on or distributed by the producer through private property solely for its own use or the use of its tenants and not for sale or transmission to others") (emphasis added).

to . . . the public or any portion thereof."[207] The relevant question is whether the electrical corporation's commodities are delivered to the public. Although the portions of PG&E's testimony discussing PacGen's status as a public utility seem to incorporate the assumption that PacGen will be making retail sales,[208] this does not reflect the practical reality contemplated by the Proposed Transaction.

PG&E's discovery responses and testimony make clear that PG&E—not PacGen—is the entity that will continue to sell and deliver electricity to the public. PG&E confirmed in discovery that PG&E will retain full responsibility for scheduling and purchasing energy from the CAISO market to serve retail load, and for delivering and selling electricity to the public.[209] PG&E, the entity, will retain full responsibility for these functions, and PG&E personnel or contractors working under PG&E's direction will carry out these functions.[210] A review of the Transaction Documents further confirms these mechanics. None of these agreements include provisions providing that PG&E will perform any function associated with selling electricity at retail on behalf of PacGen, pursuant to these agreements.[211] Thus, the Transaction is not structured such that PG&E will perform these functions *on behalf of PacGen*; rather, PG&E will be performing these functions on its own behalf, just as it does today.

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207 Cal. Pub. Util. Code § 216(a)(1) ("'Public utility' includes *every* common carrier, toll bridge corporation, pipeline corporation, gas corporation, *electrical corporation*, telephone corporation, telegraph corporation, water corporation, sewer system corporation, and heat corporation, *where* the service is performed for, or *the commodity is delivered to, the public or any portion thereof*") (emphasis added).

208 Exh. PGE-03 at 3-3:7 to 3-4:14.

209 Exh. CalCCA-01, Attach. C (PG&E response to CalCCA data requests 4.22 and 4.23).

210 *Id.*, Attach. C (PG&E response to CalCCA data request 4.23).

211 *See, e.g.*, Exh. PGE-04-A, Attach. A at 4-AtchA-36 to 4-AtchA-37 (Operations and Services Agreement Exhibits A and B); *id.*, Attach. D at 4-AtchD-5 to 4-AtchD-6 (Billing Services Agreement, Sections 2.1 and 2.3). None of the other Intercompany Service Agreements touch on any of the other steps associated with making retail sales in any more detail. Therefore, based on a review of the Transaction Documents, it does not appear that PG&E is performing the steps associated with selling at retail *on behalf of PacGen*, pursuant to these agreements.

It is also clear from PG&E's testimony that none of PacGen's charges to retail customers will be for the sale of electricity to these customers. Most of PacGen's revenue will be from wholesale sources, including CAISO market revenue associated with its sale of output from the generation assets and wholesale sales of RA and renewable energy credits (RECs) to third parties.[212] PacGen will also retain some portion of the RA and RECs from its resources to count toward Commission compliance requirements, and it will recover the value of the Retained RA and RECs through a generation rate charged to bundled service customers.[213] PacGen's only revenue streams besides wholesale sales and the charge for Retained RA and RECs will be from retail charges to collect the "above market" costs of its resources through the New System Generation Charge (NSGC aka CAM) and PCIA rates.[214] Thus, none of PacGen's retail rates will be for the sale of electricity to retail customers.

In Rebuttal Testimony, PG&E does not dispute that PacGen will not be the entity that will be performing the activities and functions related to the consummation of retail sales.[215] While PG&E points to the fact that PacGen will collect certain revenue requirements—*i.e.*, the NSGC, ERRA Generation Rate, and PCIA—based on the amount of the retail customer's consumption,[216] this does not in any way change the fact that PG&E will be the entity making retail sales by buying energy from the wholesale market and delivering it to customers. As CalCCA Witness Dickman explained during evidentiary hearings:

> The rates will be designed to recover those costs based on the amount of electricity that the customers use, but Pacific Generation is not selling electricity to those customers . . . you can design a rate to collect a certain amount of money in any number of ways. It just happened that these charges that are designed to collect a pot of

[212] Exh. CalCCA-01 at 27:3-5.
[213] *Id*. at 27:6-8.
[214] *Id*. at 27:8-11.
[215] Exh. PGE-21 at 10-2:1-29.
[216] *Id*. at 10-2:21-24.

> dollars are designed to collect that money based on customers' consumption . . . It doesn't mean that . . . the item being sold is electricity.[217]

Thus, PacGen will be operating more like an independent power producer than a public utility, as its objective as a business entity will be to optimize the performance of its generation assets, *e.g.*, through scheduling and dispatch into the CAISO market, performed by PG&E pursuant to the OSA.[218] As described in PG&E's testimony, PacGen would simply own the assets that provide a hedge against PG&E's exposure to fluctuations in the market price to serve its retail load.[219]

Given these practical realities of the contemplated operations of PacGen and PG&E, PacGen does not fit the statutory definition of a "public utility." As PacGen will not be procuring, delivering, or selling any electricity for retail customer consumption, it will not be providing any commodity to the public and thus will not be a "public utility" under California law.[220] While the Application makes clear PG&E's *intent* that PacGen be regulated as a public utility, it does not account for the fact that PacGen does not actually fit within this legal definition, or provide the Commission with sufficient assurance that PacGen will be unable to modify its regulatory status in the future. The Commission should weigh this risk in its determination of whether the Proposed Transaction will effectively preserve the jurisdiction of the Commission.

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217 2 Tr. 200:3-23 (Aug. 22, 2023 – Dickman).

218 Exh. CalCCA-01 at 27:15-18.

219 *Id*. at 27:18-20.

220 Cal. Pub. Util. Code § 216(a)(1) ("'Public utility' includes *every* common carrier, toll bridge corporation, pipeline corporation, gas corporation, *electrical corporation*, telephone corporation, telegraph corporation, water corporation, sewer system corporation, and heat corporation, *where* the service is performed for, or *the commodity is delivered to, the public or any portion thereof*") (emphasis added).

iv. The Proposed Timeline and Process for Commission Approval of the Final Transaction Documents Is Inappropriate (Scoping Ruling Issue 17)

Another major risk of the Proposed Transaction that should inform the Commission's analysis is that the terms of the agreements between and among PG&E, PacGen, and its Minority Investors are subject to change. PG&E is asking the Commission to approve the Proposed Transaction in advance of the selection of the Minority Investors and the finalization of the Transaction Documents. As a result, these form documents the Commission and stakeholders have so carefully reviewed will remain subject to change based on future negotiations with the selected Investors. Thus, at this stage, the full extent of the risks of the Proposed Transaction is simply unknowable.

PG&E argues in favor of a process in which the Commission would issue a decision on the CPCN for PacGen, the contribution of assets to PacGen, and related ratemaking and debt issuance prior to PG&E and PacGen signing with the Minority Investor(s).[221] Because during the course of those negotiations with the Investors there may be amendments or revisions to the form Transaction Documents, PG&E proposes that the final, fully executed documents, including any revisions, be submitted as part of a post-signing Tier 2 Advice Letter.[222] PG&E explains that this will allow for sufficient review because at that time the final documents will be "open to stakeholder review and comment and subject to the disposition of the advice letter by Commission staff."[223]

This proposed review process is inappropriate for a few reasons. First, as CalCCA noted previously in Section IV.B.2.i.e herein, a Tier 2 Advice Letter process is designed to review

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221 Exh. PGE-13 at 1-16:16 to 1-17:2.

222 *Id*.

223 Exh. PGE-17E at 5-7:15-20.

ministerial changes,[224] not substantive and impactful revisions to documents that will govern the operation of a newly created public utility in the state. These changes may affect material terms such as the consent and consultation rights of the Minority Investors, the types of entities that are permitted to serve as Minority Investors, and the code of conduct that will govern the Minority Investor in its ownership and management of PacGen. Revisions to Transaction Documents thus have the potential to change the entire Transaction's risk profile. The full Commission—not just Commission staff via the Advice Letter process—should weigh in on such impactful changes.

Second, although PG&E recognizes the Commission's authority to review any amendments or additions to the various Transaction Documents,[225] it states that, with respect to the Intercompany Service Agreements detailing operational matters between PG&E and PacGen, it does "not believe that *advance* Commission approval for any such amendments or additions would be required."[226] Indeed, PG&E claims that "[s]eeking Commission advance approval [of amendments to these agreements] would impose an unnecessary burden on the Commission and would involve substantial delay in implementing amendments or additions as may be required to adapt the relationship between PG&E and Pacific Generation to changed circumstances."[227] It is quite possible, however, that amendments to these intercompany operational details would be significant to the Commission. For example, the OSA—one such Intercompany Service Agreement[228]—provides the terms under which PG&E will provide the services "necessary or appropriate to operate the business of PacGen and to operate and maintain the PacGen Assets."[229] Changes to those scoped services or to the standard under which the services are performed could

224 General Order 96-B, Section 5.2.
225 Exh. PGE-16E at 4-7:24 to 4-8:5.
226 *Id*. at 4-8:1 (emphasis added).
227 *Id*. at 4-8:1-5.
228 *See* Exh. PG&E-13 at 1-17:3-6.
229 Exh. PG&E-04-A at 4-AtchA-11.

materially alter the relationship between the two utilities and/or the duties assumed by PG&E. The Commission and stakeholders should have an opportunity to review such chances in advance.

v. There is Nothing Preventing PG&E From Paying Gains From the Proposed Transaction Out as Dividends (Scoping Ruling Issue 13)

The Proposed Transaction also poses a risk that the Commission and ratepayers will assume all these additional risks and burdens associated with the Transaction, and PG&E will not even use the Transaction sale proceeds toward its capital budget. PG&E represents that it intends to use the sale proceeds to support PG&E's capital expenditure program and enable PG&E to retire existing debt that is funding rate base.[230] However, PG&E has also stated its goal to resume the payment of regular common stock dividends, and it expects to be eligible to resume dividends by mid-2023.[231] As such, PG&E will not retain and reinvest all of its earnings into capital projects going forward. Once the restriction on PG&E Corporation dividends is lifted, there is no guarantee that proceeds from the sale of Minority Equity Interests in PacGen will be spent on capital projects rather than dividends to shareholders.[232]

PG&E did not initially propose any explicit limitations on the use of proceeds from the equity sale, and it rejected CalCCA's proposed Transaction condition that would have imposed such a limitation.[233] The Transaction condition that PG&E later suggested in place of CalCCA's would require PG&E to expend capital in an amount equal to approximately double the net

[230] Exh. CalCCA-01, Attach. C (PG&E response to CalCCA data request 1.04).
[231] *Id.*, Attach. C (PG&E response to CalCCA data request 2.09, Attachment 1).
[232] California Public Utilities Code Section 817(f) enumerates the acceptable uses of proceeds from approved utility debt issuances, including the acquisition of property, improvement of utility facilities, or reorganization of utility capitalization under a corporate reorganization. There are no similar restrictions on proceeds from the sale of Minority Equity Interests.
[233] Exh. CalCCA-01, Attach. C (PG&E response to CalCCA data request 4.03).

proceeds within 18 months following the Closing.[234] Given the likely Minority Sale proceeds—between approximately $1.1 and $2.5 billion[235]—this commitment is meaningless. PG&E projects capital expenditures between $8 billion and $14 billion annually through 2027.[236] Therefore, PG&E already expects to spend *well beyond* double the likely net proceeds annually on capital expenditures. This condition would not meaningfully restrict or redirect PG&E's spending. PG&E's proposal thus still leaves open the possibility that the proceeds will be used primarily to benefit shareholders rather than ratepayers.

vi. PG&E Provides No Evidence for its Contention That the Proposed Transaction Will Have No Negative Impact on PG&E's Credit Rating (Scoping Ruling Issue 10)

At a high level, the Proposed Transaction would transfer PG&E's lower risk generation assets to a subsidiary and sell off a substantial ownership interest in that entity, while PG&E would maintain full ownership of its nuclear assets as well as its distribution and transmission assets. The assets PG&E would retain are generally understood as higher risk assets than those it would transfer to PacGen. In this context, PG&E's claims that the Transaction will have no negative impact on PG&E's credit rating are surprising. On closer examination, it is clear that these conclusions are unsupported.

PG&E Witness Becker admitted during evidentiary hearings that PG&E has been in touch with credit rating agencies regarding the impact of the Proposed Transaction, but that it has not sought an opinion from these agencies on the potential impact on PG&E's credit rating.[237] Thus, PG&E's opinion regarding credit rating impacts is not based on any analysis from any credit rating

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234 Exh. PG&E-13 at 1-AtchA-4. *See also* 1 Tr. 125:6 to 127:14 and 130:13 to 131:22 (Aug. 21, 2023 – Williams).

235 Exh. CalCCA-01 at 7:6-7.

236 *Id*. at 7:3-5.

237 2 Tr. 315:5-24 (Aug. 22, 2023 – Becker).

agency.[238] PG&E's explanation for why it has not sought an expert opinion on this topic to inform its conclusions in this proceeding did not hold up during hearings. First, Witness Becker suggested that PG&E has not sought out such an analysis because credit rating agencies "typically wait until there is more specific detail available before opining on ratings implications."[239] Later, Witness Becker conceded that credit rating agencies can provide opinions on proposed transactions if asked.[240]

Instead of relying on a credit rating agency, PG&E's Rebuttal Testimony explained PG&E's conclusion that there will be no negative impact on PG&E's credit rating in two brief bullet points, without supporting citations or further explanation: (1) the transferred assets represent only seven percent of PG&E's overall rate base, and (2) PG&E does "not anticipate that the Proposed Transaction will have a material impact on the credit metrics the rating agencies will use to evaluate PG&E and so [it] expects no negative change to PG&E's credit ratings as a result."[241]

PG&E has thus failed to support its position that the Proposed Transaction will have no negative impact on PG&E's credit rating. As it considers the Application, the Commission should understand that this risk has not been meaningfully evaluated on the record. Finally, it is also important to note that PG&E would only find out about a downgrade in credit rating *after* Commission approval of the Transaction,[242] and that FERC has stated that changes in credit outlook may trigger the need for further review of FERC's approval of the first step of this

[238] 2 Tr. 315:5 to 317:11 (Aug. 22, 2023 – Becker).
[239] 2 Tr. 315:5-24 (Aug. 22, 2023 – Becker).
[240] 2 Tr. 315:5 to 317:11 (Aug. 22, 2023 – Becker).
[241] Exh. PGE-19 at 7-1:12-27.
[242] 2 Tr. 316:15-25 (Aug. 22, 2023 – Becker).

Transaction.[243] Therefore, the Commission should recognize that the Transaction also comes with risk of protracted regulatory proceedings as new information concerning the impacts of the Transaction comes to light.

3. If the Commission Does Not Reject the Application it Should Adopt CalCCA's Conditions to Partially Mitigate Ratepayer Harm and Other Risks of the Transaction (Scoping Ruling Issues 1, 2, 4, 7, 8, 9, 10, 11, 12, 13, 16, 17)

For all the reasons discussed above, the Commission should deny the Application. The Proposed Transaction will result in net harm to ratepayers and will introduce significant new risks that could result in additional customer harm as well as additional burdens and strain on the Commission's regulatory oversight process. Thus, PG&E has failed to demonstrate that the Proposed Transaction is in the public interest under both relevant standards of review, Section 854 and Section 851. If the Commission nonetheless deems it appropriate to approve the Application, it should adopt Transaction conditions to protect California ratepayers. While no set of conditions can fully mitigate the risks of the Transaction, CalCCA initially suggested a list of 16 conditions that would help mitigate some of them.[244] PG&E countered by suggesting some of the conditions would be acceptable if revised.[245] CalCCA agrees that some of PG&E's revisions are reasonable, and the agreed conditions are set out in Section IV.B.3.ii below.

However, PG&E rejected the remaining proposed conditions in a form CalCCA believes is necessary to protect California ratepayers from the myriad risks posed by the Proposed

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243 *Order Authorizing Disposition of Jurisdictional Facilities*, 183 FERC ¶ 61,159, at P 41 (May 31, 2023) ("If, however, as a consequence of the Proposed Transaction, PG&E does experience an increase to its cost of debt, a degradation of its credit metrics, or changes to its capital structure, such changes would represent material changes in circumstances that depart from the facts or representations that the Commission relied upon in authorizing the Proposed Transaction triggering the need for a filing by PG&E.").

244 Exh. CalCCA-01, Attach. B.

245 PG&E-13 at 1-AtchA-3-6.

Transaction. These conditions, discussed further in Section IV.B.3.i below, are vital to mitigating some of the most concerning risks presented by the Application. PG&E's reluctance to acknowledge many of these risks and adopt measures to mitigate them should further convince the Commission of the need to deny the Application in its entirety.

i. PG&E's Rejection of Many of CalCCA's Conditions Should Further Convince the Commission of the Need to Deny the Application in its Entirety

PG&E rejected six of CalCCA's proposed conditions, or proposed revisions that fail to adequately mitigate the risk identified by CalCCA. Each such condition—as originally proposed by CalCCA—is listed below and followed by a discussion of PG&E's unacceptable revisions.

1. Gross proceeds from the sale of Minority Equity Interests in Pacific Generation shall be used only to fund PG&E's utility capital expenditure program. PG&E will record the gross proceeds from the equity sale in a discrete account and will report use of funds to the Commission on a project-specific basis.[246]

PG&E proposed revising this condition such that, within 18 months following the Closing, PG&E would expend capital in an amount equal to approximately double the net proceeds.[247] This revision is unacceptable, as it fails to establish a meaningful constraint on PG&E's use of proceeds. PG&E has confirmed that it projects capital expenditures between $8 billion and $14 billion annually through 2027.[248] As the sale proceeds are likely to be in the range of $1.1 to $2.5 billion,[249] a commitment to spend double the proceeds in a period of 18 months is not impressive; it would not require PG&E to do anything it does not already plan to do. The only way to ensure the sale proceeds are not paid out as dividends is to track these funds separately and restrict their use.

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[246] Exh. CalCCA-01, Attach. B (condition 4).
[247] Exh. PG&E-13 at 1-AtchA-4. *See also* 1 Tr. 125:6 to 127:14 and 130:13 to 131:22 (Aug. 21, 2023 – Williams).
[248] Exh. CalCCA-01 at 7:3-5.
[249] *Id*. at 7:6-7.

2. Pacific Generation will abide by the Commission's Standard of Conduct 4 and will demonstrate in the joint annual ERRA Compliance proceedings that scheduling and bidding practices for assets transferred to Pacific Generation are the same before and after the transaction, unless approved in advance by the Commission.[250]

PG&E's proposed revisions mischaracterize the scope of PacGen's obligations under Standard of Conduct 4 (SOC 4), limiting the scope of these obligations to scheduling and dispatch.[251] PG&E is contractually obligated under the various Transaction Documents to operate, maintain, and schedule energy from the generation assets transferred to PacGen ownership. The Commission holds authority to oversee the administration of these contractual obligations pursuant to Assembly Bill 57[252] (AB 57) through the application of SOC 4. SOC 4 requires that "[t]he utilities . . . prudently administer all contracts and generation resources and dispatch the energy in a least-cost manner."[253] The "reasonable manager standard" applies to review of that administration.[254]

SOC 4 thus requires *both* prudent administration of all contracts and generation resources *and* least-cost dispatch. Citing D.02-12-069, the Commission has clearly stated that "[u]nder SOC 4 . . . compliance would consist of a showing of prudence for contract administration (for which the reasonable manager standard would apply) and a showing that resources were dispatched in a least cost manner."[255] PG&E's proposed limitation on the scope of PG&E's responsibility under

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250 *Id.*, Attach. B (condition 5).
251 Exh. PG&E-13 at 1-AtchA-4.
252 Assembly Bill 57 (Stats. 2002, Ch. 835).
253 D.02-10-062, *Interim Opinion*, R.01-10-024 (Oct. 24, 2002), at 52: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/20249.PDF.
254 D.05-01-054, *Opinion Resolving the Reasonableness Phase of SCE's Energy Resource Recovery Account Application*, A.03-10-022 (Jan. 27, 2005) (D.05-01-054), at 15: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/43593.PDF.
255 D.05-01-054 at 15; D.21-05-030, *Phase 2 Decision on Power Charge Indifference Adjustment Cap and Portfolio Optimization*, R.17-06-026 (May 20, 2021), at 31: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M385/K738/385738144.PDF.

the prudent manager standard is an inappropriate attempt to modify the full scope of PG&E and PacGen's obligations under SOC 4.

3. PG&E will not recover in customer rates the costs incurred to undertake the Proposed Transaction. Potential costs identified in PG&E's Application include, but are not limited to:

    a. Third-party transaction costs, including financial advisor fees.

    b. Any costs incurred to obtain releases under the mortgage indenture for properties subject to the lien of the mortgage indenture that will be transferred to Pacific Generation.

    c. Any transfer taxes arising from the contribution of generation assets to Pacific Generation and the sale of Pacific Generation Interests to Minority Investor(s).

    d. Any PG&E labor costs incurred to develop and effectuate the proposed transaction and/or to implement any legal, regulatory, or other internal structural changes resulting from the Transaction.

    e. Any costs/fees associated with the re-execution of the Interconnection Agreements for each of the transferred generation facilities.[256]

PG&E proposed to revise this language such that it would just be required to apply FERC's "hold harmless" policy.[257] However, the Commission's jurisdiction and discretion is separate and distinct from FERC's, and the cost categories included in FERC's "hold harmless" policy should not be used to limit the conditions the Commission may decide to impose on the Proposed Transaction. Additionally, under FERC's "hold harmless" policy, a utility may be able to later seek recovery of costs that were initially not subject to recovery by making certain showings that would allow it to claw back those costs.[258] CalCCA's proposed condition ensures that PG&E will not be permitted to recover from customers *any* costs incurred to undertake the Proposed Transaction, regardless of whether those costs happen to fall within FERC's cost categories;

[256] Exh. CalCCA-01, Attach. B (condition 7).
[257] Exh. PG&E-13 at 1-AtchA-5.
[258] *See Policy Statement on Hold Harmless Commitments*, 155 FERC ¶ 61,189, at n. 22 (May 19, 2016).

further, it will ensure that PG&E will not be able to claw back these disallowed costs at a later date from customers, as may be permitted in some cases under FERC's policy.

4. PG&E and Pacific Generation must modify the draft Amended and Restated LLC Agreement of Pacific Generation to prohibit the Members from transferring any interests in Pacific Generation or rights under the Agreement absent Commission approval.[259]

PG&E rejected the idea that the Commission should have the ability to review any such transfer, and proposed instead that if any Member transfers *at least ten percent* of the Minority Interests, the transfer would be submitted for approval via Tier 1 Advice Letter.[260] As CalCCA has explained in detail above,[261] the Commission, on behalf of California ratepayers, has an interest in the identify of all Minority Investors. As such, Commission review of potential transfers should not be limited to those of Minority Investors holding at least ten percent of the interest in PacGen. In addition, changes in the Minority Investors in PacGen are not the type of "ministerial" details that are appropriate for Staff review and approval under a Tier 1 Advice Letter filing. The Commission *itself* should retain the ability to review the identity of all Minority Investors.

5. Minority Investor(s) and their Related Parties (as defined in the Amended and Restated LLC Agreement of Pacific Generation) and Affiliates (as defined in the Commission's Affiliate Transaction Rules) cannot be Market Participants as defined in D.06-06-066, except to the extent that Minority Investor(s) constitute Market Participants as a result of their investment in Pacific Generation.[262]

PG&E proposed deleting this requirement in its entirety. As discussed in detail in Section IV.B.2.i herein, failing to restrict in any meaningful way the Minority Investors' other business interests and affiliations presents significant risks of market impacts. Minority Investor Representatives will have access to confidential information that they could use to benefit those

[259] Exh. CalCCA-01, Attach. B (condition 8).
[260] Exh. PG&E-13 at 1-AtchA-5.
[261] *See supra* Section IV.B.2.i.
[262] Exh. CalCCA-01, Attach. B (condition 10).

separate business interests, and the Minority Investor may also have consent rights over decisions that would impact their separate business interests. PG&E's reliance on a yet-to-be drafted PacGen code of conduct, and provisions in the Transaction Documents that restrict only *disclosure* of confidential information and use of confidential information *to the detriment of PacGen* is unacceptable for the reasons discussed in Section IV.B.2.i above. PG&E has failed to show how these meager protections would mitigate these conflicts arising out of Minority Investor Representatives' use of confidential information and the Investor's management duties concerning asset sales and purchases.

> 6. Pacific Generation's authorized return on equity shall not exceed, and shall be presumed to be lower than, the return on equity granted by the Commission to PG&E. The specific differential between the authorized return on equity for Pacific Generation and PG&E will be determined in the next joint cost of capital application or earlier if and when PG&E's authorized cost of capital is updated.[263]

PG&E's proposed language would require PacGen's return on equity (ROE) to be equal to PG&E's ROE.[264] This is inappropriate in light of the draft Transaction Documents—both the FRAA and the Wildfire Indemnification Agreement (WIA)—that shift business risk away from PacGen and back to PG&E.

In D.22-12-031 the Commission articulated its goal to set ROE "at a level of return commensurate with market returns on investments having corresponding risks and adequate to enable a utility to attract investors to finance the replacement and expansion of a utility's facilities to fulfill its public utility service obligation."[265] A utility's ROE should accurately reflect its level

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263 *Id.*, Attach. B (condition 13). Note CalCCA has accepted some of PG&E's proposed revisions in this slightly modified version presented here.

264 Exh. PG&E-13 at 1-AtchA-6.

265 D.22-12-031, *Decision Addressing Test Year 2023 Cost of Capital for PG&E, SCE, Southern California Gas Company, and SDG&E*, A.22-04-008 et al. (Dec. 15, 2022) (D.22-12-031), at 15: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M500/K015/500015851.PDF.

of business risk. And contrary to PG&E's suggestion in Rebuttal Testimony,[266] the Commission specifically confirmed in D.22-12-031 that PG&E's ROE calculation accounts for wildfire risks.[267]

Both the FRAA and the WIA lower PacGen's business risk relative to PG&E. The FRAA ensures PacGen fully recovers the forecasted amount of market revenue (and natural gas fuel costs) when selling the output of its generation resources in the CAISO market.[268] If PacGen's market revenues are lower than forecasted, PG&E would make up the difference.[269] If PacGen's market revenues are higher than forecasted, PacGen would pay PG&E the difference.[270] The purpose of the FRAA is to "insulate Pacific Generation from market forecast risk associated with its market revenue . . . and further support Pacific Generation's valuation by decreasing Pacific Generation's year-over-year variability."[271] Thus, the FRAA ensures that volatility in wholesale revenue received from CAISO will be absorbed by PG&E.

The WIA provides that PG&E will indemnify PacGen for substantially all wildfire-related costs. Pursuant to the WIA, PG&E will be responsible for the cost of property damage at PacGen facilities and will pay the cost of third-party claims against PacGen arising from certain wildfires even if they are alleged to be cause by PacGen assets.[272]

PG&E's proposal to set PacGen's authorized ROE equal to that of PG&E ignores these elements of Transaction Documents specifically designed to reduce PacGen's business risk. Based

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266 *See* Exh. PGE-18 at 6-3:13-17. PG&E justifies its position by citing to D.22-12-031 for the proposition that the Commission will not consider a wildfire risk premium in the adopted ROE. However, this is a misinterpretation of this decision—the Commission actually determined in D.22-12-031 that the financial modeling performed for PG&E's ROE calculations *already includes* those wildfire risks. D.22-12-031, Finding of Fact 35 and Conclusion of Law 15.

267 D.22-12-031, Finding of Fact 35 and Conclusion of Law 15.

268 Exh. CalCCA-01 at 24:14-17.

269 *Id*. at 24:18-19.

270 *Id*. at 24:19-20.

271 *Id*. at 24:20 to 25:1.

272 *Id*. at 25:4-8.

on that reduced risk, PacGen's ROE should be presumed to be lower than that of PG&E, with the specific differential determined in the next joint cost of capital application, if not earlier.

ii. If the Commission Approves the Proposed Transaction PG&E and CalCCA Agree That a Subset of CalCCA's Proposed Conditions as Revised by PG&E Should be Adopted

If the Commission approves the Proposed Transaction, PG&E and CalCCA agree that a subset of CalCCA's proposed conditions—as revised by PG&E—should be adopted.[273] These conditions would only partially mitigate some of the risks posed by the Proposed Transaction:

1. The Commission will have the authority to review PG&E's performance of its obligations under its agreements with PacGen, including the Intercompany Service Agreements (i.e., Operations and Services Agreement, Billing Services Agreement, Generation Facility Operations, Scheduling and Dispatch Agreement, and Fuel Procurement Agreement), the Legal and Regulatory Matters Agreement, the Benefits Agreement, the Interconnection Agreements, the Forecast Realization Adjustment Agreement, and the Wildfire Indemnification Agreement.

2. PG&E cannot recover from ratepayers the costs arising from the breach by PG&E or the Minority Investor(s) of any covenant or agreement contained in any of the Amended LLC Agreement or Minority Sale Agreement.[274]

3. Any chargebacks to PG&E for disputed excess costs in PacGen's budget will not be recoverable from customers of PG&E or PacGen, provided that the foregoing will not affect PG&E's recovery of previously-authorized rates.

4. PacGen will request, through this proceeding or advice letter, Commission approval of PacGen's adoption of PG&E's most recently approved amended Bundled Procurement Plan and application of that Bundled Procurement Plan to the assets transferred to PacGen. Approval of future amendments to the Bundled Procurement Plan affecting PacGen and PG&E will be requested of the Commission through joint PG&E and PacGen filings in the applicable Integrated Resource Planning or other proceeding.

5. PacGen shall not sell, lease, assign, mortgage, or otherwise dispose of, or encumber any property necessary or useful in the performance of its duties to the public absent Commission approval.

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[273] *Id.*, Attach. B (conditions 1, 2, 3, 6, 9, 11, 12, 14, 15, 16, as revised by PG&E in Exh. PGE-13, Attach. A).

[274] In its Rebuttal Testimony, PG&E attempted to define "Transaction Documents" as including only the MSA and the LLC Agreement. Exh. PGE-13 at 1-AtchA-4. CalCCA does not agree to this limitation or definition.

6. Before the consummation of the Proposed Transaction, PacGen shall submit for Commission approval substantially all balancing accounts, preliminary statements, electric rules, and electric tariffs applicable or related to the assets to be transferred (or joint tariffs, preliminary statements, electric rules, and electric tariffs, that accomplish the same). Such documents will conform in all material respects to the documents currently in use by PG&E for these assets. PacGen and PG&E may also make subsequent advice letter filings to the extent necessary.

7. The cost of debt used to determine PacGen's initial authorized revenue requirement will be the lesser of 1) PG&E's cost of debt authorized in D.22-04-008 or 2) PacGen's actual cost of debt issued to fund the initial capitalization. PacGen's authorized cost of capital may be updated in the next joint cost of capital application filed by PG&E and PacGen or earlier if and when PG&E's authorized cost of capital is updated.

8. PG&E and PacGen are required to jointly file all General Rate Case Phase I and II, ERRA Forecast, ERRA Compliance, Cost of Capital applications, Annual Electric Trueup filings, and all other generation-related ratemaking applications in which assets from both entities are involved, unless the Commission otherwise directs. In each joint filing:

    a. The same level of detail must be provided for PacGen aspects of the filing as it is for PG&E.

    b. All Master Data Requests applicable to PG&E must also be applicable to PacGen (to the extent relevant) and provided at the outset of each of those proceedings to provide all data necessary and relevant to the review of joint applications.

9. PG&E must clearly identify in its next Phase I general rate case all costs assigned or allocated to PacGen pursuant to its Intercompany Service Agreements with PacGen (including the Operations and Services Agreement, Billing Services Agreement, Generation Facility Operations, Scheduling and Dispatch Agreement, Fuel Procurement Agreement, the Legal and Regulatory Matters Agreement, the Benefits Agreement, the Interconnection Agreements, the Forecast Realization Adjustment Agreement, and the Wildfire Indemnification Agreement), and identify how such costs previously have been assigned or allocated to PG&E's functional lines of business before the proposed Transaction.

10. In the event that the Commission (through the advice letter process) approves the Proposed Transaction before all the final versions of the Transaction Documents have been made available, any modifications to the Transaction Documents prior to the closing and following such Commission approval must be limited to non-material changes, unless the Commission otherwise directs or authorizes.

iii. If the Commission Approves the Proposed Transaction it Should Also Adopt an Additional Condition Not Included in CalCCA's Direct Testimony

If the Commission approves the Proposed Transaction, it should also adopt as a condition of its approval that PG&E must share a portion of the economic benefits of the Proposed Transaction with ratepayers. CalCCA does not propose a specific number for this allocation; the Commission should use its discretion to allocate an equitable portion of the estimated economic benefits to ratepayers in recognition of the fact that ratepayers will bear the increased costs and risks of the Proposed Transaction. Importantly, this condition would also be consistent with Public Utilities Code Section 854's requirements that (1) the Transaction provide short-term and long-term economic benefits to ratepayers, and (2) the Transaction equitably allocate the total short-term and long-term forecasted economic benefits of the Transaction such that ratepayers receive not less than 50 percent of those benefits.[275]

X. CONCLUSION

CalCCA urges the Commission to deny the Application in its entirety. The Application is not in the public interest under the standards of review contained in Public Utilities Code sections 854 and 851. If the Commission nonetheless approves the Proposed Transaction, it should adopt CalCCA's proposed conditions to partially mitigate some of the ratepayer harms and risks posed by the Transaction.

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[275] Cal. Pub. Util. Code § 854(b).

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