BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2024 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U39E)	Application 23-05-012

REPLY COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION IN RESPONSE TO ALJ RULING REGARDING FIXED GENERATION COSTS

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SUMMARY OF RECOMMENDATIONS

- The Commission should initiate a Phase II of each IOU's ERRA Forecast proceeding, and consolidate those phases, in order to ensure the Commission can develop the record necessary to ensure a reasonable and consistent resolution of the issues triggered by the ALJ Ruling without violating the Commission's *de facto* prohibition on policymaking in the ERRA Forecast proceedings.

- The Commission should initiate a consolidated Phase II after the October Update and proposed decisions in the current phase of each IOU's ERRA Forecast proceeding has passed.

- The Commission should not consider PG&E's proposed modification to the methodology it uses to allocate Collateral Costs in the current phase of this proceeding. If the Commission creates a consolidated Phase II, it should consider PG&E's proposal in Phase II.

- If the Commission creates a consolidated Phase II, it should move what is currently Scoping Ruling Item 9(a) in this proceeding to Phase II to allow the Commission to address "Fixed Generation Cost"-related issues simultaneously across service territories and avoid the prohibition on policymaking in the ERRA Forecast.

- If the Commission creates a consolidated Phase II, it should not consider PG&E's Replacement RA Costs in that phase because PG&E's current approach is a settled issue recently litigated in the utility's 2019 ERRA Compliance proceeding.

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Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2024 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U39E)	Application 23-05-012

REPLY COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION IN RESPONSE TO ALJ RULING REGARDING FIXED GENERATION COSTS

The California Community Choice Association[1] (CalCCA) hereby submits these reply comments in response to Administrative Law Judge Long's August 1, 2023 Ruling (ALJ Ruling),[2] regarding the "Fixed Generation Costs" within the *Application of Pacific Gas and Electric Company (PG&E) for Adoption of Electric Revenue Requirements and Rates Associated with its 2024 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation* submitted on May 15, 2023 (Application).

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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 (EBCE), Energy for Palmdale's Independent Choice, Lancaster Choice Energy, Marin Clean Energy (MCE), Orange County Power Authority, Peninsula Clean Energy (PCE), 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 (SJCE), Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

[2] Application ("A.") 23-05-012, *Application of Pacific Gas and Electric Company (PG&E) for Adoption of Electric Revenue Requirements and Rates Associated with its 2024 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation* (May 15, 2023) ("Application"); A.23-05-012, *Administrative Law Judge's Ruling Directing Parties To Comment Regarding Fixed Generation Costs* (Aug. 1, 2023) ("ALJ Ruling").

The investor-owned utilities' (IOUs) opening comments on the ALJ Ruling (issued in each of the three IOUs' pending ERRA Forecast proceedings) validate CalCCA's concerns. Among those concerns, CalCCA anticipated that each IOU defines and records "Fixed Generation Costs" differently.[3] CalCCA also anticipated the IOUs might interpret the ALJ Ruling as an invitation to include as many "Fixed Generation Costs" as possible in new or existing nonbypassable charges.[4] Finally, CalCCA anticipated the IOUs already spread a significant portion of their "Fixed Generation Costs" across bundled and unbundled customers, rendering any discussion of the "Fixed Generation Costs" borne by a hypothetical "Last Remaining Bundled Customer" a distraction from the substantial work to be done in the IOUs' expedited ERRA Forecast proceedings.[5]

The IOUs' opening comments demonstrate the three IOUs indeed define or record "Fixed Generation Costs" inconsistently,[6] as CalCCA and the Public Advocates Office[7] (Cal Advocates) anticipated. And while the IOUs indeed provided a long list of costs in their respective responses to Question 2, the IOUs recover the bulk of those cost categories from all customers—unbundled

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[3] A.23-05-012, *Comments of California Community Choice Association in Response to ALJ Order Regarding Fixed Generation Costs* at 5-6 (Aug. 16, 2023) (CalCCA Opening Comments).

[4] *Id*. at 2.

[5] *Id*. at 5.

[6] A.23-05-012, *Pacific Gas and Electric Company's (U 39 E) Response to Administrative Law Judge's Ruling Directing Parties to Comment Regarding Fixed Generation Costs* at 1 (Aug. 16, 2023) (PG&E Opening Comments); A.23-06-001, *Opening Comments of Southern California Edison Company (U 338 E) to Administrative Law Judge's Ruling Directing Parties to Comment Regarding Fixed Generation Costs* at 1 (Aug. 16, 2023) (SCE Opening Comments) (included as Attachment A to these reply comments); A.23-05-013, *San Diego Gas & Electric Company's (U 902 E) Opening Comments on Administrative Law Judge's Ruling Directing Parties to Comment Regarding Fixed Generation Costs* at 1 (Aug. 16, 2023) (SDG&E Opening Comments) (included as Attachment B to these reply comments).

[7] *See* A.23-05-012, *Public Advocates Office (Cal Advocates) Comments on the Administrative Law Judge's Ruling Directing Parties to Comment Regarding Fixed Generation Costs* at 4 (Aug. 16, 2023) (observing that each IOU "appeared to define "fixed costs" differently" in response to a set of data requests issued in a previous proceeding); *see also* Cal Advocates' parallel comments in A.23-06-001 (SCE 2024 ERRA Forecast proceeding) and A.23-05-013 (SDG&E 2024 ERRA Forecast proceeding).

and bundled—through existing cost recovery mechanisms. As Southern California Edison (SCE) correctly notes:

> [T]he establishment of cost recovery mechanisms [that] allocate costs across both bundled service and departing load customers, such as the [Portfolio Allocation Balancing Account or PABA] with its vintaged cost recovery, <u>greatly reduces the risk of stranded costs associated with a declining bundled service population (even assuming a continuing trend)</u>. This is because the departing load customers would continue to pay their cost responsibility through the [Power Charge Indifference Adjustment or PCIA] and [Competition Transition Charge or CTC] for PABA, and other rates that broadly allocate procurement cost, such as [Cost Allocation Mechanism or CAM] for [New System Generation Balancing Account or NSGBA], including Fixed Generation Costs recovered through the operation of these SCE Balancing Accounts.[8]

Overall, the IOUs' opening comments confirm a thorough and comprehensive evaluation of the issues triggered by the ALJ Ruling (1) requires further record development, and (2) lacks urgency. Indeed, of the three IOUs, only PG&E proposes to address any issue related to the ALJ Ruling in the current phase of its ERRA Forecast proceeding. Even SCE describes the "last bundled customer" scenario as "extreme and highly improbable."[9] The Commission should therefore adopt CalCCA's recommendations and initiate a consolidated Phase II to address the issues triggered by the ALJ Ruling once the current phase of the IOUs' 2024 ERRA Forecast proceedings is complete.

The Commission should reject PG&E's attempt to wedge a new issue into this phase of its ERRA Forecast proceeding. PG&E states it allocates two common cost categories—Energy Supply Administration (ESA) Costs and Collateral Costs—to multiple balancing accounts based on the prior year's adopted forecast **net** revenue requirements for those accounts, and now

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8 SCE Opening Comments at 5.

9 *Id*.

proposes to allocate those cost categories based on gross revenue requirements.[10] PG&E did not propose any change to its Collateral Cost allocation methodology in its Application or direct testimony and parties have therefore had no opportunity to evaluate that proposal.

The Commission should instead consider changes to PG&E's common cost allocation methodology—including the allocation of both ESA and Collateral Costs—in a Phase II. While PG&E's ESA Cost allocation methodology is currently Scoping Item 9(a), the IOUs' opening comments revealed sharply contrasting approaches to ESA Cost accounting and recovery: PG&E allocates "fixed" ESA Costs to its ERRA, PABA and NSGBA;[11] SCE forecasts no "fixed" ESA Costs;[12] and San Diego Gas & Electric Company (SDG&E) recovers its ESA Costs through distribution rates.[13] In light of the significant and unexplained disparities between the IOUs with respect to the same category of "Fixed Generation Costs," the Commission should move the ESA Cost allocation issue into a consolidated Phase II in order to address that issue consistently and comprehensively across all three IOU service territories.

The Commission should also reject PG&E's proposal to address its "Replacement Resource Adequacy (RA) Costs" in Phase II of this proceeding. PG&E's current approach—which is to assign the costs of substitute capacity during outages to the balancing account from which the need for substitute capacity originated—is a settled issue recently litigated in the utility's 2019 ERRA Compliance proceeding. The Commission should not revisit or allow PG&E to relitigate this settled issue in this proceeding.

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10 PG&E Opening Comments at 6-7.

11 *Id*. at 5.

12 SCE Opening Comments at 3.

13 SDG&E Opening Comments at 3.

I. The IOUs' opening comments reveal inconsistencies in the way the IOUs define "Fixed Generation Costs"

The IOUs do not define "Fixed Generation Costs" consistently, which makes it difficult to compare the IOUs' costs (and any projected impacts on a hypothetical last remaining bundled customer) on an "apples-to-apples" basis. PG&E's definition of "Fixed Generation Costs" mirrors the ALJ Ruling: "costs that do not change based on the amount of electricity customers use or the amount of operating time associated with the electricity generation." PG&E's response to Question 2 (Table Identifying Cost Categories), however, suggests that many of its "Fixed Generation Costs" are in fact volumetric costs that will decrease based on its customers' usage pattern.[14] SCE echoes the definition of "Fixed Generation Costs" in the ALJ Ruling, but clarifies that its definition excludes energy costs.[15] SDG&E, in sharp contrast with PG&E and SCE, defines "Fixed Generation Costs" as "costs that do not diminish as load departs."[16] SDG&E's definition leads it to list, in its response to Question 2, costs that change based on the amount of operating time associated with electricity generation (*i.e.*, costs that are conventionally considered "variable", not "fixed", such as generation fuel costs).[17]

The IOUs contrasting definitions of "Fixed Generation Cost" are clear evidence that there is no consensus around what categories of generation costs are "fixed", and they demonstrate the issue would benefit from further discussion beyond the accelerated comment schedule the ALJ Ruling affords. In order to better delineate the issues raised in the ALJ Ruling, the Commission

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14 PG&E Opening Comments at 1.

15 SCE Opening Comments at 1.

16 SDG&E Opening Comments at 1.

17 *Id*. at 1-4.

should therefore give parties a less constrained opportunity to discuss the appropriate definition of "Fixed Generation Costs" and probe other parties' definitions.

That discussion, however, should not occur in the current phase of each IOU's ERRA Forecast proceeding. The limited purpose of the ERRA Forecast proceedings is to fulfill the IOUs' obligation under Pub. Util. Code Section 454.5(d)(3) to forecast generation rates for the following year based on forecasted load and forecasted balances in the ERRA and other balancing accounts established by prior Commission decisions.[18] The Commission has largely forbidden policymaking in ERRA Forecast cases unless a prior Commission decision has ordered such policymaking.[19] The Commission should therefore adopt CalCCA's recommendation and open a consolidated Phase II of the IOU's ERRA Forecast proceeding to address the issues triggered by the ALJ Ruling. Among those issues, the parties should consider the threshold question: "What is a reasonable definition of Fixed Generation Costs for all three IOUs?"[20]

II. The IOUs' Opening Comments confirm the issues triggered by the ALJ Ruling do not require urgent Commission action

While the ALJ Ruling raises several weighty issues, the Commission need not rush to resolve any of those issues, for at least two reasons. First, as CalCCA explained in opening comments, none of the three service territories is near the extreme "last bundled customer" scenario the ALJ Ruling lays out. SCE, for example, correctly describes the "last bundled customer" scenario as "extreme and highly improbable", because "[w]hile SCE's bundled service

[18] *See* CalCCA Opening Comments at 8; SCE Opening Comments at 6 (stating the objective of SCE's 2024 ERRA Forecast application is "the timely approval of the forecasted revenue requirement and cost recovery associated with fuel and purchased power for 2024.")

[19] CalCCA Opening Comments at 9.

[20] CalCCA presents other potential Phase II scoping issues triggered by the ALJ Ruling at page 3 of its Opening Comments.

customer load has decreased in recent years, SCE has no indication that the trend will continue such that only a single bundled service customer would remain."[21]

Second, as CalCCA explained in Opening Comments, and as the IOUs' opening comments illustrate, several of the IOUs' fixed generation cost categories are already spread across bundled and unbundled customers through balancing accounts other than ERRA.[22] SDG&E's "Fixed Generation Cost" table, for example, excludes many of the "Fixed Generation Costs" it identified in its response to Question 1,[23] explaining that those costs "are constant for the last remaining bundled customer, before and after load departure, because all customers pay for those costs."[24] Indeed, as bundled customer departures have increased, departed customers have taken on more of the IOUs' "Fixed Generation Costs." As SCE correctly explains, "the establishment of cost recovery mechanisms [that] allocate costs across both bundled service and departing load customers, such as the PABA with its vintaged cost recovery, greatly reduces the risk of stranded costs associated with a declining bundled service population (even assuming a continuing trend)."[25] That means even in the extreme and unlikely "last remaining bundled customer scenario," that customer would only pay for those costs in the IOU's ERRA balancing account, which would include a fraction of the IOU's total Fixed Generation Costs.

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21 SCE Opening Comments at 5.

22 *See* CalCCA Opening Comments at 5; PG&E Opening Comments at 5 (noting that certain of its Fixed Generation Costs are recovered through balancing accounts other than ERRA, and "such broader cost allocation does not shift costs to remaining bundled service customers.")

23 Those include costs in the Portfolio Allocation Balancing Account (PABA), Transition Cost Balancing Account. (TCBA), Local Generating Balancing Account (LGBA), Modified Cost Allocation Mechanism Balancing Account (MCAMBA), the Tree Mortality Non-Bypassable Charge Balancing Account (TMNBCBA). SDG&E Opening Comments at 2.

24 SDG&E Opening Comments at 4.

25 SCE Opening Comments at 5.

In light of the IOUs' current bundled customer counts, and the existing cost recovery mechanisms in place to ensure several Fixed Generation Costs are spread to all IOU customers, the Commission can and should act deliberately in addressing the issues triggered by the ALJ Ruling. A consolidated Phase II would give the Commission the breathing room necessary to do so.

A. The Commission should reject PG&E's attempt to inject a new issue into its ERRA Forecast Proceeding at the eleventh hour

Among its "Fixed Generation Costs," PG&E identifies the costs it pays to financial institutions for posting collateral to counterparties for its electric generation portfolio ("Collateral Costs").[26] PG&E allocates Collateral Costs to ERRA and PABA using common cost allocation factors based on the prior year's adopted net revenue requirements (similar to its treatment of ESA costs), and proposes to modify that methodology and allocate Collateral Costs based on gross generation authorized costs in the current phase of this proceeding.[27]

PG&E's proposal is a wholly improper attempt to inject a new issue into this proceeding at the eleventh hour. While PG&E's Application and direct testimony proposed similar modifications to the manner in which PG&E allocates **ESA costs**, PG&E did not propose to apply that modified methodology to its Collateral Costs nor did it provide any justification for doing so.[28] PG&E proposes to change the way it allocates its Collateral Costs for the first time in its opening comments on the ALJ Ruling.

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[26] PG&E Opening Comments at 3.

[27] *Id*. at 6.

[28] *See* PG&E Direct Testimony at 5-6 – 5-7 (discussing PG&E's 2024 Collateral Costs, but making no proposal to change the underlying allocation methodology); 9-10 – 9-11 (discussing a change to the methodology for allocating ESA costs to the generation-related balancing accounts, but making no proposal related to Collateral Costs).

Intervenor testimony in this proceeding is due three weeks from the date PG&E filed its opening comments.[29] Parties simply do not have sufficient time to evaluate PG&E's new proposal and determine whether allocating Collateral Costs based on gross generation authorized costs would be consistent with applicable rules, regulations, resolutions and prior Commission decisions. The Commission should not, therefore, consider or make any changes to PG&E's allocation of Collateral Costs in the current phase of this ERRA Forecast proceeding.

Any modifications to PG&E's methodology for allocating Collateral Costs may, however, be an appropriate topic for Phase II of this proceeding. Moreover, to the extent the Commission creates a Phase II of this proceeding, the Commission should address the allocation of both ESA Costs and Collateral Costs in that phase. While PG&E's allocation of ESA Costs is currently within scope for this phase of this proceeding (Scoping Issue 9(a)), moving the issue to a Phase II will not only ensure the Commission avoids contravening the prohibition on policymaking in expedited ERRA Forecast cases, but will also ensure the Commission addresses the allocation and recovery of ESA and Collateral 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). As discussed above, the IOUs' opening comments on the ALJ Ruling reveal significant differences between the IOUs' ESA costs, including the magnitude of those costs, how those costs are recorded, and how those costs are recovered from customers. These disparities indicate the Commission would benefit from more comprehensive record development regarding the IOUs' treatment of ESA and Collateral Fixed Generation Cost categories, once the significant work related to PG&E's Forecast Application and October Update is complete.

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[29] A.23-05-012, Assigned Commissioner's Scoping Memo and Ruling at 6 (Aug. 3, 2023).

B. <u>The Commission Should Not Address Replacement Resource Adequacy Costs in a Phase II of this Proceeding</u>

In its opening comments, PG&E explains it counts its costs associated with resource outages and outage replacement (Replacement Resource Adequacy (RA) Costs) as "Retained RA" and assigns those costs to its bundled customers.[30] PG&E recommends consideration of Replacement RA Costs in a Phase II of this proceeding, and presumably seeks to change the way it records and recovers those costs.[31]

While CalCCA supports consideration of several issues raised by the ALJ Ruling in a Phase II of this proceeding,[32] the Commission should not address PG&E's Replacement RA Costs in Phase II. PG&E correctly assigns the costs of substitute capacity during outages to the balancing account from which the need for substitute capacity originated. In other words, if an ERRA resource is on outage, PG&E appropriately records the costs of substitute resources to ERRA and recovers those costs from bundled customers. Any other approach—*i.e.*, requiring unbundled customers to pay for the costs of replacing resources needed for bundled customer compliance—would unfairly require those customers to subsidize bundled customers.

PG&E, the Cal Advocates, and several CCAs ("Joint CCAs") recently addressed this issue in PG&E's 2019 ERRA Compliance proceeding, A.20-02-009. In that proceeding, the Joint CCAs observed PG&E used PCIA-eligible resources to provide replacement RA capacity for ERRA resources unavailable due to planned outages. Despite using those PCIA-resources to serve bundled customers only, PG&E incorrectly counted the substitution capacity as "Unsold RA" in the PABA, rather than counting that capacity as "Retained RA" and charging bundled customers

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30 PG&E Opening Comments at 4.

31 *Id*. at 7.

32 *See* CalCCA Opening Comments at 8-11.

for the use of that capacity.[33] PG&E ultimately agreed those costs should have been charged to bundled customers, and accordingly adjusted $4.5 million in PABA from Unsold RA to Retained RA. The Commission ultimately approved the parties' settlement in that proceeding, which reflected PG&E's agreement with respect to the appropriate treatment of substitution capacity costs.[34] PG&E now conducts a regular accounting review of ERRA, PABA and CAM to make sure those portfolios do not "lean on" each other. Where PG&E uses resources from one portfolio to substitute capacity for resources in another portfolio, it transfers the related costs to the balancing account associated with the second portfolio. PG&E has followed this approach in each of its ERRA Compliance cases since addressing the issue in A.20-02-009. The Commission should not revisit or allow PG&E to relitigate this settled issue in a Phase II of this proceeding.

III. Conclusion

CalCCA appreciates the opportunity to submit these reply comments. For the reasons in its opening and reply comments on the ALJ Ruling, CalCCA requests the Commission adopt its recommendations. To the extent the Commission initiates a consolidated Phase II of the IOUs' 2024 ERRA Forecast proceedings, CalCCA looks forward to continuing to work with the parties to this proceeding, as well as the other IOUs, on issues related to the IOUs' Fixed Generation Costs in that consolidated Phase II.

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33 A.20-02-009, *Prepared Direct Testimony of Brian Dickman on behalf of Joint Community Choice Aggregators* at 28 (Jul. 10, 2020).

34 *See* A.20-02-009, D.21-07-013 at 12 (approving settlement agreement, and describing parties' compromises, including PG&E's agreement to make an adjustment of $4.5 million in the PABA from Unsold RA to Retained RA because PG&E used PCIA-eligible resources to provide replacement RA capacity for ERRA resources unavailable due to planned outages.)

Respectfully submitted,

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ATTACHMENT A

SCE OPENING COMMENTS

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) For Approval of Its 2024 ERRA Forecast Proceeding Revenue Requirement	A.23-06-001

OPENING COMMENTS OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) TO ADMINISTRATIVE LAW JUDGE'S RULING DIRECTING PARTIES TO COMMENT REGARDING FIXED GENERATION COSTS

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Dated: **August 16, 2023**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) For Approval of Its 2024 ERRA Forecast Proceeding Revenue Requirement	A.23-06-001

OPENING COMMENTS OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) TO ADMINISTRATIVE LAW JUDGE'S RULING DIRECTING PARTIES TO COMMENT REGARDING FIXED GENERATION COSTS

Pursuant to the *Administrative Law Judge's Ruling Directing Parties to Comment Regarding Fixed Generation Costs* (Ruling) dated August 1, 2023, Southern California Edison Company (SCE) respectfully submits its Opening Comments.

I. INTRODUCTION

The Ruling directs the parties to submit comments on the issues regarding investor-owned utility (IOU) generation costs recovered through the Energy Resource Recovery Account (ERRA) Balancing Account (BA) that do not change based on the amount of electricity customers use or the amount of operating time associated with the electricity generation (referred to as "Fixed Generation Costs").[1] As discussed below, a relatively limited amount of SCE's Fixed Generation Costs are recovered through the ERRA BA. The majority of SCE's Fixed Generation Costs are recovered through SCE's Portfolio Allocation Balancing Account (PABA), New System Generation Balancing Account (NSGBA) and

1 *See* Ruling, p. 1. SCE interprets the phrase "costs that do not change based on . . . the amount of operating time associated with the electricity generation" in the Ruling's definition to exclude the circumstance where the generation facility is not operational (e.g., an unplanned outage) because if it was not operating at all, SCE would likely not incur any costs. Rather, SCE interprets this phrase to include capacity costs but not energy costs because energy costs are based on the amount of electricity generation while capacity costs are typically based on the unit's availability.

other balancing accounts that allocate cost recovery to both bundled service and departing load customers.

II. SCE'S RESPONSES

A. Identify and briefly describe each category of Fixed Generation Costs in this proceeding.

SCE's annual ERRA Forecast application includes a forecast of fuel and purchased power (F&PP) costs for the primary purpose of setting generation rates for SCE's bundled service customers. SCE's F&PP costs are recovered across a variety of cost recovery mechanisms, including SCE's ERRA BA, PABA, NSGBA, Modified Cost Allocation Mechanism Balancing Account (MCAMBA), Tree Mortality Non-Bypassable Charge Balancing Account (TMNBCBA), BioMAT Non-Bypassable Charge Balancing Account (BMNBCBA), and the Base Revenue Requirement Balancing Account (BRRBA-D). SCE's response in Question B below lists the Fixed Generation Costs included in the instant application for the Commission's review and approval.

The Fixed Generation Costs in SCE ERRA BA are associated primarily with gas transportation and capacity costs that are recovered solely from SCE's bundled service customers and constitute a relatively limited amount of SCE's total Fixed Generation Costs. The majority of SCE's Fixed Generation Costs are recovered through SCE's PABA and NSGBA. This includes costs associated with Competitive Transmission Charge (CTC) contract costs, Western Renewal Energy Generation Information System, Power Charge Indifference Adjustment (PCIA)-eligible Cogeneration/Renewables, system reliability procurement, resource adequacy and local capacity requirements (LCR), cost allocation mechanism (CAM) baseload cogeneration, renewables energy management, the adjustments from the Green Tariff Shared Renewables (GTSR), Hoover Interutility Contract, and other base revenue requirements. There are also limited Fixed Generation Costs associated with the MCAMBA, and BRRBA-D that result from system reliability and LCR capacity.

B. **Please complete the following table by filling in every blank cell – if any cost categories were identified in question 1 that are not included in this table, please include them.**

In the table below, SCE included only Fixed Generation Costs included in the 2024 ERRA Forecast application. This does not include the variable portion of the costs that are included in the application.

Cost	Balancing Account Used for Tracking	Estimated 2023 Cost	Estimated 2023 Cost for a Hypothetical Last Remaining Bundled Service Customer **
Competitive Transmission Charge Contract Costs	PABA	$7,164,867	$12,703
California Independent System Operator and North American Electric Reliability Corporation Costs	ERRA BA, PABA	$0	$0
Hedging-related Costs	ERRA BA	$0	$0
Western Renewal Energy Generation Information System Costs	PABA	$2,669	$5
PCIA-related Cogeneration/Renewables Costs	PABA	$3,782,407	$6,706
Electric Supply Administration Costs	*N/A*	$0	$0
Replacement Resource Adequacy Costs	*N/A*	$0	$0
2018 Integrated Distributed Energy Resources (IDER) Request for Offers (RFO)	ERRA BA	$322,560	$322,560
Distribution Deferral (DDCCBA-DIDF)	ERRA BA	$161,000	$161,000

Gas Transportation Costs	ERRA BA	$3,034,564	$3,034,564
Modified Cost Allocation Mechanism (MCAM) Capacity Costs (previously System Reliability Procurement Memorandum Account)	PABA, NSGBA, MCAMBA	$89,206,190	$158,157
Resource Adequacy (RA) Capacity Costs	PABA	$483,554,554	$857,313
Local Capacity Requirements (LCR) Capacity Costs	PPPAM and BRRBA-D	$37,364,803	$66,244
Cost Allocation Mechanism (CAM) Related RA Costs	NSGBA	$519,743,616	$921,476
Hoover Inter-utility Contract Payments	PABA	$4,742,861	$8,409
CAM Baseload Cogeneration Costs	NSGBA	$22,679,489	$40,209
Renewables Energy Management Costs	PABA	($109,929,827)	($194,899)
Green Tariff Shared Renewables (GTSR) Program Adjustments	PABA	($9,705,089)	($17,207)
Legacy Utility-Owned Generation (UOG) Base Revenue Requirement (Litigated in GRC)	PABA	$503,935,787	$893,449
Mountainview, Fuel Cells, Solar Photovoltaic Program (SPVP) Base Revenue Requirement (Litigated in GRC)	PABA	$223,033,866	$395,426
Total		**$1,779,091,317**	**$3,520,272**

** The estimated cost that would remain if SCE had a single remaining bundled customer.

C. **<u>Should any issues associated with Fixed Generation Costs be addressed in this proceeding? If your answer is yes, briefly identify those issues and state whether those issues should be addressed with the other issues in this proceeding or in a separate phase after the other issues are addressed in a Commission decision.</u>**

SCE is unaware of any issues associated with its Fixed Generation Costs that need to be addressed in this proceeding or elsewhere. As shown above, SCE estimates approximately $3.52 million of Fixed Generation Costs in SCE's ERRA BA. By contrast, SCE estimates approximately $1.78 billion in Fixed Generation Costs in total for all Balancing Accounts associated with the instant ERRA Forecast application. As requested in the Ruling's table above, SCE has shown the cost responsibility for the hypothetical one remaining bundled service customer. In such a circumstance, that customer would be responsible for the entire amount of fixed costs in the ERRA BA. However, this is an extreme and highly improbable assumption. While SCE's bundled service customer load has decreased in recent years, SCE has no indication that the trend will continue such that only a single bundled service customer would remain.

Moreover, the establishment of cost recovery mechanisms allocate costs across both bundled service and departing load customers, such as the PABA with its vintaged cost recovery, greatly reduces the risk of stranded costs associated with a declining bundled service population (even assuming a continuing trend). This is because the departing load customers would continue to pay their cost responsibility through the PCIA and CTC for PABA, and other rates that broadly allocate procurement costs, such as CAM for NSGBA, including Fixed Generation Costs recovered through the operation of these SCE Balancing Accounts.

D. **Should the three 2024 ERRA Forecast proceedings be consolidated for the sole purpose of addressing any issues associated with Fixed Generation Costs? Please explain your answer and, if your answer is yes, state when the consolidation should occur.**

No. SCE submit that it has no issue associated with Fixed Generation Costs and therefore no reason to support consolidation of it time-sensitive 2024 ERRA Forecast application with other IOUs' separate ERRA Forecast applications for the purpose of addressing Fixed Generation Costs. Should the Commission decide there is a need to address Fixed Generation Costs in a consolidated fashion, it should do so in a Rulemaking. In no event should consideration of Fixed Generation Costs delay the objective of SCE's 2024 ERRA Forecast application, which is the timely approval of the forecasted revenue requirement and cost recovery associated with the fuel and purchased power for 2024.

III. CONCLUSION

SCE appreciates the opportunity to submit these opening comments.

Respectfully submitted,

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August 16, 2023

ATTACHMENT B

SDG&E OPENING COMMENTS

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Application of SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E) for Approval of its 2024 Electric Procurement Revenue Requirement Forecasts, 2024 Electric Sales Forecast, and GHG-Related Forecasts	A.23-05-013

SAN DIEGO GAS & ELECTRIC COMPANY'S (U 902 E) OPENING COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING DIRECTING PARTIES TO COMMENT REGARDING FIXED GENERATION COSTS

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August 16, 2023

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Application of SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E) for Approval of its 2024 Electric Procurement Revenue Requirement Forecasts, 2024 Electric Sales Forecast, and GHG-Related Forecasts	A.23-05-013

SAN DIEGO GAS & ELECTRIC COMPANY'S (U 902 E) OPENING COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING DIRECTING PARTIES TO COMMENT REGARDING FIXED GENERATION COSTS

I. INTRODUCTION

Pursuant to the August 1, 2023, *Administrative Law Judge Ruling Directing Parties to Comment Regarding Fixed Generation Costs* (the "ALJ Ruling"), San Diego Gas & Electric Company ("SDG&E") hereby submits its Opening Comments addressing each of the four issues identified regarding generation costs recovered through the Energy Resource Recovery Account ("ERRA") Balancing Account that do not change based on the amount of electricity customers use ("Fixed Generation Costs.")[1]

II. DISCUSSION OF ISSUES IN ALJ RULING

1. Identify and briefly describe each category of Fixed Generation Costs in this proceeding.

SDG&E's primary electric commodity cost recovery balancing accounts and the category of Fixed Generation Costs tracked in each balancing account are as follows:

- ERRA – Paid by bundled customers. Fixed Generation Costs include:
  - Up-to-market Competitive Transition Charge ("CTC") contract costs and CTC California Independent System Operator ("CAISO") net revenues,

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[1] For purposes of these comments, SDG&E is interpreting "Fixed Generation Costs" to mean those costs that do not diminish as load departs.

and CAISO/North American Electric Reliability Corporation ("NERC") miscellaneous costs.

- Portfolio Allocation Balancing Account ("PABA") – Paid by both bundled and unbundled customers. Charges are developed based on load forecasts. Fixed Generation Costs include:
    - Generation fuel, contract above-market cost, utility-owned resource above-market cost, including greenhouse gas ("GHG") cost.
- Transition Cost Balancing Account ("TCBA") – Paid equally by both bundled and unbundled customers. Paid by all customers through utility distribution company ("UDC") rates. Fixed Generation Costs include:
    - Above-market CTC contract costs
- Local Generating Balancing Account ("LGBA") – Paid equally by both bundled and unbundled customers. Paid by all customers through UDC rates. Fixed Generation costs include:
    - Contract costs and associated GHG cost, utility-owned resource costs, and net CAISO revenues.
- Modified Cost Allocation Mechanism Balancing ("MCAMBA") – Paid by both bundled and unbundled customers (these costs primarily flow through PABA). Fixed Generation Costs include:
    - Contract cost, utility-owned resource cost, and net CAISO revenues.
- Tree Mortality Non-Bypassable Charge Balancing Account ("TMNBCBA") – Paid equally by both bundled and unbundled customers through the public purpose programs ("PPP") charge, which is part of UDC rates. Fixed Generation Costs include:
    - Contract costs and net CAISO revenues.

2. **Please complete the following table by filling in every blank cell – if any cost categories were identified in question 1 that are not included in this table, please include them.**

Cost	Balancing Account Used for Tracking	Estimated 2023 Cost	Estimated 2023 Cost for a Hypothetical Last Remaining Bundled Customer[2]
Competitive Transmission Charge Contract Costs	ERRA/TCBA	ERRA: $24.0M, offset by ($22M) in CAISO revenues. (paid by bundled customers only) TCBA: $10.6M (paid by all customers)	ERRA: $2.0M = net contract cost
California Independent System Operator and North American Electric Reliability Corporation Costs	ERRA	ERRA: $423.3M in load costs and $3.0M in miscellaneous CAISO and NERC costs, offset by ($17.9M) in supply revenues.	CAISO load cost for the last customer would be the current market price of electricity multiplied by the last customer's volume used. Other CAISO and NERC costs remaining in ERRA are forecasted to be $3.0M.
Hedging-related Costs	ERRA	$10.2M	$0
Western Renewal Energy Generation Information System Costs	ERRA	$.018M	$0
ERRA-related Cogeneration/Renewables Costs	Please see response to Competitive Transmission Charge Contract Costs for the ERRA portion of CTC costs.		
Electric Supply Administration Costs	Administration costs are determined in SDG&E's General Rate Case proceeding. The cost for the last bundled customer will remain the same after load departure, because it is part of the electric distribution volumetric rate.		
Replacement Resource Adequacy Costs	ERRA	Not forecasted due to low predictability	This would be an immaterial amount.

[2] The estimated cost that would remain if the investor-owned utility experienced load departure such that it had a single remaining bundled customer.

Cost	Balancing Account Used for Tracking	Estimated 2023 Cost	Estimated 2023 Cost for a Hypothetical Last Remaining Bundled Customer[2]
Other Costs: RPS and resource adequacy compliance costs	ERRA	$92.7M	Approximately $157 per year

[1] The estimated cost that would remain if the investor-owned utility experienced load departure such that it had a single remaining bundled customer.

In addition to filling out the table, SDG&E provides the following additional information/comments:

- 2023 forecasted CTC costs of $34.6M are recovered in ERRA for the up-to-market portion, and the above-market portion is recovered in TCBA. The costs in ERRA are offset by CAISO revenues for CTC contracts, which are forecasted to be $22.0M in 2023. The remaining costs of $2.0M would be considered up-to-market according to the CTC benchmark and therefore recovered in ERRA. The exact amount of actual CAISO revenues received will depend on market prices at the time, and this will affect the amount still to be recovered in ERRA.

- CAISO load cost is volumetric and calculated based on the TOU market price. Having only one customer would mean that customer is exposed to potential high rates due to under collections if electricity prices spike during the time they are using electricity.

- Hedging costs for one bundled customer would be close to zero, because hedging costs are load-based per the Bundled Procurement Plan and are therefore volumetric.

- Western Renewable Energy Generation Information System ("WREGIS") costs for one bundled customer would be close to zero. Any additional WREGIS costs would be recovered in PABA, because they are a part of the cost of renewable contracts.

- Costs in the response to question 1. that are not included in the table above are those that are constant for the last remaining bundled customer, before and after load departure, because all customers pay for those costs.

3. **Should any issues associated with Fixed Generation Costs be addressed in this proceeding? If your answer is yes, briefly identify those issues and state whether those issues should be addressed with the other issues in this proceeding or in a separate phase after the other issues are addressed in a Commission decision.**

The issue of the CTC up-to-market costs that remain in ERRA should be addressed. Pursuant to D.02-12-027 in Rulemaking 02-01-011[3], a market benchmark proxy is utilized to determine the above-market costs that can be recovered in the TCBA from bundled and unbundled customers. However, that can result in significant costs being recovered through ERRA during periods when the CAISO revenues received were less than the imputed up-to-market costs. The practice of using a market benchmark proxy should be replaced with a practice of simply measuring actual revenues against actual costs and recording the difference in the TCBA. SDG&E recommends that this issue should be addressed in a separate phase of the ERRA Forecast proceeding after a Commission decision has been issued on the main issues presented in the May 15 ERRA Forecast Application and the upcoming October Update. Alternatively, the Commission could consider addressing the issue in R.02-01-011, though that proceeding has been closed since 2021.

4. **Should the three 2024 ERRA Forecast proceedings be consolidated for the sole purpose of addressing any issues associated with Fixed Generation Costs? Please explain your answer and, if your answer is yes, state when the consolidation should occur.**

SDG&E does not believe that it is necessary to consolidate the three 2024 ERRA Forecast Proceedings for purposes of addressing issues related to Fixed Generation Costs. The issue SDG&E identified in question 3 above appears to be specific to SDG&E and therefore it does not appear that any efficiencies would be gained by consolidation. The ERRA forecast

[3] Ordering Instituting Rulemaking regarding the Implementation of the Suspension of Direct Access Pursuant to Assembly Bill 1X and Decision 01-09-060.

proceeding should only be consolidated in instances were broad-ranging, state-wide issues need to be addressed. However, should the Commission or the other IOUs identify common issues related to the Fixed Generation Costs, then perhaps it might be appropriate to either consolidate the ERRA proceedings, reopen the PCIA rulemaking (R.17-06-026), or perhaps open a new rulemaking to address common issues.

III. CONCLUSION

SDG&E appreciates the opportunity to submit these Opening Comments to the ALJs' Ruling.

Respectfully submitted,

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