FILED
09/18/23
04:59 PM
R2301007

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

Implementing Senate Bill 846 Concerning Potential Extension of Diablo Canyon Power Plant Operations.	R.23-01-007

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING BRIEF ON PHASE 1 TRACK 2 ISSUES

Evelyn Kahl
General Counsel and Director of Policy
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
One Concord Center
2300 Clayton Road, Suite 1150
Concord, CA 94520
Phone: (510) 980-9459
Email: regulatory@cal-cca.org

Tim Lindl
Nikhil Vijaykar
KEYES & FOX LLP
580 California Street, 12th Floor
San Francisco, CA 94104
Phone: (408) 621-3256
Email: tlindl@keyesfox.com
nvijaykar@keyesfox.com

September 18, 2023

TABLE OF CONTENTS

TABLE OF AUTHORITIES

Cases

Statutes

Commission Decisions

Legislation

Commission Rules of Practice and Procedure

SUMMARY OF RECOMMENDATIONS

- Failing to allocate Diablo Canyon Power Plant's (DCPP) resource adequacy (RA) attributes to all load-serving entities (LSE) contributing to the costs of extended operations at DCPP increases rates by $200 million per year with zero commensurate increase in reliability.

- Allocating DCPP's RA attributes using the process currently used for Cost Allocation Mechanism (CAM) resources builds on proven processes.

- Allocating DCPP's RA attributes based on each LSE's proportional contribution to the group's combined 12-month coincident peak follows existing CAM protocols, thereby reducing ratemaking burdens.

- The Commission should require Pacific Gas and Electric Company (PG&E) to offer an annual voluntary allocation of DCPP's greenhouse-gas (GHG) -free attributes to all LSEs contributing toward cost recovery.

- The Commission should direct PG&E to offer an annual voluntary allocation of DCPP's GHG-free attributes by extending and expanding the "interim allocation process" PG&E currently uses to allocate the GHG-free attributes of its large hydroelectric and nuclear Power Charge Indifference Adjustment portfolio facilities.

- The Commission should approve PG&E's proposal to track the net costs of DCPP's extended operations in the Diablo Canyon Extended Operations Balancing Account (DCEOBA).

- The Commission should approve PG&E's proposal to recover the net costs of DCPP's extended operations through a new statewide non-bypassable charge (NBC) and an adder specific to customers in PG&E's service territory.

- The Commission should direct PG&E to allocate the net costs of DCPP's extended operations, which are to be recovered from customers of all jurisdictional LSEs across the state, to investor-owned utility (IOU) service territories based on the IOU's contribution to the group's combined 12-month coincident peak.

- California Community Choice Association and PG&E agree there should be no floor on the statewide DCPP NBC and that customer overcollections in one year should be returned to customers as an offset to the DCPP NBC over the following year.

- The Commission should approve PG&E's proposed structure for the annual DCPP Cost Forecast Application.

- The Commission should require PG&E to present detailed projections of all costs and revenues associated with DCPP's extended operations in the DCPP Forecast Application in a manner consistent with PG&E's General Rate Case (GRC) and Energy Resource Recovery Account Forecast filings.

- The Commission should direct PG&E to demonstrate its DCPP Forecast includes common cost assumptions that are consistent with its 2023 GRC, and that its GRC and DCPP Forecast Applications do not double count any common costs proposed for recovery.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Implementing Senate Bill 846 Concerning Potential Extension of Diablo Canyon Power Plant Operations.	R.23-01-007

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING BRIEF ON PHASE 1 TRACK 2 ISSUES

The California Community Choice Association[1] (CalCCA) submits this Opening Brief on Phase 1 Track 2 issues in *Rulemaking (R.) 23-01-007 Implementing Senate Bill 846 Concerning Potential Extension of Diablo Canyon Power Plant Operations*, pursuant to Rule 13.12 of the California Public Utilities Commission's Rules of Practice and Procedure and the procedural schedule established by the Administrative Law Judge's (ALJ) August 14, 2023 E-mail Ruling as modified by the ALJ's September 13, 2023 Email Ruling.

Senate Bill (SB) 846 requires the Commission to consider extending the life of Diablo Canyon Power Plant (DCPP) to protect California from near-term capacity shortfalls as the State works to achieve its greenhouse-gas (GHG) reduction and electrification goals.[2] To achieve this

---

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

2 *See* Cal. Pub. Util. Code § 712.8(q) ("The Legislature finds and declares that the purpose of the extension of Diablo Canyon powerplant operations is to protect the state against significant uncertainty in future demand resulting from the state's greenhouse-gas-reduction efforts involving electrification of transportation and building energy end uses and regional climate-related weather phenomenon, and to address the risk that currently ordered procurement will be insufficient to meet this supply or that there may be delays in bringing the ordered resources online on schedule. Consequently, the continued operation of Diablo Canyon Units 1 and 2 beyond their current expiration dates shall not be factored into the analyses used by the commission or by load-serving entities not subject to the Commission's jurisdiction when

purpose, SB 846 transforms DCPP's cost recovery framework. Whereas Pacific Gas and Electric Company (PG&E) currently recovers DCPP's costs from only those customers in its service territory, customers across California will pay for the costs of DCPP's extended operations.[3]

Those costs will be numerous. Customers will pay for capital and operations and maintenance expenses associated with DCPP's extended operations[4] and the incremental decommissioning costs resulting from license renewal applications or license renewals.[5] Further, in lieu of a traditional return on rate base, PG&E will collect $13 from customers for each megawatt-hour (MWh) DCPP generates during extended operations, plus a fixed annual payment of $100 million.[6] PG&E will also charge all customers to fund a $300 million liquidated damages account that PG&E will use to cover the cost of replacement power during unplanned outages, *even if the outage is the result of PG&E's imprudence*.[7] Overall, if the Commission authorizes extension, customers across the State will bear a significant burden to fund DCPP's prolonged life.[8]

---

determining future generation and transmission needs to ensure electrical grid reliability and to meet the state's greenhouse-gas-emissions reduction goals."). All subsequent code sections cited herein are references to the California Public Utilities Code unless otherwise specified.

3 Cal. Pub. Util. Code § 712.8(f).

4 Cal. Pub. Util. Code § 712.8(h)(1).

5 Cal. Pub. Util. Code § 712.8(f)(1).

6 Cal. Pub. Util. Code § 712.8(f)(5)-(6). These fees are subject to annual escalation.

7 Cal. Pub. Util. Code § 712.8(g), § 712.8(i)(1)-(2).

8 In total, PG&E forecasts costs of approximately $4.5 billion for DCPP for 2025 through 2030, only $268 million of which will be recovered via government funding streams. Ex. PG&E-01 at 9 (Table 2), 15 (Table 4). However, those estimates do not include costs of taxes, benefits and standard PG&E overheads, employee retention costs, regulatory compliance items, statutory charges and fees, and, significantly, the volumetric and fixed management payments SB 846 provides. Ex. PG&E-01 at 16.

There is another side to this story. Should the Commission authorize extension, DCPP's continued operation will also generate substantial benefits for customers across the State.[9] Among those benefits, extended operations would preserve approximately 2 gigawatts (GW) of system resource adequacy (RA).[10] This benefit is particularly salient as the past few years have seen market forces and regulatory changes severely strain California's System RA market; a severe strain that exists *with* DCPP's RA available to the market today.[11] If DCPP's RA were no longer available, as PG&E proposes, several studies conclude the State would experience capacity shortages until it brings unprecedented amounts of new resources online.[12] By extending DCPP's operations and making its RA available, the Commission would avoid further squeezing the State's RA market, thereby offsetting some of the costs customers will bear to fund DCPP's extension.

CalCCA, Southern California Edison Company (SCE), and several other parties ask the Commission to ensure those costs and benefits flow equally and consistently to customers. Should the Commission authorize extension, it can ensure customers realize those benefits by allocating DCPP's RA attributes to the LSEs paying for extended operations, following the model the Commission already uses to allocate the RA benefits of Cost Allocation Mechanism (CAM) resources.

---

9 *See* Cal. Pub. Res. Code § 25548(d) ("It is the intent of the Legislature that the extension of the Diablo Canyon powerplant benefit California's electric customers[.]").

10 Ex. CalPA-01 at 3:15-17.

11 Ex. CalCCA-01 at 7:13.

12 *See* Administrative Law Judge's Ruling Requesting Comments Served as Testimony on Statutory Interpretation and Issues of Policy, and Incorporating Certain Reports into the Record of this Proceeding (Apr. 20, 2023) (ALJ April 20 Ruling), Exhibit D (California Energy Commission staff report on Diablo Canon Power Plant Extension or CEC Report) (Mar. 2023); ALJ April 20 Ruling, Exhibit E (Joint Agency Report) (Feb. 2023); Ex. CalCCA-02 at 3:4, Attachment C (CalCCA RA Stack Analysis).

PG&E, on the other hand, ignores one half of the cost-benefit equation. It asks for Commission approval to impose several new costs on customers across the State to pay for DCPP's extended operations but seeks to deprive the same customers of DCPP's considerable benefits. Notably, PG&E concedes SB 846 *permits* the Commission to allocate DCPP's attributes.[13] Yet, PG&E takes the strained position the Commission should essentially pretend those attributes do not exist, because—according to PG&E—that fiction would effectuate the Legislature's intent.[14]

The Commission need not, and should not, adopt PG&E's strained position because PG&E fundamentally misreads SB 846. While SB 846 requires that any attributes associated with DCPP's extension must not be counted towards the State's long-term reliability and greenhouse gas emissions reduction goals,[15] SB 846 plainly contemplates the Commission allocating DCPP's benefits where it 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."[16] Moreover, as this brief explains, the bill's legislative history makes clear the Legislature intended to allow DCPP to count

13 *See, e.g.* Ex. PG&E-4 at 2-15, lines 24-26; 2-24, lines 31-33 (stating "PG&E acknowledges that there is no explicit prohibition of allocating DCPP's capacity for RA purposes[.]"); PG&E-04R at 2-24, line 35 to 2-25, line 2 (stating "the Commission has the discretion to consider an allocation of RA capacity as part of this proceeding.").

14 Ex. PG&E-04R at 2-25, line 9.

15 Cal. Pub. Util. Code § 712.8(q) (prohibiting the Commission and LSEs from factoring in the continued operation of DCPP when determining future generation and transmission needs to ensure grid reliability and to meet the state's greenhouse gas emissions reduction goals); § 454.52(f)(1)-(2) (prohibiting the Commission and LSEs from including energy, capacity, or any attribute from DCPP in adopted integrated resource plan portfolios, resource stacks, or preferred system plans).

16 Cal. Pub. Util. Code § 712.8(q) (emphasis added).

towards LSEs' RA compliance requirements during extended operations as a ratepayer relief measure.[17]

Most critical to the State's already overburdened ratepayers, adopting PG&E's position would increase customers' bills by approximately **$200 million per year** while providing zero commensurate increase in reliability.[18] PG&E admitted in pre-hearing discovery that the State's severely constrained RA market renders moot its main reliability concern over allocating DCPP's RA: a reduction in demand for the capacity from other existing resources.[19] It also admitted that Integrated Resource Planning (IRP)-mandated procurement will proceed independent of whether DCPP is retired, meaning allocation of benefits will not impact the Commission's reliability and GHG-related goals.[20] The Commission should reject PG&E's invitation to distort the market[21] by ignoring the substantial benefits DCPP's extended operations can deliver to customers across the State. It should instead provide customers the relief the Legislature intended by allocating DCPP's RA and GHG-free attributes to LSEs paying for extended operations.

In a similar vein, the GHG-free energy DCPP will generate during extended operations will be valuable to LSEs seeking GHG-free attributes for Power Content Label and marketing

---

17 Senate Rules Committee, Office of Senate Floor Analyses, SB 846, Sep. 1, 2022, at 11, at: https://leginfo.legislature.ca.gov/faces/billAnalysisClient.xhtml?bill_id=202120220SB846#; *see also* Senate Third Reading, SB 846, Aug. 28, 2022, at 12, at: https://leginfo.legislature.ca.gov/faces/billAnalysisClient.xhmtl?bill_id=202120220SB846#.

18 Ex. CalPA-01 at 3:22-23; 4:6-8; Ex. CalCCA-01 at 13:12 (calculating $200 million in annual costs from RA procurements if DCPP's RA is not allocated). This estimate represents DCPP's capacity (2,280 MW) multiplied by the forecast average price of System RA in 2023 ($7.39/kW-month), converted into a $/year figure. *See* Ex. CalCCA-01 at 13, n. 21.

19 *See* Ex. PG&E-05 at 2-19:28 (noting "the tight RA market"); Ex. CalCCA-04 (PG&E Response to CalCCA 3.07) (noting PG&E's concerns "only hold true if there is a surplus in the RA capacity available in the market").

20 Ex. PG&E-04R at 3-6, lines 14-17.

21 *See* Tr. at 254:1-8 (Sep. 5, 2023) (agreeing if DCPP were operating but not counted in the RA market, it would distort that market).

purposes. The Commission should direct PG&E to continue its current, Commission-approved process of offering voluntary allocations of DCPP's GHG-free energy attributes to LSEs. It should further direct PG&E to make that allocation process available to all jurisdictional LSEs. This will ensure LSEs paying for the costs of extended operations receive the benefits of DCPP's GHG-free attributes.

This brief, like CalCCA's other submissions to date in this proceeding, focuses on Phase 1 Track 2 Scoping Issue 5, which concerns the allocation of DCPP's RA and GHG-free attributes. This brief also addresses Phase 1 Track 2 Scoping Issues 3 and 4, which concern PG&E's proposed cost recovery process and cost recovery mechanisms, respectively.

I. APPLICABLE LAW: SB 846 PERMITS THE ALLOCATION OF BENEFITS FROM EXTENDED OPERATIONS AT DCPP, WHICH INCLUDES RA AND GHG-FREE ATTRIBUTES

Phase 1 Track 2 Scoping Issue 5 requires the Commission to determine:

> Whether and how the benefits of extended operations, including resource adequacy and greenhouse gas-free attributes, should be allocated among the load-serving entities (LSEs) and customers paying for extended operations.[22]

Resolving Scoping Issue 5 requires the Commission to answer a fundamental legal question: does SB 846 give the Commission the authority to allocate DCPP's RA and GHG-free attributes during extended operations?

The Commission should answer this question in the affirmative. Several parties to this proceeding, including CalCCA, PG&E,[23] and SCE[24] agree the law permits the Commission to

22 R.23-01-007, *Assigned Commissioner's Scoping Memo and Ruling*, p. 6 (Apr. 6, 2023).

23 Ex. PG&E-04R at 2-24:35-2-25:2 (stating "the Commission has the discretion to consider an allocation of RA capacity as part of this proceeding.")

24 Ex. SCE-01 at 3-8 (explaining the allocation of Diablo Canyon's RA benefits to all LSEs is supported by the language and intent of SB 846).

allocate the benefits of DCPP's extended operations. A minority of parties disagree,[25] but those parties misinterpret the language of SB 846.

In any case involving statutory interpretation, the Commission's fundamental task is to determine the Legislature's intent so as to effectuate the law's purpose.[26] The rules for performing this task are well-established. The Commission must begin by examining the statutory language, giving it its plain and common-sense meaning.[27] The Commission must not consider the language of any statutory provision in isolation; rather, it must construe each provision in the context of the statutory frame as a whole.[28] If the statutory language is unambiguous, the Commission presumes the Legislature meant what it said, and the statute's plain meaning controls.[29] If, however, the statutory language supports more than one reasonable meaning, the Commission may look to other extrinsic aids to determine the Legislature's intent, including legislative history and maxims of statutory construction.[30]

The plain language of SB 846 indicates the Commission may allocate the benefits of DCPP's extended operations. Section 712.8(q) of the California Public Utilities Code states: "[t]o the extent the commission decides to allocate any benefits or attributes from extended operations of the Diablo Canyon power plant, the commission may consider the higher cost to customers in the operator's service area."[31] Simple logic dictates the Commission cannot "decide[] to allocate

---

[25] Those parties are the Alliance for Nuclear Responsibility (A4NR) and Women's Energy Matters (WEM). *See* Ex. A4NR-03 at 2:24-5:8; Ex. WEM-01 at 1-6.

[26] *People v. Murphy*, 25 Cal.4th 136, 142 (2001).

[27] *People v. Cole*, 38 Cal.4th 964, 974 (2006).

[28] *Moyer v. Workmen's Comp. Appeals Bd.*, 10 Cal.3d 222, 230 (1973).

[29] *Golf & Tennis Pro Shop, Inc. v. Sup. Ct.*, 84 Cal.App.5th 127, 135 (4th Dist. 2022).

[30] *In re Young*, 32 Cal.4th 900, 906 (2004); *Golf & Tennis Pro Shop, Inc. v. Sup. Ct.*, 84 Cal.App.5th 127, 134-135 (4th Dist. 2022).

[31] Cal. Pub. Util. Code § 712.8(q).

any benefits or attributes from extended operation of the Diablo Canyon power plant" as Section 712.8(q) suggests unless the Commission has the authority to make that allocation decision.

Moreover, the Commission must consider section 712.8(q) in the context of the statutory frame as a whole.[32] SB 846 includes multiple other provisions indicating the Commission has the authority to allocate DCPP's RA and GHG-free attributes during extended operations. For instance, SB 846 added section 25233.2(d) to the Public Resources Code, which requires the California Energy Commission (CEC) to report on DCPP's contribution to RA requirements during the extended operations period.[33] The Legislature could not reasonably have required the CEC to report on DCPP's contribution to RA requirements during the extended operations period unless it anticipated the Commission may enable LSEs to use DCPP's RA to contribute towards those requirements. Similarly, SB 846 added Public Utilities Code section 454.52(g), which states that "[f]or a thermal powerplant that uses nuclear fission technology not constructed in the twenty-first century, all resource attributes shall be retired on January 1, 2031, and shall be reported as a separately, line item resource for purposes of complying with [Section 398.4 of the Public Utilities Code, which requires LSEs to disclose their electricity sources and GHG emissions intensity]."[34] Again, the Legislature could not reasonably require that DCPP be reported as a separate, line item resource for Power Content Label (PCL) purposes unless it anticipated the Commission may enable LSEs to use DCPP's GHG-free energy for those purposes.

To the extent the Commission finds Section 712.8(q) ambiguous even considered in the context of the statutory frame as a whole, SB 846's legislative history leaves no doubt the

---

32 *Moyer v. Workmen's Comp. Appeals Bd.*, 10 Cal.3d 222, 230 (1973).

33 Cal. Pub. Res. Code § 25233.2(d).

34 Cal. Pub. Util. Code § 454.52(g).

Legislature intended to permit the Commission to allocate the benefits of extended operations at DCPP. The Senate Rules Committee, Office of Senate Floor Analyses report on SB 846 dated September 1, 2022 (the same day that SB 846 was passed in the Senate and Assembly), states:

> This bill also excludes DCPP from any future resource planning, either by state agencies to meet our 100 percent clean energy goals or by individual LSEs, thereby forcing LSEs to procure enough resources to treat DCPP as if it did not exist. **The exception to this DCPP exclusion is for RA procurement compliance, where DCPP is permitted to count toward LSE obligations as a ratepayer relief measure.**[35]

This statement makes it clear the Legislature intended to permit the Commission the discretion to allocate DCPP's RA attributes toward LSE's RA compliance obligations in order to provide ratepayers relief from the costs Diablo Canyon's extended operations will impose on customers across the State. Reading the statute as permitting the Commission to allocate DCPP's RA attributes (as CalCCA, PG&E, SCE and several other parties do) would therefore plainly effectuate the Legislature's purpose. Reading the statute as requiring the Commission to ignore DCPP's RA attributes (as A4NR and WEM do) would undermine that purpose.

A4NR and WEM nevertheless insist Cal. Pub. Util. Code sections 454.52(f)(1)-(2) indicate the Legislature's intent to prohibit the Commission from allocating any attributes associated with DCPP.[36] A4NR and WEM are incorrect. Cal. Pub. Util. Code sections 454.52(f)(1)-(2) prohibit the Commission and LSEs from including energy, capacity, or any attribute from DCPP in *adopted integrated resource plan portfolios, resource stacks, or preferred system plans*, but not any other context. Notably, those code sections do not prohibit the Commission from allocating DCPP's RA

---

[35] Senate Rules Committee, Office of Senate Floor Analyses, SB 846, Sep. 1, 2022, at 11, at: https://leginfo.legislature.ca.gov/faces/billAnalysisClient.xhtml?bill_id=202120220SB846# (emphasis added); *see also* Senate Third Reading, SB 846, Aug. 28, 2022, at 12, at: https://leginfo.legislature.ca.gov/faces/billAnalysisClient.xhmtl?bill_id=202120220SB846#.

[36] Ex. A4NR-03 at 2:24-5:8; Ex. WEM-01 at 1-6.

attributes for LSEs' RA compliance purposes, nor do those sections prohibit the Commission from allocating DCPP's GHG-free energy attributes for LSEs' PCL or marketing purposes. Under the maxim of statutory construction *expressio unius est exclusio alterius*[37] ("the expression of certain things in a statute necessarily involves exclusion of other things not expressed"), by providing a list of contexts in which the Commission and LSEs may not consider DCPP's benefits, sections 454.52(f)(1)-(2) necessarily exclude other contexts. For these reasons, A4NR's and WEM's arguments fail.

In sum, SB 846 plainly permits the Commission to allocate the benefits of DCPP's extended operations, and reading the statute any other way would undermine the Legislature's intent. For the reasons below, the Commission should exercise that authority and allocate both the RA and GHG-free attributes associated with DCPP's extended operations.

II. ARGUMENT

A. Customers paying for DCPP's extended operations should receive the benefits associated with extended operations (Scoping Issue 5)

SB 846 shifts the financial risk of DCPP's extended operations to customers throughout California.[38] Pursuant to SB 846, customers across the State will pay for most extended operations costs, including capital and operations and maintenance expenses, incremental decommissioning costs resulting from license renewal applications or license renewals, a $100 million fixed payment per year, up to $300 million for a liquidated damages balancing account to cover the costs of replacement power during unplanned outages (even if instances where PG&E acts imprudently), and a volumetric fee of $6.50 per MWh Diablo Canyon generates, subject to annual escalation.[39]

---

[37] *See Henderson v. Mann Theatres Corp.*, 65 Cal.App.3d 397, 403 (2d Dist. 1976).

[38] Ex. CalCCA-01 at 4:10-11.

[39] Ex. SCE-01 at 3:13-19; Cal. Pub. Util. Code §§ 712.8(f)(1), (f)(3)-(f)(6), and (g)-(i).

Customers of LSEs in PG&E's service area will pay an additional volumetric fee of $6.50 per MWh DCPP generates, subject to annual escalation.[40]

Just as customers currently paying for DCPP's operations receive the benefits of DCPP's attributes, the benefits of DCPP's extended operation—including DCPP's RA and GHG-free attributes[41]—should flow back to the customers paying for continued operation. If DCPP's System RA were available, it would help ratepayers by reducing the amount of expensive RA that LSEs would otherwise be forced to procure from a constrained market.[42] That relief is exactly what the Legislature intended. SB 846's legislative history makes clear the Legislature anticipated that DCPP's RA would provide "ratepayer relief" by counting towards LSE's short-term RA compliance obligations.[43]

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.[44] Second, the Commission might allocate resource attributes among the LSEs serving those customers.[45]

The Commission currently follows the first approach for DCPP.[46] PG&E recovers the costs to own and operate DCPP from bundled and departed load customers in its service territory through

---

40 Cal. Pub. Util. Code § 712.8(f)(5).

41 *See* Tr. at 252:15-18 (Sep. 5, 2023) (PG&E witness Kikuyama agreeing the RA and environmental attributes of DCPP "present value").

42 *See* Ex. CalPA-01 at 4:1-5 (average System RA prices in 2021, 2022 and 2023 were in the range of $6.35-6.54/kilowatt-month, which is roughly double previous System RA prices); Ex. CalCCA-02 at 4 (RA stack analysis showing an RA supply deficit, assuming the loss of DCPP, in 2023, 2024 and 2025.

43 *See supra* Section II discussing legislative history of SB 846; Ex. SCE-01 at 6:5-7:2 (discussing legislative history of SB 846).

44 Ex. CalCCA-01 at 3:4-5.

45 *Id*. at 3:5-6.

46 *Id*. at 3:7.

Power Charge Indifference Adjustment (PCIA) rates, which are structured to recognize the value of DCPP's generation-related attributes (including RA) as a credit against retail rates.[47] 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.[48] Generation output is sold into the California Independent System Operator (CAISO) market, and the market revenue is netted against DCPP costs.[49] 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 all customers.[50] Revenue received from sales of DCPP RA, if any, to third parties is also credited against DCPP costs.[51] In this way, customers paying for the costs of DCPP's operations receive the benefits those operations generate; a fair bargain.

Going forward, PG&E will not recover the costs associated with extended operations at DCPP through the PCIA. Instead, SB 846 allows PG&E to charge customers a new non-bypassable charge to recover all "reasonable costs and expenses necessary to operate [DCPP] beyond the current expiration dates,"[52] net of market revenue from DCPP operation. Under the cost recovery regime described in SB 846, customer rates will no longer reflect a credit for the value of DCPP's RA, nor will they reflect a credit to recognize the value of the GHG-free attribute of DCPP's generation. Consequently, the Commission must allocate DCPP's attributes to ensure that

---

47 *Id*. at 3:7-11.

48 *Id*. at 3:11-12.

49 *Id*. at 3:12-14.

50 *Id*. at 3:14-16.

51 *Id*. at 3:16-17.

52 Cal. Pub. Util. Code § 712.8(h)(1).

customers paying for the cost of extended operations at DCPP realize the value[53] of extended operations.

While PG&E does not support allocating DCPP's RA and GHG-Free attributes to LSEs, it argues any allocation methodology the Commission adopts must adhere to the following four principles:[54]

1. Fair allocation to all customers reflecting upfront cost responsibility.
2. Administrative efficiency by leveraging existing processes where possible.
3. Minimize reliability and affordability risk by ensuring LSEs do not fail to timely procure or retain resources to meet compliance requirements.
4. Appropriate cost recovery, including 'additional costs' incurred to meet certain RA requirements in the CAISO tariff.[55]

CalCCA's proposals to allocate DCPP's RA and GHG-Free attributes are consistent with all four principles PG&E presented. In fact, CalCCA's recommendations are specifically designed to meet the very principles PG&E identified.

1) Allocation of DCPP's costs and benefits should be aligned and fairly distributed to customers (consistent with PG&E principle 1). DCPP's RA and GHG-Free attributes should be allocated to all LSEs whose customers will be responsible for paying the cost of DCPP extended operations. Under CalCCA's proposal, allocation of DCPPs costs and benefits will align and be consistent among customers of all Commission-jurisdictional LSEs.
2) The Commission should adopt the existing CAM framework to allocate DCPP net costs and RA capacity (consistent with PG&E's principle 2). Leveraging the CAM model uses an existing process to minimize administrative burden and relies on a proven methodology.
3) Allocating DCPP RA capacity should remain available in the RA market to increase liquidity, reduce RA prices, and act as a ratepayer relief measure to partially offset the cost of extending DCPP's operations (consistent with

53 *See* Tr. at 252:15-18 (Sep. 5, 2023) (PG&E witness Kikuyama agreeing DCPP's RA and environmental attributes "present value").

54 Ex. PG&E-02 at 5-3, lines 17-31.

55 *Id*. at 5-3, lines 20-31.

PG&E's principle 3). Allocating DCPP RA to LSEs will relieve short-term RA market constraints (as discussed below) without undermining long-term integrated resource planning or Commission directives to procure new resources.

4) DCPP extended operation costs should be recovered consistent with SB 846 (consistent with PG&E's principle 4). To the extent DCPP RA is allocated to LSEs, and PG&E incurs costs to provide substitution RA capacity pursuant to CAISO tariffs, those incremental costs should be eligible for recovery through the DCPP NBC.[56]

1. The Commission should allocate DCPP's RA attributes to LSEs.

a. <u>Allocating DCPP's RA will avoid artificially understating the System RA resources available in a constrained market and save ratepayers money</u>

Even with DCPP in operation and contributing over 2GW of System RA, California LSEs face a constrained RA market—a fact that even PG&E concedes.[57] LSEs seeking to procure sufficient resources to meet their obligations under the Commission's RA program *already* face year-over-year price increases, price spikes in high demand summer months, and a lack of capacity available in the market.[58] Several different analyses have now concluded that, unless recent weather patterns shift back to pre-climate change "normal," DCPP should continue to operate to avoid significant capacity shortages until unprecedented amounts of new resources can be brought online.[59]

For instance, the CEC staff report on Diablo Canyon Power Plant Extension (CEC Report) published in March 2023, which evaluates capacity needs through 2032 assuming DCPP units are retired as currently scheduled, recommends the CEC determine that it is prudent for the State to

---

56 Ex. CalCCA-03 at 3:15-5:7.

57 *See* Ex. PG&E-04R at 2-19, lines 28-29 (noting "the tight RA market"). *See* Tr. at 252:22-25 (Sep. 5, 2023) (PG&E witness Kikuyama stating PG&E "agree[s] there is tightness within the RA market.")

58 Ex. CalCCA-01 at 7:17-20.

59 *Id*. at 7:14-16.

pursue extension of DCPP.[60] The CEC Report's recommendation is based on 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.[61] The CEC and Commission's Joint Agency Reliability Planning Assessment, published in February 2023,[62] underscores the CEC Report's recommendation. 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 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

[60] CEC Report at ii.

[61] Ex. CalCCA-01 at 7:23-8:3 (citing CEC Report at ii). The CEC Report indicates that under '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." CEC Report at 25. 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 CEC Report also acknowledges the shortcomings of its "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." Ex. CalCCA-01 at 8:5-15; 9:13-17 (citing CEC Report at 16). Notably, the CAISO conducted a probabilistic—rather than deterministic—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. Ex. CalCCA-01 at 9:17-22; February 2, 2023 Letter to CEC Vice Chair, available at http://www.caiso.com/Documents/Jan2-2023-Letter-CaliforniaEnergyCommissionViceChair-CAISOReliabilityModeling.pdf.

[62] ALJ April 20 Ruling, Exhibit E (Joint Agency Report).

> 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.[63]

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.[64]

CalCCA witnesses Eric Little and Andrew Mills (Little-Mills) present CalCCA's analysis of the constrained RA market in their testimony (CalCCA Stack Analysis). 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.[65] The CalCCA Stack Analysis projects a 433 MW shortage in RA supply for 2023, growing to a 1,258 MW shortage in 2025.

All of these assessments point to the same conclusion: System RA is scarce, it will remain scarce, and DCPP provides needed System RA.[66] When specifically asked to point out the conclusions in the Little-Mills testimony and the Joint Agency Report with which PG&E disagrees, PG&E Witness Kikuyama admitted he had reviewed both analyses in detail; he then

---

63 Ex. CalCCA-01 at 8:20-9:8 (citing Joint Agency Report at 7 (Feb. 2023)).

64 *Id*. at 9:9-12 (citing Joint Agency Report at 50 (Feb. 2023)).

65 Ex. CalCCA-02 at 3:4.

66 Ex. CalCCA-01 at 10:9-10.

explained he has "no basis to disagree with the Little-Mills testimony" and "does not disagree with the methodology or conclusions" presented in the Joint Agency Report.[67]

Moreover, PG&E admits the RA market is tight.[68] It concedes it has not conducted a stack analysis on the RA market for the period of DCPP's extended operations or otherwise assessed the tightness of the RA market in 2024 and future years.[69] Indeed, the State *is* so short on capacity that PG&E believes it will either "incur significant costs to purchase substitution capacity or not find sufficient substitution capacity at all" to replace DCPP when it undergoes an outage.[70] While PG&E suggests that capacity shortage might be short-lived—citing to a reference to "an improving reserve margin for meeting operating reserve requirements over peak load periods" in CAISO's 2023 stack analysis—PG&E admits that CAISO's analysis "does not necessarily address the system's ability to meet loads outside of the current RA program planning standard which are associated with load volatility and extreme weather events such as those experienced in the summers of 2020 and 2022."[71]

One symptom of California's 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 issued to various entities from October 2009 through November 2022.[72] As

---

67 Ex. CalCCA-04 (PG&E response to CalCCA data request 3.01 and 3.02).

68 Ex. PG&E-04R at 2-19, lines 28-29; Tr. at 252:22-25 (Sep. 5, 2023) (witness Kikuyama stating "[PG&E]. . . does agree there is tightness within the RA market.")

69 Ex. CalCCA-04 (PG&E response to CalCCA data request 3.01); Tr. at 252 (Sep. 5, 2023) (stating PG&E did an assessment of the RA market for 2023, but stating an assessment of 2024 and beyond is necessary).

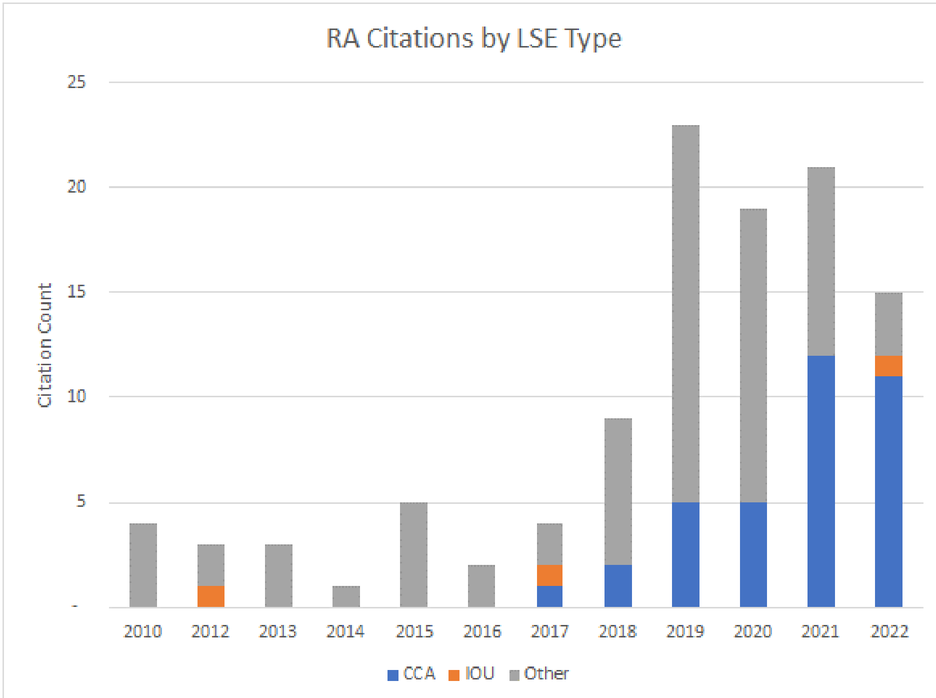
70 Ex. CalCCA-04 (PG&E response to CalCCA data request 3.03).

71 *Id*. (PG&E response to CalCCA data request 3.04).

72 Ex. CalCCA-01 at 10:12-16.

shown in Figure 1 below, citations increased sharply in 2019, and continued at elevated levels through 2022.

Figure 1[73]



Another symptom of the constrained market is the steadily increasing price of System RA. Figure 2 below reproduces Figure 4 from Energy Division's 2021 Resource Adequacy Report,[74] showing the rise in RA prices from 2017 to 2021.

---

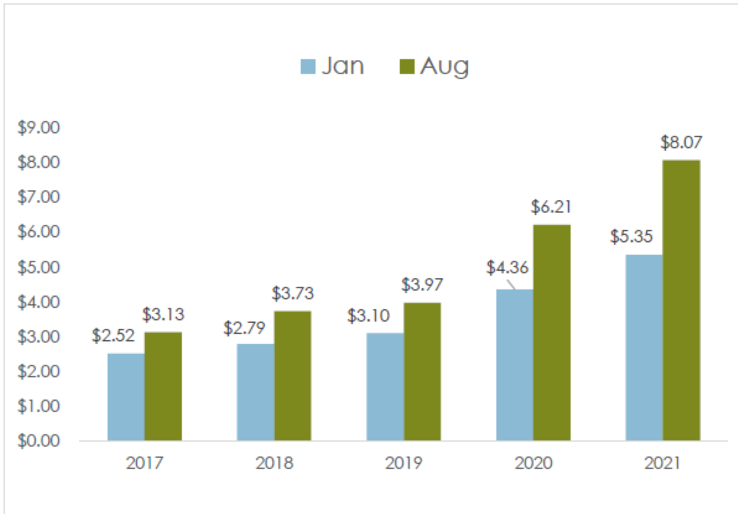
73 *Id.* at 1-2 (Figure 1).

74 Energy Division 2021 Resource Adequacy Report, available at: https://webproda.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2021_ra_report_040523.pdf.

Figure 2[75]

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 above shows, Energy Division's 2021 Resource Adequacy Report illustrates that the average price of System RA transactions executed for August 2021 was 158 percent higher than for August 2017.[76] 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.[77]

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.[78] The CalCCA

---

75 Ex. CalCCA-01 at 11.

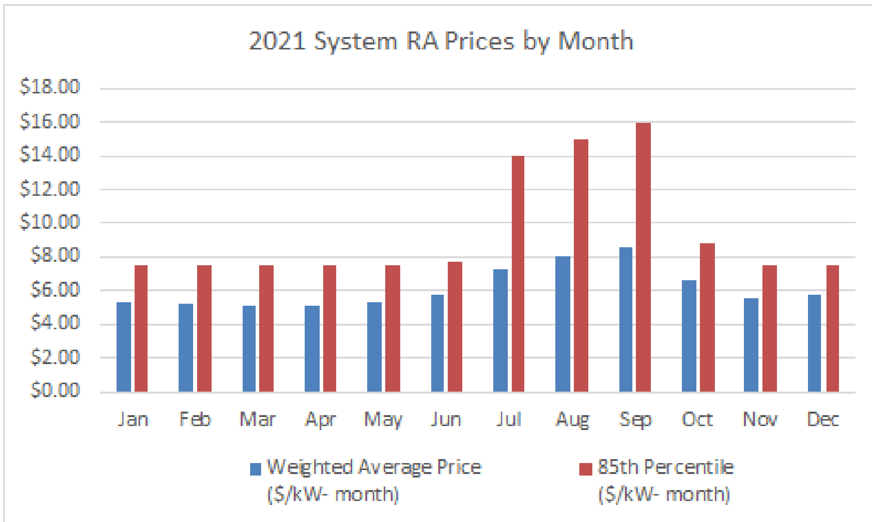
76 *Id*. at 12:3-5 (citing Energy Division 2021 Resource Adequacy Report at 28-29).

77 *See also* Ex. CalPA-01 at 4:2-4 (noting that the Commission's most recent RA report demonstrates average prices for 2021, 2022 and 2023 System RA in the range of $6.35-6.54/kilowatt-month, whereas System RA prices previously averaged less than half that level).

78 Ex. CalCCA-01 at 12:8-10 (citing Energy Division 2021 Resource Adequacy Report at 27-28).

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."[79] Figure 3 below presents Energy Division's monthly price data for 2021 in graph form.

Figure 3[80]



Price spikes such as these in the short-term RA market create a windfall for existing generation owners at the expense of retail consumers, and do not create any commensurate, incremental reliability benefit.

Withholding DCPP's 2,280 MW of capacity from the RA market would exacerbate market constraints, artificially increase rates, and cause price spikes such as those illustrated in Figure 3. More concretely, ignoring DCPP's RA attributes would increase costs for customers by over $200 million[81] annually as LSEs would be required to procure RA from the market (rather than counting DCPP's RA towards their short-term compliance requirements). In contrast, allocating DCPP's RA attributes during extended operations would introduce significant liquidity into the System RA

79 Ex. CalCCA-02, Attachment C at 2 (CalCCA Stack Analysis) (internal citation omitted).

80 Ex. CalCCA-01 at 13:5-6.

81 2,280 MW * $7.39/kW-month * 1,000 * 12 = $202.2 million.

market, reduce the RA that LSEs are required to procure from the market, and "produce lower prices by reducing LSEs' need to reach into the steepest portion of the RA supply curve and negotiate or accept expensive bids from the highest-cost suppliers."[82] The Commission should therefore allocate DCPP's RA attributes to the LSEs whose customers contribute to the costs of DCPP's extended operations.

b. Allocating DCPP's RA will not impact the State's long-term planning goals or LSEs' procurement of new resources

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.[83] SB 846 indicates that the purpose of extending DCPP's operation is to fill this very gap: "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*."[84]

PG&E argues allocating DCPP's RA attributes would conflict with the Legislature's direction to "[c]ontinue to act with urgency to bring clean replacement energy online to support reliability and achieve California's landmark climate goals."[85] PG&E's position is fatally flawed because it ignores the difference between the IRP process and the Commission's procurement-

82 Ex. CalPA-01 at 3:27-30.

83 Ex. CalCCA-01 at 14:3-5.

84 Cal. Pub. Res. Code § 25548(b) (emphasis added).

85 Ex. PG&E-04R at 2-24, line 2-6 (citing Cal. Pub. Res. Code § 25548(c)).

focused decisions, which drive the construction of new resources, and RA compliance, which drives near-term LSE procurement to optimize the use of existing resources.[86]

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 and contracted resources to compare to the optimal system.[87] 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.[88] 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."[89] 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.[90]

In contrast, 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.[91] The Commission describes the RA program as "guid[ing] resource procurement and promot[ing] infrastructure investment by requiring that LSEs procure capacity so that capacity is available to the CAISO

---

86 Ex. CalCCA-01 at 14:16-19; *see* Ex. SCE-01 at 8:7-9 (explaining that "new capacity resources are not developed through the short-term RA market...[they] are developed through procurement authorizations in the [Integrated Resource Plan] proceeding…") SCE cites three Commission decisions requiring LSEs "to procure an unprecedented amount of incremental clean resources to replace Diablo Canyon and meet system reliability and clean energy needs." Ex. SCE-01 at 7:15-16.

87 Ex. CalCCA-01 at 14:19-15:1.

88 *Id*. at 15:1-3.

89 *Id*. at 15:3-7.

90 Cal. Pub. Util. Code §§ 454.52(f)(1)-(2); Cal. Pub. Res. Code § 25548(c).

91 Ex. CalCCA-01 at 15:8-9.

when and where needed."[92] The RA program requires two types of filings: annual and monthly filings.[93] On an annual basis, LSEs are required to demonstrate that they have procured 90 percent of their System RA obligation for the five summer months of the coming compliance year.[94] On a monthly basis, LSEs must demonstrate they have procured 100 percent of their monthly System RA obligation.[95] 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.[96]

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.[97] Furthermore, LSEs are already acting to bring new capacity online from 2021 through 2026 pursuant to procurement requirements in Decisions (D.) 19-11-016[98] and 21-06-035.[99] [100] The Joint Agency Report confirms that IRPs have driven clean energy procurement: "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

---

92 *Id*. at 15:9-12 (citing https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage, accessed May 23, 2023).

93 *Id*. at 15:12-13.

94 *Id*. at 15:13-15.

95 *Id*. at 15:15-16.

96 *Id*. at 15:16-19.

97 *Id*. at 16:6-9.

98 D.19-11-016, *Decision Requiring Electric System Reliability Procurement for 2021-2023*, R.16-02-007 (Nov. 7, 2019): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M319/K825/319825388.PDF.

99 D.21-06-035, *Decision Requiring Procurement to Address Mid-Term Reliability (2023-2026)*, R.20-05-003 (Jun. 24, 2021): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603637.PDF.

100 Ex. CalCCA-01 at 16:12-15.

over 6,000 MW of new Net Qualifying Capacity (NQC) that can count toward RA capacity obligations."[101]

Even after accounting for resource additions ordered or planned through the IRP process, the Joint Agency Report found that, under extreme weather conditions, capacity shortfalls are expected to continue throughout DCPP extended operations.[102] Factoring in possible delays in planned procurement due to supply chain challenges only increases the expected shortfalls.[103] In short, the risk of insufficient or delayed resource procurement *drives* the need to extend DCPP operations; extending DCPP's operations (and allocating its RA attributes) will not *cause* delayed procurement.[104]

The Commission should therefore allocate DCPP's RA attributes to all LSEs whose customers will pay for the cost of extended operations. Contrary to PG&E's concern regarding the impacts of allocation on LSEs' procurement of new resources, the IRP and Commission procurement directives will ensure new resources will be built over the long term in furtherance of the State's climate goals.

c. Allocating DCPP's RA will not reduce the pressure on LSEs to retain existing resources needed for reliability

Without providing any analysis in support, PG&E's opening testimony on Phase 1 Track 2 issues argues that allowing LSEs to count DCPP RA toward meeting short-term RA compliance obligations "reduces the pressure for LSEs, including PG&E, to … retain existing resources needed for reliability."[105] PG&E's argument misses the reality of today's market; rests solely on

---

101 *Id*. at 15:15-19.

102 *Id*. at 16:20-17:1.

103 *Id*. at 17:1-3.

104 *Id*. at 17:3-5.

105 Ex. PG&E-02 at 5-2, lines 12-14.

one witness's belief with no supporting analysis; and was undermined when that same witness later admitted that tightness in today's RA market renders his concerns moot.

As explained above, there is no surplus of RA capacity available in the market in 2023, and the market is projected to remain tight in the foreseeable future, which means PG&E's theoretical concern is divorced from the facts on the ground. The scarcity of supply in the capacity markets already makes it difficult, if not impossible, for every LSE to meet its RA compliance obligation.[106] Many LSEs have incurred penalties because there is no capacity available to procure in the RA market to meet their compliance requirements.[107] CCAs have not only incurred penalties as a result of the tight RA market, but the Commission has also delayed CCAs' expansion into new municipalities on the basis that the CCAs failed to procure the required amount of capacity (as demonstrated by citations issued for violations of the Commission's RA program).[108]

Further, as discussed above, several reports published by the Commission, the CEC, CAISO, and CalCCA all anticipate continued capacity shortages in California due to heat events and delays in new resource procurement. RA compliance is expected to become more challenging in the future as the RA market transitions to a 24-hour slice of day framework starting in 2025.[109] If DCPP capacity is not allowed to count toward RA compliance, there is simply no surplus RA supply available for LSEs to purchase in its place.[110] Thus, the notion that allocating DCPP's RA

---

[106] Ex. CalCCA-03 at 6:21-23.

[107] *Id*. at 6:23-7:2.

[108] Resolution E-5258. *Effective Dates for the Expansions of Community Choice Aggregators: Central Coast Community Energy and East Bay Community Energy* (Apr. 27 2023), at 2: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M507/K472/507472501.PDF.

[109] D.22-06-050, *Decision Adopting Local Capacity Obligations for 2023 - 2025, Flexible Capacity Obligations for 2023, and Reform Track Framework*, R.21-10-002 (Jun. 23, 2022), at 128, OP 14: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M488/K540/488540633.PDF.

[110] Ex. CalCCA-03 at 7:10-12.

attributes will cause certain LSEs to abandon existing resources simply does not reflect the reality of the State's RA market.

Neither PG&E's opening testimony nor its rebuttal testimony presents *any* analysis – internal, third-party, government-sponsored or otherwise – supporting the argument that allocation of RA attributes will reduce support for operating existing resources.[111] When specifically asked to provide "all analyses, underlying data, and workpapers" supporting this argument in its rebuttal testimony, PG&E only cited to comments *from CalCCA* in another proceeding suggesting LSEs seek to avoid over-procurement and overcharging their customers.[112] Thus, after *three* opportunities, the utility has offered *zero* record evidence to present some type of analysis to support its arguments.

In fact, PG&E confirms in response to a CalCCA discovery request submitted in lieu of cross examination that its witness's concern about existing plants retiring would only hold true *if* there were a surplus of RA capacity available in the market.[113] PG&E admits no such surplus exists today,[114] and, during hearing, PG&E's witness admits the utility has not assessed market tightness after 2023.[115] Weighing that complete lack of evidence against the substantial record evidence from the Little-Mills testimony, the Joint Agency report, and other testimony, the record clearly

---

111 Ex. PG&E-04R at 2-25, lines 11-12.

112 *See* Ex. CalCCA-04 (PG&E response to CalCCA data request 3.06).

113 *Id*. (PG&E response to CalCCA data request 3.07) (where a surplus is defined as excess of the Commission's RA compliance requirements and CAISO's reliability requirements).

114 *See* Ex. PG&E-04R at 2-19, lines 28-29 (noting "the tight RA market"); Ex. CalCCA-04 (PG&E Response to CalCCA 3.07) (noting PG&E's concerns "only hold true if there is a surplus in the RA capacity available in the market"); Tr. at 252:22-25 (Sep. 5, 2023) (witness Kikuyama stating that PG&E "agree[s] that there is tightness within the RA market" in 2023).

115 Tr. at 252:22-25 (Sep. 5, 2023) (witness Kikuyama stating PG&E has assessed RA market in 2023, but that an assessment of 2024 and beyond is necessary).

shows there is unlikely to be any surplus of RA for the foreseeable future, and PG&E's concerns about demand for existing resources has little merit.

d. The benefits of allocating DCPP's RA attributes vastly outweigh any incremental costs PG&E would incur to comply with CAISO substitution obligations

If DCPP's RA attributes are allocated to LSEs, DCPP would be shown on PG&E's RA filing to the Commission and to CAISO as a physical resource and would therefore count toward PG&E's RA compliance obligation.[116] As a result, DCPP would be required to meet certain RA requirements, including RA availability requirements.[117] Among them, if any of DCPP's Units are out-of-service due to a maintenance outage, PG&E would be required to provide substitution capacity for the entirety of the Unit on outage.[118] PG&E asserts the Commission should ensure appropriate cost recovery for any costs incurred to meet certain RA requirements as set forth in the [CAISO] Tariff.[119] On these issues, PG&E and CalCCA largely agree.

However, putting forward another red herring to argue against allocating RA benefits, PG&E states it would incur *additional* costs through purchases in the RA market or through the use of resources from its existing portfolio, assuming the requisite substitution capacity is available.[120] However, PG&E's concern is not a new issue. Requiring PG&E to procure substitution capacity for DCPP during extended operations does not present any incremental cost or burden to PG&E compared to the *status quo* in which PG&E already procures substitution capacity for DCPP.

---

116 Ex. PG&E-04R at 2-19, lines 8-11.

117 *Id*. at 2-19, lines 11-13.

118 *Id*. at 2-19, lines 22-26.

119 Ex. PG&E-02 at 5-3, lines 29-31.

120 Ex. PG&E-04R at 2-19, lines 26-28.

PG&E currently uses its existing portfolio to perform outage substitution for DCPP's capacity,[121] and purchases capacity in the market if its existing portfolio is insufficient for outage substitution for DCPP's capacity.[122] Nor is PG&E's concern unique to DCPP. The CAISO Tariff PG&E references requires the scheduling coordinator for any RA resource to provide substitution capacity to cover certain maintenance outages if the resource has been shown on a monthly supply plan.[123] PG&E currently includes DCPP in its RA supply plan for bundled customers, and PG&E reserves RA capacity from its existing portfolio and/or makes purchases in the RA bilateral market as needed to provide substitution capacity.[124] The cost to retain RA capacity for bundled customers, including substitution capacity, is recovered from bundled customers through PG&E's generation rates.[125]

PG&E is also already required to provide substitution capacity for the CAM-eligible resources in its portfolio.[126] PG&E follows the same process to provide substitution capacity for CAM resources as it does for other resources in its portfolio, *i.e.*, it reserves RA capacity from existing resources and/or makes purchases in the RA bilateral market as needed.[127] In D.14-06-

---

121 Ex. CalCCA-04 (PG&E response to CalCCA data request 3.11).

122 *Id*. (PG&E response to CalCCA data request 3.12).

123 Ex. CalCCA-03, Attachment A (PG&E response to CalCCA data requests 2.01 and 2.04).

124 *Id*., Attachment A (PG&E response to CalCCA data request 2.03).

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

126 *Id*., Attachment A (PG&E response to CalCCA data request 2.06).

127 *Id*., Attachment A (PG&E response to CalCCA data request 2.07).

050,[128] the Commission determined that the cost to provide substitution capacity for CAM-eligible resources is recoverable through the CAM balancing account.[129]

Moreover, to the extent PG&E incurs incremental substitution capacity costs ("incremental" as compared to a scenario in which DCPP's RA is not allocated), the benefits of allocation vastly outweigh those costs. As SCE explains, "effective management of plant operations can reduce and restrict the need for substitution to a few months outside of the summer season, and the value of RA available for ensuring reliability during the summer months greatly outweighs any substitution costs incurred during non-summer months."[130] Indeed, after initially being unwilling to estimate its projected substitution capacity costs,[131] PG&E now asserts it will incur between $25.7 and $35.6 million in substitution capacity costs (in months outside the summer season) if DCPP's RA is allocated to LSEs, as compared to a scenario in which DCPP's RA is not allocated to LSEs.[132] Even if PG&E's estimate is correct, **the benefits of allocating DCPP's RA attributes are approximately 8 times greater than** PG&E's projected substitution capacity costs ($200 million in avoided RA, versus $25.7-$35.60 million in substitution capacity costs, if DCPP's RA is allocated).

Following the pattern established for CAM-eligible resources in D.14-06-050, CalCCA does not oppose PG&E recovering prudently incurred costs of DCPP substitution capacity provided pursuant to the CAISO Tariff (assuming DCPP's RA is allocated to LSEs as CalCCA

---

128 D.14-06-050, *Decision Adopting Local Procurement and Flexible Capacity Obligations for 2015, and Further Refining The Resource Adequacy Program*, R.11-10-023 (Jun. 26, 2014): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M097/K619/97619935.PDF.

129 Ex. CalCCA-03, Attachment A (PG&E response to CalCCA data request 2.08).

130 Ex. SCE-01 at 11, lines 6-9.

131 Ex. CalCCA-03, Attachment A (PG&E response to CalCCA data request 2.02).

132 Ex. CalCCA-04 (PG&E response to CalCCA data request 3.15 (calculating the estimated substitution capacity costs PG&E would incur if DCPP's RA is allocated and DCPP goes on outage)).

proposes). If PG&E provides substitution capacity using resources from its existing resource portfolio, PG&E should use the RA market price benchmark used to value retained RA for the Power Charge Indifference Adjustment to transfer the cost of capacity into the DCEOBA. PG&E should record substitution capacity costs to the Diablo Canyon Extended Operations Balancing Account (DCEOBA, discussed in more detail in Section IV. B., *infra*) and recovered from all LSEs through the DCPP non-bypassable charge. However, the red herring PG&E puts forward, that allocating DCPP benefits would somehow create incremental costs to operating DCPP compared to the *status quo*, should not fool the Commission.

e. <u>The Commission should follow the CAM model to allocate the costs and benefits of DCPP's extended operations</u>

The Commission should follow the CAM model to allocate the costs and benefits of DCPP's extended operations because the rationale and framework for extending DCPP operations described in SB 846 is similar to the rationale and framework underlying CAM. Briefly, SB 846 directs the Commission to consider extending DCPP's life for the benefit of all California's electric customers while designating a single IOU, PG&E, as the operator of that plant.[133] 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…"[134] 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, from customers of all jurisdictional LSEs in California (with limited exceptions).[135]

---

[133] Ex. CalCCA-01 at 5:607.

[134] Cal. Pub. Res. Code § 25548.7.

[135] Ex. CalCCA-01 at 5: 11-14.

Each of these elements closely resemble the CAM framework. The Commission adopted the CAM as a mechanism to streamline IOUs' procurement of critical new resources for the benefit of multiple customer groups (e.g., bundled and unbundled customers). In D.06-07-029[136] 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."[137]

Fundamentally, the CAM framework aligns the allocation of costs and benefits from CAM resources such that customers who pay for CAM resources also benefit from those resources. 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 CAISO market, are then recovered from all customers in each IOU's service territory through a volumetric NBC.[138] 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

---

136 D.06-07-029, *Opinion on New Generation and Long-Term Contract Proposals and Cost Allocation*, R.06-02-013 (Jul. 20, 2006): https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/58268.PDF.

137 *Id*. at 7.

138 PG&E's CAM NBC is known as the New System Generation Charge (NSGC).

and RA benefits received by [departed load] and bundled customers should be based on a share basis equal to the credit share received."[139]

In light of the parallels between the Commission's rationale and framework for CAM resource procurement and the potential extension of DCPP, CalCCA, Alliance for Retail Energy Markets (AReM) / Direct Access Customer Coalition (DACC)[140] and SCE[141] agree the Commission should allocate the benefits of DCPP extended operations the same way it allocates the benefits of CAM resources (CalCCA and AReM/DACC also agree the Commission should allocate the costs of DCPP extended operations the same way it allocates the costs 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[142] based on the LSE's

---

139 D.06-07-029 at 31.

140 Ex. AReM-01 at 2:6-8. In the same testimony, AReM/DACC also recommend the Commission treat each LSE's allocated share of DCPP RA as a resource, rather than a load decrement, so that an LSE with excess RA resource can sell or trade their portion. *Id*. at 7:3-6. The Commission should not adopt this recommendation, for two reasons. First, the current CAM framework treats the allocated RA as a load decrement for receiving LSEs because the resource owner retains its responsibilities as scheduling coordinator in the CAISO market and continues to report the full resource in its RA resource portfolio. Treating each LSE's allocated share as a resource would likely require a new contracting process to transfer the resource attributes from PG&E to each LSE. Second, if receiving an allocated share of DCPP capacity causes an LSE to have excess RA, the LSE already has the option to sell additional RA from its existing resource portfolio. That is, if an LSE is long on RA capacity, an RA allocation from DCPP would "free up" corresponding excess capacity from other resources, allowing the sales AReM/DACC envisions. Ex. CalCCA-03 at 11:2-12.

141 Ex. SCE-01 at 11:15 to 13:15.

142 CalCCA recognizes that a small portion of the RA allocated under its proposal may go unused by the Small and Multi-Jurisdictional Utilities (SMJUs) for purposes of the Commission's RA program. If the Commission finds this to be a compelling reason to create an alternative framework, CalCCA would not object to a financial alternative for SMJUs that are not subject to the CAISO and Commission RA compliance requirements. One possible solution is to apply the value of SMJUs' allocated portion of DCPP RA as a credit against their allocated share of DCPP net costs, while spreading an offsetting charge to all other LSEs responsible for DCPP cost recovery. An adjustment would also be required to redistribute the SMJUs' share of allocated RA capacity back to all other LSEs. It is not clear the benefits of creating this alternative for two small SMJUs outweigh the costs. Ex. CalCCA-03 at 12:3-12.

contribution to the group's combined 12-month coincident peak.[143] Each IOU would recover the allocated DCPP costs from all customers in its service territory through a new NBC.[144] 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, such that benefits follow costs.[145] Following the CAM procedures already in place for the Commission's RA compliance program, Energy Division should include an allocation of DCPP's 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.[146]

2. *The Commission should direct PG&E to continue offering voluntary allocations of DCPP's GHG-free attributes to LSEs*

Under the CEC's Power Source Disclosure program, LSEs must disclose to their customers the mix of resources used to provide electricity during the previous calendar year, as well as the GHG emissions intensity of their respective generation portfolios.[147] LSEs make that annual disclosure on "Power Content Labels" (PCL).[148] GHG-Free energy—such as the energy DCPP generates—therefore has value to LSEs because it impacts LSEs' carbon intensity for PCL purposes.[149] Receiving GHG-Free energy can also benefit LSEs' marketing efforts.[150] Since 2020, PG&E has offered allocations of GHG-free energy from its nuclear generation facilities, including

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

144 Ex. CalCCA-01 at 7:1-2.

145 *Id*. at 7:3-4.

146 *Id*. at 7:4-8.

147 Ex. CalCCA-01 at 18, fn.31; Cal. Code Regs. tit. 20 § 1394.1.

148 *Id*.

149 Ex. CalCCA-01 at 17:20-18:1.

150 *Id*. at 18:1-2.

DCPP, under a voluntary, annual process (PG&E's "interim allocation process"). In 2023, six LSEs executed agreements to receive an allocation of GHG-free energy from DCPP.[151]

In its PCIA rulemaking, R.17-06-026,[152] the Commission evaluated whether it should incorporate a credit reflecting the value of GHG-free energy 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.[153] On June 13, 2023, the Commission issued D.23-06-006[154] finding certain (large hydroelectric) resources "have a consistent, heightened incremental market value above fossil energy"[155] and established a GHG-Free Market Price Benchmark to reflect the incremental market value of large hydroelectric resources above fossil energy.[156] While the Commission did not establish a mandatory GHG-free allocation or market price benchmark process for nuclear resources such as DCPP, it allowed IOUs to continue to offer allocations of PCIA-eligible nuclear resources on a voluntary, annual basis.[157]

---

151 Ex. CalCCA-03, Attachment A (PG&E response to CalCCA data request 2.16).

152 *Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment*, R.17-06-026 (Jun. 29, 2017): https://apps.cpuc.ca.gov/apex/f?p=401:56::::RP,57,RIR:P5_PROCEEDING_SELECT:R1706026.

153 *Administrative Law Judge's Ruling Requesting Comments on GHG-Free Resources Staff Proposal and Other Issues,* R.17-06-026 (Sep. 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.

154 D.23-06-006, *Decision Addressing Greenhouse Gas-Free Resources, Long-Term Renewable Transactions, Energy Index Calculations, and Energy Service Providers' Data Access*, R.17-06-026 (Jun. 8, 2023): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M511/K378/511378919.PDF.

155 *Id.* at 45, Finding of Fact 1.

156 *Id.* at 46, Conclusion of Law 1.

157 *Id.* at 28.

Should the Commission authorize extended operations at DCPP, the plant's GHG-free energy will continue to offer value to LSEs. As discussed above in the context of DCPP's RA attributes, fundamental fairness requires that customers who pay for the costs of DCPP's extended operations should have the opportunity to receive the value of its attributes. CalCCA, as well as SCE, AReM/DACC and the Green Power Institute therefore recommend the Commission require PG&E to offer allocations of DCPP's GHG-Free attributes to all LSEs whose customers will pay for DCPP's extended operations.

a. PG&E's current "interim allocation process" requires modest modifications to allow voluntary allocations of DCPP's GHG-free energy to all cost-responsible LSEs during extended operations

Offering allocations of DCPP's GHG-free attributes to all LSEs whose customers will pay for DCPP's extended operations largely requires PG&E to continue the *status quo*. As discussed above, consistent with Resolution E-5111, PG&E already offers annual voluntary allocations of GHG-free attributes from its PCIA portfolio resources to LSEs in its service area.[158] Under PG&E's interim allocation process, 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."[159] 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

[158] 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. Ex. CalCCA-01 at 18, fn. 33.

[159] 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. Ex. CalCCA-01 at 18, fn. 34.

report the corresponding GHG-Free energy on their annual PCL under the CEC's Power Source Disclosure Program.[160]

PG&E's existing "interim allocation process" requires 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 resource, separate from PG&E's other PCIA portfolio resources. PG&E should also expand eligibility for voluntary GHG-free allocations to all California LSEs whose customers pay for DCPP's extended operations, including those LSEs in PG&E's service area and those LSEs in other IOU service areas.[161] LSEs would confirm their acceptance of a voluntary allocation of DCPP's GHG-free energy by executing a sales agreement with PG&E subject to the conditions in PG&E's BPP Appendix P.[162] Unclaimed allocations, if any, would be unused for that delivery year and would not be reported on any individual LSE PCL or other communications.[163] By continuing its "interim allocation process" with modest modifications, PG&E would ensure customers paying for DCPP's extended operations costs have the option of receiving the benefits of DCPP's GHG-free energy. Moreover, the "interim allocation process" is specifically designed to be compatible with the CEC's Power Source Disclosure requirements, rather than requiring any changes to those requirements,[164] and therefore, continuing and expanding that process as CalCCA recommends does not require the Commission to defer to the CEC, contrary to Cal Advocates' testimony.[165]

---

160 Ex. CalCCA-01 at 18:16-19:2.

161 *Id*. at 19:7-10.

162 *Id*. at 19:10-12.

163 *Id*. at 19:12-14.

164 Resolution E-5111. *Request by Pacific Gas and Electric Company to Modify Appendix P of its 2014 Conformed Bundled Procurement Plan* (Dec. 17, 2020), page 2: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M355/K599/355599650.PDF.

165 Ex. CalPA-01 at 2:10-20.

b. PG&E has not demonstrated it will incur any meaningful incremental costs from allocating DCPP's GHG-free attributes to LSEs' paying for the costs of extended operations

PG&E's chief opposition to allocating DCPP's GHG-Free energy for PCL purposes is it would incur additional costs to "administer an allocation framework and corresponding agreements with all Commission-jurisdictional LSEs, approximately 49 in total."[166] PG&E overstates the burden associated with expanding its existing interim allocation process. Again, Resolution E-5111 already adopted a streamlined contracting process for voluntary annual allocations of GHG-free energy from PG&E's PCIA resources. Under that process, PG&E makes an annual offer to sell carbon free energy and within 30 business days each LSE desiring to accept its allocation must enter into a confirmation to the EEI Master Purchase and Sale Agreement.[167] This confirmation agreement is a standard form that does not substantively change year to year. Therefore, expanding PG&E's existing interim allocation process to all Commission-jurisdictional LSEs would simply require PG&E to enter into additional standard form agreements with LSEs outside of its service territory.[168]

When asked in discovery to quantify the additional costs PG&E expected to incur if the GHG-Free allocation process were made available to all Commission-jurisdictional LSEs, PG&E responded it currently does not track the administrative costs associated with the GHG-Free allocation framework and therefore could not quantify the incremental costs of expanding the

---

166 Ex. PG&E-02 at 5-3, lines 8-12.

167 PG&E Advice 5930-E, *Update to Pacific Gas and Electric Company's Bundled Procurement Plan – Carbon Free Energy* (Appendix P) (Aug. 27, 2020), pages 6-7: https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_5930-E.pdf.

168 Ex. CalCCA-03 at 13:10-12.

program.[169] It therefore appears PG&E would incur few, if any, incremental administrative costs—or at least none PG&E believes are worth calculating at this time.

Notably, almost half of the 49 LSEs are in PG&E's service territory and are *already* eligible to receive an allocation of GHG-Free energy from DCPP.[170] In addition, because allocation would be voluntary, it is very likely that not all LSEs will accept their share.[171] For example, in 2022 and 2023, LSEs in PG&E's service territory that were eligible to receive an allocation of GHG-Free energy from DCPP totaled 22 LSEs, but only six executed agreements with PG&E.[172] Assuming the same percentage of LSEs take voluntary allocations once DCPP enters extended operations, PG&E's administrative burden would essentially increase from administering agreements with a half dozen LSEs to a baker's dozen.[173] While CalCCA continues to take the position that expanding PG&E's existing annual interim allocation process is the simplest way to fairly allocate GHG-free attributes from DCPP, CalCCA would not object to the implementation of a single GHG-free attribute allocation election window for the entire extended operations period to reduce any minor incremental administrative burden associated with an annual allocation process.

c. Allocating DCPP's GHG-free attributes to all LSEs responsible for paying for the costs of extended operations would not impact LSEs clean energy procurement activities

PG&E claims allocation of GHG-Free attributes from DCPP may reduce LSEs' incentives to procure additional clean energy resources, undermine the State's long-term decarbonization

169 *Id.*, Attachment A (PG&E response to CalCCA data requests 2.18 and 2.19).

170 *Id.*, Attachment A (PG&E response to CalCCA data request 2.17).

171 *Id.* at 14:2-4.

172 *Id.*, Attachment A (PG&E response to CalCCA data requests 2.16 and 2.17).

173 *Id.* at 14:6-8.

goals, and frustrate the Legislature's intent.[174] PG&E's concerns are not well-founded. As a threshold matter, California's zero carbon targets are for the years 2035, 2040, and 2045[175] — all of which are well-past the period of DCPP's extended operations.[176] Importantly, the Commission, the CEC and the California State Air Resources Board cannot consider DCPP's GHG-free attributes in achieving those zero carbon targets.[177] Therefore, the statutory framework guarantees any allocation of DCPP's GHG-free attributes will not compromise the State's long-term clean energy goals.

Moreover, integrated resource planning—not the CEC's Power Source Disclosure program—drives long-term clean energy procurement.[178] While the IRP planning construct considers GHG emissions, SB 846 explicitly prohibits the Commission and LSEs from considering any of DCPP's attributes, including its GHG-free attributes, in adopted integrated resource plan portfolios, resource stacks, or preferred system plans following DCPP's currently scheduled retirement dates.[179] There is therefore no risk that allocation of GHG-free attributes would adversely impact LSEs' clean energy procurement efforts.

---

[174] Ex. PG&E-02 at 5-2, lines 14-16; PG&E-04R at 2-23, lines 29-32.

[175] Cal. Pub. Util. Code § 454.53(a), Ex. CalPA-01 at 8:11-12.

[176] For Unit 1, October 31, 2029, and for Unit 2, October 31, 2030. Cal. Pub. Util. Code § 712.8(c)(1)(A)(i)-(ii).

[177] Cal. Pub. Util. Code §§ 454.53(a), (b)(5); § 712.8(q).

[178] Ex. CalCCA-03 at 15:5-7.

[179] Cal. Pub. Util. Code §§ 454.52(f)(1)-(2). In contrast, SB 846 permits LSEs to report DCPP's GHG-free attributes in their Power Content Labels. Cal. Pub. Util. Code § 454.52(g).

B. PG&E should track the net costs of DCPP extended operations in the Diablo Canyon Extended Operations Balancing Account (DCEOBA) and recover those costs through a new statewide non-bypassable charge and an adder applicable only to customers in PG&E's service territory. (Scoping Issue 4)

1. To ensure the costs and benefits of DCPP's extended operations flow to customers as consistently as possible, PG&E should allocate DCPP's net costs to LSEs based on their respective contribution to the group's coincident peak demand

Phase 1 Track 2 Scoping Issue 4 asks the Commission to determine:

> 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).

PG&E currently recovers its direct and indirect costs to operate DCPP through PCIA rates.[180] Once DCPP enters extended operations, SB 846 requires PG&E no longer include the costs associated with DCPP in the PCIA.[181] Instead, PG&E must record the costs of DCPP's extended operations in a new balancing account and recover those costs through a new NBC.[182]

PG&E correctly proposes to remove the costs associated with DCPP from the PCIA following the currently scheduled retirement dates for each Unit.[183] Further, PG&E proposes to track the costs associated with DCPP's extended operations in the newly-created "Diablo Canyon Extended Operations Balancing Account".[184] CalCCA agrees with each of those proposals.

---

[180] Ex. CalCCA-01 at 29:6-7.

[181] Cal. Pub. Util. Code § 712.8(l)(1)-(2).

[182] *Id.*

[183] In its 2024 ERRA Forecast application filed May 15, 2023, PG&E correctly removed DCPP Unit 1 from the PCIA revenue requirement effective November 2024. Ex. CalCCA-01 at 29, fn. 54.

[184] PG&E Advice 6870-E, *Establish the Diablo Canyon Transition and Relicensing Memorandum Account and the Diablo Canyon Extended Operations Balancing Account in Compliance with Decision 22-12-005*, (Mar. 1, 2023) (Advice 6870): https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_6870-E.pdf, and PG&E Advice 6870-E-A, *Supplemental: Establish the Diablo Canyon Transition and Relicensing Memorandum Account and the Diablo Canyon Extended* (Apr. 12, 2023): https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_6870-E-A.pdf.

The key disagreement between CalCCA and PG&E with respect to Scoping Issue 4 concerns PG&E's proposed rate design for the statewide non-bypassable charge. To recover the costs of DCPP's extended operations, PG&E proposes an equal-cents per kilowatt-hour statewide NBC (statewide DCPP NBC).[185] PG&E states it will collect the statewide DCPP NBC from six IOUs, including itself.[186] PG&E's proposal for a statewide equal-cents-per-kWh NBC is largely premised on its position that the Commission should not allocate DCPP's RA attributes to LSEs.[187] Effectively, under PG&E's proposal, the net cost of DCPP extended operations would be allocated to all customers across the State based on electricity usage.[188] However, if the Commission allocates DCPP's RA attributes to LSEs based on those LSEs' contribution to the group's coincident peak demand consistent with CalCCA's recommendation, then PG&E should allocate DCPP's net costs to LSEs on the same basis. Doing so would ensure the costs and benefits of DCPP's extended operations flow to customers in a consistent manner. Moreover, allocating the costs of DCPP's extended operations to LSEs based on each LSE's contribution to coincident peak demand would be consistent with the manner in which the Commission allocates the costs of CAM resources.[189]

The Commission should therefore direct PG&E to allocate DCPP's net costs to LSEs based on each LSE's contribution to the group's coincident peak demand. Further, PG&E should retain

---

185 Ex. PG&E-02 at 2-3, lines 3-4.

186 *Id*. at 2-3, lines 14-15.

187 In its rebuttal testimony, PG&E argues "it is not necessary for rate design to align with the benefit allocation if [allocation] is adopted." Ex. PG&E-04R at 2-6, lines 11-17. While it may not technically be "necessary" for the allocation of DCPP's net costs to match the allocation of DCPP's benefits, as CalCCA has emphasized in this proceeding, fundamental fairness demands that DCPP's costs and benefits flow consistently to customers.'

188 Ex. CalCCA-03 at 16:16-18.

189 Ex. CalCCA-01 at 31:3-4.

separate subaccounts in the DCEOBA for each IOU service territory as it originally proposed.[190] Separate sub-accounts will help ensure costs are not shifted between IOUs, or that the actions of one IOU (such as delayed rate implementation) do not impact another IOU's customers.[191]

2. *The DCPP NBC charged to customers of all Commission-jurisdictional LSEs should be allowed to go negative if PG&E overcharges those customers*

PG&E explains customers of all Commission-jurisdictional LSEs will be charged a systemwide NBC to collect DCPP's net costs, equal to the total forecasted annual expenses net of the forecasted annual CAISO market revenue.[192] Pursuant to SB 846, if CAISO market revenue exceeds DCPP's annual expenses, the surplus revenue will be credited solely to customers in PG&E's service territory.[193] PG&E states that when forecasted market revenue exceeds forecasted expenses, it will set the statewide NBC at a floor of zero.[194] It also proposes that the PG&E-specific rate adder should not be similarly constrained and can result in a negative rate due to the return of excess market revenue to customers in PG&E service territory.[195]

CalCCA agrees with PG&E's interpretation of SB 846 on this point, *i.e.*, that excess CAISO market revenue is to be returned solely to customers in PG&E's service territory. Nevertheless, in certain situations, the statewide NBC could decrease, if not go negative, when actual costs and revenues are trued up through the DCEOBA.[196] Because the DCPP NBC will be set based on forecasted expenses and market revenue, it is possible actual conditions will cause

190 Advice Letter 6870-E.

191 Ex. CalCCA-03 at 18:1-3.

192 Ex. PG&E-02 at 2-6, lines 11-25.

193 Cal. Pub. Util. Code § 712.8(h)(3).

194 Ex. PG&E-02 at 2-7, lines 2-4.

195 *Id*. at 2-7, lines 15-17.

196 Ex. CalCCA-03 at 18:17-19.

retail customers to be over-charged.[197] For example, if DCPP's actual net costs are lower than forecasted, retail customers will have paid too much, and the over-collections should be refunded to those customers.[198] The following tables demonstrate two possible outcomes, using hypothetical numbers, that would require funds to be returned to customers due to an overcollection of retail revenue through the statewide NBC.

Table 1 below illustrates a scenario where actual DCPP costs and CAISO market revenue are equal to the forecasted amounts, but higher than anticipated retail sales result in increased actual collections from customers. These excess customer collections should be returned to customers the following year as an offset to the statewide NBC.

Table 1[199]

Hypothetical DCPP Net Cost Scenario – High Retail Collections ($000)

	Forecast	Actual
DCPP Costs	$1,500,000	$1,500,000
Market Revenue	($1,000,000)	($1,000,000)
DCPP Net Costs	$500,000	$500,000
Retail Customer Collections	($500,000)	($600,000)
Overcollection	$0	($100,000)

Table 2 below illustrates a scenario where actual DCPP costs and customer collections are equal to the forecasted amounts. Actual market prices result in CAISO market revenue that is higher than forecasted, but still lower than the actual costs. In this scenario, the actual DCPP net costs recoverable from customers are lower than forecast, and statewide customers were over-

197 *Id*. at 18:19-21.

198 *Id*. at 18:21-19:1.

199 *Id*. at 19:8-13.

charged. These excess customer collections should be returned to customers the following year as an offset to the statewide NBC.

Table 2[200]

Hypothetical DCPP Net Cost Scenario – High CAISO Market Revenue ($000)

	Forecast	Actual
DCPP Expenses	$1,500,000	$1,500,000
CAISO Market Revenue	($1,000,000)	($1,300,000)
DCPP Net Costs	$500,000	$200,000
Retail Customer Collections	($500,000)	($500,000)
Overcollection	$0	($300,000)

CalCCA issued discovery requests to clarify PG&E agrees with CalCCA regarding the treatment of customer overcollections in the scenario described above, and PG&E indicated it agrees.[201] In the interest of clarity, the Commission should find there is no floor on the statewide DCPP NBC and that customer overcollections in one year should be returned to customers as an offset to the DCPP NBC over the following year.

C. The Commission should approve PG&E's proposed annual forecast application process. (Scoping Issue 3)

Phase 1 Track 2 Scoping Issue 3 asks:

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

200 *Id*. at 20:1-6.

201 *Id*., Attachment A (PG&E supplemental response to CalCCA data request 2.20).

PG&E describes its proposed DCPP Cost Forecast Application request and true-up process at Chapter 3 of its prepared testimony.[202] Briefly, PG&E proposes a standalone DCPP Cost Forecast Application that closely resembles its annual Energy Resource Recovery Account (ERRA) Forecast proceeding. The objective of PG&E's annual DCPP Cost Forecast Application would be to propose a forecast revenue requirement associated with DCPP's extended operations for rate-setting purposes.[203] PG&E proposes to file its annual DCPP Cost Forecast Application by March 31 of each year (with the first application to address all extended operations costs from November 3, 2024 through December 31, 2025).[204] Consistent with its ERRA Forecast proceedings, PG&E proposes to update its prepared testimony (including updated forecast DCEOBA balances) in the fourth quarter of the year in which it submits its application, and recommends a final decision resolving its application by the last business meeting in November to allow rate changes to go into effect on January 1 of each year.[205] PG&E provides a proposed schedule for its DCPP Cost Forecast Application at Table 3-1 in its testimony.[206]

The Commission should adopt PG&E's proposed structure for the annual DCPP Cost Forecast Application process. PG&E's proposal is consistent with SB 846, which requires PG&E structure its DCPP forecast proceeding to resemble its annual ERRA forecast proceeding,[207] and no party disputes the structure of PG&E's proposed annual DCPP Cost Forecast Application process. However, the Commission should require PG&E present detailed projections of all costs

---

202 Ex. PG&E-02 at 3-1 through 3-14.

203 *Id*. at 3-2, lines19-22.

204 *Id*. at 3-2, lines 4-12.

205 *Id*. at 3-3, lines 1-13.

206 *Id*. at 3-10, Table 3-1.

207 Cal. Pub. Util. Code § 712.8(h) (1).

and revenues associated with DCPP extended operations, in a manner similar to PG&E's presentation in its General Rate Case (GRC) and ERRA Forecast proceedings. For example, PG&E should provide details of DCPP fixed costs by Major Work Category and Federal Energy Regulatory Commission account.[208] Detailed generation output projections, nuclear fuel procurement costs, and other related forecast inputs should support PG&E's forecasts for variable costs.[209]

In its May 19, 2023 Prepared Testimony providing historical and forecast cost information for DCPP, PG&E presented limited cost information organized by 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.[210] That presentation is inadequate. PG&E has acknowledged its annual cost recovery application would include all costs relevant to DCPP's extended operation, including common costs such as benefits, overhead, employee retention, regulatory compliance, and statutory charges and fees.[211] As such, PG&E should present its request for cost recovery in the annual DCPP Cost Forecast Application in a manner mirroring its GRC and ERRA Forecast filings.

Further, the Commission should require PG&E to demonstrate in its DCPP Cost Forecast Application that its forecasts include common cost assumptions that are consistent with its 2023 GRC. The 2023 GRC includes attrition years extending beyond the original DCPP expiration dates to 2026 and assumes DCPP is retired.[212] PG&E should quantify the impact of DCPP's extended

---

208 Ex. CalCCA-01 at 23:17-18.

209 *Id*. at 23:18-20.

210 Ex. PG&E-01 at 2:3-18.

211 *Id*. at 16:1-13.

212 Ex. CalCCA-01, Attachment B (PG&E response to CalCCA data request 1.04).

operations on its common costs relative to the amount approved in its 2023 GRC and demonstrate it will not double count the common costs it proposes for recovery in its GRC and DCPP Forecast proceedings.

III. CONCLUSION

Costs and benefits are two sides of the same coin. Should the Commission authorize DCPP's extension, continued operation will generate significant costs and benefits. In the interest of fairness, to avoid unnecessarily raising rates by $200 million, and to offset the cost impacts of DCPP's extended operations on customers, the Commission should allocate the benefits of DCPP's extended operations to the customers funding its prolonged life. For the reasons described in this brief and in CalCCA's testimony, the Commission should adopt CalCCA's recommendations.

Respectfully submitted,

Tim Lindl
Nikhil Vijaykar
KEYES & FOX LLP
580 California Street, 12th Floor
San Francisco, CA 94104
Phone: (408) 621-3256
Email: tlindl@keyesfox.com
nvijaykar@keyesfox.com

September 18, 2023