Decision **PROPOSED DECISION OF ALJ SEYBERT (Mailed 10/26/2023)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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

DECISION CONDITIONALLY APPROVING EXTENDED OPERATIONS AT DIABLO CANYON NUCLEAR POWER PLANT PURSUANT TO SENATE BILL 846

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DECISION CONDITIONALLY APPROVING EXTENDED OPERATIONS AT DIABLO CANYON NUCLEAR POWER PLANT PURSUANT TO SENATE BILL 846

Summary

Pursuant to Senate Bill (SB) 846, this decision directs and authorizes extended operations at Diablo Canyon Nuclear Power Plant (DCPP) until October 31, 2029 (Unit 1) and October 31, 2030 (Unit 2). The approval in this decision is subject to the following conditions: (1) the United States Nuclear Regulatory Commission continues to authorize DCPP operations; (2) the $1.4 billion loan agreement authorized by SB 846 is not terminated; and (3) the Commission does not make a future determination that DCPP extended operations are imprudent or unreasonable. Additional processes are established for the Commission to continue to consider the prudence and cost-effectiveness of extended DCPP operations. This decision also allocates the costs and benefits of extended DCPP operations among all load-serving entities subject to the Commission's jurisdiction; creates a new non-bypassable charge and associated processes to collect DCPP extended operations costs; establishes a new process, similar to the annual Energy Resource Recovery Account proceedings, to review and authorize DCPP extended operations costs; and provides further direction on the use of surplus ~~ratepayer funds~~performance-based fees.

This proceeding remains open.

1. Background

1.1. Factual and Legal Background

The Diablo Canyon Nuclear Power Plant (Diablo Canyon or DCPP) is located in coastal San Luis Obispo County and consists of two reactors that have been operating since 1985 (Unit 1) and 1986 (Unit 2), with a combined generation capacity of 2,240 megawatts (MW). The plant is owned and operated by Pacific

Gas and Electric Company (PG&E) and the units are currently licensed by the United States Nuclear Regulatory Commission (NRC) to operate until November 2, 2024 (Unit 1) and August 26, 2025 (Unit 2).

In 2009, PG&E filed an application with the NRC to renew Diablo Canyon's operating licenses.[1] In 2016, PG&E asked the NRC to suspend its 2009 application pending approval by the Commission of an agreement in principle that PG&E reached with stakeholders "not to proceed with the license renewal."[2]

In Decision (D.) 18-01-022, the Commission approved PG&E's proposal to retire Diablo Canyon in 2024 and 2025, when its federal licenses expire. PG&E subsequently withdrew and terminated its 2009 license renewal application with the NRC.

On September 2, 2022, Governor Newsom signed Senate Bill (SB) 846.[3] Among other things, SB 846 invalidates Ordering Paragraph 1 and Ordering Paragraph 14 of D.18-01-022, concerning the approved retirement of Diablo Canyon, and allows for the potential extension of operations at Diablo Canyon beyond the current federal license retirement dates, up to five additional years, under specific conditions as provided. In authorizing the potential extension of Diablo Canyon operations, SB 846 states:

> 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

[1] Exhibit (Ex.) PG&E-04 at 3-24.

[2] Letter from Edward Halpin, Senior Vice President, PG&E, to U.S. Nuclear Regulation Commission (June 21, 2016) (https://www.nrc.gov/docs/ML1617/ML16173A454.pdf); *see* 88 Federal Register (Fed. Reg.) 14,395, 14,396 (March 8, 2023).

[3] SB 846 (Dodd, 2021-2022 Reg. Sess.) Diablo Canyon powerplant: extension of operations, codified as Public Resources (Pub. Res.) Code Sections 25233, 25233.2, 25302.7, 255548, and 25548.1-7; Public Utilities (Pub. Util.) Code Sections 454.52, 454.53, 712.1, and 712.8; and Water Code Section 13193.5.

> 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. Accordingly, it is the policy of the Legislature that seeking to extend the Diablo Canyon powerplant's operations for a renewed license term is prudent, cost effective, and in the best interests of all California electricity customers. The Legislature anticipates that this stopgap measure will not be needed for more than five years beyond the current expiration dates.[4]

Following the enactment of SB 846, on October 31, 2022, PG&E submitted a request to the NRC to resume its review of the 2009 license renewal application for Diablo Canyon. To avoid interruptions in service, the NRC allows nuclear reactors to operate past their license expiration dates if license renewal is sought at least five years before those dates.[5] Due to the timing of SB 846, PG&E could not make this deadline; however, by law, the NRC may also waive that five-year rule in special circumstances.[6]

On January 24, 2023, the NRC determined that it would not initiate or resume PG&E's withdrawn 2009 application to renew Diablo Canyon's operating licenses. The NRC's decision did not address PG&E's separate request, included in its October 31, 2022 letter, to receive an exception from the five-year application requirement in 10 C.F.R. Section 2.109(b).[7]

On March 3, 2023, the NRC granted PG&E a one-time exemption from 10 C.F.R. Section 2.109(b), finding the requested exemption is authorized by law, will not present an undue risk to public health and safety, and is consistent with

[4] Pub. Res. Code Section 25548(b).

[5] Title 10, Code of Federal Regulations (C.F.R.) Section 54.17(a); 10 C.F.R. Section 2.109(b).

[6] 10 C.F.R. Section 50.12.

[7] Ex. H of A4NR-01.

the common defense and security. The NRC's exemption allows Diablo Canyon to continue to operate under its current licenses past their expiration dates, provided PG&E submits a new license renewal application by the end of 2023 and satisfies various regulatory requirements at the federal and state levels.[8]

PG&E~~'s~~ filed its license renewal application ~~to~~with the NRC ~~is not expected to be submitted until later this year, with~~on November 7, 2023.[9] While the NRC's review process and timeline have yet to be determined~~.[9] Based~~, based on the current schedule for the NRC license renewal proceeding, PG&E states the NRC is unlikely to issue license renewal conditions until sometime in 2025, at the earliest.[10]

1.2. Procedural Background

In D.22-12-005, the Commission executed the following tasks in accordance with SB 846: (1) ordering PG&E to take any actions that would be necessary to preserve the option of extended operations at Diablo Canyon, (2) establishing cost-tracking mechanisms for actions associated with continued and extended operations of Diablo Canyon, and (3) invalidating Ordering Paragraph 1 and Paragraph 14 of D.18-01-022. This decision also closed Application (A.) 16-08-006, and indicated the Commission would open a new rulemaking on an expedited schedule in accordance with the range of time-sensitive SB 846-related issues that will need to be monitored, considered, and addressed.

On January 20, 2023, the Commission issued the instant Order Instituting Rulemaking (OIR) to continue to execute tasks and consider specific criteria

[8] PG&E Diablo Canyon Power Plant, Unit 1 and Unit 2, 88 Fed. Reg. 14,395 (March 8, 2023).

[9] November 7, 2023 Reporter's Transcript at 365:10-13.

~~[9] Ex. PG&E 03 at 2.~~

[10] Ex. PG&E-04 at 31-12 through 3-13.

related to the potential extension of operations at Diablo Canyon. The OIR contained a preliminary scope and schedule for this proceeding.

Opening comments on the OIR were filed by the following parties: Alliance for Nuclear Responsibility (A4NR), California Community Choice Association (CalCCA), California Energy Storage Alliance; Californians for Green Nuclear Power (CGNP), Coalition of California Utility Employees (CUE), County of San Luis Obispo (SLO County), Diablo Canyon Independent Safety Committee (DCISC), Green Power Institute (GPI), Northern Chumash Tribal Council, PG&E, Public Advocates Office at the California Public Utilities Commission (Cal Advocates), San Luis Obispo Mothers for Peace (SLOMFP), The Utility Reform Network (TURN), and Women's Energy Matters (WEM).

Reply comments were filed by the following parties: A4NR, Alliance for Retail Energy Markets (AReM) and Direct Access Customer Coalition (DACC), filing jointly, CAlifornians for Renewable Energy, Inc. (CARE), Cal Advocates, CalCCA, GPI, PG&E, SLO County, and WEM.

Small Business Utility Advocates (SBUA) and San Diego Gas & Electric Company (SDG&E) were granted party status via separate email rulings by the assigned Administrative Law Judge (ALJ) on March 14, 2023 and March 16, 2023, respectively. On March 15, 2023, the assigned ALJ issued a ruling denying the DCISC party status.

A prehearing conference (PHC) was held on March 17, 2023, to address the scope of issues, categorization, schedule of the proceeding, and other procedural matters. During the PHC, National Resources Defense Council, Inc. (NRDC), Southern California Edison Company (SCE), and the Union of Concerned Scientists (UCS) requested and were granted party status.

On April 6, 2023, the assigned Commissioner issued a Scoping Memo and Ruling (Scoping Memo) dividing the first phase of the proceeding into two tracks: Phase 1: Track 1 was narrowly scoped to consider DCISC funding issues in accordance with Pub. Util. Code Section 712.1(d), and was addressed by the Commission in D.23-08-004. Phase 1: Track 2, which is the subject of this decision, considers whether operations at Diablo Canyon should be extended, the development of extended operations cost recovery mechanisms and processes, whether and how to allocate the associated benefits of extended operations, and the use of surplus funds, among other issues.

On April 20, 2023, the assigned ALJ issued a ruling requesting comments served as testimony on statutory interpretation and issues of policy, and incorporating certain reports into the record of the proceeding (Track 2 April Ruling).

On May 19, 2023, PG&E served testimony on DCPP historical and forecast cost data through 2030.

On June 2, 2023, the assigned ALJ issued a ruling incorporating the May 2023 report by the California Energy Commission (CEC) and the Commission, entitled *Joint Agency Reliability Planning Assessment — SB 846 Second Quarterly Report*, into the record of the proceeding.

On June 7 and June 9, 2023, the following parties served proposals as opening testimony concerning the establishment of new cost agreements/mechanisms for DCPP extended operations, whether and how to allocate the benefits of extended operations, the development of a new cost recovery and approval process pursuant to Pub. Util. Code Section 712.8(h)(1), and whether additional guidance should be provided on the use of surplus funds (Track 2 Proposals): AReM/DACC, Cal Advocates, CalCCA, GPI, PG&E, SBUA, SCE, WEM, and Bear Valley Electric Service, Inc. (Bear Valley), Liberty Utilities (Liberty), and PacifiCorp d/b/a Pacific Power (PacifiCorp) (collectively, the small and multi-jurisdictional utilities or SMJUs).

On June 28, 2023, the assigned ALJ granted a motion by Calpine Corporation (Calpine) for party status.

On June 29 and June 30, 2023, the following parties served opening testimony on the Track 2 April Ruling and PG&E's May 19, 2023 historical and forecast DCPP cost data: A4NR, Cal Advocates, Calpine, CARE, CGNP, CUE, GPI, PG&E, SBUA, SLO County, SLOMFP, TURN, UCS/NRDC, and WEM.

On June 30, 2023, the assigned ALJ issued a ruling incorporating into the record of the proceeding the following DCISC reports: *Report on Fact-Finding Meeting with DCPP on March 14, 15 and 27, 2023; Report on Fact-Finding Meeting with DCPP on April 18, 19, and 20, 2023; Report on Fact-Finding Meeting with DCPP on May 2-3, 2023;* and *Report on Fact-Finding Meeting on May 5, 2023, and Comprehensive Seismic Safety Update.*

Following authorization from the assigned ALJ, on July 11, 2023, SLOMFP served supplemental comments structured as opening testimony in response to the Track 2 April Ruling and SLOMFP's data requests to PG&E.

Two remote public participation hearings (PPH) were conducted on July 25, 2023, at 2:00 p.m. and 6:00 p.m. Approximately 750 people attended the PPHs, including 115 speakers.

On July 27 and July 28, 2023, the following parties served rebuttal testimony addressing the Track 2 April Ruling and Track 2 Proposals: A4NR, AReM/DACC, Cal Advocates, CalCCA, CARE, CGNP, CUE, GPI, PG&E, SCE, SBUA, SDG&E, SLOMFP, TURN, and WEM.

On August 14, 2023, the assigned ALJ granted a motion by the SMJUs for party status.

Evidentiary hearings were held virtually on September 5-7, 2023.

On September 18, 2023, opening briefs (OB) were filed by the following parties: A4NR, AReM/DACC, Cal Advocates, CalCCA, Calpine, CARE, CGNP, CUE, GPI, PG&E, SBUA, SCE, SDG&E, SLOMFP, SMJUs, TURN, and WEM.

On September 27, 2023, the assigned ALJ issued an email ruling incorporating into the record of the proceeding the CEC's September 27, 2023, Diablo Canyon cost comparison report, entitled *Draft Senate Bill 846 Diablo Canyon Power Plant Extension Cost Comparison* (Draft Cost Comparison Report).

On September 29, 2023, reply briefs (RB) were filed by the following parties: A4NR, AReM/DACC, CalCCA, CARE, CGNP, CUE, GPI, PG&E, SBUA, SCE, SLOMFP, SMJUs, TURN, and WEM.

On October 4-6, 2023, comments on the Draft CEC Cost Comparison Report were filed by the following parties: A4NR, CARE, CGNP, GPI, PG&E, SBUA, SLOMFP, TURN, and WEM.

At A4NR's request pursuant to Rule 13.14 of the Commission's Rules of Practice and Procedure (Rules),[11] the Commission held an oral argument on November 7, 2023, in order to provide parties the opportunity to address the Commission on the issues in Phase 1: Track 2 of this proceeding.

1.3. Submission Date

This matter was submitted on November 7, 2023, upon the conclusion of oral argument.

[11] A4NR's Motion for Oral Argument, filed September 18, 2023. All subsequent references to a Rule or Rules are to the Commission's Rules of Practice and Procedure, unless otherwise specified.

2. Issues Before the Commission

The Scoping Memo sets forth the following issues to be considered in Phase 1: Track 2 of this proceeding:[12]

1. Whether operations at Diablo Canyon should be extended until October 31, 2029 (Unit 1) and October 31, 2030 (Unit 2), or whether earlier retirement dates should be established. In making this determination the Commission will consider:
   a. Whether the $1.4 billion loan provided for by Chapter 6.3 of Division 15 of the Pub. Res. Code is terminated, or whether an extension of operations at Diablo Canyon is found to be not cost-effective, imprudent, or both;
   b. Whether the NRC has extended the operation dates for Diablo Canyon;
   c. Whether the costs of any upgrades necessary to address seismic safety, issues of deferred maintenance, or NRC conditions of license renewal are too high to justify;
   d. Whether new renewable energy and zero-carbon resources that will be constructed and interconnected by the end of 2023 are an adequate substitute for Diablo Canyon, and will meet the state's planning standards for energy reliability; and
   e. If the Commission establishes earlier retirement dates, the length of time necessary for an orderly shutdown of Diablo Canyon.
2. If the Commission directs and authorizes extended operations at Diablo Canyon, whether one or more processes should be established to continue to monitor the associated utility ratepayer cost from, and reliability need for, continued operations at Diablo Canyon.
3. If the Commission directs and authorizes extended operations at Diablo Canyon, what are the new processes to authorize annual recovery of all reasonable Diablo

[12] Scoping Memo at 5-6.

Canyon extended operation costs and expenses on a forecast basis, including allocation of forecast costs among Commission-jurisdictional load-serving entities (LSE).[13]

4. Whether additional cost recovery mechanisms, agreements, plans, and/or orders are needed prior to the current retirement dates for Diablo Canyon Unit 1 and Unit 2 (*i.e.*, in 2024 and 2025, respectively).
5. Whether and how the benefits of extended operations, including Resource Adequacy (RA) and greenhouse gas (GHG)-free attributes, should be allocated among the LSEs and customers paying for extended operations.
6. Whether additional guidance should be provided on the use of any surplus ratepayer funds PG&E receives for Diablo Canyon in 2024.

3. Evidentiary Standard, the Burden of Proof, and the Burden of Production

In a rulemaking proceeding, "all parties have equal standing where their proposals are concerned,"[14] and each party "must show by a preponderance of the evidence that the Commission should adopt their proposal, rather than an alternative."[15] Preponderance of the evidence is usually defined "in terms of probability of truth, *e.g.*, 'such evidence as, when weighed with that opposed to it, has more convincing force and the greater probability of truth'."[16] Similarly, each party also bears the burden of production for those parts of their showing that ask the Commission to disregard a competing proposal.[17]

[13] The LSEs are PG&E, SCE, SDG&E, Bear Valley, Liberty, PacifiCorp, Community Choice Aggregators, and Electric Service Providers.

[14] D.18-10-019 at 32.

[15] *Ibid.*

[16] *Decision Granting a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project* [D.08-12-058] at 19 (citing Witkin, *Calif. Evidence*, 4th Edition, Vol. 1 at 184).

[17] D.87-12-067, 27 CPUC 2d 1, 22; D.18-10-019 at 32.

We have analyzed the record in this proceeding within these parameters.

4. ~~3.~~ Extension of Operations at Diablo Canyon

SB 846 requires the Commission to "direct and authorize extended operations" at Diablo Canyon until October 31, 2029 (Unit 1) and October 31, 2030 (Unit 2).[~~14~~18] However, the statute also sets forth certain conditions which, if met, either through a determination by the Commission or through certain triggering events outside of this proceeding, would allow or require the establishment of earlier retirement dates.[~~15~~19]

With this in mind, the Commission has two primary tasks with respect to the potential extension of operations at Diablo Canyon: first, each of the specific statutory conditions which would allow for the establishment of earlier retirement dates must be considered. To the extent there are disputed interpretations of law, the Commission must determine statutory intent. Second, based on the preponderance of evidence ~~presented in this proceeding~~standard, the Commission must determine whether one or more of the statutory conditions have been met. SB 846 requires the Commission to issue its final decision directing and extending operations at Diablo Canyon by December 31, 2023.[~~16~~20]

Based on the record of this proceeding, this decision finds none of the conditions set forth in Pub. Util. Code Sections 712.8(c)(2)(B) through 712.8(c)(2)(E) have been met. Accordingly, this decision directs and authorizes extended operations at Diablo Canyon until October 31, 2029 (Unit 1) and October 31, 2030 (Unit 2). The approval in this decision is conditioned upon the following: (1) the NRC continues to authorize DCPP operations; (2) the $1.4

[~~14~~18] Pub. Util. Code Section 712.8(c)(2)(A).

[~~15~~19] Pub. Util. Code Sections 712.8(c)(2)(B)-(E).

[~~16~~20] Pub. Util. Code Section 712.8(c)(2)(A).

billion loan agreement authorized by SB 846 is not terminated;[~~17~~21] and (3) the Commission does not make a future determination that DCPP extended operations are imprudent or unreasonable. Accordingly, this decision finds it is within the Commission's authority, and in ratepayers' best interest, to continue to evaluate the prudence and cost-effectiveness of continued DCPP operations, and to this end directs PG&E to provide certain historical and forecast cost information as part of its 2024 DCPP Extended Operations Cost Forecast application.

This decision also directs PG&E to file a Tier 3 advice letter to seek modification of the retirement dates approved in this decision and/or to make a recommendation on whether continued DCPP operations are prudent and reasonable, in response to any of the following events: (1) the NRC's conditions of license renewal become known; (2) the NRC approves retirement dates for Diablo Canyon that are earlier than what is approved in this decision; and/or (3) the $1.4 billion loan authorized in SB 846 is terminated. The occurrence of any of these events may cause the Commission to reevaluate the DCPP retirement dates approved in this decision.

Finally, this decision finds PG&E's six-month estimate for an orderly shutdown of Diablo Canyon to be reasonable. In the event earlier retirement dates for DCPP are approved or requested, PG&E is directed to explain whether and why there are any deviations from this six-month timeframe.

4.1. ~~3.1.~~ Whether New Renewable Energy and Zero-Carbon Resources are an Adequate Substitute for Diablo Canyon, and Meet the State's Planning Standards for Energy Reliability

[~~17~~21] Pub. Res. Code Section 25548.3.

Pub. Util. Code Section 712.8(c)(2)(D) states:[~~18~~22]

> If the commission determines that new renewable energy and zero-carbon resources that are adequate to substitute for the Diablo Canyon powerplant and that meet the state's planning standards for energy reliability have already been constructed and interconnected by the time of its decision, the commission may issue an order that reestablishes the current expiration dates as the retirement date, or that establishes new retirement dates that are earlier than provided in subparagraph (A) of paragraph (1), and shall provide sufficient time for orderly shutdown and authorize recovery of any outstanding uncollected costs and fees.

Parties were provided an opportunity to comment on this section of statute, including proposed definitions of key terms, as part of the Track 2 April Ruling. In addition, the following SB 846-mandated state agency reliability reports were incorporated into the record of this proceeding for party consideration: (1) the CEC's March 2023 report, entitled *Diablo Canyon Power Plant Extension – Final Draft CEC Analysis of Need to Support Reliability* (CEC's March 2023 Report); (2) the CEC's and the Commission's February 2023 report, entitled *Joint Agency Reliability Planning Assessment – SB 846 Quarterly Report and AB 205 Report* (February 2023 Joint Planning Assessment); and (3) the CEC's and the Commission's May 2023 report, entitled *Joint Agency Reliability Planning Assessment – SB 846 Second Quarterly Report* (May 2023 Joint Planning Assessment). The findings in each of these reports are briefly summarized below.

Using a deterministic "stack analysis" of forecasted supply and peak demand conditions during 2023-2032,[~~19~~23] the CEC's March 2023 Report indicates

[~~18~~22] All subsequent Section references are to the Public Utilities Code, unless otherwise specified.

[~~19~~23] The CEC's analysis "stacks" the projected supply of resources against defined peak load conditions under normal, above-normal, and/or extreme weather conditions in 2023-2032, and the capacity expected to come online due to past procurement orders is sufficient to meet the Commission's current RA planning reserve margin (PRM),[~~20~~24] even under an assumed scenario with 40 percent annual capacity delays. However, the CEC analysis also demonstrates that shortfalls could occur under climate-driven extreme events, including the extreme heat events California recently experienced in 2020 and 2022, and that risks are compounded if coincident wildfire risk reduced transmission capacity during peak events.[~~21~~25] Given the potential delays in resource build out to meet ordered procurement and increasing risks of climate-related threats to grid reliability, the CEC's March 2023 Report ultimately concludes it would be prudent for the state to pursue extended operations of Diablo Canyon.[~~22~~26]

The February 2023 Joint Planning Assessment also used a deterministic stack analysis to evaluate the load/resource balance during specific hours in the summer months and examined the same PRM scenarios and potential levels of online capacity procurement delays. In addition, this assessment included "Reduction Scenarios," where 20 percent and 40 percent of capacity never comes

conditions under normal, above-normal, and/or extreme weather conditions in 2023-2032, and assumes various PRMs to determine the effective capacity in meeting those peak load conditions. Procurement capacity is based on contracting compliance with the procurement orders adopted in D.19-11-016 and D.21-06-035 (*see* CEC's March 2023 Report at 15-23; Ex. PG&E-03 at 13; *also,* Ex. UCS/NRDC-01 at 8).

[~~20~~24] CEC's March 2023 Report at 16-21. PRM is used in resource planning to estimate the generation capacity needed to maintain reliability given uncertainty in demand and unexpected capacity outages. (*Id.* at B-4.) In D.22-06-050, the Commission adopted a 16 percent minimum PRM for RA 2023, and 17 percent minimum PRM for RA 2024 (*see* D.22-06-050 at 21-22).

[~~21~~25] A 2020 equivalent event was approximated using a 22.5 percent PRM, a 2022 equivalent event was approximated using a 26 percent PRM, and coincidental wildfire risk was assumed to reduce total import capacity by 4,000 MW. (*Id.* at 22-24.)

[~~22~~26] *Id.* at 24-25.

online, as well as two different supply scenarios: ordered procurement and Preferred System Plan (PSP) procurement.[~~23~~27] The February 2023 Joint Planning Assessment generally shows the same results as the CEC's March 2023 Report: planned procurement is sufficient to meet the Commission's current RA standard; however, under more extreme scenarios (*i.e.*, approximations of the heat events California experienced in 2020 and 2022) and with varying levels of procurement delays, the assessment shows shortfalls of up to 3,800 MWs over the next few years. The assessment also shows that, if 20 percent to 40 percent of the planned procurement fails to come online, the current RA standard would not be met.[~~24~~28]

Lastly, the May 2023 Joint Planning Assessment updated the status of demand and new resource additions for summer 2023. Overall, the report indicates an increase in net qualifying capacity installed through March 2023, largely associated with energy storage and paired solar-storage projects, as well as a net increase in hydroelectric generation. However, a shortfall of 200 MW remains under a 2020 equivalent event, along with an 1,800 MW shortfall under an approximated 2022 equivalent event. The report also shows an additional 3,000-4,000 MW loss of resources if coincident wildfire risk reduces transmission capacity during peak events.[~~25~~29]

[~~23~~27] The "planning track" of the Commission's Integrated Resource Planning (IRP) proceeding operates on a two-year cycle that concludes with the Commission adopting a PSP. In the PSP, the Commission identifies an optimal portfolio of resources for meeting state electric sector policy objectives at least cost and then sets requirements for LSEs to plan toward that future. (February 2023 Joint Planning Assessment at 26.)

[~~24~~28] February 2023 Joint Planning Assessment at 56-57; *also,* Ex. UCS/NRDC-01 at 11-12.

[~~25~~29] May 2023 Joint Planning Assessment at 3-6 and 9-10.

4.1.1. ~~3.1.1.~~ Party Comments

4.1.1.1. ~~3.1.1.1.~~ Definition of Terms and Statutory Intent

Parties presented a broad range of proposed definitions for new "renewable energy," new "zero-carbon resources," and "the state's planning standards for energy reliability," as used in Section 712.8(c)(2)(D), as well as the appropriate baseline for what should be considered "new."

PG&E and A4NR propose "renewable energy" be defined as resources that are compliant with the state's Renewables Portfolio Standard (RPS), while "zero-carbon resources" should have zero on-site emissions, unless permissible for compliance with the state's RPS Program.[~~26~~30] GPI also generally supports these definitions, but questions the need for the final clause in the definition of zero-carbon resources: "unless otherwise permissible for compliance with the RPS program."[~~27~~31] SBUA likewise supports the definition of "renewable energy," but recommends "zero-carbon resources" be defined as electric generation that does not burn fossil fuels or cause other carbon air pollution.[~~28~~32] Calpine argues the definition of "zero-carbon resources" should encompass electrical resources that can individually, or in combination, deliver zero-carbon electricity, including hydrogen fueled generation as well as natural gas generation retrofit with post-combustion carbon capture and sequestration technology. Calpine asserts this definition is consistent with the definition of zero-carbon resources in Pub. Res. Code Section 25216.7(d)(2).[~~29~~33]

[~~26~~30] Ex. PG&E-02 at 8-10; Ex. A4NR-02 at 15-16.

[~~27~~31] Ex. GPI-02 at 5.

[~~28~~32] Ex. SBUA-02 at 15-16.

[~~29~~33] Ex. Calpine-01 at 2-4.

Concerning the baseline for counting "new" resources, PG&E and CUE recommend using D.21-06-035 as the starting point, since this decision includes a minimum procurement order of 2,500 MWs of zero-emitting resources for the explicit purpose of replacing Diablo Canyon.[~~30~~34] In contrast, A4NR supports using D.19-11-016 as the baseline, on the basis that this decision expressly addressed concerns about impending RA shortages and was crafted in a manner consistent with the state's GHG goals,[~~31~~35] while GPI recommends using the most recent IRP baseline defined in D.23-02-040.[~~32~~36] In comments on the Draft CEC Cost Comparison Report, GPI recommends the baseline be defined as the higher of the trajectory of RPS resource procurement requirements or the trajectory of clean energy resource procurement that satisfies the state's GHG emissions reduction targets.[37] WEM and SLOMFP suggest 2016 or 2018 could serve as the point of demarcation, based on events that occurred in A.16-08-006;[~~33~~38] however, for the purpose of evaluating renewable energy, WEM urges the Commission to consider the "enormous progress that has already been accomplished to date in developing renewable and zero-carbon resources."[~~34~~39]

Cal Advocates has no recommendation regarding the appropriate baseline for "new" resources, and asserts the approximate starting point is unlikely to affect the analysis in this proceeding one way or another. Cal Advocates goes on

[~~30~~34] Ex. PG&E-03 at 8-10; Ex. CUE-02 at 9; *also,* D.21-06-035 Ordering Paragraph 6.

[~~31~~35] D.19-11-016 at 2; *also,* Ex. A4NR-01 at 21, Ex. A4NR-02 at 15-17, and Ex. SBUA-01 at 15.

[~~32~~36] Ex. GPI-02 at 5.

[37] GPI October 6, 2023 Comments at 4.

[~~33~~38] 2016 was the year the "Joint Proposal for the Orderly Replacement of Diablo Canyon Power Plant with Energy Efficiency and Renewables" was filed in A.16-08-006; 2018 was the year D.18-01-022 was issued approving the retirement of Diablo Canyon. (Ex. WEM-02 at 8-9; *also* SLOMFP OB at 34.)

[~~34~~39] Ex. WEM-02 at 8-9; *also,* WEM OB at 11.

to explain the relevant definitions hinge not on how far back in time the Commission begins counting "new" resources, but instead on the resources' ability to achieve interconnection by the end of 2023.[~~35~~40]

To be "adequate to substitute for the Diablo Canyon powerplant," PG&E proposes incremental renewable energy and zero-carbon resources should require 2,500 MW of incremental zero-emitting, and 1,000 MW of incremental firm zero-emitting, resources to be online.[~~36~~41] CUE asserts renewable resources must be able to substitute for DCPP's hourly and aggregate output on an equally reliable basis. Additionally, to meet the requirement that the resources be zero-carbon, CUE asserts qualifying storage should be tied to specific zero-carbon resources.[~~37~~42]

Lastly, in defining "the state's planning standard for energy reliability," on a system-level, PG&E supports the use of a stack analysis, such as what was used in the CEC's March 2023 Report and February/May Joint Planning Assessments. PG&E also supports use of the capacity counting rules utilized as part of the Commission's RA and IRP proceedings.[~~38~~43] Cal Advocates, UCS/NRDC, and SLOMFP support use of the 0.1 loss-of-load expectation (LOLE) probabilistic metric for evaluating energy reliability.[~~39~~44] These parties highlight that the 0.1 LOLE standard is used widely across the industry, produces results that are

[~~35~~40] Ex. CalPA-01 at 12.

[~~36~~41] PG&E explains its recommended energy and capacity resources derive from those established by D.21-06-035, Conclusion of Law 9 and Conclusion of Law 14. (*See* Ex. PG&E-03 footnote 9.)

[~~37~~42] Ex. CUE-01 at 5.

[~~38~~43] Ex. PG&E-03 at 13.

[~~39~~44] The 0.1 LOLE standard translates to one loss of load event (*i.e.*, when the grid operator is forced to implement rotating power outages) every 10 years. (Ex. UCS/NRDC-01 at 5; *also* Ex. UCS/NRDC-01 at 4-5; Ex. CalPA-02 at 8-10; and Ex. SLOMFP-05 at 6.)

probabilistic rather than deterministic,[~~40~~45] and continues to be the primary grid reliability metric in the Commission's IRP and RA proceedings.[~~41~~46] Rather than implementing new analyses, Cal Advocates also recommends utilizing the recently produced LOLE results for the IRP portfolios in D.23-02-040.[~~42~~47] Lastly, A4NR supports defining "the state's planning standard for energy reliability" as those standards adopted by the Commission pursuant to Section 380 and Section 454.52.[~~43~~48]

4.1.1.2. ~~3.1.1.2.~~ Reliability Analyses Presented In This Proceeding, and Whether the Statutory Condition Has Been Met

PG&E, CUE, GPI, and CGNP believe the conditions set forth in Section 712.8(c)(2)(D) have not been met. Citing to the potential resource shortfalls identified under the 2020/2022 Equivalent Event Scenarios in the CEC's March 2023 Report, as well as their proposed statutory definitions above, PG&E, CUE, and GPI assert sufficient new renewable energy and zero-carbon resources have not come online to replace DCPP and are unlikely to do so by the end of 2023.[~~44~~49] Additionally, PG&E claims these reports emphasize that California continues to face significant reliability risk not accounted for in the current RA planning standard, including risk created by climate change-induced heat events,

[~~40~~45] A deterministic analysis compares ordered procurement to demand to determine if a shortfall would occur in certain hours under average and extreme conditions, whereas a probabilistic analysis considers the probability of one or more extreme events occurring. (*See* Ex. NRDC-01 at 5-6; *also,* CEC March 2023 Report at 16.)

[~~41~~46] Ex. UCS/NRDC-01 at 1, 4-5; Ex. CalPA-02 at 8-10.

[~~42~~47] Ex. CalPA-02 at 9-10.

[~~43~~48] Ex. A4NR-01 at 22-23.

[~~44~~49] Ex. PG&E-03 at 14-18; Ex. CUE-01 at 6-7; Ex. GPI-02 at 5-6.

uncertain demand caused by electrification, and resource procurement delays.[~~45~~50] Citing to recent modeling in the IRP proceeding, GPI contends there will be an increase in carbon emissions in 2024/2025 as a result of the shutdown of Diablo Canyon.[~~46~~51] CGNP argues Diablo Canyon played an important role during the extreme heat events California experienced in August-September 2022, and points to increases in natural gas use for electricity generation in California.[~~47~~52]

Similarly, based upon its interpretation of Section 712.8(c)(2)(D), Cal Advocates believes it is unlikely that resources with contracted commercial online dates will be interconnected and available by the end of 2023. In furtherance of this argument, Cal Advocates notes that on August 9, 2023, the two largest LSEs, comprising more than half of the 2,500 MW obligation in D.21-06-035, filed a Joint Expedited Petition for Modification of D.21-06-035 to request the deadline for LSEs to meet the Diablo Canyon replacement requirement be extended by two years.[~~48~~53] Cal Advocates also states the Commission's recent 2026 LOLE results from D.23-02-040 are too close to the reliability planning standard LOLE of 0.1 to indicate with certainty that the portfolio is reliable without Diablo Canyon.[~~49~~54]

In contrast, A4NR, WEM, SLOMFP, and CARE believe there is sufficient evidence in this proceeding demonstrating new renewable energy and zero-carbon resources have been constructed and interconnected, or are on track to be constructed and interconnected, and will substitute for Diablo Canyon and

[~~45~~50] Ex. PG&E-03 at 16-17.

[~~46~~51] Ex. GPI-02 at 6-7.

[~~47~~52] Ex. CGNP-02 at 5-11.

[~~48~~53] Cal Advocates OB at 5.

[~~49~~54] Ex. CalPA-02 at 9-10; Cal Advocates OB at 5-7.

meet the state's energy planning standards. Pointing to the CEC's March 2023 Report and February/May 2023 Joint Planning Assessments, A4NR highlights that, under a 17 percent reserve margin scenario, all three reports show the Commission's procurement orders are sufficient to eliminate reliability shortfalls through 2030. A4NR further asserts, among other things, that: (1) installed new renewable energy and zero-carbon resources nearly double the net qualifying capacity attributed to Diablo Canyon;[~~50~~55] (2) by the end of 2023, the procurement counted towards D.19-11-016 is expected to exceed the 3,300 MW required;[~~51~~56] (3) Commission-jurisdictional LSEs have not been delayed in meeting IRP orders for new generation;[~~52~~57] and (4) Diablo Canyon is unsuitable as a contingency resource.[~~53~~58]

WEM asserts DCPP is not an appropriate resource to address summer net peak reliability issues, and suggests Diablo Canyon's contribution can instead be met with readily deployable resources, namely energy storage and demand response. Additionally, WEM argues: (1) Diablo Canyon's reported electricity generation is inflated; (2) Diablo Canyon is not needed for reducing GHG emissions; (3) the 11,500 MW procurement ordered by D.21-06-035 was aggressively designed to protect grid reliability; and (4) based on the May 2023 assessment and report produced by the California Independent System Operator (CAISO), entitled *2023 Summer Loads and Resources Assessment* (CAISO May 2023

[~~50~~55] Ex. A4NR-01 at 23-26; *also,* A4NR OB at 6.

[~~51~~56] Ex. A4NR-02 at 21.

[~~52~~57] Ex. A4NR-01 at 24; *also,* February 2023 Joint Planning Assessment at 36.

[~~53~~58] Ex. A4NR-01 at 30.

Assessment),~~[54]~~[59] there were adequate reserve margins in place for summer 2023.~~[55]~~[60]

SLOMFP argues California's current capacity shortages occur in only a limited set of hours during the summer months, making it more of an operating reserves problem not addressable through continued operation of DCPP.~~[56]~~[61] In addition, SLOMFP argues: (1) continued operation of Diablo Canyon impedes the development of other low or zero-carbon alternatives; (2) contingency reserves can address the capacity shortfalls in 2025-2026; (3) other technologies and policies are needed to support a 21st century electricity system; (4) there are several deficiencies in the CEC's March 2023 Report including, among others, a purported failure to vet the operating reserve assumptions, as well as failure to include the 4,000 MW procurement order in D.23-02-040.~~[57]~~[62]

Citing more recent reports from the Tracking Energy Development Task Force (TED)~~[58]~~[63] and CAISO,~~[59]~~[64] CARE asserts procurement of renewable and energy storage resources is on track to meet the Commission's procurement

~~54~~59 *See* CAISO May 2023 Assessment, available at: http://www.caiso.com/Documents/2023-Summer-Loads-and-Resources-Assessment.pdf (last accessed September 15, 2023).

~~55~~60 Ex. WEM-02 at 9-15; *also,* WEM OB at 6-7.

~~56~~61 Ex. SLOMFP-5 at 4-10.

~~57~~62 Ex. SLOMFP-04; Ex. SLOMFP-05; and Ex. SLOMFP-08.

~~58~~63 *See* TED Task Force, May Resource Tracking Data Report issued July 7, 2023, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/summer-2021-reliability/tracking-energy-development/resource-tracking-data-may-2023-release.pdf (last accessed September 15, 2023).

~~59~~64 *See* CAISO Special Report on Battery Storage July 7, 2023, available at: http://www.caiso.com/Documents/2022-Special-Report-on-Battery-Storage-Jul-7-2023.pdf (last accessed September 15, 2023).

orders.[~~60~~65] CARE also provides data on DCPP's recent operating history and argues it is often not available during emergencies.[~~61~~66]

SBUA asserts California needs a diversity of electric generation resources, beyond solar and battery technologies, and recommends the Commission consult with the CEC, the CAISO, and the Western Electricity Coordinating Council concerning the adequacy of the state's planning standards for energy reliability.[~~62~~67]

UCS/NRDC contend it is difficult to draw any conclusions from the "stack analysis" studies presented in this proceeding, since these studies do not account for the likelihood of extreme events occurring nor, as argued by UCS/NRDC, do they account for the availability of emergency resources.[~~63~~68] UCS/NRDC then reference the LOLE analysis contained in the CAISO May 2023 Assessment, but ultimately conclude that this analysis also does not clearly indicate whether extended operations at Diablo Canyon are needed, since the assessment does not take into account emergency resources or adequately incorporate the impacts of increasingly frequent extreme weather events.[~~64~~69]

4.1.2. ~~3.1.2.~~ Discussion

As a threshold matter, the considerations at play in this proceeding address a relatively narrow set of circumstances based on the specific language set forth in Section 712.8(c)(2)(D). This decision is not intended to inform, or serve as a precedent for, other Commission proceedings tasked with addressing

[~~60~~65] Ex. CARE-02 at 5-8.

[~~61~~66] Ex. CARE-01 at 12-18.

[~~62~~67] Ex. SBUA-02 at 17-19.

[~~63~~68] Ex. UCS/NRDC-01 at 9-12.

[~~64~~69] *Id*. at 13-15.

broader planning processes and implications, including the Commission's RA and IRP proceedings.

In ascertaining the Legislature's intent, we begin with the words of the statute, since they generally provide the most reliable indicator of Legislative intent.[~~65~~70] We also give significance, if possible, to every word or part, and harmonize the parts by considering a particular clause or section in the context of the whole.[~~66~~71]

Section 712.8(c)(2)(D) states "If the commission determines that new renewable energy and zero-carbon resources that are adequate to substitute for the Diablo Canyon powerplant and that meet the state's planning standards for energy reliability have already been constructed and interconnected by the time of its decision, the commission may issue an order that reestablishes the current expiration dates as the retirement date, or that establishes new [earlier] retirement dates…" While several of the terms in this section of the statute are not explicitly defined in SB 846, the underlying syntax is clear that "new renewable energy and zero-carbon resources" are intended to be evaluated against all of the following criteria: whether they are an adequate substitute for Diablo Canyon, meet the state's planning standards for reliability, and have already been constructed and interconnected by the end of 2023.

In considering how to begin to define the meaning of "new renewable energy and zero-carbon resources" we find the arguments presented by Cal Advocates particularly instructive and on-point. Cal Advocates reasons:

> The relevant definitions of "new renewable energy and zero-carbon resources" hinge not on how far back in time the

[~~65~~70] *Hsu v. Abbara*, 9 Cal.4th 863, 871 (1995); *Burden v. Snowden*, 2 Cal.4th 556, 562 (1992).

[~~66~~71] *Moyer v. Workmen's Comp. Appeals Bd.*, 10 Cal.3d 222, 230 (1973).

> Commission begins counting "new" resources, but instead on the resources' ability to achieve interconnection by the end of 2023… The selection of one or the other baseline list may change which specific resources are deemed "existing" or "new" but may not change the total composition of the studied portfolio.[~~67~~72]

Focusing on the current portfolio of resources expected to achieve interconnection by the end of 2023 is not only consistent with the plain language of Section 712.8(c)(2)(D), but enables parties and the Commission to incorporate the most up-to-date resource planning assumptions, grid conditions, and policy developments/procurement orders — all of which are relevant to the Commission's consideration of whether "new renewable energy and zero-carbon resources" are an adequate substitute for Diablo Canyon and meet the state's planning standards for reliability. This is particularly true in California, where rapid changes in the electricity market are being driven by "the large number of new LSEs, the major shifts in the resource mix, weather and climate uncertainty, and increasing acceleration of electrification of building and transportation energy use."[~~68~~73]

The deterministic stack analyses presented in this proceeding, including more recent updates to account for the procurement orders in D.23-02-040 and new resource additions through March 2023, indicate shortfall conditions could exist as early as 2023 under extreme heat wave conditions that approximate those experienced in California in 2020 and 2022; shortfalls increase when incorporating various resource delay assumptions.[~~69~~74] Recent probabilistic LOLE

[~~67~~72] Ex. CalPA-02 at 12.

[~~68~~73] D.21-06-035 Finding of Fact 4.

[~~69~~74] *See* CEC's March 2023 Report at 48; February 2023 Joint Planning Assessment at 21-24; May 2023 Joint Planning Assessment at 11-12.

results prepared by the Commission and CAISO also point to narrow resource margins or potential shortfalls, including a LOLE result close to 0.1 in 2026 without an extension of Diablo Canyon,[~~70~~75] as well as a potential shortfall in 2025 when considering the levels of capacity required by the Commission's procurement orders.[~~71~~76]

All of these analyses are based on various scenarios of new resources and nameplate capacity such as those identified in the Commission's most recent PSP, as well as ordered procurement.[~~72~~77] To the extent there are potential risks and shortfalls associated with these scenarios — which are designed to meet the state's GHG reduction targets and ensure electric reliability — it is not necessary to define, with specificity, what is meant by renewable energy and zero-carbon resources, since these resources are assumed to be a subset within the larger portfolio.

UCS/NRDC assert it is difficult to articulate the probability of outcomes contained in the results from a deterministic stack approach, since the actual probability of outage risks associated with different supply and demand balances are uncertain. While it is true deterministic analyses require some inference and subjectivity regarding the likelihood of various potential futures occurring, that does not mean the deterministic stack analyses presented in this proceeding provide no value or should be completely ignored. SLOMFP argues current capacity shortages are operational in nature, and extending operations at DCPP

[~~70~~75] D.23-02-040 at 58, Table 5; *also,* Cal Advocates OB at 6-7.

[~~71~~76] CAISO May 2023 Assessment at 11, Table 1.

[~~72~~77] *See* footnote 21. As part of the IRP process, the Commission adopts a PSP or an optimal portfolio of resources for meeting state electric sector policy objectives at least cost to ratepayers, in the "planning track" of the IRP proceeding. The PSP is then used to set requirements for LSEs to plan toward that resource portfolio.

would not address the issue at hand. SLOMFP appears to misunderstand how planning and operating concepts are addressed in the IRP proceeding. For system reliability (as opposed to local reliability), the PRM accounts for load forecasting error, operating outages, and operating reserves.[~~73~~78] As a result, "operating reserves" are intrinsically linked to "planning reserves" and, therefore, SLOMFP's argument is flawed. Further, while SLOMFP observes the greatest reliability risk is currently limited to only a certain set of hours during the summer months, it should be noted that DCPP is a baseload resource that is capable of operating during higher risk hours.

Notwithstanding the various other concerns raised by these and other parties, at a minimum, we believe the reliability studies presented in this proceeding are consistent with our findings in the 2023 IRP decision that the electric system "is much closer to a supply and demand balance than is comfortable for reliability purposes."[~~74~~79] On the other hand, as emphasized by Cal Advocates, Section 712.8(c)(2)(D) specifically limits the Commission's consideration of reliability issues in this proceeding to renewable and zero-carbon resources that "have already been constructed and interconnected" by the end of 2023. All of the reliability studies in this proceeding assume continued procurement during the 2024-2028 time period based on the procurement orders and associated compliance deadlines adopted in the IRP proceeding. While it is difficult to parse out the specific procurement orders intended to offset Diablo Canyon, based on the record of this proceeding, as parties have noted D.21-06-035 requires LSEs to bring online at least 2,500 MWs

[~~73~~78] PG&E RB at 12.

[~~74~~79] D.23-02-040 at 25.

of resources with specified zero-emitting attributes by June 1, 2025, as an explicit showing of replacement capacity for Diablo Canyon. We find it is unlikely that resources with contracted commercial online dates in 2024 or later will be constructed and interconnected by the end of 2023. This conclusion is further supported by the recent Joint Expedited Petition for Modification (PFM) filed in Rulemaking (R.) 20-05-003, where the two largest LSEs, comprising more than half of the 2,500 MW obligation, are requesting the Commission modify D.21-06-035 to extend their compliance deadlines from 2025 to 2027.[~~75~~80]

In addition to the conclusions above, we find party arguments in support of the early retirement of Diablo Canyon to be unpersuasive and contrary to the specific requirements in Section 712.8(c)(2)(D). A4NR's argument that the deterministic stack analyses presented in this proceeding show the current RA standard is being met miss the overall conclusion of these reports, which is that shortfalls exist when considering recent heat wave conditions and the potential for resource delays. As noted above, all of these studies also assume continued procurement during the 2024-2028 time period. A4NR further asserts the installed capacity of new renewable energy and zero carbon resources nearly doubles that of Diablo Canyon and points to procurement counted towards D.19-11-016. A4NR, however, fails to demonstrate whether the resources installed are an adequate substitute for Diablo Canyon, that the procurement in D.19-11-016 was intended to completely offset Diablo Canyon, and that these resources meet the state's planning standards for reliability.[~~76~~81]

[~~75~~80] *See, generally*, R.20-05-003, *Southern California Edison Company's (U 338-E) and Pacific Gas and Electric Company's (U 39-E) Joint Expedited Petition for Modification of Decision 21-06-035* (August 9, 2023); *see, also,* Cal Advocates OB at 4-5. This decision takes no position on the merits of this PFM, which is being considered in R.20-05-003.

[~~76~~81] Section 712.8(c)(2)(D).

SLOMFP and WEM point to different technologies, including energy storage (including long-duration storage), demand response, and solar plus storage, among others, as being viable and preferred alternatives to DCPP, but both parties fail to demonstrate whether these installed technologies are already available, will serve as an adequate substitute for Diablo Canyon, and meet the state's planning standards for reliability.[~~77~~82] Various recommendations from these parties to further develop or direct procurement of energy storage, demand response, and transmission innovations, as well as concessions such as "it is difficult to predict how successful the regulators will be [in the integration and approval of projects], or how big the supply chain problem will continue to be," further highlight that these technologies are not all in place today.[~~78~~83] Similarly, CARE also points to the significant growth in installed energy storage and renewables, but fails to demonstrate whether current projects installed are an adequate substitute for Diablo Canyon and meet the state's planning standards for reliability.

For all of the above reasons, we conclude the conditions set forth in Section 712.8(c)(2)(D) have not been met.

4.2. ~~3.2.~~ Cost, Cost-Effectiveness, and Prudence

There are two sections of SB 846 relevant to the Commission's consideration of cost, cost-effectiveness, and prudence as they pertain to the authorization of extended operations at Diablo Canyon. First, as part of the Commission's decision directing and authorizing extended operations at Diablo Canyon, Section 712.8(c)(2)(B) requires the Commission to:

[~~77~~82] *Ibid.*

[~~78~~83] Ex. WEM-01 at 35-36; Ex. SLOMFP-05 at 29-32; Ex. SLOMFP-04 at 72.

> [R]eview the reports and recommendations of the Independent Safety Committee for Diablo Canyon described in Section 712.1. If the Independent Safety Committee for Diablo Canyon's reports or recommendations cause the commission to determine, in its discretion, that the costs of any upgrades necessary to address seismic safety or issues of deferred maintenance that may have arisen due to the expectation of the plant closing sooner are too high to justify incurring, or if the United States Nuclear Regulatory Commission's conditions of license renewal require expenditures that are too high to justify incurring, the commission may issue an order that reestablishes the current expiration dates as the retirement date, or that establishes new retirement dates that are earlier than provided in subparagraph (A) of paragraph (1).

Consistent with this statutory requirement, the following DCISC reports were included in the record of this proceeding for party consideration: (1) *Report on Fact-Finding Meeting with DCPP on November 8, 9 and 10, 2022*; (2) *Report on Fact-Finding Meeting with DCPP on December 6-7, 2022*; (3) *Report on Fact-Finding Meeting with DCPP on January 31 and February 1, 2023*; (4) *Report on Fact-Finding Meeting with DCPP on March 14, 15 and 27, 2023*; (5) *Report on Fact-Finding Meeting at DCPP on April 18, 19 and 20, 2023*; (6) *Report on Fact-Finding Meeting with DCPP on May 2-3, 2023*; and (7) *Report on Fact-Finding Meeting on May 5, 2023 and Comprehensive Seismic Safety Update*. While several of these reports contain DCISC recommendations for future reviews, none of the reports entered into the record of this proceeding contain recommended upgrades or associated actions to address issues of seismic safety or deferred maintenance.

Concerning the NRC's conditions of license renewal, PG&E's license renewal application to the NRC ~~is not expected to be~~was submitted ~~until later this year, with~~on November 7, 2023, while the NRC's review process and timeline have yet to be determined. PG&E estimates any conditions the NRC might require in renewed operating licenses will likely not be available until at least 2025.~~[79]~~[84] In the absence of a renewed NRC license, the Scoping Memo determined "it is reasonable for PG&E to provide cost estimates associated with likely or potential improvements … that might reasonably be required as part of the NRC relicensing process," and directed PG&E to serve testimony on DCPP's historical and forecast cost data through 2030.~~[80]~~[85] PG&E submitted this historical and forecast cost data on May 19, 2023.

Second, in describing events that would trigger a suspension or early termination of the $1.4 billion loan provided for under SB 846, Pub. Res. Code Section 25548.3(c)(5)(C) includes the following triggering event: "A determination by the Public Utilities Commission that an extension of the Diablo Canyon powerplant is not cost effective or imprudent, or both." While there is no specific deadline associated with this section of statute, the Commission is required, as part of this decision, to consider whether the SB 846 loan has been terminated. Therefore, issues of cost-effectiveness and prudency are relevant to this decision, were included within the scope of the proceeding,~~[81]~~[86] and were the subject of extensive party comment.

As part of the Commission's consideration of the cost-effectiveness of extended operations at Diablo Canyon, parties were also provided an opportunity to comment on the CEC's Draft Cost Comparison Report, developed pursuant to Pub. Res. Code Section 25233.2(a).~~[82]~~[87] Given the date the report was

~~[79]~~[84] November 7, 2023 Reporter's Transcript at 365:10-13; Ex. PG&E-03 at 2; ~~*also,*~~ PG&E OB at 8-9.

~~[80]~~[85] Scoping Memo at 9, 13.

~~[81]~~[86] *See* Scoping Memo, Phase 1: Track 2, Issue 1.a at 5.

~~[82]~~[87] Pub. Res. Code Section 25233.2(a) requires the CEC to "present a cost comparison of whether extended operations at the Diablo Canyon powerplant compared to a portfolio of published, alongside the statutory requirement for the Commission to issue its final decision by the end of 2023, comments in response to the Draft Comparison Report were provided on an expedited one-week timeframe. Reply comments were not accepted. In summary terms, the Draft Cost Comparison Report finds there are no supply resources that can be brought online before the planned 2025 retirement of Diablo Canyon to meet the like-for-like energy generation of 18,000 gigawatt-hours per year. Using PG&E's May 22, 2023 forecast Diablo Canyon cost data in this proceeding, the Draft Cost Comparison Report also shows average forecast Diablo Canyon costs of approximately $747 million per year (2023-2030), while upfront capital investment for 725 MW of replacement capacity (DCPP has a net peak capacity of 2.2 gigawatts) is valued between $230-$330 million per year.[~~83~~88]

4.2.1. ~~3.2.1.~~ Party Comments

4.2.1.1. ~~3.2.1.1.~~ Definition of Terms and Statutory Intent

Regarding the definition of "too high to justify," PG&E and CUE argue Section 712.8(c)(2)(B) limits the Commission's consideration of costs to any recommendations and reports by the DCISC, as well as NRC license renewal conditions.[~~84~~89] While acknowledging Section 712.8(c)(2)(B) does not provide clarity or guidance on how to define "too high to justify," PG&E points to Section 712.8(k) as providing guidance on how to interpret "too high to justify."[~~85~~90]

other feasible resources available for calendar years 2024 to 2035, inclusive, is consistent with the greenhouse gases emissions reduction goals of Section 454.53 of the Public Utilities Code. As part of this comparison, the commission shall evaluate the alternative resource costs, and shall make all evaluations available to the public within the proceeding docket."

[~~83~~88] Draft Cost Comparison Report at 2, 17, and 26.

[~~84~~89] Ex. CUE-01 at 1; Ex. PG&E-03 at 3-4.

[~~85~~90] Ex. PG&E-03 at 3-5. Section 712.8(k) states, in part: "If at any point during the license renewal process or extended operations period the operator believes that, as a result of an

A4NR recommends the threshold of "too high to justify" be defined as the level at which the projected costs described in Section 712.8(c)(B) exceed the sum of: (1) available government funding streams identified in D.22-12-005; (2) "other non-ratepayer funds available" to PG&E, as contemplated by Section 712.8(c)(1)(C); and (3) the amount of any binding commitment by PG&E to forego recovery of costs in excess of item (1) and item (2) from its ratepayers or the customers of other LSEs.~~[86]~~[91] Along similar lines, CARE asserts that if the expenses for safety, deferred maintenance, and NRC requirements exceed available government funding then the costs are "too high to justify." CARE also points to the loan agreement between PG&E and the Department of Water Resources (DWR) to define what activities are allowed to be reimbursed by the $1.4 billion loan authorized in SB 846.~~[87]~~[92]

SLOMFP contends costs are "too high to justify" if they are unjust, unreasonable, or imprudent, and must consider the costs and risks to both PG&E ratepayers as well as the taxpayers of California.~~[88]~~[93] SLOMFP also provides a historic overview of how prudence has been considered in utility regulation, and highlights Pub. Res. Code Section 25548.3(c)(5)(C) as requiring early and continuing review by the Commission concerning the prudence of decisions relating to extending the operating life of Diablo Canyon.~~[89]~~[94]

renewal process or extended operations period the operator believes that, as a result of an unplanned outage, an emergent operating risk, or a new compliance requirement, the cost of performing upgrades needed to continue operations of one or both units exceed the benefits to ratepayers of the continued operation of doing so, the operator shall promptly notify the commission."

~~[86]~~[91] Ex. A4NR-01 at 2.

~~[87]~~[92] Ex. CARE-01 at 1; Ex. CARE-02 at 1-4; *also* Pub. Res. Code Section 25548.3.

~~[88]~~[93] Ex. SLOMFP-01 at 3.

~~[89]~~[94] Ex. SLOMFP-03 at 4-12.

Similarly, SBUA recommends "too high to justify" be defined in a manner similar to "not cost effective" and/or "imprudent." SBUA goes on to suggest "not cost effective" means Diablo Canyon produces electricity that is more costly than other renewable electric generation in California, while "imprudent" means continued operations at Diablo Canyon are more expensive as compared to the costs to operate other nuclear power plants in the United States.[~~90~~95]

Cal Advocates suggests the Commission use PG&E's current cost forecasts as a benchmark for comparison with future annual forecasts and actual costs or, in the alternative, compare PG&E's total DCPP operating costs with market generation costs; if there is a significant deviation between these costs, Cal Advocates suggests this may indicate that continued operation of Diablo Canyon is "too high to justify." Cal Advocates also states a significant level of costs borne by ratepayers, as opposed to government funding streams, would indicate continued operation of Diablo Canyon is "too high to justify."

GPI suggests the Commission establish a threshold whereby if the costs required to extend operations at Diablo Canyon are expected to cause the total recoverable cost of energy production to increase by more than 10 percent, then a process would commence to determine whether the cost increase is "too high to justify."[~~91~~96]

4.2.1.2. ~~3.2.1.2.~~ Whether Costs Are Too High to Justify, and/or Whether Extended Operations at Diablo Canyon Are Not Cost-Effective or Imprudent

PG&E's May 19, 2023 testimony includes the forecast of relicensing costs PG&E included in its application for funding from the Department of Energy's

[~~90~~95] Ex. SBUA-02 at 5-6.

[~~91~~96] Ex. GPI-02 at 3.

(DOE) Civil Nuclear Credit (CNC) program, totaling approximately $131 million between Q3 2022-2026. Within that amount, PG&E attributes approximately $9.5 million to "likely or potential improvements that might reasonably be required as part of the NRC relicensing process."[~~92~~97]

Additionally, PG&E provides historical and forecast costs related to Diablo Canyon using the categories and accounting methodologies adopted by the Electric Utility Cost Group (EUCG). Table 1 and Table 2 below reflect the historical and forecast cost data provided by PG&E in its May 19, 2023 testimony.[~~93~~98]

[~~92~~97] Ex. PG&E-01 at 12-13.

[~~93~~98] *Id*. at 7, 9. Note: PG&E's May 19, 2023, testimony also includes historical cost data for the 2010-2012 period.

Table 1: Historical Diablo Canyon Costs ($000)

Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Engineering	38,509	36,865	36,783	41,005	48,129	49,749	50,033	46,723	39,542	31,990
Loss Prevention	64,850	62,261	63,045	72,811	69,343	70,840	74,045	78,778	72,659	72,755
Materials and Services	8,917	12,980	8,499	8,648	3,811	3,920	6,000	4,600	4,976	8,468
Fuel Management	5,987	844	1,053	648	300	0	554	501	832	808
Operations	61,427	65,186	55,839	67,903	73,457	75,766	77,567	70,895	71,340	77,593
Support Services	134,566	155,377	151,291	147,888	104,299	61,617	98,313			
Training	10,987	11,222	9,335	7,318	7,700	7,996	10,343	11,472	9,072	7,551
Work Management	96,973	144,842	157,413	141,805	120,992	114,824	137,884	106,288	104,519	112,109
Total Nuclear Operating Costs	422,216	489,577	483,257	488,026	428,031	384,712	454,739			
Capital	209,296	209,934	217,443	183,121	161,871	106,210	102,476	43,327	34,362	12,995
Outage	45,289	87,156	52,333	58,860	64,584	48,086	81,928	44,982	41,466	63,274
Fuel	133,152	113,921	125,134	126,909	124,061	128,286	112,605			
Total	809,953	900,588	878,167	856,916	778,547	667,294	751,748	596,818	581,344	644,111

Table 2: Forecast Diablo Canyon Costs from 2023-2030 ($000)

Year	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Engineering	44,444	44,767	39,047	39,786	41,178	42,619	44,111	19,023
Loss Prevention	77,614	78,178	68,189	69,479	71,911	74,427	77,032	33,220
Materials and Services	7,887	7,944	6,929	7,060	7,308	7,563	7,828	3,376
Fuel Management	833	839	732	746	772	799	827	357
Operations	76,292	76,847	67,028	68,296	70,687	73,161	75,721	32,655
Support Services								
Training	9,352	9,420	8,216	8,371	8,664	8,968	9,282	4,003
Work Management	108,140	108,926	191,968	142,588	147,579	206,495	158,091	68,177
Total Nuclear Operating Costs								
Total Capital	150,180	150,052	150,094	154,312	119,785	123,977	96,237	20,751
Outage	46,841	46,841	96,961	50,177	51,933	107,502	55,632	23,991
Fuel								
Total	735,836	744,446	893,139	765,144	751,996	885,818	773,478	422,644

TURN identifies the following cost categories as being excluded from PG&E's May 19, 2023 forecast: Administrative and General (A&G) costs; the volumetric performance-based payment of $13 per megawatt-hour (MWh) (2022) per year authorized by SB 846;[~~94~~99] the fixed management fee of $100 million (2022) per year authorized by SB 846;[~~95~~100] the $300 million liquidated balancing account authorized by SB 846 to cover replacement power costs if Diablo Canyon is out of service due to an unplanned outage;[~~96~~101] continuation of the employee retention program approved in D.18-11-024 "on an ongoing basis until the end of operations of both units;"[~~97~~102] tax-related obligations (*i.e.*, property, payroll, business, state corportation franchise, and federal income) resulting from extended operations at Diablo Canyon; various costs included in PG&E's General Rate Case (GRC) Results of Operations Model (including transmission, uncollectibles, franchise and San Francisco Gross Reciept tax requirement, and amortization); and, miscellaneous costs, including nuclear property insurance and incremental decommissioning planning costs.[~~98~~103]

Based on an estimate of the cost categories above, and accounting for potential state and federal funds, TURN provides a revised 2024-2030 Diablo Canyon forecast totaling approximately $10.1 billion in utility ratepayer obligations. Compared to PG&E's forecast (and not accounting for state and federal funds), TURN's revised forecast represents a total increase of almost $5

[~~94~~99] Section 712.8(f)(5).

[~~95~~100] Section 712.8(f)(6)(A).

[~~96~~101] Section 712.8(g), (i).

[~~97~~102] Section 712.8(f)(2).

[~~98~~103] Ex. TURN-01 at 4-5; Ex. TURN-03, PG&E Response to TURN Data Request 5, Q5-15; Ex. TURN-04, PG&E Response to TURN Data Request 6, Q1; TURN OB at 7-15.

billion (2024-2030), or an average annual increase of approximately $800 million.[~~99~~104]

Citing to many of the same excluded cost categories as TURN, A4NR asserts PG&E's cost forecast is materially misleading, and omits nearly $2.2 billion in known costs.[~~100~~105] Additionally, A4NR contends PG&E's cost forecast excludes, or improperly accounts for, over $1 billion in previously identified prospective DOE reimbursements, authorized funding from the DWR, as well as fuel costs protected under Section 712.8(c)(1)(C).[~~101~~106]

In additon to omitted costs, several parties question the accuracy of the underlying activities and capital projects included in PG&E's forecast. Concerning NRC's potential conditions of relicensing, these parties speculate safety and environmental reviews will result in significant costs. Specifically, parties cite to potential issues of seismic safety and embrittlement, steam generator replacements, and the costs to comply with environmental review processes, amoung others.[~~102~~107] CARE asserts PG&E's cost forecast fails to include costs associated with the type of commitments the NRC required of PG&E in the original 2009 license renewal application.[~~103~~108]

In reply, PG&E concedes its May 19, 2023 cost forecast excludes many of the cost categories identified by TURN and A4NR. However, PG&E also argues: (1) many of the excluded costs will either cease to exist in extended operations,

[~~99~~104] TURN OB at 16; *also,* Ex. TURN-01 at 25.

[~~100~~105] Ex. A4NR-01 at 34.

[~~101~~106] *Id*. at 31-35.

[~~102~~107] Ex. SLOMFP-01 at 3-7; Ex. SLOMFP-02 at 5-19; Ex. SLOMFP-06 at 2-12; Ex. SLOMFP-07 at 3-12; Ex. A4NR-01 at 2-5.

[~~103~~108] Ex. CARE-02 at 9.

will be recovered through other applications, or are otherwise outside the relevant costs determined to be in the scope of this proceeding; (2) the EUCG cost reporting format was based on the requirements of the DOE's CNC application, and represents the most recent and complete set of cost information available; (3) SB 846 delegates the responsibility to provide an all-in value for use in a cost comparison to the CEC; and (4) TURN overstates the costs in the extended operations period by an average of $400 million per year, and over $3 billion in total.[~~104~~109] PG&E also states it is in the process of developing an estimate of the Diablo Canyon extended operations using existing GRC cost structures, and that this forecast will be complete for inclusion in the extended operations cost recovery application to be filed in early 2024.[~~105~~110] Additionally, PG&E disagrees with SLOMFP's characterizations and conclusions on the issues to be overseen by the NRC, asserting related expenditures can only be analyzed for prudency at the time and in the context in which they arise, and contends that CARE is incorrect in claiming PG&E's forecast failed to include costs associated with the types of commitments the NRC required in PG&E's 2009 license renewal application.[~~106~~111]

Regarding the current reports and recommendations produced by the DCISC, parties generally agree the DCISC does not yet have, or is still in the process of reviewing, the information necessary to perform the analyses required by Section 712.8(c)(2)(B).[~~107~~112] This includes the updated seismic study PG&E is required to conduct pursuant to Pub. Res. Code Section 25548.3(c)(13), any

[~~104~~109] Ex. PG&E-03 at 1-2 through 1-6.

[~~105~~110] *Id*. at 1-4; *also,* PG&E OB at 14-15.

[~~106~~111] *Id*. at 3-11 through 3-14.

[~~107~~112] PG&E OB at 11-13; SLOMFP OB at 25-27.

updated seismic-related information included in PG&E's NRC license renewal application, as well as PG&E's revised maintenance schedule, which adds 200 activities previously removed as a result of the expected shutdown in 2024 and 2025.~~[108]~~[113]

Parties provide different recommendations based on the evidence and arguments above. PG&E and CUE highlight that there are currently no recommendations from the DCISC for seismic safety upgrades or deferred maintenance activities, or conditions of NRC's license renewal; therefore, these parties argue it is not possible at this time to determine whether the associated costs for unknown activities are "too high to justify."~~[109]~~[114] Citing to current cost uncertainties, TURN also contends there is insufficient information to be able to determine whether the costs of extended operations at Diablo Canyon are "too high to justify incurring,"or whether "an extension of operations at Diablo Canyon is found to be not cost effective, imprudent, or both."~~[110]~~[115]

Based on its own evaluation of the costs to operate DCPP compared to the costs of RPS contracts and the average cost of nuclear power in the United States, SBUA concludes DCPP extended operations are cost-effective and prudent.~~[111]~~[116] GPI believes the preliminary costs and lack of capital projects presented in this proceeding indicate DCPP extended operations are not "too high to justify."~~[112]~~[117] Using the Commission's Avoided Cost Calculator (ACC), CUE estimates Diablo Canyon's contribution to the grid results in a ratepayer benefit ranging from

~~[108]~~[113] PG&E OB at 8, 12; Ex. A4NR-02 at 9-11; Ex. A4NR-04 at 2.

~~[109]~~[114] CUE OB at 2-3; PG&E OB at 9-10.

~~[110]~~[115] TURN OB at 1-2.

~~[111]~~[116] Ex. SBUA-01 at 5-10.

~~[112]~~[117] Ex. GPI-02 at 2-4; Ex. GPI-03 at 3-5; GPI OB at 3-6.

$1.555 to $1.676 billion per year (2025-2029),[~~113~~118] while CGNP contends DCPP operations are cost-effective based on data obtained from PG&E's Federal Energy Regulatory Commission (FERC) Form 1 filings.[~~114~~119]

In contrast, A4NR and SLOMFP believe there is sufficient evidentiary record demonstrating the costs in Section 712.8(c)(2)(B) are already "too high to justify," while SLOMFP contends DCPP extended operations are "not cost effective or imprudent, or both." A4NR's position is based on the level of omitted costs from PG&E's Diablo Canyon cost forecast, which A4NR argues will exceed the amount of available government funding by over $1 billion.[~~115~~120]

SLOMFP asserts Diablo Canyon is not cost-effective for the following reasons: (1) the Commission previously made a finding of fact that "Continuing operation of Diablo Canyon Unit 1 beyond 2024 and Unit 2 beyond 2025 would require renewal of NRC licenses, and would not be cost effective;"[~~116~~121] (2) using an assumed cost of $70 per MWh based on the cost of operations of aging nuclear reactors similar to Diablo Canyon, SLOMFP argues operations at Diablo Canyon are signficantly higher than the price for alternative renewable energy and zero carbon resources;[~~117~~122] (3) based on its assertion that Diablo Canyon Unit 1 will need to be repaired or replaced to address issues of embrittlement, SLOMFP estimates the resultant costs to be between $250-$500 million;[~~118~~123] and (4)

~~113~~118 Ex. CUE-01 at 3-4.

~~114~~119 CGNP OB at 3.

~~115~~120 Ex. A4NR-02 at 2-10; A4NR OB at 5-6.

~~116~~121 D.18-01-022 Finding of Fact 1; SLOMFP OB at 9-11.

~~117~~122 Ex. SLOMFP-08 at 5-7 and 16-29.

~~118~~123 Ex. SLOMFP-07 at 11.

SLOMFP highlights costs associated with obtaining the necessary environmental permits and authorizations to extend operations.[~~119~~124]

Concerning the prudency of extended operations, SLOMFP concludes a capably managed utility would not chose to extend operations at Diablo Canyon based on the following assertions, among others: (1) neither PG&E, nor any governmental agency, has conducted a study demonstrating the need for Diablo Canyon to address grid reliability, while PG&E's position in A.16-08-006 was that retiring Diablo Canyon in 2024/2025 would not impact reliability;[~~120~~125] (2) keeping Diablo Canyon online will impede the production of renewable and zero-carbon power supply at the lowest possible cost;[~~121~~126] (3) when it comes to non-airborne pollutants, aging nuclear reactors rank among the least green fuels, in the same category as coal and gas;[~~122~~127] and (4) actual and forecast costs in this proceeding demonstrate it is costly to extend operations at Diablo Canyon.[~~123~~128]

Concerning whether the costs in Section 712.8(c)(2)(B) are "too high to justify," SLOMFP asserts PG&E's "slow walking" of the statutorily-mandated information should be interpreted to mean that the information is more likely than not to demonstrate an extension of Diablo Canyon operations is too high to justify. Notwithstanding this argument, since the DCISC does not have the requisite seismic information, SLOMFP asserts it is within the Commission's authority to issue an order affirming the current NRC license expiration dates of 2024/2025, or to prescribe the timing of the extension order, delaying it unless

[~~119~~124] Ex. SLOMFP-01 at 3-7.

[~~120~~125] Ex. SLOMFP-03 at 12-14.

[~~121~~126] Ex. SLOMFP-04 at 31-32; Ex. SLOMFP-05 at 32-37.

[~~122~~127] Ex. SLOMFP-04 at 17-18.

[~~123~~128] SLOMFP OB at 32.

and until the prerequisites of Section 712.8(c)(2)(B) are met.~~[124]~~[129] Lastly, should the Commission nevertheless make a determination on the conditions in Section 712.8(c)(2)(B), SLOMFP urges the Commission to consider potential updates to the DCPP seismic assessment, additional maintenance activities identified by PG&E which SLOMFP argues should be considered "deferred maintenance," as well as purported embrittlement issues with Diablo Canyon's Unit 1 pressure vesssel.~~[125]~~[130]

~~Laslty~~Lastly, regarding the CEC's Draft Cost Comparison Report, PG&E, CGNP, and SBUA generally find the CEC's conclusions (*i.e.*, that there are insufficient resources to replace DCPP) to be reasonable.~~[126]~~[131] In contrast, most other parties believe the Draft Cost Comparison Report fails to provide useful information or should not be used to inform the decisions in this proceeding. TURN, A4NR, CARE, and GPI argue that the Draft Cost Comparison Report excludes almost all viable alternative resource options, preventing any meaningful comparison, while the DCPP cost forecast ignores a wide array of cost catagories and updated costs identified in this proceeding.~~[127]~~[132] SLOMFP and WEM highlight that this is a draft version of the report, and therefore should not be relied upon.~~[128]~~[133]

~~[124]~~[129] *Id.* at 25-27.

~~[125]~~[130] *Id.* at 27-32.

~~[126]~~[131] PG&E October 6, 2023 Comments at 1-2; CGNP October 4, 2023 Comments at 4 and 11-13; SBUA October 6, 2023 Comments at 1.

~~[127]~~[132] TURN October 6, 2023 Comments at 3-12; A4NR October 6, 2023 Comments at 1-10; CARE October 5, 2023 Comments at 4-8; GPI October 6, 2023 Comments at 1-7.

~~[128]~~[133] SLOMFP October 6, 2023 Comments at 1; WEM October 6, 2023 Comments at 1.

4.2.2. ~~3.2.2.~~ Discussion

As part of the requirement for the Commission to issue a decision by the end of 2023 directing and authorizing extended DCPP operations, Section 712.8(c)(2)(B) requires the Commission to review the following costs to determine if they are too high to justify: (1) costs or upgrades necessary to address the DCISC's recommendations on seismic safety or issue of deferred maintenance; and (2) expenditures stemming from NRC's conditions of license renewal. While SB 846 does not provide guidance or parameters on what level of costs might be considered "too high to justify," it is clear that the scope of costs being considered in Section 712.8(c)(2)(B) are limited to any costs associated with recommendations by the DCISC, as specified, or conditions of NRC's license renewal.

Concerning the definition of "too high to justify," as used in Section 712.8(c)(2)(B), the Commission agrees with SLOMFP that the "plain and commonsense meaning" of the statutory language is clear.[~~129~~134] In interpreting statutory language, the Commission "give[s] the words of the statute 'a plain and commonsense meaning' unless the statute specifically defines the words to give them a special meaning."[~~130~~135] The Merriam-Webster dictionary defines "justify" as "to prove or show to be just, right, or reasonable" and SB 846 does not give the phrase "too high to justify" any "special meaning."[~~131~~136]

Importantly, the plain and commonsense meaning of the statutory language must not be understood in "isolation," but, instead, must be

[~~129~~134] Ex. SLOMFP-01 at 3.

[~~130~~135] *MacIsaac v. Waste Mgmt. Collection & Recycling, Inc.*, 134 Cal.App.4th 1076, 1083 (2005) (citations omitted).

[~~131~~136] *Id. See, also,* Merriam-Webster's definition at: https://www.merriam-webster.com/dictionary/justify (last accessed October 19, 2023).

determined "in the context of the statutory framework as a whole in order to determine its scope and purpose and to harmonize the various parts of the enactment."[~~132~~137] Within the Commission's broader review of charges demanded or received by a public utility, the Commission is statutorily obligated to ensure that utility operations result in rates that are "just and reasonable."[~~133~~138] The Commission implements its mandatory review under Section 451 by assessing the reasonableness and prudence of utility actions, an evaluation that incorporates consideration of cost-effectiveness, among other factors.[~~134~~139] Thus, the statutory framework of the Public Utilities Code supports the Commission applying its established reasonableness and prudence standard to determine whether the specific costs identified in Section 712.8(c)(2)(B) are reasonable and prudent.

In enacting SB 846, the Legislature affirmed the Commission's broad statutory mandate in Section 451 by requiring the Commission to ensure extended DCPP operations are cost-effective and prudent. As explained elsewhere, SB 846 provides several conditions which, if met, would allow, or require the Commission to establish earlier retirement dates for DCPP. One such condition is the termination of the $1.4 billion loan agreement under SB 846, which may be triggered through "[a] determination by the [Commission] that an

[~~132~~137] *Sierra Club v. Superior Ct.*, 57 Cal.4th 157, 165 (2013).

[~~133~~138] Section 451.

[~~134~~139] *See, e.g., Application of San Diego Gas & Elec. Co. (U902e) for Authorization to Recover Costs Related to the 2007 S. California Wildfires Recorded in the Wildfire Expense Memorandum Acct. (Wema), Order Denying Rehearing of Decision (D.) 17-11-033, D.18-07-025*, at *4 (July 12, 2018); *see also* Ex. SLOMFP-03 at 9-10 (citations omitted) (summarizing Commission's Prudent Manager Standard).

extension of the Diablo Canyon powerplant is not cost effective or imprudent, or both.”[~~135~~140]

Therefore, to “harmonize the [Legislature’s] enactment”[~~136~~141] of the phrase “too high to justify” in Section 712.8(c)(2)(B) with the statutory framework of the Public Utilities Code and SB 846 itself, the Commission interprets the phrase as requiring it to assess whether the specific types of costs identified in Section 712.8(c)(2)(B) (*i.e.*, the cost of upgrades to address seismic safety or deferred maintenance concerns identified by the DCISC, or the cost of PG&E complying with NRC license renewal conditions for DCPP), are justified, or reasonable, under the Commission’s established reasonableness and prudency review standard. In accordance with Pub. Res. Code Section 25548.3(c)(5)(C) and the Commission’s overarching responsibility to determine whether extended operations of DCPP will result in just and reasonable rates, it follows that the Legislature intended for the Commission to apply the same, established prudency and reasonableness standard to the Commission’s review of the two specific types of costs identified in Section 712.8(c)(2)(B). This includes consideration of whether these specific costs cause DCPP extended operations to fail to be cost-effective.

Notwithstanding our interpretation of Section 712.8(c)(2)(B) and Pub. Res. Code Section 25548.3(c)(5)(C) above, we find the Commission does not have sufficient information at this time to be able to determine whether extended operations at DCPP are “too high to justify” or “not cost-effective or imprudent.”

[~~135~~140] Pub. Res. Code Section 25548.3(c)(5)(C).

[~~136~~141] *Sierra Club v. Superior Ct.*, 57 Cal.4th 157, 165 (2013).

At the time of this decision there are no recommendations from the DCISC for seismic safety upgrades or deferred maintenance activities associated with extended Diablo Canyon operations, nor does the Commission have before it any NRC license renewal commitments or conditions. Absent any actual recommendations and conditions from the DCISC and NRC, it is not possible for the Commission to assess whether associated, unknown costs render the extension of Diablo Canyon operations too high to justify.

A4NR attempts to argue DCPP extended operations costs are “too high to justify” based on allegations that omitted costs from PG&E’s forecast exceed government funding streams by over $1 billion. A4NR’s argument, however, relies on broad cost categories — including costs authorized under SB 846, DOE reimbursements, authorized funding from DWR, as well as fuel costs — all of which are well beyond the scope of potential (let alone known) DCISC recommendations or NRC’s conditions of license renewal. SLOMFP also provides several potential conditions of NRC’s license renewal, while at the same time admitting “it is premature to speculate what deficiencies the NRC Staff may find and require PG&E to address through negotiated upgrades or license conditions.”~~[137]~~[142] Further, SLOMFP’s allegation that PG&E’s “slow walking” of statutorily mandated information indicates costs are likely too high to justify is pure speculation, while its suggestion that the Commission delay its decision until the prerequisites of Section 712.8(c)(2)(B) are met is in direct conflict with the requirement in SB 846 for the Commission to direct and authorize extended DCPP operations no later than December 31, 2023.~~[138]~~[143]

~~[137]~~[142] Ex. SLOMFP-06 at 3.

~~[138]~~[143] Section 712.8(c)(2)(A).

Accordingly, this decision determines the conditions set forth in Section 712.8(c)(2)(B) have not been met.

SLOMFP is the only party to argue there is sufficient evidentiary record demonstrating DCPP extended operations are not cost-effective. The majority of SLOMFP's arguments hinge on purported extended operation costs that are either unsubstantiated, undefined, or not specifically tied to Diablo Canyon.[~~139~~144] For example, SLOMFP's cost comparison is based on the operating cost of aging nuclear reactors that are *similar* to Diablo Canyon, rather than actual DCPP site-specific costs. SLOMFP's allegation that DCPP Unit 1 will need to be replaced is also speculative, and involves nuclear safety embrittlement issues that are expected to be considered by the NRC as part of PG&E's forthcoming license renewal application. SLOMFP points to "substantial" costs associated with environmental permitting but does not attempt to estimate these costs or prove why they would make extended operations at DCPP fail to be cost-effective. Finally, SLOMFP highlights that D.18-01-022, the Commission's 2018 decision approving the retirement of Diablo Canyon, found continuing operation of DCPP would require NRC license renewal, and would not be cost-effective. The Commission's 2018 decision, however, was based on circumstances at the time, and did not consider the current energy market or the $1.4 billion SB 846 loan and other government funding streams intended to address the cost of NRC license renewal.

[~~139~~144] It should be noted that SLOMFP submitted hundreds of pages of testimony and exhibits in this proceeding concerning safety-related technical, operational, and license renewal issues overseen by the NRC. (*See* Ex. SLOMFP-01; SLOMFP-02; Ex. SLOMFP-06; Ex. SLOMFP-07; Ex. SLOMFP-28; and Ex. SLOMFP-29.) While this proceeding is scoped to consider the potential *costs* of NRC's conditions of license renewal (*see* Scoping Memo at 8-9), SLOMFP's underlying testimony often focuses almost exclusively on nuclear safety issues to be overseen by the NRC, with little to no information on the associated potential costs.

On a related note, we find party proposals that assert DCPP extended operations are cost-effective to be materially incomplete or inconclusive, and further highlight the uncertainty of costs presented in this proceeding. For example, CGNP's use of FERC Form 1 reports and PG&E's original forecast in this case excludes a wide range of historical costs directly attributable to DCPP that were collected from ratepayers.[~~140~~145] CUE's calculation of the "significant value" of DCPP extended operations relies on inputs into the Commission's ACC. As noted by TURN, the ACC is used "to determine the primary benefits of distributed energy resources across Commission proceedings,"[~~141~~146] and any expansion of the ACC to value large-scale transmission connected generation would transform the limited purpose of this tool.[~~142~~147] The purpose and design of the ACC tool was not a focus of this proceeding, and any expansion of its use would benefit from broader party participation. Lastly, it is undisputed that: (1) PG&E's May 2023 DCPP forecast cost testimony in this proceeding excludes various cost categories associated with DCPP's extended operation, including cost categories that would typically be presented as part of PG&E's GRC; and (2) the CEC's cost forecast of continued Diablo Canyon operations, as presented in its Draft Cost Comparison Report, is based on PG&E's testimony in this proceeding, and therefore similarly omits costs associated with DCPP extended operations. SBUA's cost-effectiveness evaluation is also based on PG&E's May 2023 cost forecast.[~~143~~148] Absent a complete and transparent accounting of all

[~~140~~145] Including depreciation, return on ratebase, various taxes, amortization, employee retention programs, and a variety of shared costs PG&E allocates to DCPP. (TURN RB at 6).

[~~141~~146] D.22-05-002 at 3.

[~~142~~147] TURN RB at 11-12.

[~~143~~148] Ex. SBUA-02 at 14.

DCPP extended operation costs, it is not possible for the Commission to determine at this time whether DCPP extended operations are cost-effective.

Concerning the prudency of extended operations, SLOMFP asserts a capably managed utility would not choose to extend operations at DCPP and, therefore, continued DCPP operations are imprudent. SLOMFP's arguments are without merit. References to PG&E's position in A.16-08-006 and whether nuclear generation is "green" ignore the fact that DCPP operations are being directed by the Legislature, based on ~~a finding that continued~~the policy determination that "seeking to extend the Diablo Canyon powerplant's operations for a renewed license term is ~~"~~prudent, cost effective, and in the best interest of all California's electricity customers."[~~144~~149] Further, PG&E's position in A.16-08-006 was based on its bundled energy needs, whereas current reliability considerations are based on system needs.[~~145~~150] As discussed elsewhere in this decision, the reliability studies presented in this proceeding support previous Commission findings that the "electric system is much closer to a supply and demand balance than is comfortable for reliability purposes,"[~~146~~151] while any recommendations or conditions by the DCISC and NRC are unknown at this time. Lastly, SLOMFP argues that keeping Diablo Canyon online will impede the production of renewable and zero-carbon power supply at the lowest possible cost. As we found in D.18-01-022:

> The IRP is supposed to incorporate the analysis leading to an optimized portfolio of resources, reflecting constraints such as GHG emissions, reliability, cost, and RPS and energy efficiency requirements, while ensuring safe and reliable

[~~144~~149] Pub. Res. Code Section 25548(b).

[~~145~~150] September 5, 2023 Reporter's Transcript at 220:7-23.

[~~146~~151] D.23-02-040 at 25.

> electricity service at just and reasonable rates. (R.16-02-007 at 13.) In short, the IRP has the ability to look at a bigger picture than this proceeding, and can better analyze the potential impacts of the retirement of Diablo Canyon and its interaction with other dynamics in the electricity markets in a manner consistent with state policies.~~[147]~~[152]

Issues concerning how renewable and zero-carbon resources contribute to the production of safe, reliable, and cost-effective generation that meets the state's GHG emissions goals are actively being considered in the Commission's IRP proceeding. Further, since SB 846 prohibits the IRP proceeding from considering the DCPP in IRP portfolios, resource stacks, or PSPs after 2024 (Unit 1) and 2025 (Unit 2),~~[148]~~[153] the extension of DCPP operations should not impede the development of new GHG reducing energy resources. Therefore, the IRP proceeding continues to be better equipped to address general resource portfolio issues, including the production of renewable and zero-carbon generation at the lowest possible cost.

For all of the above reasons, the Commission is unable to determine whether DCPP extended operations are "too high to justify," or "not cost effective or imprudent, or both." As of the date of this decision, we find the conditions set forth in Section 712.8(c)(2)(B) and Pub. Res. Code Section 25548.3(c)(5)(C) have not been met. We discuss the Commission's continued evaluation of the prudency, reasonableness, and cost-effectiveness of extended DCPP operations, including the opportunity for further consideration of any DCISC recommendations and NRC's conditions of license renewal, in Section ~~3.4~~4.4 of this decision.

~~147~~152 D.18-01-022 at 22.

~~148~~153 Section 454.52(f)(1).

4.3. ~~3.3.~~ Nuclear Regulatory Commission License Renewal and Senate Bill 846 Loan

Section 712.8(c)(2)(C) allows the Commission to establish earlier retirement dates for Diablo Canyon if the $1.4 billion loan authorized under SB 846 is terminated. In addition, Section 712.8(c)(1)(B) specifies the Commission must establish earlier retirement dates if the SB 846 loan is terminated. Meanwhile, Section 712.8(c)(2)(E) conditions any extension of operations at Diablo Canyon upon continued authorization to operate by the NRC. In the event the NRC does not extend the current expiration dates or renews the licenses for Diablo Canyon Unit 1 or Unit 2 for a shorter period of time, the Commission must modify its orders to direct a retirement date that is consistent with the NRC's license expiration date.[~~149~~154]

At the time of this decision the $1.4 billion SB 846 loan has not been terminated.[~~150~~155] Further, as noted previously, the NRC has allowed Diablo Canyon to continue to operate past the current license expiration dates, provided PG&E submits a new license renewal application by the end of 2023 and satisfies various regulatory requirements at the federal and state levels.[~~151~~156] PG&E's license renewal application to the NRC ~~is expected to be~~was recently submitted ~~by the end of~~on November 7, 2023, while the NRC's review process and timeline ~~has~~have yet to be determined.[~~152~~157]

Since neither of the above conditions have occurred, there is no basis to establish retirement dates earlier than October 31, 2029 (Unit 1) and October 31,

[~~149~~154] Section 712.8(c)(2)(E).

[~~150~~155] PG&E RB at 2.

[~~151~~156] PG&E Diablo Canyon Power Plant, Unit 1 and Unit 2, 88 Fed. Reg. 14,395 (March 8, 2023).

[~~152~~157] Ex. PG&E-03 at 2; November 7, 2023 Reporter's Transcript at 365:10-13.

2030 (Unit 2).[~~153~~158] Pursuant to Section 712.8(c)(2)(E) and Section 712.8(c)(1)(B), the approval of DCPP extended operations until 2029/2030 is conditioned upon authorization by the NRC to continue to operate and continuation of the SB 846 loan agreement. In the event the NRC does not renew the licenses for Diablo Canyon Unit 1 and Unit 2, or renews for a period that is earlier than what is authorized in this decision, PG&E shall immediately file a Tier 3 advice letter to notify the Commission and to modify the retirement dates approved in this decision. Similarly, in the event the SB 846 loan is terminated, PG&E shall immediately file a Tier 3 advice letter to notify the Commission and to make a recommendation regarding earlier retirement dates for DCPP. As part of its advice letter filing, PG&E shall address the prudence and cost-effectiveness of extended operations, how PG&E intends to recover any remaining activities in connection with relicensing and transitioning Diablo Canyon from existing operations into extended operations (which SB 846 prohibits from being recovered from utility ratepayers),[~~154~~159] as well as the length of time needed for an orderly shutdown of Diablo Canyon. A copy of the above advice letters shall be served on the service list to this proceeding.

4.4. ~~3.4.~~ Whether One or More Processes Should Be Established to Continue to Monitor the Ratepayer Costs, Prudence, and Reliability Need for Extended Operations at Diablo Canyon

Parties were asked to comment on whether one or more processes should be established to continue to monitor the associated ratepayer costs from, and

[~~153~~158] Section 712.8(c)(1)(A).

[~~154~~159] *See* Section 712.8(c)(1)(C); *also*, D.22-12-005 at 10-11 and 15-19.

reliability need for, Diablo Canyon during extended operations.[~~155~~160] In addition, several parties provided recommendations concerning ongoing evaluation of the cost-effectiveness and prudence of DCPP extended operations.

PG&E believes a comprehensive process for monitoring ongoing ratepayer costs and establishing the reliability need for Diablo Canyon are already set forth in SB 846, and asserts it would be administratively inefficient and cause unnecessary costs to layer on additional review processes.[~~156~~161] As part of the Section 712.8(k) notification process,[~~157~~162] PG&E proposes to submit a report at the time of any DCISC recommendations on seismic safety upgrades or deferred maintenance, or at the time the NRC issues a renewed license, to assess any associated costs and make recommendations on whether it is prudent to incur the cost to support continued operations. PG&E proposes to submit this report through a Tier 3 advice letter filing.[~~158~~163]

In contrast, TURN argues the near-term statutory obligation to issue a decision by the end of 2023 does not represent the sole opportunity for the Commission to review the cost-effectiveness of extended operations, and recommends PG&E be directed to provide a more robust cost forecast in its upcoming DCPP Extended Operations Cost Forecast application~~ (*see* Section 7.5 of this decision)~~. TURN "urges the Commission to avoid falling into the trap of authorizing extended operations without an adequate assessment of

[~~155~~160] Track 2 April Ruling at 7-8.

[~~156~~161] PG&E OB at 20-24.

[~~157~~162] Section 712.8(k) states: "If at any point during the license renewal process or extended operations period the operator believes that, as a result of an unplanned outage, an emergent operating risk, or a new compliance requirement, the cost of performing upgrades needed to continue operations of one or both units exceed the benefits to ratepayers of the continued operation of doing so, the operator shall promptly notify the commission."

[~~158~~163] Ex. PG&E-03 at 4-5 and 20-21; PG&E OB at 21-22.

cost-effectiveness and then being forced to provide a virtual blank check to PG&E for the actual costs over time."[~~159~~164] A4NR recommends a monthly reporting process be established modeled on the reports required in Investigation (I.) 12-10-013, concerning San Onofre repair costs.[~~160~~165] SBUA recommends the Commission continue to review the costs related to ongoing operations at Diablo Canyon based on cost-effectiveness and prudency,[~~161~~166] while GPI contends DCPP costs should be scrutinized "if the needed capital costs for the extension add more than ten percent to the total cost of energy production."[~~162~~167] GPI also asserts the appropriate forums for evaluating ongoing reliability need are the RA and IRP proceedings.[~~163~~168]

In reply, PG&E argues that SB 846 and the Scoping Memo for this proceeding intend the CEC's Draft Cost Comparison Report to be the primary means of assesssing the cost-effectivness and prudence of DCPP extended operations, and recommends the Commission reject any proposal that establishes new evidentiary burdens for PG&E's DCPP Extended Operations Cost Forecast applications.[~~164~~169]

4.4.1. ~~3.4.1.~~ Discussion

This decision finds it is well within the Commission's authority and in ratepayers' best interest to continue to evaluate the reasonableness and prudence of continued DCPP operations, including ongoing evaluation of the

~~159~~164 TURN OB at 5, 20.

~~160~~165 Ex. A4NR-01 at 29; A4NR OB at 8-9.

~~161~~166 Ex. SBUA-02 at 5-10 and 20; SBUA OB at 8-9.

~~162~~167 Ex. GPI-02 at 2-4; GPI OB at 3.

~~163~~168 Ex. GPI-02 at 7-8.

~~164~~169 PG&E RB at 4-6.

cost-effectiveness of extended DCPP operations. In support of this continued evaluation, PG&E is directed to produce a complete and transparent forecast of DCPP operations through 2030 as part of its 2024 DCPP Extended Operations Cost Forecast application. In addition, PG&E's proposal to file a Tier 3 advice letter following the establishment of any conditions as a part of NRC's license renewal process is approved. This decision does not find it necessary, or an efficient use of party and Commission resources, to establish one or more new processes to continue to monitor the reliability need for Diablo Canyon. Further guidance is provided on the scope of issues to be considered as part of any future reasonableness and prudence review of continued DCPP operations.

While it is reasonable for the Commission to consider the CEC's Draft Cost Comparison Report as part of its cost-effectiveness determination, since the CEC's report is required by SB 846, includes an evaluation of DCPP and alternative resource costs, and results in an efficient use of party and Commission resources, it is clear from the record in this proceeding that the CEC's report relies on PG&E's May 2023 cost testimony in this proceeding, and therefore excludes several cost categories associated with actual DCPP extended operations. Given current available information, the CEC's report also does not reflect the costs associated with PG&E's forthcoming license renewal application or any DCISC recommendations concerning seismic safety and deferred maintenance. PG&E does not contest the relevancy of these omitted costs, but merely asserts the CEC is charged with performing the relevant cost-effective analysis.

PG&E's arguments are unpersuasive. Pub. Res. Code Section 25548.3(c)(5)(C) does not require the Commission to rely solely on the CEC's Draft Cost Comparison Report, nor does it require the Commission to make a cost-effectiveness determination by the date of this decision. Further, as explained above, the Commission has broad authority over public utilities,[~~165~~170] and is statutorily required to ensure utility rates associated with DCPP extended operations are just and reasonable.[~~166~~171] Therefore, it is well within the Commission's statutory authority and obligations to continue to evaluate the prudence and cost-effectiveness of continued DCPP operations.

Additionally, we find it in ratepayers' best interest to require PG&E to produce a more comprehensive and transparent forecast of the costs associated with DCPP extended operations for Commission and party review, compared to what has been presented to date in this proceeding. As discussed elsewhere, PG&E's May 2023 cost forecast excludes a variety of cost categories associated with actual extended DCPP operations. While PG&E's DCPP cost forecast is responsive to the direction in the Scoping Memo to consider the potential costs of NRC's conditions of relicensing, and the related conditions in Section 712.8(c)(2)(B), it does not reflect all of the costs associated with DCPP extended operations, and is not an adequate foundation upon which to evaluate the cost-effectiveness of extended DCPP operations. An upfront, transparent forecast of all anticipated DCPP costs through 2030 is also expected to provide a more comprehensive framework to aid parties and the Commission in determining whether the costs included in PG&E's annual DCPP Extended Operations Cost Forecast applications are reasonable and prudent.

[~~165~~170] *San Diego Gas & Electric Co. v. Superior Court*, 13 Cal.4th 893, 915 (1996); *People v. Superior Court,* 62 Cal.2d 515 (1965); *Sale v. Railroad Commission*, 15 Cal.2d 612 (1940); *Kern County Land Co. v. Railroad Com.*, 2 Cal.2d 29 (1934).

[~~166~~171] Section 451.

For all these reasons, PG&E is instructed to provide the following information as part of its 2024 DCPP Extended Operations Cost Forecast application:

1. Updated Diablo Canyon historical and forecast costs (2022-2030), presented using PG&E's existing GRC cost structures. This estimate shall include, or be accompanied by:

    a. All DCPP costs to be recovered from ratepayers over time, in a single analysis, including A&G, uncollectibles, associated taxes, all funds authorized under SB 846, *etc.*[~~167~~172] PG&E argues several GRC cost categories would be allocated $0 using the then-current operational cessation dates at the time of PG&E's 2023 GRC filing.[~~168~~173] We reject PG&E's argument. As described later in this decision, SB 846 allocates broad cost responsibility for extended DCPP operations to ratepayers of all LSEs subject to the Commission's jurisdiction, with corresponding funding that should be incremental to, and outside the scope of, PG&E's 2023 GRC. As such, it is reasonable for PG&E to include, in a single forecast analysis, any and all costs PG&E expects to be recovered from utility ratepayers for DCPP extended operations.

    b. Costs associated with PG&E's 2023 license renewal application to the NRC, any DCISC recommendations on seismic safety upgrades or deferred maintenance, as well as any costs associated with NRC's conditions of license renewal. Costs associated with DCISC recommendations or NRC's conditions of license renewal shall only be included to the extent there are *actual* recommendations and conditions from the DCISC and NRC.

~~167~~172 *See* TURN OB at 7-15.

~~168~~173 Ex. PG&E-04 at 1-5 through 1-6.

c. Any government-funded transition costs. Since these costs will not be recovered from utility ratepayers, they are outside the Commission's purview and general mandate to ensure just and reasonable rates,~~[169]~~[174] and therefore will not be considered 'costs' as part of any cost-effectiveness evaluation considered by the Commission; however, since costs that are not recovered through government funding streams may be borne by utility ratepayers, these transition costs should be clearly identified in PG&E's DCPP cost forecast.

d. A transparent comparison or walk-through between PG&E's cost forecast and the EUCG cost forecast presented in this proceeding. While we recognize the cost accounting formats may not perfectly align, PG&E shall present, to the best of its ability, clear information that can be used to understand and assess the evolving cost forecasts.

2. A copy of the CEC's final Cost Comparison Report.

a. While PG&E has the burden of proof in demonstrating all DCPP extended operation forecast costs, as identified above, are just and reasonable, PG&E shall not be held responsible for the conclusions and analysis developed by the CEC. Rather, the purpose of providing this report is to aid parties and the Commission in any cost-effectiveness evaluation of DCPP extended operations, which is reasonable given the additional cost forecast information above as well as the limited opportunity afforded for parties to comment on the CEC's report as part of this proceeding.

In addition to the above, we adopt PG&E's proposal to file a Tier 3 advice letter, following the establishment of any conditions as part of the NRC's license renewal process, to make a recommendation whether it is prudent, cost-effective, and beneficial to customers to incur the cost to support continued operations.

~~[169]~~[174] Section 451.

PG&E's proposal appears to be consistent with Section 712.8(k). Further, since PG&E indicates the conditions of NRC's license renewal will not be available until at least 2025,[~~170~~175] we find PG&E's proposal would allow for the timely consideration of any new and emergent information. Since the DCISC is expected to have access to PG&E's license renewal application to the NRC, as well as PG&E's reports/assessments on seismic safety[~~171~~176] and deferred maintenance at Diablo Canyon, by the end of 2023, we anticipate many of the DCISC's recommendations concerning seismic safety and deferred maintenance may be available by the DCISC's next public meeting on February 21 and 22, 2024. As a result, it is reasonable and timely to consider any costs associated with the DCISC's recommendations as part of PG&E's 2024 DCPP Extended Operations Cost Forecast application, rather than a separate advice letter filing. Further, since any recommendations by the DCISC are expected to help inform whether PG&E's 2024 DCPP Extended Operations Cost Forecast application contains activities and associated costs that are reasonable and needed,[~~172~~177] PG&E shall ensure the DCISC has all the information it needs to make timely and informed recommendations.

Given the adopted cost reporting processes above, we do not find it necessary to adopt an additional monthly reporting process modeled on the cost repair reports required in I.12-10-013. Further, we decline to adopt GPI's recommended 10 percent cost increase threshold for applying enhanced scrutiny to DCPP extended operation costs since, as noted by TURN, it is not clear what standard would be used to distinguish between capital and operations and

[~~170~~175] PG&E OB at 8.

[~~171~~176] Pub. Res. Code Section 25548.3(c)(13).

[~~172~~177] Section 712.8(h)(1).

maintenance spending, while GPI provides no compelling rationale for applying a 10 percent threshold.[~~173~~178]

Additionally, this decision does not adopt a process to continually monitor the reliability need for extended DCPP operations. As noted by parties, ongoing long-term system reliability needs are already considered and addressed through the Commission's IRP proceeding (R.20-05-003),[~~174~~179] and no party specifically advocated for a new process to monitor the reliability need for ongoing DCPP operations. Moreover, as discussed elsewhere in this decision, the evidence presented in this proceeding is consistent with previous Commission findings that the "electric system is much closer to a supply and demand balance than is comfortable for reliability purposes,"[~~175~~180] while the specific requirements in SB 846 — including the requirement that new renewable and zero-carbon resources be interconnected by the end of 2023,[~~176~~181] as well as the exclusion of Diablo Canyon in IRP portfolios, resource stacks, or PSPs[~~177~~182] — suggest that the Legislature did not intend for the Commission to continually re-evaluate the reliability need for Diablo Canyon.

Concerning the reasonableness and prudency of extended DCPP operations, we further clarify that any subsequent review by the Commission shall focus on new or updated information~~as well as arguments not previously considered in this proceeding~~. This may include, for example, updated and more complete DCPP forecast cost information, the cost-effectiveness of DCPP

[~~173~~178] TURN RB at 11.

[~~174~~179] Ex. CalPA-02 at 17; Ex. GPI-02 at 7-8.

[~~175~~180] D.23-02-040 at 25.

[~~176~~181] Section 712.8(c)(2)(D).

[~~177~~182] Section 454.52(f)(1).

extended operations, as well as any recommendations from the DCISC or conditions of NRC's license renewal. ~~It would not be an efficient use of Commission or party resources to revisit the prudency arguments already considered in this proceeding, including the various arguments presented by SLOMFP.~~ Further, this Commission will not consider nuclear safety issues under the purview of the NRC. Lastly, and for the reasons explained above, this Commission will not revisit issues concerning the electric system reliability need for Diablo Canyon.

4.5. ~~3.5.~~ Length of Time for an Orderly Shutdown and Recovery of Outstanding Costs and Fees

In the event the Commission establishes retirement dates earlier than 2029 (Unit 1) and 2030 (Unit 2), SB 846 provides the Commission shall provide sufficient time for an orderly shutdown of Diablo Canyon and authorize recovery of any outstanding uncollected costs and fees.[~~178~~183]

PG&E identified the following activities to support an orderly shutdown of Diablo Canyon: (1) ramp down and offload of spent fuel from the reactor vessel to the spent fuel pools; (2) severance to de-fueled technical specification staffing requirements; (3) retraining and redeployment programs for employees; and (4) termination of ongoing contracts. PG&E indicates these activities would occur in parallel with a duration of approximately six months.

Concerning the recovery of uncollected fees, PG&E states the timing will vary depending upon the status of activities at the time Diablo Canyon is shutdown. Further, PG&E highlights the potential for increased costs if newly

[~~178~~183] Sections 712.8(c)(2)(B)-(D).

established retirement dates are revised after a final Commission decision in this proceeding.[~~179~~184]

Many parties defer to PG&E on this issue, or otherwise don't provide a specific recommendation. A4NR generally supports PG&E's identified actions and associated six-month estimate for an orderly shutdown of Diablo Canyon. A4NR urges the Commission to "carefully shape its actions on retirement dates to maximize the ongoing value of the $109.4 million PG&E ratepayers have already invested in decommissioning planning," while maintaining flexibility for future incremental adjustments, if needed.[~~180~~185] Additionally, A4NR notes the Commission's ability to authorize recovery of any outstanding uncollected costs and fees would not be affected by its determination of sufficient time for orderly shutdown.[~~181~~186] GPI recommends PG&E's planning process for Diablo Canyon include provisions for a more rapid shutdown in case earlier retirement dates are issued.[~~182~~187]

4.5.1. ~~3.5.1.~~ Discussion

We generally find PG&E's six-month estimate for an orderly shutdown of Diablo Canyon to be reasonable, but agree with A4NR that some additional adjustments may be warranted in the future. In the event PG&E proposes to shutdown Diablo Canyon earlier than October 31, 2029 (Unit 1) and October 31, 2030 (Unit 2), based upon the criteria set forth in Section 712.8(k), or on any of the additional review processes and requirements set forth in SB 846 and this

[~~179~~184] Ex. PG&E-03 at 18-19.

[~~180~~185] A4NR OB at 7-8.

[~~181~~186] Ex. A4NR-01 at 26-27.

[~~182~~187] Ex. GPI-02 at 7.

decision, PG&E shall explain whether there are any deviations from its six-month estimate in this proceeding and why.

There is no need to establish further guidance at this time concerning the recovery of outstanding costs and fees. As noted by parties, the ability to recover outstanding uncollected costs and fees is not affected by the time needed for an orderly shutdown at DCPP, and there are cost recovery mechanisms and processes in place (including those established by this decision) that will allow for further consideration and recovery of any outstanding uncollected costs and fees.

5. ~~4.~~ Eligible Diablo Canyon Nuclear Power Plant Extended Operations Costs and Applicability to Non-Pacific Gas and Electric Company Customers

As a threshold matter, this decision addresses the interactions between Section 712.8(c)(4) and Section 712.8(l)(1) as they relate to the allocation of costs related to extended operations at DCPP. Subsection (c)(4) states:

> Except as authorized by this section, customers of load-serving entities shall have no other financial responsibility for the costs of the extended operations of the Diablo Canyon powerplant. In no event shall load-serving entities other than the operator and their customers have any liability for the operations of the Diablo Canyon powerplant.

While Subsection (l)(1) states:

> Any costs the commission authorizes the operator to recover in rates under this section shall be recovered on a fully nonbypassable basis from customers of all load-serving entities subject to the commission's jurisdiction, as determined by the commission, except as otherwise provided in this section. The recovery of these nonbypassable costs by the load-serving entities shall be based on each customer's gross consumption of electricity regardless of a customer's net metering status or purchase of electric energy and service from an electric service provider, community choice

aggregator, or other third-party source of electric energy or electricity service.

This decision concludes that the intent of the Legislature was to assign broad responsibility for the costs of extended operations of DCPP to ratepayers of all LSEs subject to the Commission's jurisdiction, as outlined in Section 712.8(l)(1). However, certain costs are only to be paid by PG&E ratepayers. All of these costs and their responsible payers are defined in Section 712.8, and are set out in the table below.

Pub. Util. Code Section 712.8	Cost	Payer
Subsection (f)(1)	Reasonable costs incurred to prepare for the retirement of Diablo Canyon Unit 1 and Unit 2.	PG&E ratepayers — bundled and unbundled — via a non-bypassable charge (NBC).
Subsection (f)(1)	Any reasonable additional costs associated with decommissioning planning resulting from the license renewal applications or license renewals.	Ratepayers of all LSEs subject to the Commission's jurisdiction — via an NBC.
Subsection (f)(2)	Funding for the employee retention program approved in D.18-11-024, as modified to incorporate 2024, 2025, and additional years of extended operations, on an ongoing basis until the end of operations of both units.	Not specified in subsection (f)(2), so presumed to be ratepayers of all LSEs subject to the Commission's jurisdiction — via an NBC — per subsection (l)(1).
Subsection (f)(4)	Reasonable costs incurred to prepare for, respond to, provide information to, or otherwise participate in or engage the independent peer review panel under Section 712.	Not specified in subsection (f)(4), so presumed to be ratepayers of all LSEs subject to the Commission's jurisdiction — via an NBC — per subsection (l)(1).
Subsection (f)(5)	Payment in lieu of a rate-based	$6.50 (2022 dollars) per MWh

Pub. Util. Code Section 712.8	Cost	Payer
	return on investment (volumetric).	to be paid by PG&E ratepayers – bundled and unbundled – via an NBC. Plus $6.50 (2022 dollars) per MWh to be paid by ratepayers of all LSEs subject to the Commission's jurisdiction (including PG&E's bundled and unbundled ratepayers) – via an NBC.
Subsection (f)(6)(A)	Payment in lieu of a rate-based return on investment in acknowledgment of the greater risk of outages in an older plant (lump sum).	Not specified in subsection (f)(6)(A), so presumed to be ratepayers of all LSEs subject to the Commission's jurisdiction – via an NBC – per subsection (l)(1).
Subsection (g)	Diablo Canyon Extended Operations liquidated damages balancing account.	Ratepayers of all LSEs subject to the Commission's jurisdiction – via an NBC.[~~183~~188]
Subsection (h)(1)	All reasonable costs and expenses necessary to operate Diablo Canyon Unit 1 and Unit 2 beyond the current expiration dates, including those in subsections (f) and (g), net of market revenues for those operations and any	Not specified in subsection (h)(1), so presumed to be ratepayers of all LSEs subject to the Commission's jurisdiction – via an NBC – per subsection (l)(1).

[~~183~~188] While subsection (g) does not refer to the customers of all LSEs by name, it states that these costs shall be recovered "as part of the charge under paragraph (1) of subdivision (l)" which is the subsection that assigns cost responsibility via an NBC to the customers of all LSEs.

Pub. Util. Code Section 712.8	Cost	Payer
	production tax credits of the operator.	
Subsection (h)(2)	Any significant one-time capital expenditures during the extended operation period amortized over more than one year for the purpose of reducing rate volatility.	Not specified in subsection (h)(2), so presumed to be ratepayers of all LSEs subject to the Commission's jurisdiction — via an NBC — per subsection (l)(1).
Subsection (i)(1)	Reasonable replacement power costs, if incurred, associated with Diablo Canyon powerplant unplanned outage periods.	Not specified in subsection (i)(1), so presumed to be ratepayers of all LSEs subject to the Commission's jurisdiction — via an NBC — per subsection (l)(1).

This decision finds Section 712.8(c)(4)[~~184~~189] does not forbid allocation of the eligible costs listed above to all LSEs subject to the Commission's jurisdiction. This decision holds that the clause in subsection (c)(4) that states "[e]xcept as authorized by this section" refers to the broad cost allocation authority granted to the Commission by Section 712.8(l)(1), and therefore grants the Commission discretion to allocate many of the costs related to DCPP extended operations to the customers of all LSEs.

Furthermore, this decision finds the language of Section 712.8(l)(1) that states "except as otherwise provided in this section" does not refer to the general prohibition on cost recovery from ratepayers outlined in Section 712.8(c)(4), as this interpretation would lead to an absurd result where each exception clause

[~~184~~189] Section 712.8(c)(4) states: "Except as authorized by this section, customers of load-serving entities shall have no other financial responsibility for the costs of the extended operations of the Diablo Canyon powerplant."

negates the other. It is this decision's holding that the general prohibition on cost recovery from ratepayers outlined in Section 712.8(c)(4) is meant to apply to costs outside of those delineated in Section 712.8, as the prohibitionary language applies to "other financial responsibility for the costs of the extended operations of the Diablo Canyon powerplant" (emphasis added). For example, such excluded costs could include the tax payments due on lump sum performance payments highlighted by TURN.[~~185~~190]

For all of these reasons, this decision holds that it is the intent of the Legislature to allocate the costs for DCPP extended operations described in Section 712.8 among all the ratepayers of all LSEs subject to the Commission's jurisdiction.

6. ~~5.~~ Cost Allocation

As this decision determines that many of the costs of DCPP extended operations should be allocated among ratepayers of LSEs subject to the Commission's jurisdiction, it is necessary to determine how to allocate those costs among the various LSEs. Parties proposed two distinct approaches.

PG&E proposes a simple method, whereby all eligible costs not specific to PG&E customers be recovered through an equal-per-kilowatt-hour (kWh) rate from all LSE customers. Bundled and unbundled customers in PG&E's service area would pay an additional adder to recover the PG&E-specific Volumetric Performance Fee expense (*i.e.*, the additional \$6.50/MWh fee charged only to PG&E's bundled and unbundled ratepayers, as defined in Section 712.8(f)(5)). Implicitly, PG&E's approach does not allow for any differential allocation of costs among the utilities;[~~186~~191] it simply takes the total amount of electricity sales

[~~185~~190] *See* TURN OB at 9.

[~~186~~191] As used in this decision, utilities broadly refer to PG&E, SCE, SDG&E, Bear Valley, PacifiCorp, and Liberty. The investor-owned utilities (IOUs) refer to PG&E, SCE, and SDG&E,

in kWh among all LSEs and divides the annual cost of DCPP extended operations by that figure. SCE supports PG&E's approach, noting its simplicity and transparency.[~~187~~192]

In contrast, CalCCA recommends each utility territory be assigned a share of DCPP costs based on each utility's contribution to the total utility 12-month coincident peak. This would allow for differential cost allocation depending on how "peaky" the utility's customers are relative to other utilities. CalCCA believes the annual costs of extended operations at DCPP and the share of each utility based on 12-month coincident peak should be calculated in a stand-alone proceeding initiated by PG&E every year. The Commission's decision in the proceeding would calculate a $/kWh charge to be collected from the ratepayers of each LSE based on that utility's share of the 12-month coincident peak among all the utilities.[~~188~~193] AReM/DACC agree with CalCCA's proposal.[~~189~~194]

SCE objects to CalCCA's proposal, arguing it would be unworkable to attempt to differentially allocate costs among all the utilities each year, and may create customer confusion if a volumetric charge for DCPP is higher in some utility territories than in others.[~~190~~195] PG&E also opposes the 12-month coincident peak revenue allocation model, arguing that because DCPP is a baseload plant that runs at the same power level 24 hours per day, it would not comport with cost causation principles to apply more of the DCPP extended operations costs to

PacifiCorp, and Liberty. The investor-owned utilities (IOUs) refer to PG&E, SCE, and SDG&E, while the SMJUs refer to Bear Valley, Liberty, and PacifiCorp.

~~187~~192 Ex. SCE-02 at 12.

~~188~~193 Ex. CalCCA-02 at 2.

~~189~~194 Ex. AREM-02 at 9.

~~190~~195 Ex. SCE-02 at 12.

those customers (or utilities) with more peak demand.[~~191~~196] For its part, SDG&E objects to the CalCCA proposal as well, arguing the coincident peak allocation process would be inefficient and unnecessary. SDG&E believes the extension of DCPP operations was a "legislatively mandated policy that benefits customers statewide," and therefore a simple volumetric NBC that has the same price statewide would be a fair and equitable way to allocate and collect costs.[~~192~~197]

PG&E presents the view that cost allocation principles can be divorced from the methods used for benefit allocation. PG&E states "[a]llocation of benefits, if any, should not drive the rate design in the case of the [DCPP extended operations] NBC, particularly when benefit allocation is not the reason extended operations of DCPP is being considered. It is not necessary for rate design to align with the benefit allocation if one is adopted. Instead, rate design should be established independent of any benefit allocation."[~~193~~198] CalCCA disagrees, stating:

> [C]osts and benefits of DCPP extended operation should flow to customers as consistently as possible. Following the existing [Cost Allocation Mechanism] framework, DCPP's RA capacity would be allocated to LSEs based on their respective contribution to the monthly coincident peak demand. To be consistent, DCPP's net costs should also be allocated based on the coincident peak demand in each IOU service territory. Each IOU would then be responsible to calculate and implement the DCPP NBC as a delivery charge to customers of all LSEs in its service territory and remit the proceeds to PG&E. Due to differences in customer usage in unique IOU

[~~191~~196] Ex. PG&E-02 at 2-3.

[~~192~~197] Ex. SDG&E-02 at GM-3.

[~~193~~198] Ex. PG&E-02 at 2-6.

service territories, the allocated net costs and recovery from customers should be tracked separately for each IOU.[~~194~~199]

The SMJUs offer the view that extended operations of DCPP will provide minimal benefits, if any, to the SMJUs, and therefore customers of the SMJUs should be allocated less costs than other California LSEs that are more likely to benefit from the continued operation of DCPP.[~~195~~200] They argue such treatment would be consistent with statute, as "nothing in Section 712.8(l)(1) requires the Commission to apply identical rates for DCPP extension costs to all LSEs and nothing restricts the Commission from adjusting how costs are allocated to different LSEs."[~~196~~201]

The SMJUs reason that they are entitled to a lower share of the DCPP costs because Liberty and PacifiCorp operate outside the CAISO, and Bear Valley only has limited connections to the CAISO, meaning that the reliability of CAISO's system is essentially irrelevant for these utilities. Further, the SMJUs assert they are "winter-peaking" utilities and therefore extended operations of the CAISO-located DCPP are unlikely to benefit the SMJUs from either a reliability or a GHG reduction perspective.[~~197~~202]

6.1. ~~5.1.~~ Discussion

As stated by PG&E, "the public policy underlying the extended operations at Diablo Canyon must be considered when developing a rational rate design proposal. Diablo Canyon's extended operation costs are being incurred over a multi-year period (2025 to 2030) to ensure the State can seamlessly transition its

[~~194~~199] Ex. CalCCA-02 at 17.

[~~195~~200] Ex. SMJU-01 at 8.

[~~196~~201] *Id.* at 9.

[~~197~~202] *Id.* at 10.

generation supply portfolio to GHG-free energy without compromising system reliability."[~~198~~][203] This decision concurs with PG&E that the Commission should look toward public policy and the Legislature's intent to settle the question of cost allocation, but disagrees with PG&E's application of it. Given that ensuring system reliability is a key legislative rationale for the billions of ratepayer dollars that may be spent to keep DCPP operating, it follows that allocating the costs of those extended operations based on an IOU's share of a 12-month coincident peak load is fair and equitable.[~~199~~][204]

PG&E argues the baseload nature of DCPP makes the use of a peak-based cost allocation contradictory with the principles of cost causation. While ordinarily PG&E would be correct, this is an exceptional case where the Legislature believes DCPP is of utmost importance to maintaining *system reliability*,[~~200~~][205] which is highly correlated with coincident peak (and net peak) demand, not with energy consumption. This decision has previously addressed the question of whether DCPP is necessary to ensure system reliability and will not revisit that discussion here. What matters is that the Legislature determined that DCPP extended operations are necessary to address reliability, and this decision therefore finds that it should allocate the statutorily defined costs of DCPP extended operations among the three large electrical corporations (*i.e.*, PG&E, SCE, and SDG&E) using the 12-month coincident demand methodology

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[~~198~~][203] Ex. PG&E-02 at 2-6 and 2-7.

[~~199~~][204] *See* Ex. AREM-02 at 10 ("[b]y not reflecting the underlying fact that the operating life of the DCPP is being extended because of the reliable capacity it provides, [PG&E's] equal-cents rate design is neither fair nor equitable. Rate design should, to the extent possible, reflect cost causation. The CalCCA proposal does this while PG&E's does not").

[~~200~~][205] SB 846, Section 18 (finding that DCPP extended operations are necessary to ensure "electrical reliability in the California electrical system").

as proposed by CalCCA. The three large electrical corporations shall collectively do so in each of PG&E's annual DCPP Extended Operations Cost Forecast application proceedings. The IOUs may use public load data to determine each electrical corporation's share of 12-month coincident peak demand.

The process for allocating these eligible costs to the LSEs *within* each IOU's territory should ~~use~~mirror the Cost Allocation Mechanism (CAM), as recommended by CalCCA and others. The CAM was established by the Commission in D.06-07-029, where the Commission designated each IOU to procure new generation capacity in its own territory, with the costs and benefits allocated to all customers in the territory (including bundled and unbundled customers). The CAM was further expanded and refined in decisions subsequent to D.06-07-029.~~[201]~~[206] Use of ~~the~~a process that mirrors CAM also aligns well with cost allocation among IOUs based on their share of 12-month peak coincident demand. When establishing the CAM, the Commission determined that "[a]ll RA counting benefits and net costs are spread to the LSEs whose customers are allocated costs based on [their] share of 12-month coincident peak, adjusted on a monthly basis to facilitate load migration. The contract costs paid and RA benefits received by [departed load] and bundled customers should be based on a share basis equal to the credit share received."~~[202]~~[207]

~~[201]~~[206] Generally, once a CAM resource becomes operational (or the contract start date begins), LSEs in the IOU's service territory are allocated capacity allocations which are applied towards meeting the LSE's resource adequacy requirements. These allocations are done annually and quarterly and are based on each LSE's load ratio share. Costs are allocated directly to the LSE's customers through the IOU's distribution charge. Customers pay only for the net cost of the capacity, determined as the net of the total cost of the contract less the energy revenues associated with dispatch of the contract.

~~[202]~~[207] D.06-07-029 at 31.

Because LSEs are familiar with the CAM and it is a proven mechanism for allocating costs among the LSEs in a large electrical corporation's territory, it is reasonable to use a process that mirrors the CAM process to allocate DCPP extended operations costs within each IOU's territory. Each large electrical corporation shall ~~use~~mirror the CAM process, as defined in D.06-07-029 and subsequent decisions, to allocate its own share of the DCPP extended operations costs to LSEs in its territory.

This decision further holds that Bear Valley, Liberty, and PacifiCorp should be allocated DCPP costs differently than the large electrical utilities. While the majority of California LSEs are summer-peaking, the SMJUs are winter-peaking utilities and face different reliability concerns and requirements. Given their locations and winter-peaking nature, CAISO-centric reliability concerns do not present the same challenges for the SMJUs as they do for most California LSEs. Indeed, in the Commission's proceeding to ensure reliable electric service and address extreme weather events, R.20-11-003, none of the SMJUs were required to undertake additional procurement or adopt any supply- or demand-side requirements given their unique positions. Similarly, in the Commission's IRP proceedings, R.16-02-007 and R.20-05-003, none of the SMJUs were subjected to procurement requirements ordered to address reliability concerns.[~~203~~208]

Because statute grants no discretion as to whether Bear Valley, Liberty, and PacifiCorp customers should contribute to eligible DCPP costs, these three utilities must be assigned some share of the costs, even if they do not benefit from extended operations at DCPP. However, in light of the historic differential

[~~203~~208] *See* D.19-11-016, D.20-12-044, D.21-06-035, and D.23-02-040.

treatment received by the SMJUs with respect to reliability and planning requirements, the fact that an additional reliability resource within CAISO offers little benefits to these utilities, and in order to promote equity and fairness, this decision finds that Bear Valley, Liberty, and PacifiCorp should each be allocated a nominal $10,000 in eligible DCPP extended operations revenue responsibility in each year such revenues are allocated among the LSEs subject to the Commission's jurisdiction. This total amount of $30,000 shall be deducted from the total revenue responsibility that would otherwise be assigned to PG&E ratepayers. Each year that DCPP extended operations costs are collected from PG&E ratepayers, Bear Valley, Liberty, and PacifiCorp shall each collect $10,000 through a non-bypassable, equal-cents-per-kWh charge and remit the collected amount to PG&E on an annual basis. This decision agrees with the SMJUs that Section 712.8(l)(1) grants the Commission discretion to allocate DCPP extended operations costs amongst the LSEs as it sees fit, including as outlined above.[~~204~~209]

7. ~~6.~~ Benefit Allocation

Potentially billions of dollars in costs may be accrued for extended operations at DCPP, and those costs should be allocated to the utilities and other LSEs as described above. However, there are also benefits that accrue from extended operations; this section of the decision discusses how to allocate those benefits across the LSEs.

7.1. ~~6.1.~~ Resource Adequacy Benefits

In its opening testimony, AReM/DACC argue the Commission should allocate the RA benefits associated with DCPP extension in the same way that the current CAM capacity is allocated. Specifically, AReM/DACC believe that

[~~204~~209] SMJU OB at 6-7.

because DCPP provides for reliability, and in light of the fact that DCPP is currently a source of net qualifying capacity for the RA market, it should be treated as an RA resource allocated to LSEs using existing mechanisms. Language in SB 846 forbidding the use of DCPP for IRP processes should not, in AReM/DACC's view, be used to prevent DCPP from being utilized for RA purposes.[~~205~~210] Furthermore, AReM/DACC argue that allocating the RA benefits of DCPP to LSEs does not relieve LSEs of their respective capacity procurement requirements per Commission orders.

CalCCA supports this position and argues the allocation of RA benefits to LSE customers paying for DCPP extended operations is a matter of equity. CalCCA estimates payments to PG&E for DCPP extended operations will more than double the existing ratebase payments to PG&E shareholders, and argues it would be unfair to impose these costs on all LSE customers "without realizing the corresponding benefits of the plant's extended operation."[~~206~~211] CalCCA believes those benefits should be distributed to each LSE to lower the LSE's rates generally and provide benefits to customers paying for DCPP's extended operations.[~~207~~212]

PG&E opposes the allocation of RA benefits to LSEs, arguing it would be counter to the intent and direction of SB 846. Specifically, PG&E believes the statute's prohibition of utilizing DCPP attributes for IRP purposes, and its focus on promoting reliability, means that RA benefits should not be allocated. PG&E reasons that by denying the allocation of RA benefits, other LSEs would be incentivized to continue robust RA procurement and thereby enhance system

[~~205~~210] Ex. AREM-01 at 2-3.

[~~206~~211] Ex. CalCCA-01 at 5.

[~~207~~212] *Id*. at 3-4.

reliability.[~~208~~213] PG&E's testimony clarifies that it did not believe RA benefits should be allocated to any LSE, including PG&E itself.[~~209~~214] WEM also opposes the allocation of RA benefits, similarly claiming it is contrary to statute.[~~210~~215]

CalCCA disagrees with these positions in rebuttal testimony, as did AReM/DACC, arguing that SB 846 only prohibits the allocation of RA benefits for IRP purposes (which is a long-term planning process) and not for the separate purpose of meeting RA capacity obligations (which is designed to ensure grid reliability in the near-term).[~~211~~216] Furthermore, AReM/DACC argue that allocating the RA benefits of DCPP to LSEs would not disincentivize LSE procurement of additional resources, noting "[i]Incremental procurement being performed by LSEs are for resources with on-line dates many years in the future and based on direction in the IRP which already does not count Diablo; [and] those decisions are not impacted by the determination of if Diablo's RA can be counted in the near-term."[~~212~~217]

It its rebuttal testimony, SCE argues the Commission should allocate the RA benefits of extended Diablo Canyon operations to the customers of all LSEs that pay for extended operations. SCE reasons it is reasonable to do so "to ensure that customers receive the value they are paying for and to minimize the substantial costs of extended operations."[~~213~~218] For support, SCE cites to the language of SB 846, claiming that Section 712.8(q) grants the Commission

[~~208~~213] Ex. PG&E-01 at 5-1 to 5-2.

[~~209~~214] *Id*. at 5-2.

[~~210~~215] Ex. WEM-01 at 2-3.

[~~211~~216] Ex. AREM-02 at 3.

[~~212~~217] *Id*. at 7.

[~~213~~218] Ex. SCE-02 at 1.

authority to allocate benefits or attributes generally from Diablo Canyon's extended operations while Sections 454.52(f)(1)-(2) specifically exclude the allocation of certain elements of Diablo Canyon's attributes to LSEs. SCE reasons that, since RA benefits are not included in the list of attributes specifically excluded from allocation, such benefits should be included in the general authority to allocate benefits granted to the Commission by statute.[~~214~~][219]

SCE and PG&E disagree as to whether the allocation of Diablo Canyon RA benefits to LSEs will reduce the incentives for those LSEs to build out or procure needed RA resources. SCE asserts that allocating RA benefits "will minimize LSEs' short-term RA procurement costs and provide rate relief to customers as new resources are being developed and brought online and help address any delays in bringing new ordered resources online…"[~~215~~][220] AReM/DACC also disagree with PG&E's conclusions, arguing statute only prohibits DCPP RA attributes from being used for IRP purposes instead of prohibiting their use in the RA market.[~~216~~][221]

Finally, SCE suggests allocating RA benefits to the paying LSEs will provide relief to ratepayers that will be asked to pay for the "substantial" costs of extended operations at Diablo Canyon.[~~217~~][222]

Functionally, SCE believes the Commission should allocate the RA benefits associated with extended operations at DCPP in the same way the Commission

[~~214~~][219] *Id.* at 4-5 ("[t]he Legislature expressly excluded counting [Diablo Canyon] attributes in the IRP process during extended operations and could have easily done the same for RA compliance and power content labeling").

[~~215~~][220] Ex. SCE-02 at 6.

[~~216~~][221] Ex. AREM-01 at 2.

[~~217~~][222] Ex. SCE-02 at 8.

currently allocates the benefits of CAM resources among LSEs.[~~218~~223] Cal Advocates takes a different position, arguing RA benefits should be allocated to paying LSEs in proportion to their share of Diablo Canyon extension costs.[~~219~~224]

The SMJUs point out that two of their members — Liberty and PacifiCorp — are currently not subject to RA requirements or other CAISO reliability requirements. While Bear Valley is located within the CAISO, it has no direct interties to a CAISO bus bar, but rather is served via SCE's system. None of the SMJUs are subject to Commission RA requirements.[~~220~~225] In the Commission's proceeding to ensure reliable electric service and address extreme weather events, R.20-11-003, none of the SMJUs were required to undertake additional procurement or adopt any supply- or demand-side requirements given their unique positions. Similarly, in the Commission's IRP proceedings, R.16-02-007 and R.20-05-003, none of the SMJUs were subjected to procurement requirements ordered to address reliability concerns.[~~221~~226] The SMJUs ultimately argue that "continued operation of DCPP is unlikely to provide benefits to customers of the SMJUs."[~~222~~227]

7.1.1. ~~6.1.1.~~ Discussion

It is fair and reasonable to allocate RA benefits to the large electrical corporations in the same manner that eligible costs for extended operations at DCPP are allocated to them (*i.e.*, by each large electrical corporation's share of 12-month coincident peak demand). As outlined above, RA benefits constitute a

~~218~~223 *Ibid*.

~~219~~224 Ex. CalPA-01 at 5.

~~220~~225 Ex. CASMU-01 at 5-6, while also noting that "[Bear Valley] complies with CAISO RA and reliability requirements."

~~221~~226 *Id*. at 6.

~~222~~227 *Id*. at 7.

substantial financial value and are already attributed to DCPP operations. Those ratepayers that are paying for extended operations at DCPP should, as a matter of equity, realize the financial benefits of those extended operations, and those benefits should be distributed to each utility in the same manner of DCPP extended operations costs. Regarding PG&E's arguments that the intent and language of SB 846 do not provide for RA benefit allocation, this decision disagrees. No language in SB 846 forbids the allocation of RA benefits to LSEs. The language cited by PG&E regards the use of DCPP attributes for IRP purposes, but that is not the same thing as allocating the RA compliance benefits of DCPP extended operations.[~~223~~228] SB 846 authorizes the Commission to "allocate any benefits or attributes from extended operations of the Diablo Canyon powerplant,"[~~224~~229] and this decision concludes that this includes the RA benefits of DCPP extended operations.

Furthermore, in response to party arguments that allocating RA benefits may unduly influence the RA market, it should be noted the implementation track of the (now closed) RA proceeding increased the RA-related PRM to 17 percent, "[g]iven the realities of available RA supply and persistent delays in development projects decision…."[~~225~~230] This decision recognizes that extending the RA credits for a 2,300 MW resource such as DCPP may have impacts on the RA market and, potentially, the PRM established for LSEs in a future RA proceeding, and that the extension of DCPP and the availability of these RA

[~~223~~228] *See* AReM/DACC OB at 3-4 ("The language of SB 846 prevents DCPP extension period attributes from being used in three circumstances: (1) integrated resources plans, (2) preferred system plans, and (3) resource stacks. RA compliance does not belong to any of these three categories").

[~~224~~229] Section 712.8(q).

[~~225~~230] D.23-06-029, Finding of Fact 4.

credits in the RA market may help inform PRM decisions in future RA proceedings. On the other hand, this decision also notes that recognizing the availability of DCPP for RA and PRM purposes will have no impact on the IRP proceeding in which the planning for and ordering of new resources takes place, as that proceeding is prohibited by statute from including DCPP as an existing resource.

As with the cost allocation discussion above, Bear Valley, Liberty, and PacifiCorp are afforded special treatment with respect to RA benefit allocations. Because Bear Valley, Liberty, and PacifiCorp are not required by the Commission to procure RA capacity, it would be nonsensical to allocate RA capacity to them. However, Bear Valley, Liberty, and PacifiCorp are each required to contribute $10,000 toward the costs of extended operations at DCPP, and because the allocation of RA attributes and their benefits to LSEs is grounded in the equity of affording benefits of extended operations at DCPP to those LSEs that pay for the costs of extended operations, it is equitable that Bear Valley, Liberty, and PacifiCorp receive an equivalent amount of financial benefits from the RA attributes related to extended operations at DCPP.

Therefore, PG&E shall ensure on an annual basis that $30,000 in financial benefits from PG&E's portion of the RA attributes of extended operations at DCPP are set aside for Bear Valley, Liberty, and PacifiCorp. PG&E shall distribute $10,000 annually to each of Bear Valley, Liberty, and PacifiCorp in consideration of the RA attributes they would have received for DCPP extended operations had they been required by the Commission to procure RA capacity. Bear Valley, Liberty, and PacifiCorp shall credit these funds to their ratepayers using the same rate element used to collect their allocated portion of the costs of extended operations at DCPP. This approach is consistent with CalCCA's proposal that RA benefits for SMJUs be accounted for by "apply[ing] the value of SMJUs' allocated portion of DCPP RA as a credit against their allocated share of DCPP net costs…."[~~226~~231]

7.2. ~~6.2.~~ Using the Cost Allocation Mechanism to Allocate Resource Adequacy Benefits

Once RA benefits are allocated to each large electrical corporation on the basis of 12-month coincident peak demand, it is necessary to allocate the RA capacity among each large electrical corporation's LSEs. Several of the parties supporting the allocation of RA benefits to LSEs argue that the Commission should utilize the CAM in allocating those benefits, just as this decision determines should be done for the costs of extended operations at DCPP. Even PG&E grants that, if the Commission were to allocate RA benefits to LSE, then it should use "existing Commission processes" to do so while not naming the CAM specifically.[~~227~~232]

The CAM was established by the Commission in D.06-07-029, where the Commission designated each large electrical corporation to procure new generation capacity in its own territory, with the costs and benefits allocated to all customers in the territory (including bundled and unbundled customers). The LSEs in the large electrical corporation's service territory are allocated rights to the capacity, which can in turn be applied toward each LSE's RA capacity requirements. All customers pay for the net cost of this capacity (*i.e.*, the cost of procurement minus the revenue collected from selling energy and ancillary services) through an NBC. All RA benefits are allocated to the LSEs based on their share of 12-month coincident peak.

[~~226~~231] Ex. CalCCA-02 at 12.

[~~227~~232] Ex. PG&E-01 at 5-3.

The CAM is a proven system that LSEs currently use and understand. Allocating DCPP-related RA benefits using a process that mirrors the CAM process would therefore be efficient and require the least amount of new program design. While agreeing that RA benefits should be allocated to LSEs, CalCCA and AReM/DACC disagree as to how exactly the RA attributes of DCPP extended operations should be allocated. AReM/DACC advocate for the fungible RA capacity itself to be allocated to the LSEs, while CalCCA believes DCPP extended operations should be treated as a load decrement for LSEs to use against their RA compliance obligations. CalCCA argues that treating the RA benefit allocated to LSE as a load decrement is more efficient and would eliminate the need for a new contracting process. In order to make RA benefit allocation efficient and consistent with existing mechanisms, CalCCA's proposal is adopted~~, and~~. The RA benefits of DCPP extended operations~~, once allocated to each large electrical corporation,~~ shall be allocated to LSEs, including SCE and SDG&E but not PG&E,[233] as a load decrement using a process that mirrors the CAM process~~.~~~~[228]~~, once RA benefits have been allocated to each electrical corporation service area on the basis of 12-month coincident peak demand.[234]

Regarding PG&E's argument that the costs of RA substitution capacity would be necessary to include in any DCPP-related RA benefits, this decision

[233] PG&E is expected to show DCPP in its RA compliance filings to count toward PG&E's system RA compliance requirements, and as such does not need to be 'allocated' additional credits.

~~[228]~~[234] CalCCA also advised that, 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. (CalCCA OB at 33.) This proposal is reasonable and Energy Division should endeavor to do so.

notes the argument of CalCCA that the Commission's CAM process already accounts for these costs. As stated by CalCCA:

> PG&E is… already required to provide substitution capacity for the CAM eligible resources in its portfolio. 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. In D.14-06-050, the Commission determined that the cost to provide substitution capacity for CAM-eligible resources is recoverable through the CAM balancing account."~~229~~[235]

Therefore, this decision concludes that using a process that mirrors the CAM process to distribute RA benefits to LSEs will account for the substitution capacity costs cited by PG&E.

In comments on the proposed decision, PG&E argues the Commission "should suspend RA allocations during any month in which there is an outage, or when existing outages extend beyond the planned period, so that the operational and safety needs of DCPP are not compromised in favor of reducing RA compliance obligations of LSEs."[236] PG&E's comments focus primarily on needed maintenance, cleaning, and refueling performed during planned outages.[237] As demonstrated by CalCCA, SCE, and Cal Advocates, PG&E already reserves RA capacity from its existing portfolio and makes purchases in the RA bilateral market, as needed, to provide substitute capacity during DCPP maintenance outages;[238] PG&E's current practice is to conduct DCPP maintenance outage work outside of peak months, when it is much less

~~229~~235 Ex. CalCCA-02 at 9.

236 PG&E opening comments on the proposed decision at 9.

237 *Id.* at 10.

238 Ex. CalCCA-03, Attachment A.

expensive to procure substitution capacity, and this practice should continue to be encouraged; and other LSEs lack visibility into planned outages at Diablo Canyon.[239] For all these reasons, we find it reasonable for PG&E to retain responsibility for obtaining substitute capacity during DCPP outages, and do not believe there is a need to suspend RA allocations during planned outages. However, to promote the safe operation of DCPP and ensure costs are not shifted to PG&E bunded customers, PG&E is authorized to recover, from all LSEs that are allocated RA benefits in this decision, the reasonable administrative and procurement costs associated with meeting DCPP substitution capacity obligations, including associated penalties and costs borne by non-DCPP resources.

Lastly, while the above approach appears reasonable for planned outages, based on the record of this proceeding, there is a much more limited record in this proceeding concerning how RA penalties or the RA penalty point structure consequences might be applied in the event PG&E would need to attempt to secure sufficient replacement RA during an unplanned summer outage of one or both units. An unplanned, emergency outage is fundamentally different than the circumstance of PG&E using DCPP to provide RA for its bundled customers and being responsible for replacement RA for its bundled load responsibilities. This scenario is another example of the impact that extending the RA credits for such a large resource may have on the RA market, as discussed in Section 7.1.1, and similarly, may warrant further consideration in a future RA proceeding.

7.3. ~~6.3.~~ Greenhouse Gas Benefits

[239] CalCCA OB at 27-29; SCE OB at 19-20; Cal Advocates opening comments on the proposed decision at 4.

SCE, CalCCA, and AReM/DACC all support the Commission authorizing voluntary allocations of DCPP's GHG-free attributes to LSEs for power content label purposes. SCE proposes all LSEs whose customers pay for extended operations should receive a voluntary allocation of GHG-free attributes from DCPP for use on their power content labels. SCE reasons that this treatment is justified, as "all LSE customers will pay substantial costs for [Diablo Canyon's] extended operations and should receive all benefits and attributes generated by [Diablo Canyon] that are permitted by statute."~~[230]~~[240]

TURN does not oppose the allocation of GHG attributes to LSEs that pay a share of Diablo Canyon costs subject to the following constraints: (1) the allocation should not affect any GHG emissions forecasting or reporting by LSEs in the IRP program; (2) any public claims by the LSE should be limited to those permitted under the regulations for the Power Source Disclosure Program; and (3) LSEs must execute a power purchase agreement with PG&E in advance of any DCPP generation to receive credit for a zero GHG specified purchase pursuant to Power Source Disclosure Program regulations.[241] TURN asserts these conditions are necessary to ensure compliance with Section 712.8(q) and Section 454.53(a).[242]

WEM opposes any allocation of GHG-free attributes, claiming such an allocation violates SB 846 and that the CEC's power content label regulation does

[240] Ex. SCE-02 at 11.

[241] TURN RB at 17-18.

~~[230] Ex. SCE-02 at 11.~~[242] Section 712.8(q) establishes a prohibition on the extension of Diablo Canyon operations from undermining the achievement of California's GHG reduction goals. Section 454.53(a) specifies that the achievement of California's electric sector GHG emissions targets may not "increase carbon emissions elsewhere in the western grid and shall not allow resource shuffling."

not allow unbundled renewable energy credits (REC) to count toward the GHG intensity of an LSE's electricity supply. SCE retorts that LSEs will not be using *unbundled* RECs to count on their power content labels and, in any event, RECs are not created by Diablo Canyon.[~~231~~243] Cal Advocates believes the Commission should demur on this issue and leave it for the CEC to determine how the GHG-free attributes of DCPP should be used for power content label purposes.[~~232~~244]

PG&E opposes the allocation of DCPP GHG attributes to LSEs on the basis that the costs to administer an allocation framework would be too great to justify. SCE disagrees and argues "[t]he potential administrative burden to implement any allocation framework should not outweigh the fundamental fairness of reimbursing LSEs and their customers for part of the substantial costs of extended operations."[~~233~~245] PG&E also asserts that offering to assign the GHG attributes of DCPP to LSEs may reduce the incentive for LSEs to procure other resources to meet their GHG-free sourcing requirements.[~~234~~246] However, as noted by other parties including SCE, SB 846 does not allow the long-term IRP planning and procurement process that guides the LSEs towards meeting their GHG-free sourcing requirements to consider DCPP GHG attributes, thus obviating PG&E's concern.

As a matter of law, SB 846 prohibits including the GHG attributes of Diablo Canyon in the Commission's IRP process. However, as noted by SCE, SB 846 does not prohibit the Commission from allocating the GHG attributes of

[~~231~~243] *Id*. at 10.

[~~232~~244] Ex. CalPA-01 at 2.

[~~233~~245] Ex. SCE-02 at 11.

[~~234~~246] Ex. PG&E-02 at 2-23.

Diablo Canyon for the purpose of helping to construct an LSE's power content label.[~~235~~247] Even more, SCE points out that SB 846, by way of Section 454.52(g), states "[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 separate, line item resource for purposes of complying with Section 398.4."[~~236~~248] This suggests that SB 846 places an affirmative requirement to include the GHG attributes of Diablo Canyon as a part of power content labeling, at least until January 1, 2031. Ultimately, those LSEs that pay for extended operations at DCPP should be allowed to access the benefits of extended operations, including the GHG attributes of DCPP.

Therefore, PG&E shall offer to LSEs that are paying for extended operations of DCPP the ability to use their share of DCPP's GHG-free attributes for their power content label. The process for making and accepting these offers, as described by AReM/DACC and CalCCA in their testimony, is adopted. The existing process for voluntarily offering the GHG attributes of certain resources to LSEs, as adopted in D.22-06-066, should be used as a model.

As noted by CalCCA, Commission Resolution (Res.) E-5111 approved PG&E's current interim allocation process that allocates GHG attributes from resources in PG&E's Power Charge Indifference Adjustment (PCIA) portfolio. According to CalCCA, 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." Once a year PG&E offers each LSE its Allocation Ratio which, after execution of a Sales Agreement, corresponds to an allocated

[~~235~~247] Ex. SCE-02 at 9-10.

[~~236~~248] *Ibid*. Section 398.4 is a section specific to power content labeling requirements that includes nuclear power as a reportable resource at Section 398.4(h)(4).

quantity of GHG-free energy sold to the LSE during the delivery year. Under this framework, LSEs that accept the allocations may report the corresponding GHG-free energy on their annual Power Content Label under the CEC's Power Source Disclosure Program.~~[237]~~[249]

CalCCA's proposal based on this existing process shall be used by PG&E to allocate the GHG attributes of DCPP during extended operations. Specifically, PG&E should modify its Bundled Procurement Plan (BPP) Appendix P to accommodate an annual allocation and offer process for DCPP as a stand-alone specified resource. PG&E shall calculate DCPP GHG-free generation separate from PG&E's other resources, and expand eligibility to receive an allocation of DCPP generation to all California LSEs paying for eligible DCPP extended operations costs, including PG&E and other utilities, but excepting Bear Valley, Liberty, and PacifiCorp.~~[238]~~[250] LSEs may confirm their acceptance of an allocation by executing a sales agreement with PG&E subject to the conditions in PG&E's BPP Appendix P. Unclaimed allocations, if any, would be unused for that delivery year and would not be reported on any individual LSE power content label or other communications.~~[239]~~[251] PG&E shall file a Tier 2 advice letter no later than 180 days after the issuance date of this decision formalizing the process to allow LSEs to be allocated GHG attributes of extended operations at DCPP.

~~[237]~~[249] Ex. CalCCA-01 at 18-19.

~~[238]~~[250] Bear Valley, Liberty, and PacifiCorp are excluded as their financial contributions to DCPP extended operations will likely be zero after netting their quantified RA benefits from their defined cost contribution.

~~[239]~~[251] Ex. CalCCA-01 at 19. PG&E notes that only six of the 22 LSEs in its territory currently accept GHG attributes of DCPP for purpose of their power content labels, suggesting that not all LSEs will agree to accept DCPP GHG attributes (Ex. PG&E-02 at 2-22).

This decision also clarifies that these orders with respect to DCPP's GHG attributes do not prejudice any regulatory changes to the Power Source Disclosure Program that may be made by the CEC, as such changes are not within the Commission's jurisdiction. This decision only seeks to address the narrow issue of how to allocate DCPP's GHG-free attributes to LSEs whose customers are paying for extended operations for the purpose of power content labeling. Further, as argued by TURN, we clarify that GHG attributes subject to allocation may not be resold.

8. ~~7.~~ Diablo Canyon Nuclear Power Plant Extended Operations Ratesetting

8.1. ~~7.1.~~ Calculating a Non-Bypassable Charge

Statute requires the use of a volumetric NBC to collect DCPP extended operation costs specified in Section 712.8 from the ratepayers of all LSEs subject to the Commission's jurisdiction. However, the price of the NBC to be charged will vary depending on the LSE. For example, unbundled and bundled PG&E customers are responsible for paying all costs spelled out by Section 712.8, while non-PG&E ratepayers are only responsible for a subset of those costs. The price for PG&E and non-PG&E customers will also vary depending on each large electrical corporation's share of 12 months' worth of coincident peak demand, as this is the inter-IOU cost and benefit allocation methodology adopted by this decision (intra-IOU cost and benefit allocation among an IOU's LSEs and among rate classes proceeds according to the CAM).[~~240~~252] Further, as noted above, ratepayers of the SMJUs will only be charged an NBC price that corresponds to their set share of the DCPP extended operations costs (*i.e.*, $10,000 per SMJU).

[~~240~~252] As noted by AReM/DACC and others, the CAM requires differential treatment of customer classes within a large electrical corporation's territory.

PG&E proposes a statewide DCPP extended operations NBC be an equal-cents-per-kWh rate paid for by all Commission-jurisdictional customers, except that customers in PG&E's service area will pay an additional adder to recover the PG&E-specific Section 712.8(f)(5) expense. SCE ~~supports~~and SDG&E support PG&E's proposal.[~~241~~253] However, due to the findings made previously in this decision and recited above, it is not possible to charge each customer the same, statewide price for the DCPP extended operations NBC. Instead, the price of each DCPP extended operations NBC for each customer class in each LSE will be determined in the DCPP Extended Operations Cost Forecast application proceeding on an annual basis, using the cost and benefit allocation methodologies adopted by this decision.

This is admittedly a more complex option than the one recommended by PG&E, but it reflects the legislatively determined purpose of using DCPP extended operations to ensure system reliability. It is also consistent with the historic treatment of cost and benefit allocation for CAM resources, which DCPP will closely resemble as of November 3, 2024, and is consistent with the allocation of RA benefits discussed elsewhere in this decision.

As an alternative to an equal-cents-per-kWh rate, TURN recommends DCPP costs be split with capacity costs allocated pursuant to the CAM method and energy costs subject to a different allocator.[254] TURN's proposal is rejected for all the reasons above. Further, we are not convinced the additional granularity benefits gained through TURN's proposal outweigh the administrative complexity it would require.

[~~241~~253] Ex. SCE-02 at 12; SDG&E opening comments on the proposed decision at 4-5.

[254] TURN RB at 14-15.

PG&E argues the rate design adopted by this decision is inconsistent with statute.~~[242]~~[255] This is not so. Section 712.8(l)(1) states "[a]ny costs the commission authorizes the operator to recover in rates under this section shall be recovered on a fully nonbypassable basis from customers of all load-serving entities subject to the commission's jurisdiction, as determined by the commission…" The final clause is instructive. The Commission is granted the authority to determine the nature of the DCPP extended operations NBC, and the Commission exercises that authority in this decision by: (1) setting a fixed amount of DCPP extended operations costs and benefits to be recovered from SMJU customers, (2) allocating the costs and benefits of DCPP extended operations among the large electrical corporations on the basis of 12-month coincident peak demand, and (3) utilizing a process that mirrors the CAM process to allocate the costs and benefits of DCPP extended operations among LSE customers within the territories of each of the large electrical corporations.

All DCPP extended operations costs established by statute as eligible for collection from all ratepayers of LSEs subject to the Commission's jurisdiction must be pooled, and then allocated to the large electrical corporations on the basis of their share of 12-month coincident peak demand. The $30,000 owed collectively by Bear Valley, Liberty, and PacifiCorp will be subtracted from PG&E's total each year.

~~For clarity, and as described later in this decision, the volumetric performance fee to be collected from ratepayers pursuant to Section 712.8(f)(5) (volumetric fee) is a set amount of revenue that must be collected from ratepayers. The volumetric fee is not a cost per se, as it must be used to pay for~~

~~[242]~~[255] PG&E OB at 32.

~~DCPP extended operations costs before it is used for any other purpose. It is consistent with statute to regard the volumetric fee as a "revenue floor" rather than a cost that must be recovered.[243]~~

~~Therefore, the bundling and allocation of costs described above should not include a debit for the volumetric fee. Instead, the proportionate responsibility for the volumetric fee to be paid by the ratepayers of all the LSEs subject to the Commission's jurisdiction (including the additional amount owed exclusively by PG&E customers), and its associated revenue, should be allocated among the large electrical corporations, and their LSEs, in the same manner as the DCPP extended operations costs. This will ensure the volumetric fee revenue, collected on a volumetric basis through the DCPP extended operations NBC, does not end up being a net gain or benefit for any customer class, LSE, or large electrical corporation. Per Cal Advocates' recommendation, and consistent with SB 846, PG&E shall record the full amount of the volumetric fee revenue it receives as a DCPP Extended Operations Balancing Account (DCEOBA) credit.[244] PG&E shall file a Tier 2 advice letter no later than 90 days following the issuance date of this decision making this change to the DCEOBA.~~

The allocation of these attributes among the LSEs of each large electrical corporation service territory should utilize a process that mirrors the CAM process. In PG&E's case, they will need to calculate additional volumetric fee responsibility for their ratepayers given that statute requires PG&E ratepayers alone to shoulder a $6.50/MWh volumetric performance fee. This PG&E-specific

~~[243] *See* Cal Advocates OB at 14-15.~~

~~[244] *Id.* at 16.~~

volumetric fee should be allocated to PG&E's LSE customers in the same manner as other DCPP costs (*i.e.*, the CAM) for the reasons stated previously.

In the event actual conditions cause retail customers to be over-charged, since the DCPP extended operations NBC will be based on forecasted expenses and market revenues, CalCCA 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 NBC over the following year. Further, in certain circumstances, these parties agree the offset could result in the NBC going below zero (*i.e.*, a credit to customers).[256] We agree there should be no floor on the statewide DCPP NBC, and clarify that customer overcollections in one year should be returned to customers as an offset to the NBC over the following year.

8.2. ~~7.2.~~ Billing and Remittance of Diablo Canyon Nuclear Power Plant Extended Operations Non-Bypassable Charge

PG&E proposes to require PG&E and Commission-jurisdictional utilities to enter into the Servicing Order Agreement attached as Attachment A to PG&E's June 9, 2023 testimony. PG&E claims its proposed form of Servicing Order Agreement provides for prompt remittance of the DCPP extended operations NBCs collected by the utilities to PG&E consistent with Section 712.8(l)(2).~~[245]~~[257]

PG&E proposes a timely remittance of revenues from the Diablo Canyon extended operations NBC from all utilities, specifically the use of a daily

[256] CalCCA OB at 42-44. In reply comments on the proposed decision, PG&E indicates it would not agree with this accounting treatment if the proposed decision is not revised to treat the volumetric performance payment as a cost and compensation to PG&E. (PG&E reply comments at 3-4.) Since the decision has been revised on this point in response to comments, we assume PG&E once again agrees there should be no floor on the statewide DCPP NBC.

~~[245]~~[257] PG&E OB at 39.

remittance schedule. SCE supports this proposal since it mirrors SCE's current remittance schedule for its DWR Wildfire Fund NBC. SCE argues the Commission should not adopt a different proposal as doing so would result in increased costs and time for implementation of the DCPP extended operations NBC, as well as increased financing costs for PG&E that are ultimately borne by all Commission-jurisdictional customers.

SCE proposes to provide monthly reports — as opposed to daily reports — to PG&E along with remittances, given that billed kWh data may not be available on a daily basis but could be provided in monthly reporting. SCE further suggests modifying PG&E's template for a Servicing Order Agreement to provide that "Operator and Utility agree" rather than "Operator agrees, and Utility is ordered." SCE believes this language better reflects the relationship between the utilities in the context of the DCPP extended operations NBC.

SCE's proposal is reasonable and should be adopted. PG&E's remittance proposal shall be utilized by SCE and SDG&E, except as modified per SCE's suggestion. With respect to the language of the Servicing Order Agreement, PG&E shall make any changes necessary to the Servicing Order Agreement to comply with the cost allocation, benefit allocation, ratesetting process, and rate design for the DCPP extended operations NBC adopted by this decision, including SCE's recommended changes. PG&E shall seek approval of revisions to the Servicing Order Agreement through a Tier 2 advice letter to be filed within 90 days of the issuance date of this decision.

8.3. ~~7.3.~~ Bill Presentment

SCE argues any DCPP extended operations NBC be presented to customers via a separate line-item on their bills. PG&E concurs that the DCPP extended operations NBC should appear on customer bills as a stand-alone charge, with PG&E's implementation of such charge to follow completion of its billing system modernization project.~~[246]~~[258] SDG&E supports these arguments. ~~CalCCA believes the DCPP extended operations NBC should be included in the IOUs' delivery rate component.[247]~~

The Commission is not persuaded it is necessary to include the DCPP extended operations NBC as a separate line item on customer bills. ~~For~~Current public purpose program (PPP) rates already include a variety of state-mandated programs, and it is not clear how a separate, stand-alone DCPP extended operations charge on customer bills would improve customer understanding of this charge, or why DCPP extended operations should be presented in a different manner than other state-mandated programs. Therefore, for bill presentment purposes, each of the large electrical corporations ~~shall~~and the SMJUs are instructed to include the DCPP extended operations NBC in their ~~public purpose program (PPP)~~PPP rates.

8.4. ~~7.4.~~ Incremental Costs Associated with Diablo Canyon Nuclear Power Plant Extended Operations Non-Bypassable Charge

SCE seeks Commission approval for the establishment of a memorandum account to track "any unforeseen DCPP-specific costs that may arise in the future, such as, but not limited to, DCPP NBC customer notification or support costs."~~[248]~~[259] PG&E makes a similar request.~~[249]~~[260] ~~Their request is denied. Any~~While we anticipate the incremental costs associated with ~~SCE's and SDG&E's~~the implementation of the DCPP NBC to be limited, these costs were

~~[246]~~[258] PG&E OB at 26.

~~[247] Ex. CalCCA-01 at 30-31.~~

~~[248]~~[259] SCE OB at 7.

~~[249]~~[260] Ex. PG&E~~-OB~~-02 at ~~39~~2-9.

not considered or addressed in prior utility GRCs. Therefore, SCE's and PG&E's request is approved. PG&E, SCE, and SDG&E are authorized to establish a new DCPP Extended Operations Memorandum Account to track incremental, IOU-specific costs incurred related to the implementation, billing, and communication of ~~a~~the new DCPP ~~extended operations~~ NBC ~~(*e.g.*, participation in a~~ As explained by SCE, this approach equitably keeps the incremental costs within each IOU's service area, as there may be differences in costs for each IOU to implement the new DCPP NBC.[261] The IOUs shall file Tier 2 advice letters within 30 days of the effective date of this decision to establish their respective DCPP Extended Operations ~~Cost Forecast~~Memorandum Account. The IOUs may, through an application ~~proceeding or adjustments made to rate schedules to reflect the DCPP extended operations NBC) are regarded as normal business operations that are already accounted for in the A&G costs approved in each large electrical corporation's GRC. Pursuant~~, request reasonableness review and recovery of the DCPP NBC implementation costs, as recorded in its IOU-specific memorandum account, only from customers in its service area.[262] In their respective applications, the IOUs must demonstrate recorded costs are incremental, just, and reasonable. Further, pursuant to Section 712.8(c)(1)(C), PG&E's activities to prepare for DCPP extended operations are not eligible to be recovered from utility ratepayers. Therefore, to the extent PG&E's DCPP NBC implementation and support costs are to prepare for DCPP extended operations, ~~these costs cannot be funded through PG&E's approved A&G GRC budget. Instead, PG&E may request review of any NBC implementation and support~~

[261] SCE OB at 7.

[262] The request for cost review and recovery may be submitted through a stand-alone application, or consolidated with another application (such as a Test Year GRC application).

~~costs through its annual DCPP Extended Operations Cost Forecast application process, as described below. For any costs PG&E proposes to recover from utility ratepayers,~~ PG&E must also demonstrate that the recovery of such costs from ratepayers is not prohibited by Section 712.8(c)(1)(C).

8.5. ~~7.5.~~ Annual Energy Resource Recovery Account-Like Process for Allocating Costs and Benefits, and Setting the Price of the Diablo Canyon Nuclear Power Plant Extended Operations Non-Bypassable Charge

PG&E proposes a standalone DCPP Extended Operations 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 forecast costs of extended operations, provide for a forecast of market revenues for Diablo Canyon in the relevant ratemaking period, and annually establish the DCPP extended operations NBC applicable to all Commission-jurisdictional customers based on forecast net costs, and any applicable true-up amounts.[~~250~~263]

PG&E proposes to file its annual DCPP Extended Operations 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. Consistent with its ERRA Forecast proceedings, PG&E proposes to update its prepared testimony (including updated forecast DCPP Extended Operations Balancing Account (DCEOBA) balances) in the fourth quarter of the year in which it submits its application, and recommends a final decision resolving its

[~~250~~263] *Id*. at 25.

application by the last business meeting in November to allow rate changes to go into effect on January 1 of each year.

PG&E also recommends the Commission direct Commission-jurisdictional utilities coordinate with PG&E to appropriately notice PG&E's extended operation cost recovery consistent with the requirements of Rule 3.2.

With respect to the statute's required true-up process, PG&E proposes to use a Tier 3 advice letter to request Commission authorization of true-up amounts for costs recorded to the DCEOBA, to the extent that such true-up amounts do not exceed 115 percent of its forecast costs approved as part of a prior application. Specifically, PG&E proposes to include over- or under-collections resulting from actually incurred expense project costs and O&M expenses, so long as such costs are at or below 115 percent of PG&Es forecast costs. Under PG&E's proposal, over- or under-collections within such 115 percent threshold would be amortized in rates on January 1 of each year, subject to any final adjustments through the Commission's advice letter process.[~~251~~264]

SCE supports PG&E's overall cost recovery application proposal in order to ensure that an annual Diablo Canyon Extended Operations Forecast proceeding would result in annual rates that go into effect on January 1 of each year. SCE stresses that a Commission decision in such a proceeding would be required no later than the end of November in order to make a rate change by January 1 of each year "as SCE requires approximately four weeks to implement

[~~251~~264] PG&E OB at 26-30.

a rate change in its billing system when sales adjustments or structural changes are involved.”[~~252~~265]

SCE also supports the use of a “Fall Update” for the Diablo Canyon forecast proceeding in October of each year. SCE asserts a Fall Update would allow for the use of each IOU’s latest available load forecast by PG&E for the calculation of the single equal-cents-per-kWh rate to be used by all IOUs.[~~253~~266]

CalCCA supports PG&E’s proposal, and asks the Commission to adopt PG&E’s proposed structure for the annual DCPP Extended Operations Cost Forecast application process. CalCCA believes PG&E’s proposal is consistent with SB 846, which requires PG&E to structure its DCPP forecast proceeding to resemble its annual ERRA forecast proceeding, and no party disputes the structure of PG&E’s proposed annual DCPP Extended Operations Cost Forecast application process.[~~254~~267]

However, CalCCA recommends the Commission require PG&E to present detailed projections of all costs and revenues associated with DCPP extended operations, in a manner similar to PG&E’s presentation in its GRC and ERRA Forecast proceedings. For example, CalCCA would like to see PG&E provide details of DCPP fixed costs by Major Work Category and FERC account. CalCCA reasons that detailed generation output projections, nuclear fuel procurement costs, and other related forecast inputs would support PG&E’s forecasts for variable costs.[~~255~~268]

[~~252~~265] Ex. SCE-02 at 15.

[~~253~~266] SCE OB at 5.

[~~254~~267] CalCCA OB at 45; PG&E OB at 27.

[~~255~~268] CalCCA OB at 45-46.

CalCCA further recommends the Commission require PG&E to demonstrate in its DCPP Extended Operations Cost Forecast application that its forecasts include common cost assumptions that are consistent with its 2023 GRC. CalCCA argues that since the 2023 PG&E GRC includes attrition years extending beyond the original DCPP expiration dates to 2026 and assumes DCPP is retired, PG&E should quantify the impact of DCPP's extended 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.[~~256~~269]

CalCCA also believes PG&E should be required to submit an update to forecasted costs, during the pendency of the annual DCPP forecast application, to capture the most recent market conditions available prior to establishing the final net cost forecast. CalCCA asks the Commission require PG&E to prepare its annual DCPP Extended Operations Cost Forecast application based on the same forecast assumptions used to develop the ERRA Forecast for the corresponding period (including, for example, forecasted market revenues, fuel costs, generation output, and other variables), and procedural milestones in the DCPP Extended Operations Cost Forecast application should follow a timeline that runs in parallel with the ERRA Forecast proceeding.[~~257~~270]

8.5.1. ~~7.5.1.~~ Discussion

Section 712.8(h)(1) requires the establishment of an ERRA-like process to authorize PG&E to recover forecast DCPP extended operations costs, with a subsequent true-up to actual costs and market revenues for the prior calendar

[~~256~~269] *Id*. at 46-47.

[~~257~~270] *Ibid*.

year via an expedited Tier 3 advice letter process.[~~258~~271] In general, PG&E's proposal complies with this statutory obligation and should be adopted.[~~259~~272] PG&E shall file the first of these DCPP Extended Operations Cost Forecast applications no later than March 29, 2024, and the first application shall address forecasted DCPP extended operations costs from November 3, 2024 through December 31, 2025. PG&E shall file annual DCPP Extended Operations Cost Forecast applications no later than March 31 beginning in 2025, and ending the year before extended operations are complete; each of these applications shall consider the following calendar year's forecasted DCPP extended operations costs. PG&E's proposed Tier 3 advice letter process for considering annual true-ups is consistent with statute and therefore should be approved. PG&E shall file its annual Tier 3 DCPP Extended Operations Costs True-Up advice letter annually until the end of DCPP extended operations, so long as over- or under-collections are within the statute's defined 115 percent threshold.

Because this decision directs other utilities to bill their customers for DCPP-related costs and remit those funds to PG&E, each of SCE, SDG&E, Bear Valley, Liberty, and PacifiCorp shall coordinate with PG&E and the Commission's Public Advisor's Office so that each utility may ensure that it complies with the Rule 3.2 noticing requirements triggered by PG&E's application in the applicable utility service territory. SCE and SDG&E shall each file responses to each of PG&E's annual DCPP Extended Operations Cost Forecast applications to ensure that they are parties to the proceeding and

[~~258~~271] Section 712.8(h)(1).

[~~259~~272] This decision does not require the specific schedule proposed by PG&E other than the deadline for filing of the application itself.

contribute as needed to ensure that they are allocated their share of DCPP extended operations costs.

As recommended by CalCCA, and as discussed in Section ~~3.4~~4.4 of this decision, PG&E shall present in its DCPP Extended Operations Cost Forecast applications detailed projections of all costs and revenues associated with DCPP extended operations, in a manner similar to PG&E's presentation in its GRC and ERRA Forecast proceedings. PG&E shall, in its DCPP Extended Operations Cost Forecast application, also quantify the impact of DCPP's extended 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 Extended Operations Cost Forecast applications.

This decision previously determined that a process mirroring the CAM process should be used to allocate DCPP extended operations costs and benefits within the service territories of PG&E, SCE, and SDG&E, and that each large electrical corporation's share of 12-month peak coincident demand should be used to allocate costs and benefits among the large electrical corporations. Therefore, the Diablo Canyon Extended Operations Cost Forecast proceeding shall annually: (1) determine the allocation of costs~~, volumetric fee revenue,~~ and benefits of DCPP extended operations among the large electrical corporations' service areas; and (2) utilize a process that mirrors the CAM process to determine the price of the volumetric NBC to be charged by each of the large electrical corporations~~; and (3)~~. Since Energy Division currently allocates, as part of the CAM process, RA credits to individual LSEs based on confidential load forecast information, Energy Division is instructed to utilize the CAM process to determine the allocation of DCPP RA benefits to SCE and SDG&E and among the LSEs in each large electrical corporation's territory. Energy Division staff should endeavor to provide all LSEs with allocations of DCPP's RA benefits for the upcoming compliance year sufficiently in advance of the October 31 year-ahead RA compliance filing deadline.

9. ~~8.~~ Surplus ~~Ratepayer Funds~~Performance-Based Fees

Section 712.8(s)(1)[~~260~~273] establishes several conditions on PG&E's use of the volumetric payment for energy produced by DCPP established by Section 712.8(f)(5). PG&E must submit a plan to the Commission explaining how it proposes to use the funds remitted, on an annual basis. The funds may not be paid out to shareholders. The funds may be spent on several public purpose priorities defined by statute, "to the extent it is not needed for Diablo Canyon…"[~~261~~274] ~~These~~The funds collected pursuant to Section 712.8(f)(5) are known informally as "surplus ~~ratepayer funds~~performance-based fees."[275]

PG&E believes the statutory language of Section 712.8(s)(1) is clear enough to implement on its face, without additional guidance from the Commission. PG&E also states that detailed questions regarding the use of surplus ~~ratepayer funds~~performance-based fees could be held over to Phase 2 of this proceeding, while this decision need only concern itself with the timing of the spending plan's annual submittal.[~~262~~276] PG&E proposes the plan be submitted to the

[~~260~~273] Prior to July 2023 this section of the Pub. Util. Code was known as Section 712.8(t)(1).

[~~261~~274] Section 712.8(s)(1). The public purpose priorities are defined as: accelerating customer and generator interconnections, accelerating actions needed to bring renewable and zero-carbon energy online and modernize the electrical grid, accelerating building decarbonization, workforce and customer safety, communications and education, and increasing resiliency and reducing operational and system risk.

[275] In the Scoping Memo and party testimony, the "surplus performance-based fees" are also referred to as "surplus ratepayer funds."

[~~262~~276] Ex. PG&E-01 at 6-2, 6-3.

Commission for review via a Tier 2 advice letter to be filed on or before March 31 of each year.[~~263~~277]

SCE proposes any ~~surplus ratepayer funds~~performance-based fees received in 2024 be used to reduce the costs of extended operations and minimize rate impacts to all customers, before any surplus ~~ratepayer~~ funds are spent on critical public purposes priorities. SCE reasons that the language of Section 712.8(s)(1) only allows expenditures on critical public purposes priorities to the extent surplus ~~ratepayer funds~~performance-based fees are not needed for extended operations at DCPP.[~~264~~278] SDG&E and Cal Advocates concur with SCE on this point.[~~265~~279] PG&E disagrees and argues that, while the Legislature may have contemplated a scenario whereby volumetric performance funds may be spent on DCPP, Section 712.8(s)(1) should not be read as requiring the use of these funds to first offset operational costs as a matter of standard, annual practice.[~~266~~280]

Cal Advocates is concerned the statutory language could be interpreted to allow PG&E to use funds collected from the ratepayers of all LSEs to fund its own public purposes priorities, which would not benefit other LSE ratepayers. Cal Advocates considers this outcome inequitable and argues the Commission should require PG&E to return any surplus ~~ratepayer funds~~performance-based fees equitably to all customers that would contribute payments for extended operations at DCPP. Cal Advocates further recommends the critical public

[~~263~~277] Ex. PG&E-01 at 6-4.

[~~264~~278] Ex. SCE-01 at 18.

[~~265~~279] Ex. SDG&E-02 at GM-5.

[~~266~~280] Ex. PG&E-02 at 2-28.

purpose priorities identified by statute be interpreted to mean those that are necessary to comply with Commission orders, resolutions, and decisions.[~~267~~281]

TURN served ample rebuttal testimony on this issue. In general, TURN argues the Commission should adopt requirements in this proceeding to ensure any surplus ~~ratepayer funds~~performance-based fees are "constructively" applied for the benefit of ratepayers, including by providing direction to PG&E regarding spending priorities and accounting requirements in this proceeding or a successor proceeding.[~~268~~282]

TURN criticizes PG&E's proposal to use an annual advice letter to outline the proposed use of surplus ~~ratepayer funds~~performance-based fees, arguing such a process would not afford discovery rights to parties, would not permit critical examination of spending proposals, and would be poorly suited to the consideration of alternative proposals.[~~269~~283] TURN grants that an annual advice letter process may be appropriate for retrospective reporting on the use of surplus ~~ratepayer funds~~performance-based fees, so long as the Commission employs a more robust process to determine which uses are appropriate.[~~270~~284]

TURN expands somewhat on the proposals made by SCE and SDG&E to spend surplus funds on DCPP extended operations, first by adding an additional emphasis on affordability, stating that "[a]bsent a demonstration of *compelling need* to use funds in the current year for an allowable critical public purpose priority, the Commission should require funds to be applied as a credit against the costs of operating Diablo Canyon funded by ratepayers" (emphasis

[~~267~~281] Ex. CalPA-01 at 9-10.

[~~268~~282] Ex. TURN-02 at 3.

[~~269~~283] *Id.* at 4.

[~~270~~284] *Ibid.*

added).~~271~~285 TURN's proposal essentially seeks a Commission determination that Section 712.8(s)(1) should be interpreted to not only prioritize spending ratepayer funds on DCPP extended operations costs, but also to elevate affordability as a primary concern. TURN argues doing so would allow the Commission to return surplus ~~ratepayer funds~~performance-based fees to ratepayers each year unless a "compelling need" for one of the public purpose priorities arose.~~272~~286 TURN also recommends that, regardless of any compelling need, no surplus ~~ratepayer funds~~performance-based fees sourced from non-PG&E customers should be used to support critical public purpose priorities on PG&E's system.~~273~~287

TURN proposes the following guidelines be applied to any use of surplus ~~ratepayer funds~~performance-based fees:

- Surplus ~~ratepayer funds~~performance-based fees collected from PG&E's customers should be applied to fund critical public purpose priorities found reasonable by the Commission and subject to Commission approval. PG&E should file an application every two years demonstrating the reasonableness, incrementality, and compliance with Commission requirements for use of surplus ~~ratepayer funds~~performance-based fees. According to TURN, this would help ensure compliance with statutory language forbidding shareholder benefit or double recovery using surplus ~~ratepayer funds~~performance-based fees. This application process would consider both prospective

~~271~~285 *Id.* at 5.

~~272~~286 As described by TURN, "[t]he Commission should require that any Surplus Ratepayer Funds collected but not spent in each year on critical public purpose priorities be automatically credited to the amount of DCPP operational costs eligible for recovery from ratepayers. Any credits should be included in the Annual Electric True-up advice letter filing" (Ex. TURN-02 at 5).

~~273~~287 *Id.* at 7.

spending and actual spending in the past to determine compliance with statute and Commission direction.[~~274~~288]

- Any surplus ~~ratepayer funds~~performance-based fees used by PG&E to fund eligible critical public purpose priorities should offset shareholder equity capital and be accounted for as Contributions in Aid of Construction (CIAC).
- Of the critical public purpose priorities listed by Section 712.8(s)(1), priority should be given to capital expenditures for wildfire mitigation and customer connections or energization efforts.
- Commission oversight of spending using surplus ~~ratepayer funds~~performance-based fees should be ongoing, and include identifying multi-year spending priorities, establishing specific requirements governing the allocation of funds between work areas, and prohibiting funds from being spent on certain types of work.
- All surplus ~~ratepayer funds~~performance-based fees collected from ratepayers located outside PG&E's service territory, and any funds collected from ratepayers located in PG&E's service territory that are not spent on critical public purpose priorities, should be used to reduce the costs of extended operations at DCPP.
- PG&E should report and record the use of surplus ~~ratepayer funds~~performance-based fees in a detailed manner. While a Tier 2 advice letter process can be utilized for this purpose, according to TURN, the reporting should include a reconciliation of revenue collections with spending, demonstrate that PG&E's spending did not deviate from advance Commission guidance, and show compliance with other requirements adopted by the Commission. This reporting obligation should not replace the retrospective compliance analysis conducted in the application process, according to TURN.

[~~274~~288] *Id*. at 10.

- A separate memorandum account should be created to record the receipt and use of surplus ~~ratepayer funds~~performance-based fees. This would be an appropriate mechanism to assist the Commission in determining if the funds were spent reasonably.

TURN also speculates that PG&E's proposed process would not prevent surplus ~~ratepayer funds~~performance-based fees from being used to backfill underspending on work unrelated to DCPP that is approved in prior GRCs, or allocated to cover overspending on expense categories that would otherwise be the responsibility of shareholders.[~~275~~289]

9.1. ~~8.1.~~ Discussion

~~The~~While the Commission agrees with SCE and Cal Advocates that the plain meaning of Section 712.8(s)(1) requires funds collected pursuant to Section 712.8(f)(5) to be spent on costs associated with DCPP extended operations ~~in the first instance~~, before any surplus ~~ratepayer funds~~performance-based fees are used for critical public purpose priorities~~.[276] As noted by Cal Advocates, a legislative floor analysis supports this conclusion, which states the volumetric fees "cannot be paid to shareholders, but rather must be used to first meet needs at [Diablo Canyon] and then to accelerate, or increase spending on, critical priorities."[277]~~

[~~275~~289] *Id.* at 13.

~~[276] "Such compensation, to the extent it is not needed for Diablo Canyon, shall be spent to accelerate, or increase spending on, the following critical public purpose priorities…" (emphasis added). In briefs TURN also clarified that it supported this position, "so long as this application [of funds] does not relieve PG&E of any risk that DCPP spending would otherwise be deemed imprudent and assigned to shareholders." (TURN OB at 38.)~~

~~[277] Ex. CalPA-02 at 3-4, citing SB 846 Senate Third Reading at 4 and SB 846 Senate Rules Committee Senate Floor Analysis at 12.~~

,[290] we also agree with PG&E ~~disputes the arguments of SCE and Cal Advocates, and claims that "[c]ollecting funds from customers only to return them back is an ineffective use of those funds and does not serve the policy goals that this volumetric performance funds could otherwise advance."[278] PG&E misconstrues the "policy goals" established by statute. The plain meaning of Section 712.8(s)(1) is that the first and primary policy goal to be fulfilled by Section 712.8(f)(5) funds is paying down the costs needed for DCPP~~that the Legislature did not envision applying these funds as a full offset to any and all DCPP operational costs as a matter of standard, annual practice. As noted by PG&E, this approach would result in little to no funding for the public purpose priorities enumerated in Section 712.8(s)(1), effectively rendering this section moot.[291]

As to the meaning of the phrase "needed for Diablo Canyon," this decision interprets this part of Section 712.8(s)(1) to mean ~~those DCPP extended operations~~any costs ~~eligible for recovery from ratepayers under Section 712.8, with the exception of revenue collected pursuant to~~in excess of PG&E's approved

[290] "Such compensation, to the extent it is not needed for Diablo Canyon, shall be spent to accelerate, or increase spending on, the following critical public purpose priorities…" (emphasis added). In briefs TURN also clarified that it supported this position, "so long as this application [of funds] does not relieve PG&E of any risk that DCPP spending would otherwise be deemed imprudent and assigned to shareholders." (TURN OB at 38.)

[278] ~~PG&E OB at 51.~~

[291] PG&E OB at 51; PG&E comments on the proposed decision at 6. Cal Advocates asserts there is no conflict, since "[i]n a year with exceptionally high market revenues, PG&E would find itself in a position to spend the volumetric fee revenue on "critical public purpose priorities" while also returning surplus market revenues to customers." (Cal Advocates reply comments on the proposed decision at 3.) Cal Advocates' assertion is based on the extraordinary gas price spikes observed in February 2022, and is devoid of any actual analysis specific to DCPP operations. Further, this argument is contrary to Cal Advocates' earlier assertion that it is "highly unlikely that market revenues for DCPP will exceed expenses" since the Commission has taken action to address spikes in market prices. (Cal Advocates OB at 12.)

annual DCPP Extended Operations Cost Forecast application. We find this interpretation to be consistent with the plain language in Section 712.8(~~f~~h)(~~5~~1)~~.~~[279], which expressly recognizes the volumetric payments as a cost of operations, while giving meaning to the public purpose priorities enumerated in Section 712.8(s)(1). At the same time, this interpretation provides a level of ratepayer protection against unexpected DCPP extended operation cost increases, and is consistent with the Legislative direction that the volumetric fees "must be used to first meet needs at [Diablo Canyon] and then to accelerate, or increase spending on, critical priorities."[292]

~~This conclusion is based on the fact that the Legislature has, in great detail, specified the needs of DCPP during its extended operations period, as expressed in the specific DCPP extended operations costs that will be paid for by ratepayers. It can be reasonably presumed that if the Legislature did not believe those ratepayer-funded costs were necessary to keep DCPP operating for an extended period of time, then they would have been excluded from the law governing DCPPs extended operations.~~[280]

~~As noted by Cal Advocates in its rebuttal testimony, PG&E's description of its DCEOBA in PG&E advice letter (AL) 6870-E and AL 6870-E-A already describe many of DCPP's "needs" during the period of extended operations.~~

[279] ~~Revenue due from ratepayers under Section 712.8(f)(5) is excluded as it would be an absurd result to interpret statute to require a charge to pay for itself.~~

[292] Ex. CalPA-02 at 3-4, citing SB 846 Senate Third Reading at 4 and SB 846 Senate Rules Committee Senate Floor Analysis at 12.

[280] ~~For example, one might argue that an employee retention program is not required to continue physically operating DCPP, but the Legislature believes that such a program is important enough to include during an extended operations period that it should be funded by ratepayers across California on a non-bypassable basis. This legislative codification transforms the non-corporal concept of an employee retention program into a "need" to continue DCPP operations.~~

~~This decision therefore determines that PG&E shall add the revenue collected pursuant to Section 712.8(f)(5) to its forecast of each year's market revenues and any production tax credits for DCPP appearing in the DCEOBA. PG&E shall then balance this sum against all debits in the DCEOBA and its various subaccounts, including but not limited to: pensions, taxes, benefits and standard overheads, and regulatory compliance items; plant equipment and improvement costs; nuclear fuel costs; spent fuel storage capacity costs; employee retention costs as approved by the Commission; DCISC operations costs; incremental decommissioning planning costs resulting from the license renewal of Diablo Canyon; and interest on the average balance of the DCEOBA.[281]~~

~~Critically, and as previously held in this decision, PG&E must remove from the DCEOBA any debit entries related to the payments due under Section 712.8(f)(5). This is in accord with this decision's determination that the funds collected under Section 712.8(f)(5) work as intended by the Legislature, which is to pay for extended operations at DCPP before they are used for another purpose.~~

To be clear, while we interpret Section 712.8(s) as providing PG&E some amount of discretion on the use of surplus performance-based fees, subject to the statutory conditions and review discussed below, in the event actual recorded costs are above PG&E's approved forecast then PG&E must first use the volumetric performance-based fees to offset any costs above the approved forecast before they be used for another purpose.

In practical application, the DCEOBA shall be used to track the amount of volumetric fees collected pursuant to Section 712.8(f)(5). The amount collected

~~[281] *See* Ex. CalPA-02 at 6.~~

pursuant to Section 712.8(f)(5) may not be spent on the critical public purpose priorities in Section 712.8(s)(1) until the Commission has reviewed and approved PG&E's proposed use of the funds, as described later in this decision. PG&E shall file a Tier 2 advice letter no later than 90 days following the issuance date of this decision to make any necessary changes to the DCEOBA.

9.2. ~~8.2.~~ Surplus ~~Ratepayer Funds~~Performance-Based Fees Application

Section 712.8(s)(1) requires annual Commission review of the use of funds collected by PG&E pursuant to Section 712.8(f)(5). The Commission agrees with TURN's recommendation that a formal application be used to review and plan for PG&E's use of surplus ~~ratepayer funds. This~~performance-based fees, which is in accord with the requirements of Section 712.8(s) for an annual review and planning process, and maximizes transparency and party review of PG&E's past and planned use of funds collected pursuant to Section 712.8(f)(5).

PG&E attempts to argue that "[t]he statute does not direct the CPUC to approve the usage of funds before they are spent, but instead requires only that PG&E present information for CPUC review."[293] We disagree. There would be no purpose in having the Commission review PG&E's proposed usage of funds if the Commission did not also have the ability to modify or reject PG&E's proposed spending, as needed. Further, given the hundreds of millions of dollars that are expected to be collected every year from the volumetric fee, we find a formal application process is best suited to ensure any surplus performance-based fees are spent in accordance with the directives in Section 712.8. The Commission may revisit the direction to conduct its review through a

[293] PG&E opening comments on the proposed decision at 7.

formal application process if it determines, after having reviewed one or more of PG&E's applications, that the appropriate guidelines have been put into place.

Therefore, PG&E shall submit an application (hereinafter, Surplus ~~Ratepayer Funds~~Performance-Based Fees Application) to the Commission, on an annual basis beginning ~~November~~March 1, ~~2025,~~~~[282]~~2026,[294] reporting on the amount of ratepayer funds collected under Section 712.8(f)(5), how it was spent, and a plan for prioritizing the uses of such funds the next year. In its application, PG&E shall demonstrate that the performance-based fees were not "paid out to shareholders,"[295] and that PG&E did not "earn a rate of return for any of the expenditures."[296] In addition, PG&E shall describe how any future proposed spending is reasonable, incremental to existing authorized expenditures, and complies with Commission decisions, resolutions, and orders.

For retrospective reporting on the use of surplus ~~ratepayer funds~~performance-based fees, PG&E shall cite to the DCEOBA and the costs recorded there to demonstrate how the funds were used, and also ~~describe how~~whether any ~~remaining~~of the funds were used ~~if the DCEOBA was in~~

~~[282]~~[294] This date is chosen as the existing retirement date for DCPP Unit 1 is November 2, 2024. Because surplus ~~ratepayer funds~~performance-based fees are collected on a volumetric basis only during the period of DCPP extended operations, PG&E will not know how much revenue they have collected under Section 712.8(f)(5) until ~~some time has passed~~ after November 2, 2024. The application date of ~~November~~March 1, ~~2025~~2026 gives PG&E approximately one year to collect surplus ~~ratepayer~~ funds under Section 712.8(f)(5), perform a true-up of actual DCPP extended operation costs, and develop a plan for ~~their expenditure if there are~~any remaining funds ~~in the DCEOBA~~collected pursuant to Section 712.8(f)(5). Consistent with the discussion elsewhere, PG&E may not use the volumetric performance-based fees on the critical public purpose priorities in Section 712.8(s)(1) until the Commission has reviewed and approved PG&E's proposed use of the funds; therefore, PG&E's first Surplus Performance-Based Fees Application will focus on the planned usage of any surplus funds.

[295] Section 712.8(s)(1).

[296] Section 712.8(s)(2).

~~surplus~~to offset costs in excess of PG&E's approved DCPP Extended Operations Cost Forecast application. PG&E shall include in the ~~application~~Surplus Performance-Based Fees Application a declaration, under penalty of perjury, from PG&E's Chief Financial Officer that:

- None of the funds collected pursuant to Section 712.8(f)(5) were paid out to shareholders.
- None of the funds collected pursuant to Section 712.8(f)(5) earned a rate of return for PG&E.
- No profit was realized by PG&E's shareholders through the expenditures of funds collected pursuant to Section 712.8(f)(5).
- Neither PG&E nor any of its affiliates or holding company increased public earning per share guidance as a result of compensation provided under Section 712.8.

In light of TURN's concern that surplus ~~ratepayer funds~~performance-based fees could be used to offset shareholder cost obligations, and thus increase shareholder earnings in contravention of statute, PG&E shall include in its retrospective reporting on the use of surplus ~~ratepayer funds~~performance-based fees a detailed report on how ~~surplus ratepayer funds~~the fees were used solely for the purpose of covering DCPP extended operations costs ~~borne by ratepayers pursuant to Section 712.8 (excluding revenue collected under Section 712.8(f)(5) itself)~~ or critical public priorities authorized by the previous year's Surplus ~~Ratepayer Funds~~Performance-Based Fees Application proceeding. The Commission may render a decision in the Surplus ~~Ratepayer Funds~~Performance-Based Fees Application proceeding that sanctions PG&E if it finds that PG&E did not comply with the requirements of Section 712.8 that prohibit using funds collected under Section 712.8(f)(5) to enrich shareholders.

If there are any funds collected pursuant to Section 712.8(f)(5) that remain after ~~paying for~~the true-up of actual DCPP extended operations costs~~ through the DCEOBA~~, as discussed above, then PG&E may in a Surplus ~~Ratepayer Funds~~Performance-Based Fees Application propose how to use the remainder to accelerate, or increase spending on, the following critical public purpose priorities identified by the Legislature in Section 712.8(s)(1):

- Accelerating customer and generator interconnections.
- Accelerating actions needed to bring renewable and zero-carbon energy online and modernize the electrical grid.
- Accelerating building decarbonization.
- Workforce and customer safety.
- Communications and education.
- Increasing resiliency and reducing operational and system risk.

~~If PG&E makes a proposal for spending on public purpose priorities, PG&E shall describe how any such proposed spending is reasonable, incremental to existing authorized expenditures, and complies with Commission decisions, resolutions, and orders. PG&E shall also describe how the proposed spending will avoid benefiting shareholders, including how the proposed spending will not offset underfunded expenses or reprioritized work.~~

Notably, Section 712.8(s)(1) does not purport to rank or prioritize the identified public policy priorities. Accordingly, while the Surplus Performance-Based Fees Application shall detail PG&E's spending proposals, PG&E is not required to justify how it intends to allocate surplus funds among the listed categories. The Commission's review of PG&E's Application will be focused on determining whether the proposed spending properly falls within one or more of the categories identified in Section 712.8(s)(1), and that the spending would not result in double recovery in rates, cause compensation to be paid out to PG&E shareholders, or cause PG&E to earn a rate of return on any of the expenditures.[297]

This decision does not define in greater detail the critical public purpose priorities defined by statute, except to state its conclusion that the critical public purpose priorities relate only to such priorities in PG&E's service territory. If the statute was read to apply potential spending to public purpose priorities in other utility service territories, as posited by Cal Advocates and TURN, this would create considerable administrative complexity that the Commission does not believe the Legislature intended.

Parties will litigate, and the Commission will ultimately determine, whether PG&E's proposal actually conforms with the activities defined in statute. The Commission may render a decision that replaces or modifies the PG&E proposal utilizing proposals made by other parties to the proceeding, if those party proposals comply with statute as interpreted by this decision. Parties are encouraged to offer a variety of proposals, including those incorporating concepts such as CIAC and Customer Advances for Construction in each Surplus ~~Ratepayer Funds~~Performance-Based Fees Application, as applicable.

Lastly, as noted by PG&E and A4NR, the Scoping Memo limits the provision of guidance on the use of surplus performance-based fees in this proceeding to calendar year 2024.[298] Parties presented extensive arguments in this proceeding concerning the use of the volumetric fees in Section 712.8(f)(5)

[297] Sections 712.8(s)(1) and 712.8(s)(2).

[298] PG&E opening comments on the proposed decision at 8-9; A4NR opening comments on the proposed decision at 10.

and Section 712.8(s)(1), including broader policy and legal interpretations that go well beyond 2024, and as such it is appropriate and reasonable for this decision to address the full extent of party arguments presented. However, in recognition of the specific language in the Scoping Memo, and in order to ensure due process, parties will be afforded an opportunity in Phase 2 of this proceeding to comment on whether any changes should be made on the use of surplus performance-based fees for the calendar years following 2024.

10. ~~9.~~ Summary of Public Comment

Rule 1.18 allows any member of the public to submit written comment in any Commission proceeding using the "Public Comment" tab of the online Docket Card for that proceeding on the Commission's website. Rule 1.18(b) requires that relevant written comment submitted in a proceeding be summarized in the final decision issued in that proceeding.

As of October 1, 2023, over 330 public comments have been submitted in this proceeding. Comments generally focus on the potential extension of operations at Diablo Canyon, with a majority (approximately 65 percent) supporting some form of extension. Comments in support of an extension generally cite the need for clean, reliable, and carbon-free electricity in the state, as well as the safety and cost-effectiveness of nuclear generation generally, and at Diablo Canyon in particular. Comments in opposition to extended operations at Diablo Canyon largely focus on concerns over nuclear safety, cost, the storage of nuclear waste, as well as the desire for increased spending on renewable energy and energy storage technologies. Some comments also express concerns with PG&E being the operator of the plant.

11. ~~10.~~ Motions

All previous rulings made during this proceeding are affirmed.[~~283~~][299] All other outstanding motions or requests for which rulings have not been issued are deemed denied.

12. ~~11.~~ Comments on Proposed Decision

The proposed decision of ALJ Ehren D. Seybert in this matter was mailed to the parties in accordance with Section 311 of the Pub. Util. Code and comments were allowed under Rule 14.3. Comments were filed on November 15, 2023, by A4NR, AReM/DACC, CalCCA, CARE, CGNP, CUE, GPI, PG&E, SBUA, SCE, SDG&E, SLOMFP, SMJUs, TURN, and ~~reply~~WEM. Reply comments were filed on ~~by~~ November 20, 2023, by A4NR, AReM/DACC, Cal Advocates, CalCCA, CGNP, CUE, PG&E, SBUA, SCE, SDG&E, and TURN.

Pursuant to Rule 14.3(c), "[c]omments shall focus on factual, legal or technical errors in the proposed decision and in citing such errors shall make specific references to the record or applicable law. Comments which fail to do so will be accorded no weight." Pursuant to Rule 14.3(d), replies to comments "shall be limited to identifying misrepresentations of law, fact or condition of the record contained in the comments of other parties."

We have carefully reviewed and considered the parties' comments and made appropriate changes to the proposed decision where warranted. We find that all further comments not specifically addressed by revisions to the proposed

[~~283~~][299] Note: A minor correction to the June 14, 2023 assigned ALJ's Ruling on A4NR's showing of significant financial hardship (June 14, 2023 Ruling) is expected to be included as part of the Commission's decision addressing A4NR's October 9, 2023 request for intervenor compensation in this proceeding. These minor corrections are not expected to change the overall findings in the June 14, 2023 Ruling.

decision do not raise any factual, legal, or technical errors that would warrant modifications to the proposed decision.

13. ~~12.~~ Assignment of Proceeding

Karen Douglas is the assigned Commissioner and Ehren D. Seybert is the assigned ALJ in this proceeding.

Findings of Fact

1. The NRC's March 3, 2023 exemption allows the DCPP to continue to operate under its current licenses past their expiration dates (*i.e.*, November 2, 2024 (Unit 1) and August 26, 2025 (Unit 2)), provided PG&E submits a new federal license renewal application by the end of 2023, and satisfies various regulatory requirements at the federal and state levels.

2. ~~At the time of this decision PG&E has not submitted a new federal~~PG&E filed its license renewal application ~~for DCPP~~with the NRC on November 7, 2023.

3. The NRC's process and timeline for reviewing PG&E's license renewal application has yet to be determined.

4. At the time of this decision the $1.4 billion loan authorized under SB 846 has not been terminated.

5. The considerations at play in this proceeding address a relatively narrow set of circumstances based on the specific language set forth in Pub. Util. Code Section 712.8.

6. As determined in D.21-06-035, rapid changes in the electricity market are being driven by the large number of new LSEs, the major shifts in the resource mix, weather and climate uncertainty, and increasing acceleration of electrification of building and transportation energy use.

7. The deterministic stack analyses presented in this proceeding indicate shortfall conditions could exist as early as 2023 under extreme heat wave conditions that approximate those experienced in California in 2020 and 2022.

8. More recent probabilistic LOLE results prepared by the Commission and CAISO point to narrow resource margins or potential shortfalls, including a LOLE result close to 0.1 in 2026 without an extension of Diablo Canyon, as well as a potential shortfall in 2025 when considering the levels of capacity required by the Commission's procurement orders.

9. The reliability studies presented in this proceeding are consistent with the Commission's findings in D.23-02-040 that the electric system is much closer to a supply and demand balance than is comfortable for reliability purposes.

10. All of the reliability studies in this proceeding assume continued procurement during the 2024-2028 time period based on the procurement orders and associated compliance deadlines adopted in the IRP proceeding.

11. The "planning track" of the Commission's IRP proceeding results in the adoption of a PSP, or an optimal portfolio of resources for meeting the state's electric sector policy objectives at least cost, which is then used to set requirements for LSEs to plan toward that future.

12. D.21-06-035 requires LSEs to bring online at least 2,500 MWs of resources with specified zero-emitting attributes by June 1, 2025, as an explicit showing of replacement capacity for Diablo Canyon.

13. On August 9, 2023, a Joint Expedited Petition for Modification of D.21-06-035 was filed to extend the compliance deadline for the 2,500 MWs of Diablo Canyon replacement capacity from 2025 to 2027.

14. A4NR, SLOMFP, WEM, and CARE fail to demonstrate that new renewable energy and zero-carbon resources meet all of the following criteria:

(a) are an adequate substitute for DCPP; (b) meet the state's planning standards for reliability; and (c) will be online and interconnected by the end of 2023.

15. At the time of this decision there are no recommendations from the DCISC for seismic safety upgrades or deferred maintenance activities associated with extended Diablo Canyon operations, nor does the Commission have before it any NRC license renewal commitments or conditions.

16. SLOMFP's arguments that extended DCPP operations are not cost-effective are unsubstantiated, undefined, or are not specifically tied to DCPP.

17. D.18-01-022 did not consider the current energy market, or the $1.4 billion SB 846 loan and other government funding streams intended to address the cost of NRC license renewal.

18. The cost-effectiveness arguments presented by CUE, CGNP, and SBUA are materially incomplete or inconclusive.

19. PG&E's position in A.16-08-006 was based on its bundled energy needs, whereas the reliability considerations set forth in SB 846 are based on system needs.

20. Pub. Res. Code Section 25548(b) states "it is the policy of the Legislature that seeking to extend the Diablo Canyon powerplant's operations for a renewed license term is prudent, cost effective, and in the best interests of all California electricity customers."

21. The IRP proceeding is broader in scope than this proceeding, and is considering how optimized portfolios of generation resources will meet the state's GHG emissions goals at the lowest cost.

22. Pub. Util. Code Section 712.8(c)(2)(A) requires the Commission to issue its decision directing and authorizing extended operations at DCPP no later than December 31, 2023.

23. PG&E's May 19, 2023 testimony in this proceeding excludes a variety of cost categories associated with actual extended DCPP operations.

24. The CEC's Draft Cost Comparison Report relies on PG&E's May 19, 2023 testimony to forecast DCPP extended operations costs, and does not reflect the costs associated with PG&E's forthcoming license renewal application or any DCISC recommendations concerning seismic safety and deferred maintenance.

25. Party comments on the CEC's Draft Cost Comparison Report in this proceeding were provided on an expedited timeframe.

26. No party in this proceeding disputes that the omitted costs in PG&E's May 19, 2023 testimony are relevant to the cost-effectiveness of DCPP extended operations.

27. Since SB 846 allocates broad cost responsibility for extended DCPP operations to ratepayers of all LSEs subject to the Commission's jurisdiction, any corresponding funding should be incremental to, and outside the scope of, PG&E's 2023 GRC.

28. PG&E's proposal to file a Tier 3 advice letter, following the establishment of any conditions during the NRC's license renewal process, allows for the timely consideration of new and emergent information.

29. The DCISC is expected to have access to PG&E's license renewal application to the NRC, as well as PG&E's reports on seismic safety and deferred maintenance at Diablo Canyon, by the end of 2023.

30. Ongoing long-term system reliability needs are being considered and addressed through the Commission's IRP proceeding, R.20-05-003.

31. No party advocated for the development of a new process to monitor the reliability need for ongoing DCPP operations.

32. There are cost recovery mechanisms and processes in place, including those established by this decision, that will allow for further consideration and recovery of any outstanding DCPP uncollected costs and fees.

33. System reliability is highly correlated with coincident peak and net peak demand.

34. LSEs are familiar with the CAM process, and it is a proven mechanism for allocating costs among the LSEs in a large electrical corporation's territory.

35. The SMJUs (Bear Valley, Liberty, and PacifiCorp) are winter-peaking utilities and face different reliability concerns and requirements than the majority of other LSEs in California.

36. In the Commission's proceeding to ensure reliable electric service and address extreme weather events, R.20-11-003, none of the SMJUs were required to undertake additional procurement or adopt any supply- or demand-side requirements given their unique positions; similarly, in the Commission's IRP proceedings, R.16-02-007 and R.20-05-003, none of the SMJUs were subjected to procurement requirements ordered to address reliability concerns.

37. RA benefits constitute a substantial financial value and are already attributed to DCPP operations.

38. There is no language in SB 846 that forbids the allocation of RA benefits to LSEs, while Pub. Util. Code Section 712.8(q) authorizes the Commission to "allocate any benefits or attributes from extended operations of the Diablo Canyon powerplant."

39. Allocating DCPP-related RA benefits as a load decrement using a process that mirrors the CAM process requires the least amount of new program design.

40. ~~Using the CAM to distribute RA benefits to LSEs accounts for substitution capacity costs.~~Costs and penalties may be incurred if DCPP RA allocations, as contemplated in this decision, are not suspended during any month in which there is an outage at DCPP.

41. PG&E has experience procuring substitute capacity for CAM resources, including for planned outages at DCPP.

42. PG&E's current practice is to conduct DCPP maintenance outage work outside of peak summer months, when it is less expensive to procure substitute capacity.

43. There is limited record in this proceeding concerning the procurement of replacement RA during a potential unplanned summer outage of one or both units at DCPP.

44. Energy Division currently allocates, as part of the CAM process, RA credits to individual LSEs based on confidential load forecast information.

45. ~~41.~~ Res. E-5111 approved an interim allocation process for PG&E to allocate GHG attributes from resources in PG&E's PCIA portfolio to other LSEs within PG&E's service territory.

46. ~~42.~~ Pub. Util. Code Section 712.8(l)(1) grants the Commission the authority to determine the nature of the DCPP extended operations NBC.

~~43. The volumetric performance fee to be collected from ratepayers pursuant to Section 712.8(f)(5) (volumetric fee) is a set amount of revenue that must be collected from ratepayers.~~

47. Because the DCPP extended operations NBC will be set based on forecasted expenses and market revenue, it is possible actual conditions may cause retail customers to be over-charged.

48. ~~44.~~ Given the different cost and benefit methodologies adopted by this decision, it is not possible to charge each customer the same statewide price for the DCPP extended operations NBC.

49. ~~45.~~ In its June 9, 2023 testimony, PG&E provides a Servicing Order Agreement for the remittance of the DCPP extended operations NBCs collected by utilities to PG&E, and proposes a daily remittance schedule.

50. ~~46.~~ The IOU's billed kWh data may not be available on a daily basis.

51. ~~47.~~ SCE's proposed changes to the Serving Order Agreement better reflect the relationship between the utilities in the context of the DCPP extended operations NBC.

52. ~~48.~~ The large electric IOUs ~~and CalCCA~~ provided various recommendations in this proceeding concerning how the DCPP extended operations NBC should appear on customer bills.

53. Current PPP rates include a variety of state-mandated programs.

54. ~~49. Any~~There are incremental costs ~~associated with~~related to the implementation of ~~a~~the DCPP extended operations NBC ~~(*e.g.*, participation in a DCPP Extended Operations Cost Forecast application proceeding or adjustments made to rate schedules to reflect the DCPP extended operations NBC) are regarded as normal business operations that are already accounted for in the A&G costs approved in each large electrical corporation's GRC~~on customer bills that were not considered or addressed as part of prior utility GRCs.

55. ~~50.~~ PG&E proposes a standalone DCPP Extended Operations Cost Forecast application, to be submitted by March 31 of each year, that closely resembles its annual ERRA Forecast proceeding.

56. ~~51.~~ PG&E proposes to use a Tier 3 advice letter to request Commission authorization of true-up amounts for costs recorded to the DCEOBA, to the

extent that such true-up amounts do not exceed 115 percent of its forecast costs approved as part of a prior application.

57. ~~52.~~ CalCCA recommends the Commission require PG&E to present detailed projections of all costs and revenues associated with DCPP extended operations, in a manner similar to PG&E's presentation in its GRC and ERRA Forecast proceedings, and to demonstrate that its forecasts include common cost assumptions that are consistent with its 2023 GRC.

~~53. The Legislature, in SB 846, specifies in great detail the needs of DCPP during its extended operations period, as expressed in the specific DCPP extended operations costs that will be paid for by ratepayers.~~

58. Applying the funds in Section 712.8(f)(5) as a full offset to any and all DCPP operational costs as a matter of standard, annual practice would result in little to no funding for the public purpose priorities enumerated in Section 712.8(s)(1).

59. Section 712.8(h)(1) expressly recognizes the volumetric payments in Section 712.8(f)(5) as a cost of operations.

60. ~~54.~~ The Senate Rules Committee Senate Floor Analysis, SB 846 Senate Third Reading, states the volumetric payment for energy produced by DCPP "~~cannot be paid to shareholders, but rather~~ must be used to first meet needs at [Diablo Canyon] and then to accelerate, or increase spending on, critical priorities."

~~55. PG&E's AL 6870-E and AL 6870-E-A describe many of DCPP's "needs" during the period of extended operations.~~

61. ~~56.~~ It would be a direct violation of statute if surplus funds pursuant to Section 712.8(f)(5) were used to offset shareholder cost obligations.

62. Section 712.8(s)(1) does not rank or prioritize the critical public policy priorities, as provided.

63. The Assigned Commissioner's Scoping Memo and Ruling limited the consideration of additional guidance for the implementation of Section 712.8(s)(1) to the use of any surplus performance-based fees PG&E receives for Diablo Canyon in 2024.

64. Parties presented extensive arguments in this proceeding concerning the use of surplus performance-based fees PG&E receives for Diablo Canyon, including broader policy and legal interpretations on the intended application and use of such funds.

Conclusions of Law

1. In Commission rulemakings, all parties have equal standing where their proposals are concerned.

2. The standard of proof in this proceeding is preponderance of the evidence.

3. ~~1.~~ Based on the evidence presented in this proceeding, none of the conditions set forth in Pub. Util. Code Sections ~~712.8(2~~712.8(c)(2)(B)-(E) have been met.

4. ~~2.~~ PG&E should be directed and authorized to extend operations at DCPP until October 31, 2029 (Unit 1) and October 31, 2030 (Unit 2).

5. ~~3.~~ Consistent with Pub. Util. Code Sections ~~712.8(2~~712.8(c)(2)(B)-(E) and Pub. Res. Code Section 25548.3(c)(5)(C), the approval in this decision should be conditioned upon continued authorization to operate by the NRC, the $1.4 billion loan agreement authorized by SB 846 not being terminated, and the Commission not making future determination that DCPP extended operations are imprudent, unreasonable, or not cost-effective.

6. ~~4.~~ This decision is not intended to inform, or serve as a precedent to, other Commission proceedings tasked with addressing broader planning processes and implications, including the Commission's RA and IRP proceedings.

7. ~~5.~~ Focusing on the current portfolio of resources expected to achieve interconnection by the end of 2023 is not only consistent with the plain language in Section 712.8(c)(2)(D), but enables parties and the Commission to incorporate the most up-to-date resource planning assumptions, grid conditions, and policy developments/procurement orders.

8. ~~6.~~ To the extent there are potential risks and shortfalls associated with the entire PSP portfolio, which is designed to meet the state's GHG reduction goals and ensure electric grid reliability, it is not necessary to define, with specificity, what is meant by new renewable energy and zero-carbon resources in Pub. Util. Code Section 712.8(c)(2)(D), since these resources are assumed to be a subset within the larger PSP portfolio.

9. ~~7.~~ It is unlikely new renewable energy and zero-carbon resources with contracted commercial online dates in 2024 or later will be constructed and interconnected by the end of 2023.

10. ~~8.~~ Issues concerning the production of renewable and zero-carbon power supply should be addressed in the Commission's IRP proceeding.

11. ~~9.~~ The review required in Pub. Util. Code Section 712.8(c)(2)(B) and Pub. Res. Code Section 25548.3(c)(5)(C) is consistent with the Commission's reasonableness and prudence standard.

12. ~~10.~~ Absent any actual recommendations and conditions from the DCISC and NRC, it is not possible for the Commission to assess at this time whether associated, unknown costs render the extension of Diablo Canyon operations "too high to justify."

13. ~~11.~~ PG&E should be directed to file a Tier 3 advice letter in response to any of the following events: (a) NRC's conditions of license renewal become known; (b) the NRC approves retirement dates for Diablo Canyon that are earlier than what is approved in this decision; and (c) the $1.4 billion loan authorized in SB 846 is terminated.

14. ~~12.~~ Pub. Res. Code Section 25548.3(c)(5)(C) does not require the Commission to rely solely on the CEC's Draft Cost Comparison Report or make a cost-effectiveness determination by the end of 2023, while the Commission has broad authority to ensure just and reasonable rates under Pub. Util. Code Section 451.

15. ~~13.~~ It is well within the Commission's authority, and in ratepayers' best interest, to continue to evaluate the prudence and cost-effectiveness of continued DCPP operations.

16. ~~14.~~ PG&E's cost forecast does not reflect all of the costs associated with DCPP extended operations, and therefore is not an adequate foundation upon which to evaluate the cost-effectiveness, prudence, or reasonableness of DCPP operations.

17. ~~15.~~ PG&E should be directed, as part of its 2024 DCPP Extended Operations Cost Forecast application, to provide certain DCPP historical and forecast cost information as well as a copy of the CEC's Cost Comparison Report.

18. ~~16.~~ It is reasonable for PG&E to provide, in a single forecast analysis, any and all costs PG&E expects to be recovered from utility ratepayers for DCPP extended operations.

19. ~~17.~~ It is reasonable to assume many of the DCISC's recommendations concerning seismic safety and deferred maintenance will be available by the DCISC's next public meeting on February 21-22, 2024.

20. ~~18.~~ Specific requirements in SB 846 — including the requirement that new renewable and zero-carbon resources be interconnected by the end of 2023, as well as the exclusion of DCPP in IRP portfolios, resource stacks, or PSPs — suggest that the Legislature did not intend for the Commission to continually re-evaluate the reliability need for DCPP.

21. ~~19.~~ Any subsequent DCPP prudency review by the Commission should focus on new or updated information ~~as well as arguments not previously considered in this proceeding~~.

22. ~~20.~~ PG&E's six-month estimate for an orderly shutdown of DCPP is reasonable.

23. ~~21.~~ In the event earlier retirement dates for DCPP are approved or requested, PG&E should be directed to explain whether and why there are any deviations from the six-month timeframe for an orderly shutdown of DCPP.

24. ~~22.~~ It is reasonable to interpret the clause in Pub. Util. Code Section 712.8(c)(2) stating "[e]xcept as authorized by this section" as referring to the cost allocation authority granted to the Commission by Section 712.8(l)(1), resulting in the broad cost responsibility of DCPP extended operations costs to ratepayers of all LSEs subject to the Commission's jurisdiction, and with certain, specified, costs to be paid only by PG&E ratepayers.

25. ~~23.~~ It is reasonable to interpret Pub. Util. Code Section 712.8(l)(1), which states "except as otherwise provided in this section," as not referring to the general prohibition on cost recovery from ratepayers outlined in Section 712.8(c)(4), as this interpretation would lead to an absurd result where each exception clause swallows the other.

26. ~~24.~~ The Legislature intended to allocate the costs for DCPP extended operations described in Section 712.8, excepting those reserved solely for

customers of PG&E, among all the ratepayers of all LSEs subject to the Commission's jurisdiction.

27. ~~25.~~ Ensuring system reliability is a key legislative rationale for the extension of DCPP operations.

28. ~~26.~~ Allocating the costs of DCPP extended operations, excepting those reserved solely for customers of PG&E, based on an IOU's share of a 12-month coincident peak load is fair and equitable.

29. ~~27.~~ The three large electrical corporations (PG&E, SCE, and SDG&E) should collectively allocate the statutorily defined costs of DCPP extended operations in each of PG&E's annual DCPP Extended Operations Cost Forecast application proceedings. PG&E, SCE, and SDG&E may use public load data to determine each electrical corporation's share of 12-month coincident peak demand.

30. ~~28.~~ Each large electrical corporation should use a process that mirrors the CAM process, as defined in D.06-07-029 and subsequent decisions, to allocate its own share of the DCPP extended operations costs to LSEs in its territory.

31. ~~29.~~ Bear Valley, Liberty, and PacifiCorp should be allocated DCPP costs differently than the large electrical corporations.

32. ~~30.~~ Because the statute grants no discretion as to whether SMJU customers should contribute to eligible DCPP costs, these three utilities should be assigned some share of the costs, even if they do not benefit from extended operations at DCPP.

33. ~~31.~~ In light of the historic differential treatment of SMJUs with respect to reliability and planning requirements, and in order to promote equity and fairness, it is reasonable to require Bear Valley, Liberty, and PacifiCorp to each

collect $10,000 through a non-bypassable, equal-cents-per-kWh charge and remit the collected amount to PG&E on an annual basis.

34. ~~32.~~ Ratepayers that are paying for extended operations at DCPP should, as a matter of equity, realize the financial benefits of those extended operations, and those benefits should be distributed to each utility and its customers in the same manner of DCPP extended operations costs.

35. ~~33.~~ It is reasonable, and consistent with SB 846, to allocate the RA benefits of DCPP extended operations to each large electrical corporation service area on the basis of 12-month coincident peak demand.

36. ~~34.~~ Because Bear Valley, Liberty, and PacifiCorp are not required by the Commission to procure RA capacity, it would be nonsensical to allocate RA capacity to them.

37. ~~35.~~ To ensure the SMJUs receive equivalent financial benefits from the RA attributes related to extended operations at DCPP, PG&E should be instructed to distribute $10,000 annually to each of Bear Valley, Liberty, and PacifiCorp in consideration of the RA attributes that they would have received for DCPP extended operations had they been required by the Commission to procure RA capacity.

38. ~~36.~~ It is reasonable to allocate RA benefits to LSEs, including SCE and SDG&E but not including PG&E, as a load decrement using a process that mirrors the CAM process, once RA benefits have been allocated to each large electrical corporation service area on the basis of 12-month coincident peak demand.

39. PG&E should be allowed to recover, from all LSEs that are allocated DCPP RA benefits in this decision, the reasonable administrative and

procurement costs associated with meeting DCPP substitute capacity obligations, including associated penalties and costs borne by non-DCPP resources.

40. ~~37.~~ SB 846 does not prohibit the Commission from allocating the GHG attributes of DCPP for the purpose of helping to construct an LSE's power content label, while Pub. Util. Code Section 454.52(g) suggests an affirmative requirement to include the GHG attributes of DCPP as a part of power content labeling, at least until January 1, 2031.

41. ~~38.~~ LSEs that pay for extended operations at DCPP should be allowed to access the benefits of extended operations, including the GHG attributes of DCPP.

42. ~~39.~~ PG&E should offer to LSEs that are paying for extended operations of DCPP the ability to use their share of DCPP's GHG-free attributes for their power content label using the interim allocation process approved in Res. E-5111.

~~40. The volumetric performance fee to be collected from ratepayers pursuant to Section 712.8(f)(5) should be regarded as a "revenue floor," rather than a cost that must be recovered, since it must be used to pay for DCPP extended operations costs before it is used for any other purpose.~~

43. ~~41.~~ It is reasonable, and consistent with SB 846, to allocate the revenue associated with the $6.50/MWh volumetric fee under Section 712.8(f)(5) to each large electrical corporation on the basis of 12-month coincident peak demand.

44. ~~42.~~ The price of each DCPP extended operations NBC for each LSE customer class should be determined in the DCPP Extended Operations Cost Forecast application proceeding on an annual basis, using the cost and benefit allocation methodologies adopted by this decision.

45. Where the DCPP extended operations NBC results in an overcollection in one year, the overcollection should be returned to customers as an offset to the DCPP extended operations NBC in the following year.

46. Where overcollections through the DCPP extended operations NBC are returned to customers in the following year, there should be no floor on the DCPP extended operations NBC (*i.e.*, the charge can be negative).

47. ~~43.~~ PG&E's remittance proposal should be utilized by SCE and SDG&E, except as modified per SCE's suggestion to provide monthly, as opposed to daily, reports.

48. ~~44.~~ PG&E should make changes to its Servicing Order Agreement to comply with the cost allocation, benefit allocation, ratesetting process, and rate design for the DCPP extended operations NBC adopted by this decision.

49. ~~45.~~ For bill presentment purposes, each of the large electrical corporations and the SMJUs should include the DCPP extended operations NBC in their PPP rates.

50. ~~46.~~ SCE's and PG&E's request for the establishment of a memorandum account to track ~~unforeseen DCPP-specific costs~~the incremental costs of implementing the DCPP extended operations NBC should be ~~denied~~granted.

51. ~~47.~~ In general, PG&E's proposed ERRA-like forecast to recover forecast DCPP extended operations costs, with a subsequent true-up to actual costs and market revenues for the prior calendar year via an expedited Tier 3 advice letter process, complies with Pub. Util. Code Section 712.8(h)(1) and should be adopted.

52. ~~48.~~ PG&E should file the first DCPP Extended Operations Cost Forecast application no later than March 29, 2024, to address forecast DCPP extended operations costs from November 3, 2024 through December 31, 2025.

53. ~~49.~~ Subsequent DCPP Extended Operations Cost Forecast applications should be filed no later than March 31 every year thereafter, and should consider the following calendar year's forecasted DCPP extended operations costs, with the last application filed in 2029.

54. ~~50.~~ As part of its annual DCPP Extended Operations Cost Forecast applications, PG&E should: (a) provide detailed projections of all costs and revenues associated with DCPP extended operations, in a manner similar to PG&E's presentation in its GRC and ERRA Forecast proceedings; (b) quantify the impact of DCPP's extended operations on its common costs relative to the amount approved in its 2023 GRC; and (c) demonstrate it will not double count the common costs it proposes for recovery in its GRC and DCPP Extended Operations Cost Forecast applications.

55. ~~51.~~ The Diablo Canyon Extended Operations Cost Forecast proceeding should: (a) determine the allocation of costs and benefits of DCPP extended operations among the large electrical corporations~~;~~' service areas; and (b) utilize a process that mirrors the CAM process to determine the price of the volumetric NBC to be charged by each of the large electrical corporations~~; and (c)~~. Energy Division should utilize the CAM process to determine the allocation of RA benefits to SCE and SDG&E and among the LSEs in each large electrical corporation's territory, and should endeavor to provide all LSEs with allocations of DCPP's RA benefits for the upcoming compliance year sufficiently in advance of the October 31 year-ahead RA compliance filing deadline.

56. ~~52.~~ SCE and SDG&E should each file responses to each of PG&E's annual DCPP Extended Operations Cost Forecast applications to ensure that they are parties to the proceeding and contribute as needed.

57. ~~53.~~ PG&E should file its Tier 3 DCPP Extended Operations Costs True-Up advice letter annually until the end of DCPP extended operations, so long as over- or under-collections are within the statute's defined 115 percent threshold.

58. ~~54.~~ Because this decision directs other utilities to bill their customers for DCPP-related costs and remit those funds to PG&E, each of SCE, SDG&E, Bear Valley, Liberty, and PacifiCorp should coordinate with PG&E and the Commission's Public Advisor's Office to ensure compliance with the Rule 3.2 noticing requirements triggered by PG&E's application in the applicable utility service territory.

~~55. Pub. Util. Code Section 712.8(s)(1) requires funds collected pursuant to Section 712.8(f)(5) to be spent on costs associated with DCPP extended operations in the first instance, before any surplus ratepayer funds are used for critical public purpose priorities.~~

~~56. If the Legislature did not believe the ratepayer-funded costs in Pub. Util. Code Section 712.8 were necessary to keep DCPP operating for an extended period of time, then they would have been excluded from the law governing DCPPs extended operations.~~

59. ~~57.~~ As used in Pub. Util. Code Section 712.8(s)(1), the phrase "needed for Diablo Canyon" is interpreted to mean ~~those DCPP extended operations~~any costs ~~eligible for recovery from ratepayers under Section 712.8, with the exception of revenue collected pursuant to Section 712.8(f)(5)~~in excess of PG&E's approved annual DCPP Extended Operations Cost Forecast application.

~~58. PG&E should add the revenue collected pursuant to Pub. Util. Code Section 712.8(f)(5) to its forecast of each year's market revenues and any production tax credits for DCPP appearing in the DCEOBA, and then balance this sum against all debits in the DCEOBA and its various subaccounts.~~

~~59. PG&E should remove from the DCEOBA any debit entries related to the payments due under Section 712.8(f)(5).~~

60. The compensation earned under Section 712.8(f)(5) should be used to offset any costs in excess of PG&E's approved annual DCPP Extended Operations Cost Forecast application, as considered in the annual true-up process adopted in this decision, before these funds can be used for the public purpose priorities in Section 712.8(s)(1).

61. ~~60.~~ PG&E should be directed to submit an annual application, beginning ~~November~~March 1, ~~2025~~2026, to report the amount of compensation earned under Section 712.8(f)(5), how it was spent, and a plan for prioritizing the uses of such compensation the next year.

62. ~~61.~~ PG&E should demonstrate, in its retrospective reporting on the use of surplus ~~ratepayer funds~~performance-based fees, how the funds were used solely for the purpose of covering DCPP extended operations costs to borne by ratepayers pursuant to Section 712.8 or critical public priorities authorized by the previous year's Surplus ~~Ratepayer Funds~~Performance-Based Fees Application proceeding.

63. ~~62.~~ The critical public purpose priorities in Pub. Util. Code Section 712.8(s)(1) are interpreted to mean priorities in PG&E's service territory.

64. It is reasonable to adopt a general framework and guidance on the use of any surplus performance-based fees PG&E receives for Diablo Canyon during extended operations, along with the opportunity for parties to comment on whether there should be any changes made post-2024 as part of Phase 2 of this proceeding.

65. ~~63.~~ Any outstanding motions or requests that have not been addressed in this decision or elsewhere are deemed denied.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company is directed and authorized to extend operations at Diablo Canyon Nuclear Power Plant (DCPP) until October 31, 2029 (Unit 1) and October 31, 2030 (Unit 2), subject to the following conditions: (a) the United States Nuclear Regulatory Commission continues to authorize DCPP operations, (b) the $1.4 billion loan authorized by Senate Bill 846 is not terminated, and (c) the Commission does not make a future determination that DCPP extended operations are imprudent or unreasonable.

2. Pacific Gas and Electric Company is directed to present the Diablo Canyon Nuclear Power Plant (DCPP) historical and forecast cost information described in this decision as part of its 2024 DCPP Extended Operations Cost Forecast application.

3. Pacific Gas and Electric Company is directed to immediately file a Tier 3 advice letter to reevaluate the Diablo Canyon Nuclear Power Plant retirement dates approved in this decision in response to any of the following events: (a) the United States Nuclear Regulatory Commission (NRC) approves retirement dates that are earlier than what is approved in this decision; (b) the NRC's conditions of license renewal become known; and/or (c) the $1.4 billion loan authorized in Senate Bill 846 is terminated.

4. Pacific Gas and Electric Company's (PG&E's) proposed Energy Resource Recovery Account-like process to authorize forecast Diablo Canyon Nuclear Power Plant (DCPP) extended operations costs, with a subsequent true-up to actual costs and market revenues for the prior calendar year via an expedited Tier 3 advice letter process, is approved as modified by this decision. PG&E shall file the first of these DCPP Extended Operations Cost Forecast applications no

later than March 29, 2024, and shall file subsequent annual DCPP Extended Operations Cost Forecast applications no later than March 31 beginning in 2025, and ending the year before extended operations are complete.

5. Pacific Gas and Electric Company (PG&E), Southern California Edison Company, San Diego Gas & Electric Company, Bear Valley Electric Service, Inc., Liberty Utilities, and PacifiCorp d/b/a Pacific Power shall coordinate with each other and the Commission's Public Advisor's Office so that each utility may ensure that it complies with the Commission's Rules of Practice and Procedure Rule 3.2 noticing requirements triggered by PG&E's Diablo Canyon Nuclear Power Plant Extended Operations Cost Forecast applications in the applicable utility service territory.

6. Southern California Edison Company and San Deigo Gas & Electric Company are directed to file responses to each of Pacific Gas and Electric's annual Diablo Canyon Nuclear Power Plant Extended Operations Cost Forecast applications.

7. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) are directed to provide joint testimony proposing an allocation among themselves of the statutorily defined Diablo Canyon Nuclear Power Plant (DCPP) extended operations costs applicable to all load serving entities, and the revenue associated with the $6.50 per megawatt-hour volumetric fee under Public Utilities Code Section 712.8(f)(5), in each of PG&E's DCPP Extended Operations Cost Forecast application proceedings, using the processes and methodologies described in this decision. PG&E, SCE, and SDG&E may use public load data to determine each electric corporation's share of the 12-month coincident peak demand.

8. For every year that Diablo Canyon Nuclear Power Plant extended operations costs are collected, Bear Valley Electric Service, Inc., Liberty Utilities, and PacifiCorp d/b/a Pacific Power, are directed to collect $10,000 each through a non-bypassable charge and remit the collected amount to Pacific Gas and Electric Company on an annual basis.

9. Excepting Bear Valley Electric Service, Inc., Liberty Utilities, and PacifiCorp d/b/a Pacific Power, the resource adequacy benefits (RA) associated with Diablo Canyon Nuclear Power Plant extended operations shall be allocated among Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) service areas on the basis of 12-month coincident peak load~~, and then~~ in each of PG&E's annual Diablo Canyon Nuclear Power Plant Extended Operations Cost Forecast applications. Energy Division will then allocate the RA benefits among all load-serving entities subject to the Commission's jurisdiction in each utility's territory, including SCE and SDG&E, as a load decrement using a process that mirrors the Cost Allocation Mechanism process~~, in each of PG&E's annual Diablo Canyon Nuclear Power Plant Extended Operations Cost Forecast applications.~~.

10. Pacific Gas and Electric Company is directed to file a Tier 2 advice letter no later than 180 days after the issuance date of this decision formalizing the process to allow load-serving entities to be allocated greenhouse gas attributes of extended operations at Diablo Canyon Nuclear Power Plant, as described in this decision.

11. For every year that Diablo Canyon Nuclear Power Plant extended operations costs are collected, Pacific Gas and Electric Company shall distribute $10,000 annually to each of Bear Valley Electric Service, Inc., Liberty Utilities, and PacifiCorp d/b/a Pacific Power (collectively, the small and multi-jurisdictional

utilities or SMJUs), in consideration of the resource adequacy attributes that the SMJUs would have received for Diablo Canyon Nuclear Power Plant (DCPP) extended operations, and the SMJUs shall each credit these funds to its ratepayers using the same rate element used to collect its allocated portion of the costs of extended operations at DCPP.

12. Pacific Gas and Electric Company ~~(PG&E)~~ shall file a Tier 2 advice letter no later than 90 days following the issuance date of this decision ~~that modifies~~to make any necessary changes to the Diablo Canyon Nuclear Power Plant Extended Operations Balancing Account ~~(DCEOBA) to remove all debits related to the volumetric fee revenue to be received under Public Utilities Code Section 712.8(f)(5) and instead describe those revenues as a credit in the DCEOBA. PG&E shall add the revenue collected pursuant to Section 712.8(f)(5) to its forecast of each year's market revenues and any production tax credits for Diablo Canyon Nuclear Power Plant appearing in the DCEOBA. PG&E shall then balance this sum against all debits in the DCEOBA and its various subaccounts, as discussed in~~as a result of this decision.

13. Pacific Gas and Electric Company's (PG&E's) proposed Servicing Order Agreement is adopted as modified by this decision. PG&E shall seek approval of revisions to the Servicing Order Agreement through a Tier 2 advice letter to be filed within 90 days of the issuance date of this decision.

14. Pacific Gas and Electric Company, Southern California Edison Company, ~~and~~ San Diego Gas & Electric Company, Bear Valley Electric Service, Inc., Liberty Utilities, and PacifiCorp d/b/a Pacific Power, are each authorized to establish a new non-bypassable charge (NBC) to collect Diablo Canyon Nuclear Power Plant extended operations costs, as described in this decision. For bill presentment

purposes, each of ~~the large~~these electrical corporations shall include the NBC in their public purpose program rates.

15. Pacific Gas and Electric Company is directed to file an annual application, as described in this decision, beginning ~~November~~March 1, ~~2025~~2026, until the retirement of Diablo Canyon Nuclear Power Plant Unit 1 and Unit 2, to report the amount of compensation earned under California Public Utilities Code Section 712.8(f)(5), how it was spent, and a plan for prioritizing the uses of such compensation the next year.

16. Within 30 days of the effective date of this decision, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are authorized to submit Tier 2 advice letters to establish memorandum accounts to track their incremental costs of implementing the Diablo Canyon Nuclear Power Plant extended operations non-bypassable charge.

17. All motions not previously addressed are deemed denied.

18. ~~16.~~ Rulemaking 23-01-007 remains open.

This order is effective today.

Dated ____________________, at ~~Sacramento~~San Francisco, California.

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