CAC Chair Report Item 10

TO: East Bay Community Energy Board of Directors

FROM: Anne Olivia Eldred, Chair, Community Advisory Committee

SUBJECT: **CAC Chair Report (Informational Item)**

DATE: September 20, 2023

Recommendation

Accept Chair report on items below.

Al Weinrub

We would like to celebrate the acquisition of 50 years of Al Weinrub's writings and his historical archive of social movement documents by the University of Massachusetts, Amherst Libraries. The Al Weinrub Justice Papers join the Library's W.E.B. Dubois and Daniel Elsberg collections, among others, as important historical archives for activists, researchers, historians, and scholars.

Celebration of Life for Al Weinrub 1943-2023
1:00 pm – 5:00 pm, September 23, 2023
Chapel of the Chimes

In lieu of flowers, please consider donating to the Al Weinrub Justice Fund: https://minutefund.uma-foundation.org/project/38424

Sustainability and Climate Action Plan City Staff and EBCE Coordination Report

Staff prepared a response to the report that Community Advisory Committee Member, At-Large Jim Lutz prepared and presented in the July meeting. The CAC received this response at Monday's meeting. Lutz was saddened that the primary message that EBCE member cities were happy with EBCE staff, and wanted to participate earlier in the process so that more of our member cities, particularly our small cities, could take full advantage of EBCE programmatic offerings was missed. Staff offered to meet with Member Lutz off line.
Staff response is attached.

CalCCA filing in the CPUC Diablo Canyon extension proceeding

Attached is a CalCCA filing in the CPUC Diablo Canyon extension proceedings. It outlines how non-bypassable charges should be allocated among customers and asks to use RA capacity and GHG-free attributes after 2025. The filing is regarding SB 846.

CAC Comments on Agenda Item 14 - Update on Planning for Net Billing Tariff (NBT)

Comments submitted from a technical expert on the CAC who is a homeowner with solar panels with questions regarding the climate and consumer benefits of NBT.

Attachments

A. Staff Response to the Sustainability and Climate Action Plan City Staff and EBCE Coordination Report

B. CalCCA filing in the CPUC Diablo Canyon extension proceeding

C. Comments on Agenda Item 14. Update on Planning for Net Billing Tariff

CAC Item C4B
Staff Report

TO: East Bay Community Energy Community Advisory Committee

FROM: Cait Cady, Public Engagement Coordinator

SUBJECT: **EBCE Municipal Staff Coordination**

DATE: September 18, 2023

Recommendation

Receive an update on EBCE's ongoing engagement efforts with municipal staff partners.

Background and Discussion

A report was presented at the July Community Advisory Committee (CAC) meeting, in which Member Jim Lutz documented conversations with municipal sustainability staff from EBCE's member jurisdictions and summarized key findings about EBCE's current municipal engagement efforts. In response to this report, and subsequent interest from Members of the CAC on this topic, EBCE staff would like to share more information about the agency's ongoing efforts to engage with the staff of our member jurisdictions. EBCE staff were pleased to hear that municipal staff appreciate their jurisdiction's partnership with EBCE and we are always interested in hearing suggestions for how we can improve our public engagement efforts.

Summary of EBCE's Engagement with Municipal Staff Partners
EBCE sees municipal staff as key partners and stakeholders. As such, we strive for frequent and consistent collaboration.

A central component of our engagement strategy are the monthly meetings with municipal partners. These 'MuniPals' meetings are hosted by EBCE's Public Engagement team and designed to keep our muni partners up to date on all things

EBCE and provide a forum for feedback/questions. The meetings are often attended by members of the EBCE team across various departments, who share their expertise and project updates. Our MuniPals meetings regularly cover topics such as local development/programs, legislative tracking, customer care/billing updates, annual budget overviews, marketing efforts, and many more. Every month, EBCE staff coordinate internally to select topics we see as most pressing to share with municipal partners that month.

Additionally, between MuniPals meetings EBCE staff will regularly send out important updates to the group and monthly marketing toolkits to supply member jurisdictions with EBCE content for their own communications efforts.

In the report, a frequent topic was EBCE's engagement with municipal staff on local programs, with a recommendation that EBCE should be doing more to engage muni partners in program design. First, to highlight some of the engagement our team currently does, over the past year, local programs staff have joined 8 of the past 12 MuniPals meetings and provided lengthy updates on programs in all stages of development. For many of these programs, this initial outreach was a jumping off point for future coordination, numerous ad hoc conversations with interested city staff, and opportunities to solicit feedback on implementation.

Given EBCE's frequent engagement with city staff, we are aware that some staff partners would prefer a more involved role in program design. EBCE staff appreciate both the enthusiasm and critical expertise municipal staff partners can and do bring to these conversations. Our Local Programs team works diligently to collaborate with key stakeholders, like muni staff, for many programs, particularly regarding implementation planning. In terms of input on the overall direction of EBCE's programmatic efforts, the Board of Directors is responsible for deciding what programs the agency will pursue, but we encourage coordination between municipal staff and their respective Board Member.

Some programs more than others are very well positioned for significant muni staff input, like those that are designed for municipalities specifically. The Critical Municipal Facilities Resilience program is a great example of this type of program, and municipal staff engagement has been at the center of implementation. The program was designed to address key barriers that our municipal staff colleagues identified for implementing resilience projects in their cities and EBCE has been in constant coordination with our municipal colleagues throughout several phases of the program.

Lastly, when EBCE starts developing new programs, staff design them to serve communities all across the service area. However, there may be times when a program is available to some cities but not all due to a multi-phased implementation approach. For example, public EV charger deployment and the Critical Municipal Facilities Resilience program utilized this approach and were not available to all cities at the time of their initial rollout.

Comparison to Other CCAs/Utilities
EBCE staff wanted to learn more about how other regional agencies, especially neighboring CCAs, engage with municipal staff from the communities that they serve. After soliciting feedback from neighboring CCAs about their engagement practices, it appears that EBCE's current engagement strategy already meets or goes above and beyond many best practices in the industry. For example, many comparable agencies do not host regular meetings with municipal staff.

Conclusion
EBCE is grateful for the high levels of engagement from our municipal staff colleagues, and we look forward to continuing this close partnership.

Fiscal Impact

This update has no fiscal impact.

Docket No.: R.23-01-007

Exhibit No.: ________________

Date: June 9, 2023

Witnesses: Brian Dickman

OPENING TESTIMONY OF BRIAN DICKMAN
ON BEHALF OF
THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

RULEMAKING IMPLEMENTING SENATE BILL 846 CONCERNING
POTENTIAL EXTENSION OF DIABLO CANYON POWER PLAN OPERATIONS

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ATTACHMENTS

I. INTRODUCTION AND SUMMARY OF TESTIMONY

The California Community Choice Association (**CalCCA**) presents this opening testimony in the *Rulemaking Implementing Senate Bill 846* (**SB 846**) *Concerning Potential Extension of Diablo Canyon Power Plant Operations*[1] (**DCPP OIR**). This testimony has been prepared on behalf of CalCCA by Brian Dickman, Partner, NewGen Strategies and Solutions, LLC. Mr. Dickman's qualifications are set forth in Attachment A.

CalCCA has a particular interest in the Diablo Canyon Power Plant (**DCPP**) extended operations and this DCPP OIR because SB 846 directs that certain costs of extended operations will be recovered from customers of all load-serving entities (**LSEs**) subject to the California Public Utilities Commission's (**Commission**) jurisdiction, including customers of community choice aggregators (**CCA**) that are members of CalCCA. This testimony presents CalCCA's proposals on certain issues falling within Phase 1: Track 2 as established in the April 6, 2023, Assigned Commissioner's Scoping Memo and Ruling[2] (**OIR Scoping Ruling**). Specifically, CalCCA's proposals address three scoping items, listed below:[3]

1. If the Commission directs and authorizes extended operations at DCPP, what are the new processes to authorize annual recovery of all reasonable DCPP extended operation costs and expenses on a forecast basis, including allocation of forecast costs among Commission-jurisdictional load-serving entities.

2. Whether additional cost recovery mechanisms, agreements, plans, and/or orders are needed prior to the current retirement dates for Diablo Canyon Units 1 and 2 (i.e., in 2024 and 2025, respectively).

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[1] Rulemaking (**R.**) 23-01-007, *Rulemaking Implementing Senate Bill 846 Concerning Potential Extension of Diablo Canyon Power Plant Operations* (Jan. 12, 2023): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M501/K368/501368884.PDF.

[2] R.23-01-007, *Assigned Commissioner's Scoping Memo and Ruling* (Apr. 6, 2023) (**Scoping Ruling**), at 5-6: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M505/K462/505462882.PDF.

[3] CalCCA reserves the right to respond or comment on other matters within the scope of this proceeding at the appropriate time as included in the OIR Scoping Ruling or other scoping rulings during the course of the proceeding.

3. Whether and how the benefits of extended operations, including resource adequacy and greenhouse gas-free attributes, should be allocated among the LSEs and customers paying for extended operations.

As described further in my testimony, CalCCA recommends the following:

- The Commission should adopt the same process currently used for resources subject to the Cost Allocation Mechanism (**CAM**) to allocate DCPP's resource adequacy (**RA**) capacity to all LSEs contributing toward cost recovery. Capacity should be allocated based on each entity's proportional contribution to the group's combined 12-month coincident peak.

- The Commission should require DCPP's green-house gas (**GHG**)-Free attributes be made available to all LSEs contributing toward cost recovery through a voluntary allocation, similar to the current 'interim' approach approved for Pacific Gas and Electric Company's (**PG&E**) large hydroelectric and nuclear facilities.

- The Commission should require PG&E to file a stand-alone application seeking approval of the forecasted net costs of DCPP continued operations on an annual basis. PG&E should be required to present detailed projections of all DCPP costs and revenues in a format similar to the information provided in its general rate case (**GRC**) and Energy Resource Recovery Account (**ERRA**) proceedings.

- Net DCPP costs that are to be recovered from customers of all jurisdictional LSEs in the state should be allocated to investor-owned utility (**IOU**) service territories based on the contribution to the group's combined 12-month coincident peak.

- The Commission should require PG&E to track the net costs of DCPP extended operations in a new balancing account and recover those costs through a new non-bypassable charge (**NBC**) included in each IOU's delivery rates.

- In sum, the ratemaking process for DCPP costs would be:

    1. PG&E prepares an annual DCPP Forecast Application that is similar to but separate from the ERRA Forecast Application.

    2. A Commission decision in the DCPP Forecast Application sets the level of the revenue requirement to be collected through the DCPP-specific NBC in each IOU's service territory.

    3. That revenue requirement is translated to a $/kWh charge for eligible customers in an IOU's service territory in November and December via each IOU's consolidated rate change advice letter filing.

II. CUSTOMERS PAYING FOR EXTENDED OPERATIONS SHOULD RECEIVE THE BENEFITS OF DCPP'S RA AND GHG-FREE ATTRIBUTES

There are two ways for the Commission to ensure customers benefit from the value of a resource's attributes. *First*, the Commission might assign customers a credit against retail rates. *Second*, the Commission might allocate resource attributes among the LSEs serving those customers.

Currently, the Commission follows the first approach for DCPP. The costs to own and operate DCPP are recovered from bundled and departed load customers in PG&E's service territory through Power Charge Indifference Adjustment (**PCIA**) rates, which are structured to recognize the value of DCPP's generation-related attributes as a credit against retail rates. PG&E charges customers for DCPP's above-market costs, calculated as the cost of the resource less the market value of its energy and capacity. Generation output is sold into the CAISO market, and the market revenue is netted against DCPP costs. The value of DCPP RA that PG&E retains to meet a portion of its bundled customer RA requirement is reflected as a credit against DCPP costs and reduces PCIA rates for customers. Revenue received from sales of DCPP RA, if any, to third parties is also credited against DCPP costs.

Going forward, costs associated with extended operations at DCPP will not be recovered through the PCIA. Instead, SB 846 allows PG&E to charge customers a new NBC to recover all "reasonable costs and expenses necessary to operate [DCPP] beyond the current expiration dates,"[4] net of market revenue from DCPP operation. Under the cost recovery regime described in SB 846, customer rates will no longer reflect a credit

[4] Cal. Pub. Util. Code § 712.8(h)(1).

for the value of RA, nor will they reflect a credit to recognize the value of the GHG-free attribute of the generation.

Consequently, the Commission would need to follow the second method to ensure that customers that pay the cost of continued DCPP operation realize the value of continued operations.

A. Costs And Benefits of DCPP Extended Operations Should Be Aligned and Fairly Allocated to Customers

1. SB 846 Shifts The Financial Risk of Extending DCPP Operations to Customers, and They Should Benefit Accordingly

SB 846 alters the cost recovery framework for DCPP during extended operations and shifts the financial risk of extending operations to customers throughout California. Pursuant to SB 846, PG&E will assess several new charges to customers to compensate PG&E shareholders "in lieu of a rate-based return on investments and in acknowledgment of the greater risk of outages in an older plant."[5] Specifically, PG&E will collect \$13.00/MWh for each MWh generated by DCPP, plus a fixed payment of \$100 million (\$50 million per unit) annually. Together, these fees collected in lieu of a rate-based return total approximately \$320 million[6] per year, compared to \$143 million in annual return on rate base proposed by PG&E in its 2023 GRC. SB 846 entitles PG&E to recover from customers the cost of replacement power during unplanned outage periods, *even if the unplanned outage is the result of a failure by PG&E to meet the reasonable manager standard*.[7] In fact, PG&E is allowed to charge all customers up front to fund a \$300 million liquidated damages balancing account that can be used to cover the cost of

[5] Cal. Pub. Util. Code § 712.8(f)(5) and § 712.8(f)(6).
[6] Volumetric payments estimated based on actual generation output during 2021.
[7] Cal. Pub. Util. Code § 712.8(i)(1).

replacement power during these imprudent outages. It is not reasonable for customers to bear all of these costs, including more than doubling the payments to PG&E shareholders, without realizing the corresponding benefits of the plant's extended operation.

2. The Commission Should Follow The CAM Model To Allocate The Costs and Benefits of DCPP Extended Operations

SB 846 extended the life of the DCPP plant for the benefit of all California's electric customers while designating a single IOU, PG&E, as the operator. Public Resources Code Section 25548.7 states, "Continued operation of the Diablo Canyon powerplant as provided in this chapter is in all respects for the welfare and the benefit of the people of the state…" Based on this rationale, SB 846 also alters the cost recovery framework for DCPP during extended operations. SB 846 entitles PG&E to recover the reasonable and necessary costs to operate DCPP beyond the current expiration dates, net of market revenue from DCPP operation. With limited exceptions, SB 846 specifies that DCPP extended operations costs are to be recovered from customers of all jurisdictional LSEs in California.

The rationale and framework for extending DCPP operations described in SB 846 is similar to the CAM concept originally established by the Commission in Decision (**D.**) 06-07-029. The Commission adopted the CAM as a mechanism to streamline procurement of critical new resources for the benefit of multiple customer groups (e.g., bundled and unbundled customers). In D.06-07-029 the Commission stated, "[We] are adopting a cost-allocation mechanism… that allows the advantages and costs of new generation to be shared by all benefiting customers in an IOU's service territory. We designate the IOUs to procure this new generation. The LSEs in the IOU's service territory will be allocated rights to the capacity that can be applied toward each LSE's RA requirements. The LSE's customers receiving the benefit of this additional capacity pay only for the net cost of this capacity, determined as a net of the total cost of the contract minus the energy revenues associated with dispatch of the contract."[8]

As directed by the Commission, IOUs procure CAM resources for the benefit of all customers in their respective service territories. CAM resource costs, net of revenues from selling energy and ancillary services into the California Independent System Operator (**CAISO**) market, are then recovered from all customers in each IOU's service territory through a volumetric NBC. PG&E's CAM NBC is known as the New System Generation Charge (**NSGC**).

Recognizing the similarities between CAM and DCPP extended operations, a fundamental principle that should be followed here is that the allocation of costs and benefits should be aligned and fairly distributed to customers. When establishing the CAM, the Commission determined, "[a]ll RA counting benefits and net costs are spread to the LSEs whose customers are allocated costs based on share of 12-month coincident peak, adjusted on a monthly basis to facilitate load migration. The contract costs paid and RA benefits received by [departed load] and bundled customers should be based on a share basis equal to the credit share received."[9]

The Commission should allocate the costs and benefits of DCPP extended operations the same way it allocates the costs and benefits of CAM resources. Specifically, net costs that PG&E will recover from customers of all jurisdictional LSEs in the state, per SB 846, should be allocated to IOU service territories based on the contribution to the group's combined 12-month coincident peak.[10] As I describe later in

[8] D.06-07-029 at 7.

[9] *Id*. at 31.

[10] The 12-month coincident peak allocation should be consistent with the RA attribute allocation prepared by Energy Division to match costs and benefits.

my testimony, each IOU would recover the allocated DCPP costs from all customers in its service territory through a new NBC included in delivery rates.

Each Commission-jurisdictional LSE should also receive a proportional share of DCPP's RA attributes, based on a share of the 12-month coincident peak. At a high level, following the CAM procedures already in place for the Commission's RA compliance program, Energy Division should include an allocation of DCPP RA capacity in the RA template for each LSE, reducing the System RA requirement for each LSE by its share of DCPP capacity for compliance periods during extended operations. Below, I describe in more detail how the Commission should allocate DCPP RA to LSEs.

B. DCPP RA Capacity Should Be Allocated to LSEs

1. Allocating DCPP RA To LSEs Will Avoid Artificially Understating Resources Available in A Constrained Market

California LSEs face a constrained RA market, despite the fact that DCPP remains in operation. Several different analyses have now concluded that, unless recent weather patterns shift back to "normal," to avoid significant capacity shortages until unprecedented amounts of new resources can be brought online, DCPP should continue to operate. As LSEs seek to procure sufficient resources to meet their obligations under the Commission's Resource Adequacy program they are *already* faced with year-over-year price increases, price spikes in high demand summer months, and a lack of capacity available in the market. Ignoring DCPP in the RA market, especially when it is still operating and providing system capacity, will only exacerbate the market constraints and artificially increase rates.

The California Energy Commission (**CEC**) staff report on Diablo Canyon Power Plant Extension (**CEC Report**) published in March 2023 recommends the CEC determine that it is prudent for the state to pursue extension of DCPP due to the risk that sufficient resources may not be built in time to reach procurement targets ordered by the Commission and to address potential grid demands in extreme heat events.[11] The CEC Report relies on a deterministic resource stack analysis to evaluate capacity needs through 2032 assuming DCPP units are retired. The analysis indicates that under planning, or 'normal,' circumstances the CAISO market should have sufficient capacity to meet demand. However, the report demonstrates that deviations from normal conditions, such as the heat waves experienced in California during 2020 and 2022, will put significant strain on the available capacity and result in resource shortages during critical summer months.

The CEC also recognizes that its analysis relies on aggressive assumptions, including the "ability to build new clean energy resources at a pace not seen before and in the face of supply chain, interconnection, and permitting delays."[12] In fact, when the CEC considered resource delays and summer temperatures equivalent to those experienced in 2022, the stack analysis demonstrates anticipated capacity shortfalls exceeding 2,000 MW through 2029.

The relevance of this conclusion is underscored by the Joint Agency Reliability Planning Assessment (**Joint Agency Report**) published by the CEC and the Commission in February 2023. The Joint Agency Report details that climate driven events had a significant impact on CAISO system reliability *in each of the last three years*:

> Climate change is causing substantial variability in weather patterns and an increase in climate-driven natural disasters, which is resulting in more challenges to maintaining grid reliability. In 2020, a west-wide heat event resulted in rotating outages August 14 and 15. In 2021, dry conditions resulted in a wildfire in Oregon that impacted transmission lines that California depends on for

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[11] CEC Report at. ii.

[12] *Id*. at 25.

> reliability, resulting in a loss of 3,000 megawatts (MW) of imports to the California Independent System Operator (California ISO) territory and 4,000 MW of overall import capacity to the state. In 2022, California experienced record high temperatures between August 31 and September 9. On September 6, 2022, the California ISO recorded a new record peak load at 52,061 MW, nearly 2,000 MW higher than the previous record, despite significant efforts to reduce load during this peak period.[13]

As part of its reliability assessment, the Joint Agency Report concluded that if DCPP is retired by 2025, capacity shortfalls of 500 MW to 3,800 MW are expected between 2023 and 2027 unless the heat events that occurred in 2020 and 2022 are aberrations and not part of the 'new normal' Californians face.[14]

The CEC Report also acknowledges the shortcomings of a deterministic stack analysis approach, stating, "It is difficult to articulate the probability of the outcomes contained in the results from a deterministic stack approach. Thus, the actual probability of the outage risks associated with different supply and demand balances are uncertain, especially when looking far into the future."[15] Notably, the CAISO conducted a probabilistic production cost modeling analysis to support the Commission IRP process, inform summer preparedness activities, and support the CEC's evaluation of the prudence of extending DCPP operation. The CAISO analysis found capacity shortages between approximately 750 MW and 1,285 MW are expected in 2025 and 2026, even after considering new resource additions identified in the IRP or as ordered by Commission procurement decisions.[16]

CalCCA witnesses Eric Little and Andrew Mills sponsor testimony in this proceeding to present an analysis of the constrained RA market published by CalCCA in

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13 Joint Agency Reliability Planning Assessment at 7 (Feb. 2023).

14 *Id.* at 50.

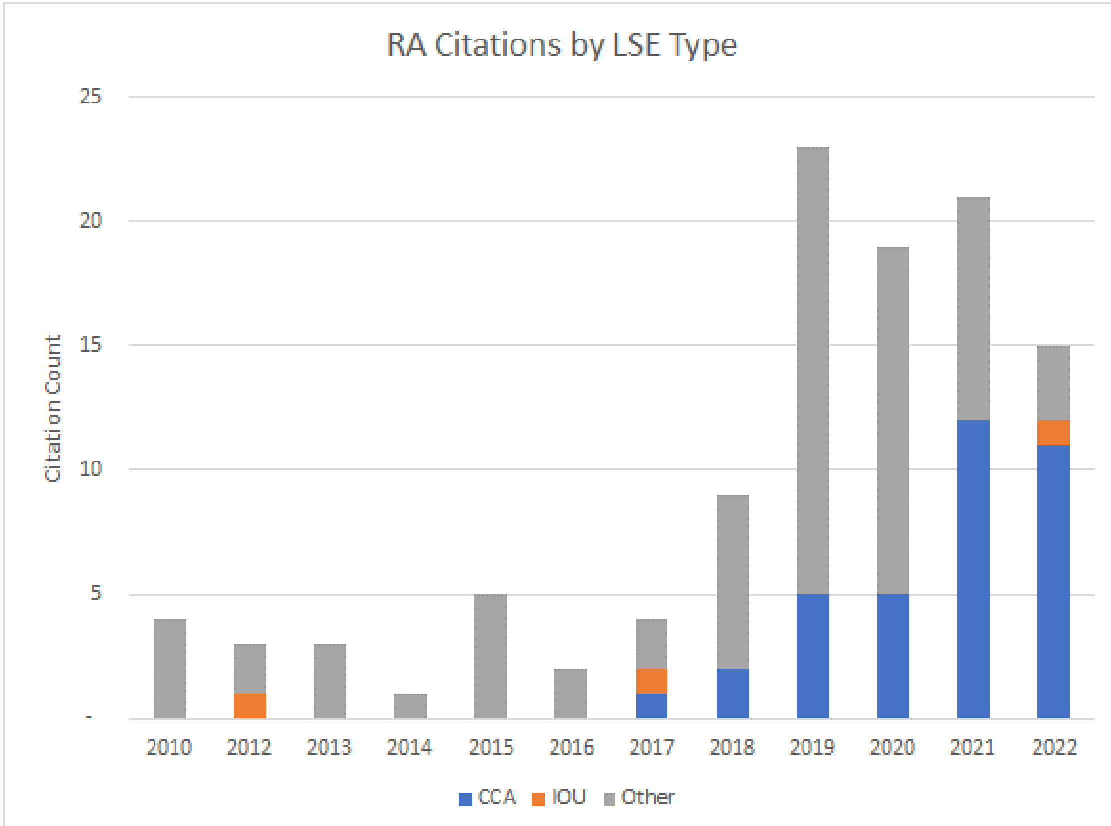
15 CEC Report at 16.

16 February 2, 2023 Letter to CEC Vice Chair, available at http://www.caiso.com/Documents/Jan2-2023-Letter-CaliforniaEnergyCommissionViceChair-CAISOReliabilityModeling.pdf.

March 2023 (**CalCCA Stack Analysis**), updated to include recent information regarding the status of the RA market. The CalCCA Stack Analysis concurs with the CEC's analysis, finding that certain conditions similar to those considered in the CEC analysis are contributing to RA shortfalls including extreme weather conditions, declining hydro resource availability due to drought, delays bringing new resources online, increasing capacity needs across the Western region, and restrictive regulatory requirements. Based on its updated analysis, CalCCA anticipates a 433 MW shortage for 2023, growing to a 1,258 MW shortage in 2025.

All of these assessments point to the same conclusion: capacity is scarce, it will remain scarce, and DCPP provides needed System RA. One symptom of the constrained RA market is that many LSEs have been unable to meet their System RA requirements despite being willing to pay. The Enforcement Actions Spreadsheet updated by the Consumer Protection and Enforcement Division in February 2023 tracks RA citations issues to various entities from October 2009 through November 2022. As shown in Figure 1, there was a sharp increase in the number of citations in 2019, and elevated levels continued through 2022.

Figure 1



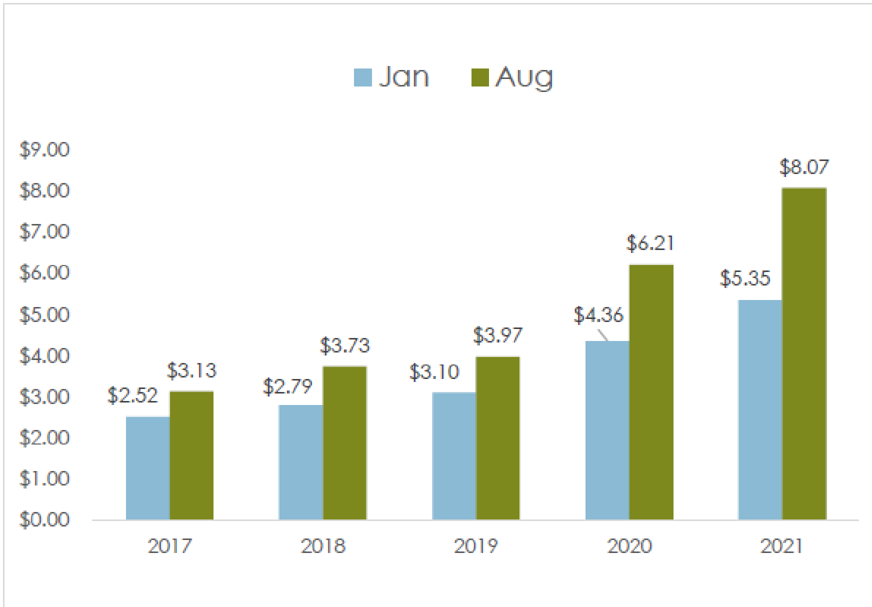
Another symptom of the constrained market is the steadily increasing price of System RA. Figure 2 below reproduces Figure 4 from the 2021 Resource Adequacy Report,[17] showing the rise in RA prices from 2017 to 2021.

[17] *2021 Resource Adequacy Report*: https://webproda.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2021_ra_report_040523.pdf.

Figure 2

2021 Resource Adequacy Report

Figure 4: Weighted Average Price of System RA ($/kW-month), January and August 2017- 2021



Source: 2017-2021 price data submitted by LSEs.

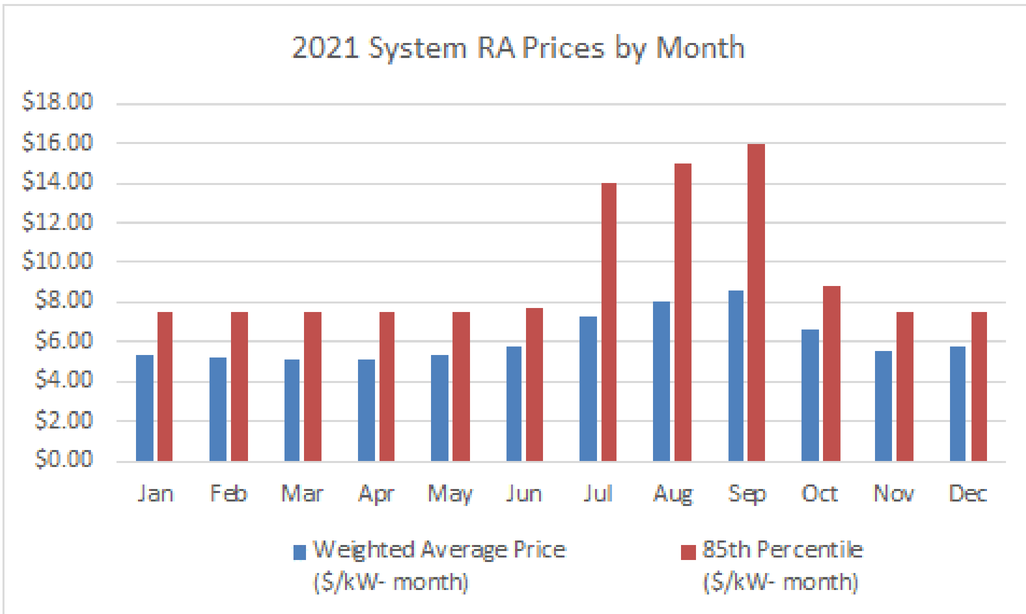
As the figure shows, Energy Division's 2021 Resource Adequacy Report illustrates that the average price of System RA transactions executed for August 2021 was 158% higher than for August 2017.[18] The RA market price benchmarks calculated by Energy Division in September 2022 report that System RA prices in 2022 averaged $8.11/kW-month over the entire year, and the forecast for average System RA prices in 2023 is $7.39/kW-month.

Energy Division's data also shows that variation in RA prices during 2021 was significantly greater during high-demand summer months relative to other periods; prices for 15 percent of transactions exceeded $14/kW-month during July – September 2021.[19]

[18] *Id.* at 28-29.
[19] *Id.* at 27-28.

The CalCCA Stack Analysis concurs, finding "Resources that garnered $3.63 kilowatt (kW)-month in 2019 rose to prices as high as the mid-$40 kW-month for summer 2023 and are increasingly unavailable at any price."[20] Figure 3 below presents Energy Division's monthly price data for 2021 in graph form.

Figure 3



Price spikes such as these in the short-term RA market simply create a windfall for existing generation owners at the expense of retail consumers. There is no incremental reliability benefit to the system from these increased costs.

Withholding DCPP's 2,280 MW of capacity from the RA market would worsen the market constraints causing such spikes. Further squeezing the RA market by ignoring DCPP will increase costs for customers by over $200 million[21] annually as they are required to procure RA rather than count the DCPP capacity they pay for during extended operations. There will be no incremental reliability benefit accompanying this dramatic rate increase.

[20] CalCCA Stack Analysis at 2. Internal citation omitted.
[21] 2,280 MW * $7.39/kW-month * 1,000 * 12 = $202.2 million.

2. Allocating DCPP's Attributes Will Not Impact The State's Long-Term Planning Goals

Regardless of the cause of the scarcity in the RA market, and the resulting high prices, California will need more resources to contribute to meeting the Commission's RA requirements until new zero-carbon reliability resources can be built. Recognizing this need, SB 846 describes the purpose of extending DCPP operation: "Preserving the option of continued operations of the Diablo Canyon powerplant for an additional five years beyond 2025 may be necessary to improve statewide energy system reliability and to reduce the emissions of greenhouse gases while additional renewable energy and zero-carbon resources come online, *until those new renewable energy and zero-carbon resources are adequate to meet demand*."[22]

In Reply Comments on the Order Instituting Rulemaking to establish this proceeding, PG&E argued, "RA allocation to reduce RA compliance procurement activity is in conflict with Legislative direction that the state act with urgency to bring clean replacement energy to support reliability and achieve California's landmark climate goals."[23] This position ignores the difference between the Integrated Resource Planning (**IRP**) process and the Commissions procurement focused decisions, which drive the construction of new resources, and RA compliance, which drives near-term LSE procurement to optimize the use of already-existing resources. California's IRP process for Commission-jurisdictional LSEs comprises two parts: 1) identifying an optimal portfolio for meeting state policy objectives, and 2) aggregating the LSEs' collective efforts for planned

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[22] PRC § 25548(b). Emphasis added.

[23] R.23-01-007, *Reply Comments of Pacific Gas And Electric Company (U 39 E) on Administrative Law Judge's Ruling Requesting Comments on Phase 1: Track 1 Issues* (May 31, 2023) (**PG&E Reply Comments**), at 8: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M510/K286/510286991.PDF.

and contracted resources to compare to the optimal system. The Commission IRP process requires jurisdictional LSEs to submit plans every two years to ensure they can meet GHG reduction targets while maintaining system reliability.[24] In the IRP planning track, the Commission adopts a preferred system plan identifying the optimal portfolio spanning over a ten-year forecast period, and then sets requirements for LSEs to plan toward that future. "To the extent that the CPUC orders procurement in the IRP proceeding, it is generally to meet a reliability or GHG reduction need identified in the planning track."[25]

The purpose of the Commission's RA program is to ensure capacity resources are contracted for and available to meet California demand in the short term. The Commission describes that the RA program "guides resource procurement and promotes infrastructure investment by requiring that LSEs procure capacity so that capacity is available to the CAISO when and where needed."[26] The RA program has two types of filings: annual and monthly. On an annual basis, LSEs are required to demonstrate that they have procured 90% of their System RA obligation for the five summer months of the coming compliance year. On a monthly basis, LSEs must demonstrate they have procured 100% of their monthly System RA obligation. LSEs can demonstrate compliance with their RA obligations either through long-term procurement (i.e., pursuant to the IRP and Commission procurement decisions) or through purchases of RA capacity from third parties in the bilateral market.

PG&E also argued in its Reply Comments that allocated RA capacity from DCPP to LSEs for RA compliance purposes "would in effect provide a procurement reprieve to

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24 Joint Agency Report at 25.

25 *Id.* at 26.

26 https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage, accessed May 23, 2023.

LSEs, thus, countering the incentive for LSEs to engage in incremental procurement to improve reliability of the state's electrical system…[T]he Commission is currently considering extended operation through 2030 and, if LSEs assume RA and GHG-free energy from DCPP through 2030, that could impact whether they enter into contracts today for delivery in the late 2020s."[27]

This is not true. The Commission's IRP process and ensuing procurement decisions will continue to dictate the pace of long-term resource procurement even if DCPP RA counts toward jurisdictional LSEs' RA compliance obligations in the near term. SB 846 prohibits LSEs from including DCPP energy, capacity, or GHG-free attributes in their resource planning and requires the state to continue to act with urgency to bring clean replacement energy online.[28] As discussed earlier, however, long-term resource planning differs from short-term RA compliance procurement. Furthermore, LSEs are already acting to bring new capacity online from 2021 through 2026 pursuant to procurement requirements in D.19-11-016 and D.21-06-035, although the Commission recognized in D.23-02-040 challenges related to procuring long-lead time resources. The Joint Agency Report confirms, "Between 2020 and late 2022, the CPUC's IRP procurement orders and prior LSE procurement resulted in over 11,000 MW of new nameplate energy resources, equivalent to over 6,000 MW of new Net Qualifying Capacity (NQC) that can count toward RA capacity obligations."[29]

Even after accounting for resource additions ordered or planned through the IRP process, the Joint Agency Report found that, under extreme weather conditions, capacity

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[27] PG&E Reply Comments at 8-9.
[28] PRC § 25548(c).
[29] Joint Agency Report at 29.

shortfalls are expected to continue throughout DCPP extended operations. Factoring in possible delays in planned procurement due to supply chain challenges only increases the expected shortfalls. In short, the risk of insufficient or delayed resource procurement *drives* the need to extend DCPP operations; extension of operations is not the *cause* of delayed procurement.

DCPP RA should be allocated among all LSEs whose customers will pay for the cost of extended operations to avoid artificially understating available resources in an already constrained RA market. The IRP and Commission procurement directives will ensure new resources will be built over the long term. The Commission designed the RA program to ensure resources are under contract and available to meet peak demand in the short term. Removing DCPP from the pool of resources available to count toward System RA requirements will artificially constrict the market, despite DCPP's continued operation.

C. The Commission Should Direct PG&E To Continue Offering Voluntary Allocations of DCPP's GHG-Free Attributes To LSEs

In R.17-06-026, the Commission has been evaluating whether it should incorporate a credit for GHG-Free attributes into the PCIA to reflect the premium value of GHG-Free energy as an offset to resource costs. Analysis of historical market transaction data led Energy Division to conclude in September 2022 that "there is currently a premium for GHG-Free resources" in California and to recommend the value be recognized in the PCIA.[30] GHG-Free energy has value to LSEs because it impacts

[30] R.17-06-026, *Administrative Law Judge's Ruling Requesting Comments on GHG-Free Resources Staff Proposal and Other Issues* (Sept. 12, 2022), Attachment A, "GHG Free Data Analysis and Staff Proposal" (**September 12 Staff Proposal**), at 5: https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=496874129.

LSEs' carbon intensity for the purpose of their Power Content Label.[31] Receiving GHG-Free energy also impacts LSEs' marketing efforts. On May 4, 2023, the Commission issued a proposed decision in R.17-06-026 (**PCIA OIR Proposed Decision**) finding that there was sufficient data to support a "heightened value for GHG-Free resources, which can be attributed to [Power Content Label] value or meeting an individual LSEs' GHG reduction goals more broadly."[32]

The Commission should require PG&E to offer allocations of DCPP's GHG-Free attributes to LSEs whose customers will pay for extended operations. Doing so simply requires the Commission to continue the *status quo*, with a few modifications. Resolution E-5111 approved PG&E's current 'interim' allocation process which allocates GHG-Free attributes from resources in PG&E's PCIA portfolio.[33] PG&E offers LSEs within its service territory an allocated amount of GHG-Free energy generated by specified facilities corresponding to each LSE's "Allocation Ratio."[34] Once a year PG&E offers each LSE its Allocation Ratio which, after execution of a Sales Agreement, corresponds to an allocated quantity of GHG-Free energy sold to the LSE during the delivery year. Under this framework, LSEs that accept the allocations may report the corresponding

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[31] Under the CEC's Power Source Disclosure program, LSEs must disclose to their customers the mix of sources used to provide electricity service during the previous calendar year, and the greenhouse gas emissions intensity of their portfolio. The annual disclosure is made on an LSE's "Power Content Label."

[32] R.17-06-026, Proposed *Decision Addressing Greenhouse Gas-Free Resources, Long-Term Renewable Transactions, Energy Index Calculations, and Energy Service Providers' Data Access* (issued May 4, 2023), at 17: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M508/K069/508069560.PDF.

[33] Allocation of PG&E's GHG-Free resource was first approved in Resolution E-5046, which adopted Appendix P to PG&E's 2014 Bundled Procurement Plan specifying the terms under which GHG-Free attributes would be allocated. Resolution E-5111 approved several modifications to Appendix P based on experience with the allocation process to that point.

[34] The Allocation Ratio is defined as the LSE's monthly load forecast used in PG&E's ERRA Forecast Application compared to the total forecasted load for customers responsible for the costs of the resources. Because allocation of DCPP GHG-Free attributes during extended operations would involve LSE outside of PG&E's service territory, the CEC's California Energy Demand forecast, as updated annually, could be used to determine the applicable Allocation Ratio.

GHG-Free energy on their annual Power Content Label under the CEC's Power Source Disclosure Program.

PG&E should continue to offer voluntary allocations of the GHG-free attributes associated with DCPP.[35] PG&E's existing allocation process needs only minor modifications to conform to DCPP's extended operations. PG&E should modify its Bundled Procurement Plan (**BPP**) Appendix P to accommodate an annual allocation and offer process for DCPP as a stand-alone specified resource. Under my proposal, PG&E would calculate DCPP GHG-Free generation separate from PG&E's other resources, and would expand eligibility to receive an allocation of DCPP generation to all California LSEs subject to the DCPP NBC, including PG&E and other IOUs. LSEs can confirm their acceptance of an allocation by executing a sales agreement with PG&E subject to the conditions in PG&E's BPP Appendix P. Unclaimed allocations, if any, would be unused for that delivery year and would not be reported on any individual LSE PCL or other communications.

Continuing voluntary allocations is a reasonable approach to ensuring that cost-responsible customers continue to have the option of receiving the benefits of DCPP's GHG-free energy.

[35] The PCIA OIR Proposed Decision adopts a GHG-Free allocation or Market Price Benchmark process for large hydroelectric resources, and allows, but does not require, the IOUs to continue to offer allocations of GHG-Free attributes from PCIA-eligible nuclear resources on a voluntary, annual basis. The PCIA OIR Proposed Decision ties this framework to the PCIA and eliminates it once the PCIA sunsets. It does not address the continuation of voluntary allocation under a non-PCIA rate mechanism.

III. PG&E SHOULD BE REQUIRED TO FILE A STAND-ALONE APPLICATION SEEKING APPROVAL OF THE FORECASTED NET COSTS OF DCPP CONTINUED OPERATION ON AN ANNUAL BASIS

A. A New Annual Application for The Recovery of The Forecasted Costs of DCPP Extended Operations Should Be Structured in The Same Manner As PG&E's Annual ERRA Forecast Proceeding

PG&E currently establishes the annual cost to operate DCPP through a combination of its GRCs, annual ERRA proceedings, and other filings to address specific issues such as employee retention and decommissioning costs.[36] PG&E recovers DCPP costs from bundled and departed load customers in its service territory through PCIA and Nuclear Decommissioning rates.[37] SB 846 directed the Commission to authorize PG&E to recover the net cost of DCPP extended operations through a new proceeding structured similarly to its annual ERRA Forecast proceeding.[38]

For the period of DCPP extended operations, PG&E should present for approval a single application with an annual forecast of all DCPP-related costs eligible for recovery from ratepayers (**DCPP Forecast Application**). As California Public Utilities Code Section 712.8(h)(1) suggests, the DCPP Forecast Application should follow a similar process as the ERRA Forecast proceeding, *i.e.*, an initial application presenting PG&E's forecast of net costs for the subsequent year, followed by a period of party review and opportunities to file testimony. PG&E should also be required to submit an update to forecasted costs, during the pendency of the annual forecast proceeding, to capture the most recent market conditions available prior to establishing the final net cost forecast.[39] The Commission should require

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[36] PG&E Response to CalCCA Data Request 1.01.
[37] PG&E Response to CalCCA Data Request 1.02.
[38] Cal. Pub. Util. Code § 712.8(h)(l).
[39] In PG&E's annual ERRA Forecast proceedings, PG&E files a "Fall Update" in October providing updated forecasted costs.

PG&E to prepare its annual DCPP Forecast Application based on the same forecast assumptions used to develop the ERRA Forecast for the corresponding period (including, for example, forecasted market revenues, fuel costs, generation output, and other variables), and procedural milestones in the DCPP Forecast Application should follow a timeline that runs in parallel with the ERRA Forecast proceeding.

Despite the similarity between the two filings, the DCPP Forecast Application should be a standalone application to facilitate participation from all affected stakeholders in the state without complicating PG&E's ERRA Forecast application process. That application is typically limited to a handful of parties seeking to address PG&E-specific issues and rarely includes the other IOUs as parties. Moreover, a substantial amount of work is done in that proceeding, including ratemaking and the implementation of policy directed by other cases. Examples of these issues in just the past few years include:

- The methodology to refund a CAM misallocation;[40]
- The methodology to return ERRA overcollections in an equitable manner;[41]
- The methodology to calculate the RA component of Green Tariff Shared Renewable rates;[42]
- Implementation of changes to the methodology used to calculate the PCIA from D.18-10-019 and D.19-10-001;[43]
- The inclusion of unapproved Catastrophic Event Memorandum Account and Wildfire Expense Memorandum Account costs in the PCIA revenue requirement;[44] and

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40 D.20-02-047 at 10.
41 *Id*. at 11-12.
42 D.20-12-038 at 28-29.
43 *See, e.g.,* D.18-10-019 at Ordering Paragraphs (**OPs**) 8 and 10; D.19-10-001 at OPs 2-4.
44 A.21-06-001, PG&E Prepared Testimony at 9-8:10-16 to 9-9:1-4 and Table 9-2.

- Addressing the accounting resulting from PG&E acting as a Central Procurement Entity (D.20-06-002), to meet 2021 summer reliability targets (D.21-02-028); or to meet the incremental procurement targets 2021-2023 (D.19-11-016) that impact the CAM balancing account, ModCAM balancing accounts and the Portfolio Allocation Balancing Account.

Creating a standalone proceeding for DCPP-related issues would avoid overwhelming the expedited ERRA Forecast proceeding with parties and issues that seek to only address DCPP-related issues. The significant non-DCPP-related policy and implementation issues are frequently addressed in PG&E's ERRA Forecast proceeding.

PG&E would no longer present DCPP-related costs in its ERRA Forecast or recover those costs through PCIA rates during the period of extended operations. Rather, PG&E would recover the Commission-approved DCPP net cost forecast through distinct NBCs included in the delivery rates for each IOU's service territory.

Each year as part of the DCPP Forecast Application the Commission would approve 1) the total forecasted DCPP net costs, and 2) the amount allocated to customers in each IOU's service territory. Each IOU would then be responsible for calculating the corresponding volumetric NBC charged to customers of all jurisdictional LSEs based on electricity consumption in their own service territory.[45] The IOUs would include their respective NBCs in delivery rates via each IOU's annual consolidated rate change advice letter process (*e.g.*, the Consolidated Rate Change in Southern California Edison's service territory and the Annual Electric True-UP (**AET**) in PG&E's service territory).[46]

In sum, the ratemaking process for DCPP costs would be:

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45 Cal. Pub. Util. Code § 712.8(l)(1).

46 *See* Resolution E-5217 (establishing uniform procedures to standardize the large energy utilities' annual end-of-year consolidated electric revenue for January 1 rate change advice letter filings to provide a more efficient process) Small jurisdictional IOUs subject to the requirements of SB 846 would follow the equivalent process for routine rate updates in their respective service territories (Aug. 4, 2022): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M496/K459/496459720.PDF.

1. PG&E prepares an annual DCPP Forecast Application that is similar to but separate from the ERRA Forecast Application.

2. A Commission decision in the DCPP Forecast Application sets the level of the revenue requirement to be collected through the DCPP-specific NBC in each IOU's service territory.

3. That revenue requirement is translated to a $/kWh charge for eligible customers in an IOU's service territory in November and December via each IOU's consolidated rate change advice letter filing.

B. PG&E's DCPP Forecast Application Should Include Detailed Support of The Projected Net Costs to Be Charged Customers

As described earlier, PG&E is entitled to recover from customers the reasonable costs and expenses necessary to operate DCPP beyond the current expiration dates, net of market revenue from DCPP operation. The Commission should require PG&E to present detailed projections of all costs and revenues during DCPP extended operations in the annual DCPP Forecast Application. The presentation of costs and revenue included in the DCPP Forecast Application should be similar to the information provided in PG&E's GRC and ERRA proceedings. For example, PG&E should provide details of DCPP fixed costs by Major Work Category (**MWC**) and FERC account. Detailed generation output projections, nuclear fuel procurement costs, and other related forecast inputs should support forecasts for variable costs.

To incorporate the new SB 846 framework, the traditional DCPP revenue requirement calculation requires several changes. For example, SB 846 allows PG&E to recover all operating expenses and certain tax costs, but it is no longer allowed to record capital expenditures to rate base. Routine capital expenditures are to be recovered as operating expenses, and significant one-time capital expenditures may be amortized over more than one year as authorized by the Commission. Furthermore, several new fees will be charged to customers to compensate PG&E shareholders in lieu of a rate-based return on investments, including a volumetric performance-based fee of $13.00/MWh for each MWh generated by DCPP and a fixed payment of $100 million ($50 million per unit) annually. PG&E is also entitled to charge customers $12.5 million per month to fund a $300 million liquidated damages balancing account that can be used to cover the cost of replacement power during certain outages. Figure 4 provides an illustrative revenue requirement compilation, following a format consistent with the GRC and ERRA, demonstrating the calculation of DCPP net costs before and after adopting the changes that must be implemented pursuant to SB 846.

Figure 4

Line	Cost Category	Source	Current	SB 846
			($000)	
1	**Operating Expenses**			
2	Production	2023 GRC; February Update	$315,173	$315,173
3	Transmission	2023 GRC; February Update	$4,283	$4,283
4	Uncollectibles	2023 GRC; February Update	$3,765	$3,765
5	Administrative and General	2023 GRC; February Update	$241,315	$241,315
6	Franchise & SFGR Tax Requirement	2023 GRC; February Update	$9,577	$9,577
7	Amortization	2023 GRC; February Update	$31,327	$31,327
8	Other Adjustments	2023 GRC; February Update	($1,142)	($1,142)
9	**Taxes**			
10	Property	2023 GRC; February Update	$19,669	$19,669
11	Payroll	2023 GRC; February Update	$18,735	$18,735
12	Business	2023 GRC; February Update	$264	$264
13	Other	2023 GRC; February Update	$4,964	$4,964
14	State Corporation Franchise	2023 GRC; February Update	$30,786	$30,786
15	Federal Income Tax	2023 GRC; February Update	$24,010	NA
16	**Other**			
17	Depreciation	2023 GRC; February Update	$409,011	NA
18	Other Revenue	2023 GRC; February Update	($4,684)	($4,684)
19	Employee Retention and License Renewal Costs	2023 ERRA/AL 5268-E; 5461-E-A	$53,192	$53,192
20	**SB 846 Items**			
21	Fixed Payment In Lieu of Rate-Based Return	PUC § 712.8(f)(6)		$100,000
22	Volumetric Payment In Lieu of Rate-Based Return	PUC § 712.8(f)(5)		$228,035
23	Liquidated Damages Balancing Acct Funding	PUC § 712.8(g), § 712.8(i)		$150,000
24	Replacement Power Costs	PUC § 712.8(i)		TBD
25	Incremental Decommissioning Planning	PUC § 712.8(f)(1), 712.8(f)(3)		TBD
26	Independent Review Panel Costs	PUC § 712.8(f)(4)		TBD
27	Annual Capital Expenditures	PUC § 712.8(h)(2)		TBD
28	**Return on Rate Base**			
29	Rate Base	2023 GRC; February Update	$1,952,370	NA
30	Rate of Return		7.34%	NA
31	Return on Rate Base	2023 GRC; February Update	$143,304	NA
32	**Variable Production Costs**			
33	Fuel	2021 FERC Form 1	$121,881	$121,881
34	**Total Costs**		**$1,425,430**	**$1,327,140**
35	**CAISO Market Revenue**			
36	2023 NP-15 Market Price ($/MWh)	2023 ERRA Energy Index	$84.22	$84.22
37	Annual Generation (GWh)	2021 FERC Form 1	17,541	17,541
38	**Total Wholesale Market Revenue**		**$1,477,318**	**$1,477,318**
39	**Net Costs**		**($51,887)**	**($150,178)**

In its May 19, 2023, Prepared Testimony (**DCPP Cost Testimony**) providing historical and forecast cost information for DCPP, PG&E presented limited cost information according to the Electric Utility Cost Group (**EUCG**) method which excludes several cost categories that PG&E considers corporate costs but that are assigned or allocated to DCPP for ratemaking purposes.[47] As operator of the plant, PG&E will continue to incur common corporate costs in support of DCPP extended operations, and these costs are appropriately recovered from customers through the DCPP NBC. PG&E acknowledged in its DCPP Cost Testimony that the annual cost recovery application for extended operations would include all costs relevant to DCPP operations, including common costs such as benefits, overhead, employee retention, regulatory compliance, and statutory charges and fees.[48] As such, PG&E should present its request for cost recovery in the DCPP Forecast Application in a manner consistent with the GRC and ERRA filings.

In addition, the Commission should require PG&E to demonstrate in its DCPP Forecast Application that its DCPP Forecast includes common cost assumptions that are consistent with its 2023 GRC. This GRC includes attrition years that extend beyond the original DCPP expiration dates to 2026 and assumes DCPP is retired.[49] For example, to determine the DCPP revenue requirement in its GRC PG&E allocates several categories of common corporate costs (*e.g.*, administrative and general expense) to DCPP using approved allocation factors. When asked in discovery, PG&E objected to providing details of the common costs allocated to DCPP in the 2023 GRC and opted not to explain whether actual common costs would be impacted by extended operations.[50] Because PG&E would not provide these additional details, Figure 4 contains only an illustrative

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[47] PG&E Prepared Testimony (May 19, 2023) at 2:3-18.
[48] *Id*. at 16:1-13.
[49] PG&E Response to CalCCA Data Request 1.04.
[50] PG&E Responses to CalCCA Data Requests 1.05- 1.08.

revenue requirement using summarized cost categories from PG&E's GRC for the 2023 test period. In its DCPP Forecast Application, the Commission should require PG&E to quantify the impact of DCPP extended operations on its common costs relative to the amount approved in its 2023 GRC and demonstrate that there is no double counting of common costs proposed for recovery in the GRC and DCPP NBC.

Lastly, SB 846 states: "To the extent the commission decides to allocate any benefits or attributes from extended operations of the Diablo Canyon powerplant, the commission may consider the higher cost to customers in the operator's service area." [51] As a trade association with members that are both within and outside of "the operator's service area," CalCCA has a deep interest in finding the fairest way for the Commission to act upon such considerations.

Under SB 846, PG&E will assign a small portion of the costs authorized for recovery directly to customers of LSEs in its service territory. Those customers are also the sole beneficiaries of surplus wholesale market revenue and the return of excess funds paid into the liquidated damages balancing account by all customers. For example, half of the volumetric payment in lieu of a rate-based return ($6.50, in 2022 dollars, for each megawatt hour generated by DCPP during the period of extended operations)[52] is to be paid only by the customers of LSEs in PG&E service territory. In exchange for this cost responsibility, customers of LSEs in PG&E service territory will receive a credit for all surplus wholesale market revenue remaining after offsetting DCPP's annual operating costs.

[51] Cal. Pub. Util. Code § 712.8(q).
[52] Cal. Pub. Util. Code § 712.8(f)(5).

Figure 5 is an illustrative division of net annual costs and revenue recovered from all customers versus those charged only to customers of LSEs in PG&E service territory. Notably, at current wholesale market prices it is possible that the total DCPP costs will be less than the total market revenue. In that case, PG&E will return the surplus revenue only to customers of LSEs in its service territory. Furthermore, even though customers of all LSEs in California will fund the liquidated damages balancing account ($12.5 million per month, up to a total balance of $300 million), funds remaining in the balancing account at the end of DCPP extended operations will be returned solely to customers of LSEs in PG&E service territory.[53]

[53] Cal. Pub. Util. Code §§ 712.8(g), 712.8(i), 712.8(u).

Figure 5

Line	Cost Category	Costs	Market Revenue	Net Costs
1	Operating Expenses	$604,298		
2	Taxes	$74,418		
3	Other	$48,508		
4	SB 846 Items			
5	Fixed Payment In Lieu of Rate-Based Return	$100,000		
6	Volumetric Payment In Lieu of Rate-Based Return	$114,018		
7	Liquidated Damages Balancing Acct Funding	$150,000		
8	Replacement Power Costs	TBD		
9	Incremental Decommissioning Planning	TBD		
10	Independent Review Panel Costs	TBD		
11	Annual Capital Expenditures	TBD		
12	Variable Production Costs	$121,881		
13	**Recovered From All Customers**	**$1,213,123**	**($1,213,123)**	**$0**
14	SB 846 Items			
15	Volumetric Payment In Lieu of Rate-Based Return	$114,018		
16	**Recovered From PG&E Service Territory Customers**	**$114,018**	**($264,195)**	**($150,178)**
17	**Grand Total**	**$1,327,140**	**($1,477,318)**	**($150,178)**
18	**CAISO Market Revenue**			
19	2023 NP-15 Energy Index ($/MWh)	$84.22		
20	Annual Generation (GWh)	17,541		
21	**Total Wholesale Market Revenue**	**$1,477,318**		

IV. THE NET COSTS OF DCPP EXTENDED OPERATIONS SHOULD BE TRACKED IN A NEW BALANCING ACCOUNT AND RECOVERED THROUGH A NEW NBC INCLUDED IN IOU DELIVERY RATES

As described earlier, PG&E currently recovers its costs to operate DCPP, both direct and indirect, through PCIA rates. To properly track and recover the net costs of DCPP extended operations, all related costs items should no longer be included in the PCIA but should be recorded in a new balancing account established specifically for this purpose.[54] PG&E has been developing parameters for the new balancing account, and

[54] Notably, in its 2024 ERRA Forecast application filed May 15, 2023, PG&E removed DCPP Unit 1 from the PCIA revenue requirement effective November 2024.

required subaccounts, to enable tracking and allocation of costs to appropriate LSEs; CalCCA largely supports PG&E's approach on this matter.

A. PG&E Has Already Developed A New Balancing Account to Record The Net Costs of DCPP Extended Operations

PG&E proposed the Diablo Canyon Extended Operations Balancing Account (**DCEOBA**) in Advice Letter (**AL**) 6870-E to track the costs during DCPP extended operations. CalCCA reviewed PG&E's proposed tariff statements as part of the AL 6870-E process, and PG&E incorporated CalCCA's feedback into the tariff language. CalCCA supports using the DCEOBA to track DCPP extended operations cost recovery as long as the tariff language accommodates recording all common costs that may be allocated to DCPP. CalCCA agrees with PG&E's proposal to allocate cost responsibility by IOU service territory in separate subaccounts of the DCEOBA.

B. A New NBC Should Be Created and Charged to Customers in Jurisdictional IOUs' Delivery Rates

California Public Utilities Code Section 712.8(I)(1) specifies, "The recovery of these non-bypassable costs by the [LSEs] shall be based on each customer's gross consumption of electricity regardless of a customer's net metering status or purchase of electric energy and service from an [ESP], [CCA], or other third-party source of electric energy or electricity service." As such, each IOU will need to implement its own NBC and remit to PG&E the revenue received through the charge.

As described earlier in my testimony, one outcome of PG&E's DCPP Annual Forecast will be an allocation of the net costs of DCPP extended operations for the upcoming year by IOU service territory. To develop the DCPP NBC, each IOU would first need to allocate its share of DCPP costs among its unique customer classes. The net costs by customer class would then be divided by the forecast class energy consumption to develop a $/kWh rate. Similar to the allocation across service territories, DCPP costs should be allocated among customer classes using each customer class's contribution to 12-month coincident peak. This is also the approach currently used to develop CAM surcharges. On an annual basis, each IOU should submit its DCPP NBC proposal for Commission approval and implementation in rates through the annual consolidated rate change advice letter process.

This concludes my testimony.

ATTACHMENT A

CURRICULUM VITAE OF BRIAN DICKMAN

NewGen Strategies & Solutions

Brian Dickman
PARTNER
BDICKMAN@NEWGENSTRATEGIES.NET

Mr. Brian Dickman is a partner in NewGen's energy practice with 20 years of utility industry experience. Mr. Dickman's career includes over a decade working for PacifiCorp, a vertically integrated investor-owned utility, including senior-level positions in regulatory, financial, and commercial roles. He began consulting in 2017, assisting a wide array of clients across the United States and internationally, including utilities, large consumers, and private investment firms. Mr. Dickman has extensive experience preparing and evaluating utility revenue requirements and cost allocation studies, developing utility avoided costs, and analyzing the impact of new initiatives and transactions on a utility and its customers. In addition to his extensive technical experience, Mr. Dickman understands the regulatory governance process, and he has personally testified as an expert witness before state public utility commissions in California, Idaho, Indiana, Oregon, Utah, Washington, and Wyoming.

Mr. Dickman advises numerous Community Choice Aggregator (CCA) clients in California, focusing on regulatory and rate issues such as the state-mandated exit fee known as the Power Charge Indifference Adjustment (PCIA). He also represents California CCAs as a member of the Cost Allocation Mechanism Procurement Review Groups for PG&E and Southern California Edison established by the California Public Utility Commission to provide an independent review of the centralized procurement of local generation capacity requirements.

EDUCATION

- Master of Business Administration, Finance Emphasis, University of Utah
- Bachelor of Science, Accounting, Utah State University

KEY EXPERTISE

- Cost of Service and Rates
- Financial Analysis and Modeling
- Power Charge Indifference Amount
- Regulatory Strategy
- Revenue Requirement

RELEVANT EXPERIENCE

Electric Cost of Service, Rate Design, and Regulatory Analysis

Mr. Dickman leads projects developing utility revenue requirements, preparing cost of service and rate design studies, and performing financial and regulatory analyses for electric utilities. Mr. Dickman previously held leadership positions at a multi-billion-dollar utility. He was responsible for interfacing with state regulatory agencies in support of revenue requirements, cost recovery mechanisms, avoided costs, valuations of potential asset acquisitions and other commercial opportunities, and financial impacts of utility initiatives. Mr. Dickman now works with clients and stakeholders to prepare pro forma financial models to determine revenue sufficiency, evaluate the cost of service studies and rate design proposals, and support such proposals before local and state governing bodies. Mr. Dickman's experience also includes evaluating the financial and rate impact of proposed mergers and acquisitions, acquisition and divestiture of utility assets, negotiated retail service contracts, changing business models, and stranded costs due to exiting load.

Expert Witness and Litigation Support

Mr. Dickman provides comprehensive expert witness testimony related to utility revenue requirements, cost of service, rate design, and other ratemaking issues before state and local regulatory bodies. He has provided litigation support in wholesale and retail jurisdictions, including California, Idaho, Indiana, Oregon, Washington, Wyoming, Utah, the Federal Energy Regulatory Commission, and Ontario Energy Board. Mr. Dickman offers expert witness testimony and litigation support in the following areas.

Revenue Requirement | Cost Allocation | Rate Design

Mr. Dickman prepared revenue requirements, inter-jurisdictional cost allocation, coincident peak allocation studies, and supporting testimony for PacifiCorp over many years. He now provides litigation support and expert testimony for clients wishing to review utility filings on revenue requirement, cost allocation, and rate design, including program-specific rate tariffs.

Power Supply Costs | Stranded Costs | Rate Adjustment Mechanisms

Mr. Dickman has prepared and evaluated variable power supply cost forecasts, power supply cost balancing accounts and other rate mechanisms, stranded costs, and exit fees for departing load. Since 2019, Mr. Dickman has actively participated in PCIA matters in California on behalf of CCA clients.

Avoided Costs | Resource Valuation

Mr. Dickman provided expert testimony for PacifiCorp on various components included in a proposed method for valuing solar generation resources, the calculation of Public Utility Regulatory Policies Act avoided costs for large resources, and support of modifications to the avoided cost calculation for small resources.

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

- Abu Dhabi Distribution Company, UAE
- Central Coast Community Energy, CA
- City and County of San Francisco, CA
- Clean Power Alliance, CA
- Duke Energy, NC
- East Bay Community Energy, CA
- Hydro One, Ontario, CA
- Liberty Utilities, CA
- Lubbock Power and Light, TX
- Minnesota Power, MN
- New York Power Authority, NY
- Portland General Electric, OR
- San Diego Community Power, CA
- San Jose Clean Energy, CA
- Silicon Valley Clean Energy Authority, CA
- Vermont Gas Systems, VT

A sample of Mr. Dickman's non-utility clients includes the following:

- Blackstone Group, NY
- California Community Choice Association, CA
- Facebook, CA
- Hemlock Semiconductor, MI
- Newmont Mining, NV
- SABIC Innovative Plastics, IN
- Tri-County Metropolitan Transportation District, OR
- Vistra Energy, TX

WORKSHOPS AND PRESENTATIONS

Host organizations and the topics Mr. Dickman presented are displayed below.

Customer Choice at a Vertically Integrated Utility
Advanced Workshop in Regulation and Competition, Center for Research in Regulated Industries, 2018

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
1. SCE	A.12-01-008 A.12-04-020 A.14-01-007	Declaration supporting response to petition for modification of D.15-01-051, addressing changes to optional green tariff program rates	California Public Utilities Commission	Clean Power Alliance, California Choice Energy Authority	2022
2. SCE	A.22-05-014	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	Clean Power Alliance, California Choice Energy Authority, and Central Coast Community Energy	2022
3. PG&E, SCE, SDG&E	A.20-02-009 A.20-04-002 A.20-06-001 (Consolidated)	Expert testimony evaluating the unrealized sales volumes and revenue due to Public Safety Power Shutoff events	California Public Utilities Commission	CCA Parties (9 individual CCAs)	2022
4. San Diego Gas & Electric	A.21-09-001	Expert testimony responding to proposed residential electrification tariff	California Public Utilities Commission	San Diego Community Power and Clean Energy Alliance	2022
5. San Diego Gas & Electric	R.20-05-003	Declaration supporting motion for clarification of D.19-11-016, quantifying impact to allocated incremental reliability procurement requirement due to departing load	California Public Utilities Commission	San Diego Community Power	2021
6. Southern California Edison	A.21-06-003	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	Clean Power Alliance and California Choice Energy Authority	2021
7. Pacific Gas & Electric	A.21-06-001	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	Joint Community Choice Aggregators	2021
8. San Diego Gas & Electric	A.21-04-010	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	San Diego Community Power and Clean Energy Alliance	2021
9. Pacific Gas & Electric	A.12-01-008 A.12-04-020 A.14-01-007	Declaration supporting petition for modification of D.15-01-051, recommending changes to optional green tariff program rates designed to avoid shifting costs of resource capacity to non-participants	California Public Utilities Commission	Joint Community Choice Aggregators	2021

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
10. Pacific Gas & Electric	A.19-11-019	Expert testimony (adopted) addressing use of marginal costs to determine economic development rates and responding to proposed electrification tariff for retail customers	California Public Utilities Commission	Joint Community Choice Aggregators	2021
11. Pacific Gas & Electric	A.20-07-002	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	Joint Community Choice Aggregators	2020
12. Southern California Edison	A.20-07-004	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	Clean Power Alliance and California Choice Energy Authority	2020
13. Pacific Power	Docket UE 375	Joint testimony supporting a settlement agreement resolving the annual variable power supply cost forecast and generation resource dispatch model	Public Utility Commission of Oregon	Facebook, Inc.	2020
14. Pacific Gas & Electric	A.20-02-009	Expert testimony evaluating the appropriateness of entries recorded to the Portfolio Allocation Balancing Account to true up the Power Charge Indifference Amount	California Public Utilities Commission	Joint Community Choice Aggregators	2020
15. Vectren Energy Delivery of Indiana	Cause No. 43354 MCRA 21 S1	Expert testimony supporting a settlement agreement regarding the calculation and use of a 4CP load study to allocate tariff rider costs among customer classes	Indiana Utility Regulatory Commission	SABIC Innovative Plastics Mt. Vernon, LLC	2020
16. PacifiCorp	Docket UE 307	Expert testimony supporting the annual variable power supply cost forecast and generation resource dispatch model	Public Utility Commission of Oregon		2016
17. PacifiCorp	Docket UM 1662	Joint testimony with Portland General Electric regarding the need for a renewable resource tracking mechanism to provide cost recovery related to the impacts of renewable resource generation	Public Utility Commission of Oregon		2015
18. PacifiCorp	Docket UE 296	Expert testimony supporting the annual variable power supply cost forecast and generation resource dispatch model	Public Utility Commission of Oregon		2015

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
19. PacifiCorp	Docket No. 20000-469-ER-15	Expert testimony regarding the annual variable power supply cost forecast and modifications to the Energy Cost Adjustment Mechanism	Public Service Commission of Wyoming		2015
20. PacifiCorp	Docket No. 15-035-03	Provided expert testimony regarding the true up of variable power supply costs in the Energy Balancing Account mechanism	Public Service Commission of Utah		2015
21. PacifiCorp	Docket UM 1716	Expert testimony proposing changes to the calculation of PURPA avoided costs for large resources	Public Utility Commission of Oregon		2015
22. PacifiCorp	Docket No. 20000-481-EA-15	Expert testimony proposing changes to the calculation of PURPA avoided costs for large resources	Public Service Commission of Wyoming		2015
23. PacifiCorp	Docket No. 15-035-T06	Expert testimony updating standard PURPA avoided cost prices and supporting modifications to the avoided cost calculation for small resources	Public Service Commission of Utah		2015
24. PacifiCorp	Case No. PAC-E-15-03	Expert testimony proposing changes to the calculation of PURPA avoided costs for large resource	Idaho Public Utilities Commission		2015
25. PacifiCorp	Docket UE-144160	Declaration supporting updates to standard PURPA avoided cost prices and supporting modifications to the avoided cost calculation for small resources	Washington Utilities and Transportation Commission		2014
26. PacifiCorp	Docket UE 287	Expert testimony supporting the annual variable power supply cost forecast and generation resource dispatch model	Public Utility Commission of Oregon		2014
27. PacifiCorp	Case No. PAC-E-14-01	Expert testimony regarding the true up of variable power supply costs in the Energy Cost Adjustment Mechanism	Idaho Public Utilities Commission		2014
28. PacifiCorp	Docket A.14-08-002	Expert testimony supporting the annual variable power supply cost forecast and the true up of costs in the Energy Cost Adjustment Clause mechanism	California Public Utilities Commission		2014
29. PacifiCorp	Docket No. 20000-447-EA-14	Expert testimony regarding the true up of annual variable power supply cost in the Energy Cost Adjustment Mechanism	Public Service Commission of Wyoming		2014

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
30. PacifiCorp	Docket No. 14-035-31	Expert testimony regarding the true up of variable power supply costs in the Energy Balancing Account mechanism	Public Service Commission of Utah		2014
31. PacifiCorp	Case No. PAC-E-13-03	Expert testimony regarding the true up of variable power supply costs in the Energy Cost Adjustment Mechanism	Idaho Public Utilities Commission		2013
32. PacifiCorp	Docket A.13-08-001	Expert testimony supporting the annual variable power supply cost forecast and the true up of costs in the Energy Cost Adjustment Clause mechanism	California Public Utilities Commission		2013
33. PacifiCorp	Docket No. 13-035-32	Expert testimony regarding the true up of variable power supply costs in the Energy Balancing Account mechanism	Public Service Commission of Utah		2013
34. PacifiCorp	Docket UM 1610	Expert testimony proposing changes to the calculation of PURPA avoided costs for large and small generation resources	Public Utility Commission of Oregon		2012
35. PacifiCorp	Docket A.12-08-003	Expert testimony supporting the annual variable power supply cost forecast and the true up of costs in the Energy Cost Adjustment Clause mechanism	California Public Utilities Commission		2012
36. PacifiCorp	Docket No. 12-035-67	Expert testimony regarding the true up of variable power supply costs in the Energy Balancing Account mechanism	Public Service Commission of Utah		2012
37. PacifiCorp	Docket No. 20000-389-EP-11	Expert testimony regarding the collection of deferred balances accrued through previous Power Cost Adjustment Mechanisms	Public Service Commission of Wyoming		2011
38. PacifiCorp	Docket No. 20000-405-ER-11	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Public Service Commission of Wyoming		2011
39. PacifiCorp	Case No. GNR-E-11-03	Expert testimony proposing changes to the calculation of PURPA avoided costs for large and small generation resources	Idaho Public Utilities Commission		2011
40. PacifiCorp	Case No. PAC-E-06-10	Expert testimony regarding low income customer weatherization rebates	Idaho Public Utilities Commission		2010

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
41. PacifiCorp	Docket No. 20000-405-ER-10	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Public Service Commission of Wyoming		2010
42. PacifiCorp	Docket No. 10-035-89	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Public Service Commission of Utah		2010
43. PacifiCorp	Docket No. 20000-352-ER-09	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Public Service Commission of Wyoming		2009
44. PacifiCorp	Case No. PAC-E-08-07	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Idaho Public Utilities Commission		2008
45. PacifiCorp	Docket No. 20000-333-ER-08	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Public Service Commission of Wyoming		2008

ATTACHMENT B

SELECT DATA RESPONSES

PACIFIC GAS AND ELECTRIC COMPANY
Diablo Canyon Power Plant Operations Extension OIR
Rulemaking 23-01-007
Data Response

PG&E Data Request No.:	CalCCA_001-Q001		
PG&E File Name:	DiabloCanyonPowerPlantOperationsExtensionOIR_DR_CalCCA_001-Q001		
Request Date:	May 5, 2023	Requester DR No.:	001
Date Sent:	May 19, 2023	Requesting Party:	California Community Choice Association
PG&E Witness:	Ryan Stanley / Tom Baldwin	Requester:	Nikhil Vijaykar

QUESTION 001

Please identify all accounting mechanisms (including balancing accounts, memorandum accounts, etc.) PG&E relies on to record costs related to Diablo Canyon operation, maintenance, licensing, and decommissioning and retirement.

ANSWER 001

PG&E currently relies on the following active accounting mechanisms to record costs and cost recovery related to Diablo Canyon Power Plant's (DCPP) operations as follows:

Portfolio Allocation Balancing Account (PABA)

The purpose of this balancing account is to recover all "above-market" costs from all generation resources eligible for recovery through Power Charge Indifference Adjustment (PCIA) rates. This includes several different operational activities as found in PG&E's Electric Preliminary Statement Part HS and described further below:[1]

Utility-Owned Generation Revenue Requirements

PABA recovers the base revenue requirements associated with DCPP's operations, maintenance, and capital recovery as identified in PG&E's general rate case (as one of several utility-owned generation facilities). PABA also recovers specific revenue requirements related to the DCPP Retention Program and DCPP license renewal costs associated with relicensing costs for the current operating license period (i.e., prior to SB 846). Please see Electric Preliminary Statement Part HS, Tariff Lines 5.n., 5.p through 5.r. for relevant entries related to Utility-Owned Generation revenue requirements.

1 Hyperlink at: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_PRELIM_HS.pdf.

CAISO-Related Entries

PABA also records relevant CAISO activity. This includes energy market revenues from scheduling and/or bidding DCPP into the CAISO market net of any miscellaneous or site-specific load that is also incurred for DCPP. Please see Electric Preliminary Statement Part HS, Tariff Lines 5.t. through 5.v. for relevant CAISO-related entries.

Fuel Costs

In addition, PABA is authorized to recover nuclear fuel expenses and miscellaneous expenses for DCPP, as well as carrying costs on PG&E's net outstanding nuclear fuel inventory at the rate of the three-month commercial paper rate. Please see Electric Preliminary Statement Part HS, Tariff Lines 5.z. and 5.aa. for relevant nuclear fuel entries.

Note: Recovery within PABA is included through the current licensing period and will not include extension period activity.

Nuclear Decommissioning Adjustment Mechanism (NDAM)

This account recovers authorized nuclear decommissioning revenue requirements and to provide full recovery of costs. In addition, the approved tariff includes recovery of other related expenses including costs to satisfy the requirements of CA Bill 968 and Public Utilities Code Section 712.5 Section 3, DCPP Employee Retraining Program budget, and authorized recovery of funds approved in the Community Impact Mitigation Program (CIMP). Detailed accounting entries can be found in PG&E's Electric Preliminary Statement Part DB.[2]

Diablo Canyon Retirement Balancing Account (DCRBA)

This account is used to track actual expenses and capital revenue requirements against expense budgets or capital revenue requirements related to (1) DCPP full book value by the time Units 1 & 2 cease operations, (2) the DCPP Employee Retention Program, and (3) the DCPP Employee Retraining Program. The differences are transferred to PABA or NDAM as applicable and as authorized by the Commission. Detailed entries can be found in PG&E's Electric Preliminary Statement Part HK.[3]

Nuclear Regulatory Commission Rulemaking Balancing Account (NRCRBA)

This account is used for recovery of actual expenses for complying with existing, emerging or evolving NRC regulations and directives. These costs include but are not limited to, the following four major NRC rulemaking processes currently in progress: Fukushima Daiichi Rulemaking, Cyber-Security Rulemaking, Emergency Planning

2 Hyperlink at: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_PRELIM_DB.pdf.

3 Hyperlink at: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_PRELIM_HK.pdf.

Rulemaking, and the new National Fire Protection Standard (NFPA) 805 Rulemaking. Detailed entries can be found in PG&E's Electric Preliminary Statement Part GM.[4]

Department of Energy Litigation Balancing Account (DOELBA)

This account tracks and records for customers of any proceeds, net of costs, from PG&E's lawsuit against the Department of Energy (DOE) filed in the Federal Court of Claims on January 22, 2004, regarding the DOE's breach of spent fuel contracts and any additional claims for reimbursement that PG&E may have against DOE arising out of or related to spent fuel contracts. This account ensures the proper crediting and allocation of proceeds and costs for the benefit of customers as determined by the Commission between the Diablo Canyon and Humboldt Bay nuclear power plants. The DOELBA will expire after litigation is completed, proceeds have been received, and the Commission has authorized disposition of the balance. Amounts get transferred to PABA or NDAM as authorized by the Commission. Detailed entries can be found in PG&E's Electric Preliminary Statement Part DZ.[5]

Additional mechanisms related to costs for extend operations of DCPP in accordance with SB 846 were proposed as part of PG&E's Advice Letter 6870-E and Supplemental Advice Letter 6870-E-A, currently pending disposition from the Commission.

4 Hyperlink at: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_PRELIM_GM.pdf
5 Hyperlink at: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_PRELIM_DZ.pdf

PACIFIC GAS AND ELECTRIC COMPANY
Diablo Canyon Power Plant Operations Extension OIR
Rulemaking 23-01-007
Data Response

PG&E Data Request No.:	CalCCA_001-Q002		
PG&E File Name:	DiabloCanyonPowerPlantOperationsExtensionOIR_DR_CalCCA_001-Q002		
Request Date:	May 5, 2023	Requester DR No.:	001
Date Sent:	May 19, 2023	Requesting Party:	California Community Choice Association
PG&E Witness:	Ryan Stanley	Requester:	Nikhil Vijaykar

QUESTION 002

Please identify all rate mechanisms currently relied on by PG&E to recover any costs related to Diablo Canyon and describe the costs included in each mechanism.

ANSWER 002

PG&E currently recovers costs associated with Diablo Canyon through two nonbypassable charges:

- Power Charge Indifferent Adjustment (PCIA) rates
- Nuclear Decommissioning rates

PCIA revenues are credited to the Portfolio Allocation Balancing Account (PABA). Nuclear Decommissioning revenues are credited to the Nuclear Decommissioning Adjustment Mechanism (NDAM). Please see PG&E's response to Question 1 of this data request for further details on the activities recovered within PABA and NDAM, as well as other accounts transferred to PABA and NDAM for cost recovery.

PACIFIC GAS AND ELECTRIC COMPANY
Diablo Canyon Power Plant Operations Extension OIR
Rulemaking 23-01-007
Data Response

PG&E Data Request No.:	CalCCA_001-Q004		
PG&E File Name:	DiabloCanyonPowerPlantOperationsExtensionOIR_DR_CalCCA_001-Q004		
Request Date:	May 5, 2023	Requester DR No.:	001
Date Sent:	May 19, 2023	Requesting Party:	California Community Choice Association
PG&E Witness:	Brian Ketelsen	Requester:	Nikhil Vijaykar

QUESTION 004

Please confirm that PG&E's 2023 GRC assumes the Diablo Canyon Power Plant is retired in 2024 (Unit 1) and 2025 (Unit 2). If not confirmed, please explain.

ANSWER 004

PG&E objects to this data request as irrelevant and outside the scope of this proceeding. Subject to and without waiving that objection, PG&E confirms that PG&E's 2023 GRC assumes DCPP is retired in 2024 (Unit 1) and 2025 (Unit 2).

PACIFIC GAS AND ELECTRIC COMPANY
Diablo Canyon Power Plant Operations Extension OIR
Rulemaking 23-01-007
Data Response

PG&E Data Request No.:	CalCCA_001-Q005		
PG&E File Name:	DiabloCanyonPowerPlantOperationsExtensionOIR_DR_CalCCA_001-Q005		
Request Date:	May 5, 2023	Requester DR No.:	001
Date Sent:	May 19, 2023	Requesting Party:	California Community Choice Association
PG&E Witness:		Requester:	Nikhil Vijaykar

QUESTION 005

Please quantify all common costs by category allocated to Diablo Canyon Power Plant revenue requirement in 2023, 2024, 2025, and 2026 as included in PG&E's February Update of its 2023 GRC. For each category, explain the basis for the total common costs and the method used to allocate costs to Diablo Canyon Power Plant.

ANSWER 005

PG&E objects to this data request on grounds that it is irrelevant and outside the scope of this proceeding.

PACIFIC GAS AND ELECTRIC COMPANY
Diablo Canyon Power Plant Operations Extension OIR
Rulemaking 23-01-007
Data Response

PG&E Data Request No.:	CalCCA_001-Q006		
PG&E File Name:	DiabloCanyonPowerPlantOperationsExtensionOIR_DR_CalCCA_001-Q006		
Request Date:	May 5, 2023	Requester DR No.:	001
Date Sent:	May 19, 2023	Requesting Party:	California Community Choice Association
PG&E Witness:		Requester:	Nikhil Vijaykar

QUESTION 006

Please explain whether the common costs identified in the previous request allocated to Diablo Canyon Power Plant prior to its retirement are assumed to be reallocated among other resources and/or departments after Diablo Canyon Power Plant retirement.

ANSWER 006

PG&E objects to this data request on grounds that it is irrelevant and outside the scope of this proceeding.

PACIFIC GAS AND ELECTRIC COMPANY
Diablo Canyon Power Plant Operations Extension OIR
Rulemaking 23-01-007
Data Response

PG&E Data Request No.:	CalCCA_001-Q007		
PG&E File Name:	DiabloCanyonPowerPlantOperationsExtensionOIR_DR_CalCCA_001-Q007		
Request Date:	May 5, 2023	Requester DR No.:	001
Date Sent:	May 19, 2023	Requesting Party:	California Community Choice Association
PG&E Witness:		Requester:	Nikhil Vijaykar

QUESTION 007

Please explain whether PG&E assumed a reduction in overall common costs through 2026 due to Diablo Canyon Power Plant retirement. If yes, please quantify the reduction by year and by category. If no, please explain why not.

ANSWER 007

PG&E objects to this data request as irrelevant and outside the scope of this proceeding.

PACIFIC GAS AND ELECTRIC COMPANY
Diablo Canyon Power Plant Operations Extension OIR
Rulemaking 23-01-007
Data Response

PG&E Data Request No.:	CalCCA_001-Q008		
PG&E File Name:	DiabloCanyonPowerPlantOperationsExtensionOIR_DR_CalCCA_001-Q008		
Request Date:	May 5, 2023	Requester DR No.:	001
Date Sent:	May 19, 2023	Requesting Party:	California Community Choice Association
PG&E Witness:		Requester:	Nikhil Vijaykar

QUESTION 008

Please explain whether continued operation of Diablo Canyon Power Plant will cause PG&E common costs to be higher than projected in 2025 and 2026 relative to the amount assumed in PG&E's GRC. If yes, please quantify the incremental common costs by year and category. If not, please explain.

ANSWER 008

PG&E objects to this data request on grounds that PG&E's GRC costs are irrelevant and outside the scope of this proceeding.

Notwithstanding this objection, PG&E's May 19, 2023, Testimony in Rulemaking (R.) 23-01-007, Table 2, presents cost forecasts through 2030 that include accounting categories adopted by the Electric Utility Cost Group (EUCG). The "Support Services" line item includes costs for organizations outside of DCPP such as Information Technology, Insurance, Legal, Finance, Executive Leadership, Communications, Safety and Health, Procurement, and Human Resources.

These organizations have separate GRC chapters and are not included in the Nuclear chapter in PG&E's most recent GRC Application, Application 21-06-021 and therefore could be considered common costs supporting Diablo Canyon.

Of note, the EUCG cost presentation in PG&E's May 19, 2023, Testimony does not capture items such as property taxes, depreciation, interest expense, and revenues.

Agenda Item 14: Update on Planning for Net Billing Tariff (NBT) (Informational Item)
Comments submitted from a technical expert on the CAC who is a homeowner with solar panels

Some background:
NEM 3 has been in effect since April 14th, 2023 and if you applied for a system prior to this, it is still technically under NEM2 -- unless you add more solar panels, at which time utilities (under the direction of the CA PUC) can now push you to NEM3. The PUC made a request to various community organizations such as the Sierra Club, Grid Alternatives, and NDRC. Their response can be found here: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M500/K043/500043682.PDF
Many of these concerns still exist with the PUC's NBT decision. Now we are changing the NEM structure again and I as a rooftop solar owner, community member, and consumer, would like to know how this can possibly be good for me.

Mission of EBCE/Ava Community Energy:
It appears to me that EBCE / Ava Community Energy's *"...mission is to reinvest profits directly into East Bay communities creating local green energy jobs and clean power projects",* is counterproductive to rooftop solar, and the organization is more inclined to build renewable infrastructure, profiting through investments in solar and wind farms. How can we call this a community organization when it is using the very dollars it accrues through electricity subsidized by rooftop solar production, to sell it back to these same rooftop solar producers at night at consumer pricing?

Incentives for battery storage:
Here is the url for EBCE's battery incentive which mentions a $500 incentive for battery storage.: https://ebce.org/resilient-home/
They are partnered with Sunrun, which when I called to ask if I can *add a battery system to my solar PV system*, twice said that they could do it and would call me back, but then never did. From this experience, I suspect that they are not very interested in selling just battery systems.

Cost analysis using payback period:
The payback period for a solar system with no battery storage doubles with NEM 3.0; going from 5-6 years for NEM 2.0 to a decade for NEM 3 (albeit from a battery storage provider): https://www.fortresspower.com/nem3-why-is-battery-storage-so-important/#:~:text=NEM%202.0%20had%20a%20solar,of%20savings%20under%20NEM%203.0.
This is also corroborated from a non-biased site: https://www.energysage.com/blog/net-metering-3-0/
However, lower Solar PV pricing and rising electric rates can change this payback period. Until the various utilities decide on how to implement NBT, we cannot calculate how this would impact the payback period.

Conflict to consumers concerning EV vehicles and adding solar PV:
In the meantime, EBCE has pushed for folks to move to electric cars, which is a great business decision in terms of profits, as they would sell more electricity, and would push most solar PV owners into the import mode for electricity.

Profits over community:
I understand the need for EBCE / Ava Community Energy to prioritize profits, but the organization is supposed to be a green alternative, something that puts community above profits: https://ebce.org/about/

Conclusion:
The current trend for NEM seems counterintuitive in motivating homeowners to add rooftop solar (and wind) installations, and pushing California further away from both decarbonization and a future micro-grid resiliency model.

BTW - (this is more of a question than a statement...) I am still confused as to the Time of Use Cost being the NEM 3.0 platform. You asked a great question about PV homeowners exporting at a wholesale lower rate, and then paying a higher consumer rate for importing electricity. Ms. Kelly's answer was confusing to me. I am also concerned about how grandfathering would work. Can you please ask her to elaborate on this as well?