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12/19/25
04:59 PM
A2503015

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE

STATE OF CALIFORNIA

In Attendance: PRESIDENT ALICE REYNOLDS
COMMISSIONER DARCIE L. HOUCK
COMMISSIONER JOHN REYNOLDS
COMMISSIONER KAREN DOUGLAS
COMMISSIONER MATTHEW BAKER

ADMINISTRATIVE LAW JUDGE JACK CHANG, presiding

Application of Pacific Gas and Electric Company to Recover in Customer Rates the Costs to Support Extended Operation of Diablo Canyon Power Plant from January 1 through December 31, 2026, and for Approval of Planned Expenditure of 2026 Volumetric Performance Fees (U39E).	ORAL ARGUMENT Application 25-03-015

REPORTERS' TRANSCRIPT
San Francisco, California
December 1, 2025
Pages 1 - 77
Volume 1

Reported by: Jacquelyn Haupt, CSR No. 13964
Shannon Ross Winters, CSR No. 8916

PUBLIC UTILITIES COMMISSION, STATE OF CALIFORNIA
SAN FRANCISCO, CALIFORNIA

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SAN FRANCISCO, CALIFORNIA

DECEMBER 1, 2025 - 1:36 P.M.

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ADMINISTRATIVE LAW JUDGE CHANG: We'll be on the record now. The Commission will come to order.

This is the time and place set for oral arguments in Application 25-03-015, the Application of Pacific Gas and Electric to Recover in Customer Rates the Costs to Support Extended Operation of Diablo Canyon from January 1, '26, through December 31, 2026, and for Approval of Planned Expenditure of 2026 Volumetric Performance Fees.

My name is Jack Chang, the assigned administrative law judge for this proceeding. I'm joined by the sitting assigned commissioner, Commissioner Karen Douglas, as well as President Alice Reynolds, Commissioner Darcie Houck, Commissioner John Reynolds, and Commissioner Matthew Baker.

A ruling issued on November 18th, 2025, outlined the agenda and speaking order. Accordingly, we will begin with ten-minute opening statements followed by five-minute responses. Proceeding analyst Christina Dang will also inform speakers of remaining time.

I ask for the benefit of our court reporters here that everyone speak clearly and not too fast so she -- they can record everything and to speak when called on.

So for now, with that, PG&E, please give us -- well, there are six parties today, including the applicant. When I call your organization's name, please make your statement. And please refer to this document that was circulated about the speaking order.

So with that, PG&E, please proceed with your opening statements.

ARGUMENT BY MS. RAFII

Thank you, Judge.

Good afternoon, Commissioners, ALJ Chang, and parties.

UNIDENTIFIED SPEAKER IN THE AUDIENCE: Mic.

MS. RAFII: Thank you.

I hope everyone had a nice holiday. My name is Lillian Rafii, and I'm here on behalf of PG&E.

We'd first like to thank the Commission for the opportunity to present this afternoon. We recognize the demands on your time as you consider the proposed decision in the 2026 Diablo Canyon extended operations forecast case, which covers the first full year of Diablo Canyon's extended operations for both units. We also appreciate the heavy lift by Commissioner Douglas, ALJ Chang, and Commission staff to issue this decision in time for the December 4th voting meeting, which is critical for enabling the three IOUs to implement rates by January 1st.

PG&E respectfully urges the Commission to adopt the proposed decision without material changes. It reflects a thoughtful and fair resolution supported by the robust, thorough, and litigated record and appropriately weighs the evidence in reaching its findings and conclusions. While PG&E's opening comments identify some corrections and clarifications that are needed, the proposed decision should overall remain intact.

Adoption of the proposed decision will result in a small decrease in system average bundled rates for PG&E, SCE, and SDG&E in 2026. Since SB 846 was signed, there has been tremendous progress by PG&E and state and federal agencies. The NRC license renewal process is nearly complete. The legislature determined that extending operations at Diablo Canyon is in the best interest of California customers, and that has proven true. The continued operation of Diablo Canyon has helped maintain reliability for millions of customers and deliver safe, reliable, affordable, and clean energy.

I'll address three topics today: the categorization between transition and extended operations cost, the escalation methodology on the fixed payment, and the 2026 volumetric performance fees or the VPFs.

Regarding the distinction between transition and extended operations cost, the Commission should affirm the reasonable and workable framework that is timing based it adopted in last year's decision. Some parties incorrectly argue that PG&E is inappropriately charging customers for transition costs that are prohibited from customer recovery. These assertions demonstrate a fundamental misunderstanding of these two cost categories.

SB 846 designates as transition costs the costs to prepare for and obtain approval of license renewal from the NRC and costs in preparation of extended operations. These are the only costs prohibited from customer rates. Further, these costs are limited.

The misunderstanding that parties have and as PG&E has emphasized in its testimony and briefs is beyond those identified costs, there is no bright line that says the rest of the costs are or are not transition versus extended operation costs. In other words, most costs could fall into either category, especially, in particular, the cost of projects that span multiple years.

In last year's decision, the Commission adopted a workable date-based framework to assign costs for recovery through government funding, i.e. transition costs, or customer rates, i.e. extended operations cost. The proposed decision correctly applies that framework to Diablo's 2026 costs and should be approved.

PG&E also accepts that the proposed decision has directed we should provide more detail as to the reasoning of the categorization, which we will do in next year's application.

Certain parties also argue that the Commission should expand the scope of the proceeding to include review of transition costs reported in the transition memo account. The proposed decision appropriately rejects these arguments. What these arguments ignore is that transition costs are reviewed by the Commission through a different process. SB 846 expressly establishes a review process for these costs by DWR and the Commission. This review has been occurring and will continue to occur for as long as costs are recorded in the transition memo account. There is no need for an additional duplicative review of these costs in these annual proceedings.

Regarding the escalation methodology on the fixed payment, the proposed decision correctly adopts the CPI-U methodology instead of continuing with the generation capital methodology adopted last year. The fixed payment of $50 million per unit per year is financial compensation to PG&E authorized by statute in lieu of a rate of return escalated annually. After reviewing multiple years of data from both methodologies, the proposed decision rightly determines that the CPI-U is more stable, widely used, and reflective of actual dollar inflation. In contrast, the generation capital indexes were deflationary between 2022 and 2025, an illogical outcome on its face given inflation trends in those years.

Finally, the proposed decision appropriately uses 2022 as the base year consistent with statutory language requiring escalation from 2022 dollars.

Regarding the 2026 volumetric performance fees, PG&E's 2026 plan includes over 16 programs advancing SB 846 priorities, including grid resiliencies, building decarbonization, workforce and customer safety, and education consistent with the statute. The proposed decision properly rejects additional requirements that have no support anywhere in the statute. Up to this point, the Commission has already provided great clarity, detail, and direction on VPF spent over the past four decisions on this topic. PG&E's first post-spend report or annual compensation report will be filed in March and will be reviewed by the Commission and parties.

On the topic of affordability, each program in the 2026 portfolio reflects affordability as a guiding principle as described in PG&E's supplemental testimony and in compliance with D.25-06-002. With that said, this decision was issued months after PG&E presented its 2026 plan and testimony, meaning that each of the programs were selected chiefly to comply with the statutory public purpose priorities, again, such as grid resiliency and risk reduction and to ensure no double recovery. At the same time, customer benefits, including affordability, were integral to program selection, which is why PG&E was able to provide factual support in its supplemental testimony following the decision issuance.

Neither the statute nor D.25-06-002 mandate a specific quantitative methodology for demonstrating affordability. Restricting the analysis to one metric would present an incomplete view of program impacts. Respectfully, these recommendations advanced by some parties are inconsistent with clear legislative direction.

On the topic of power generation programs on the -- in the VPF suite, TURN's objections to the application of VPFs to hydrogeneration work, even when total recorded expense is below authorized rates, is unfounded. This approach does not confer any direct shareholder compensation, and TURN's interpretation misapplies the prohibition on no double recovery. This is why in opening comments PG&E urges the Commission to adopt a conclusion that confirms that shareholder prohibitions applies only to measurable, direct compensation to shareholders and not to speculative benefit.

For these reasons, PG&E respectfully requests that the Commission adopt the proposed decision without material changes, ensuring safe, reliable, and affordable energy for Californians. Thank you.

ALJ CHANG: Thank you.

Next, Alliance For Nuclear Responsibility.

ARGUMENT BY MR. GEESMAN

Thank you, Judge Chang. I'm John Geesman representing the Alliance for Nuclear Responsibility.

As one of the signatories to PG&E's 2016 joint proposal to retire Diablo Canyon, the Alliance for Nuclear Responsibility has always recognized SB 846 to be a one-sided bargain. On the other hand, the legislation does force PG&E to separately identify the specific costs of operating Diablo Canyon. That's a public disclosure never required before. Prior to SB 846, PG&E was allowed to lump its Diablo costs in with its other electric generation expenses while assuring customers that the plant produced billions of dollars of savings. But in order to gain access to the SB 846 cookie jar, PG&E has to provide a separate accounting each year.

For the second year forecast now in front of you, it's clear that Diablo Canyon cannot come remotely close to covering its annual operating costs with the revenues it earns in the electricity markets. Last year, you approved $723 million in above-market costs. And this proposed decision would add another $382 million to that.

PG&E's forecasts now cover a little more than one-third of the five-year extended operations period, and already we've got more than $1.1 billion in above-market costs. And don't forget to add in the nearly one-and-a-half billion dollar taxpayer subsidy that SB 846 and AB 180 gave PG&E in the form of a zero interest forgivable loan.

The proposed decision rubber stamps PG&E's 2026 request in full and makes no attempt to rein in the abusive accounting practices upon which $88.7 million of that request is based. And it's not as if PG&E went to great lengths to conceal what it was doing. Having gained approval in Decision 24-12-033 for a calendar-based system to choose which projects to charge to government funding and which to charge to ratepayers, PG&E knew exactly what to do when cost overruns exceeded the government funding appropriations: manipulate the project schedules to automatically convert certain transition costs into ratepayer obligations.

PG&E's financial witness described this maneuvering as, quote, "reprioritization," close quote. And he admitted that it was motivated by the need to, quote, "ensure we got back down to the 1.4 billion," close quote, amount of the state loan.

But SB 846 explicitly prohibits charging ratepayers for PG&E's costs of preparing for extended operations. The legislature expected those costs to be paid from general fund appropriations with PG&E absorbing any shortfall. The proposed decision is silent about the large magnitude and cost shifting effect of the arbitrary project reschedulings documented in the record.

In addition to those project costs that the company pushed past the Commission's approved calendar threshold, PG&E invented a whole new category of transition costs that it labels, quote, "not eligible for government funding," close quote. That was the designation according to PG&E's financial witness, quote, "if there were not enough remaining funds within the DWR loan to fund them," quote close.

Now, you and I know this is precisely the scenario for which the legislature designed the ratepayer protections in Public Utilities Code Section 712.8(c)(1)(C). PG&E's brazen attempt to avoid responsibility for the cost overruns simply erases that part of the statute. What does the proposed decision say about that? Absolutely nothing.

PG&E is shameless in characterizing other costs as not eligible for government funding. My favorite example is the $12.7 million cost for dry cask storage of spent nuclear fuel. PG&E's financial witness admitted the dry cask storage is expressly authorized in the two written agreements PG&E entered into with DWR. How does the proposed decision deal with this obvious contradiction? With silence.

PG&E's effort to relitigate the fixed management fee escalation rate approved in Decision 24-12-033 is equally underhanded. Framing the issue as simply a choice of whether the 2026 escalation should be based on the Consumer Price Index or the Electric Generation Index, which the Commission approved last year, PG&E insisted that it, quote, "does not propose to modify the 2024 fixed payment escalation factors adopted in Decision 24-12-033." But that statement is false. PG&E has packed all of the earlier years' escalation into a cumulative increase for 2026 of 15.5 percent. That is the type of impermissible collateral attack on a Commission decision that Public Utilities Code Section 1709 prohibits.

Rule 16.4 requires PG&E's request to take the form of a petition for modification. When compared to applying the CPI for a single year, PG&E is trying to grab an extra $12.1 million. What does the proposed decision recommend? Rubber stamp approval.

Although it was reined in by the changes Decision 25-06-049 made to calculating the resource adequacy market price benchmark, PG&E still seeks to recover five times the market price for substitute capacity during 2026's only scheduled outage. This stratagem relies upon a credulous Commission. Despite admitting that its own market price curves project a cost of $5.2 million, PG&E audaciously requests $26.3 million. This scam exploits the imperfect fit of

PCIA methodology to cost shifting across utility service territories.

To grant such an outlandish request, the Commission must ignore the economic benefit of scheduling Diablo Canyon outages in off-peak months and instead rely on a volume-weighted, annualized benchmark dominated by three peak months and ignore the commitment in Decision 23-12-036 to encourage scheduling of Diablo outages off peak, quote, "when it is much less expensive to procure substitution capacity," close quote, and] ignore that similar market-price curves were used by PG&E and deemed reasonable by the independent evaluator to guide pricing for more than 6,100 megawatts in Resource Adequacy contracts during the most recent year on the record.

How does the proposed decision respond? Rubber-stamp approval citing PG&E's, quote:

> "Persuasive argument that the same RA calculation methodology should be used across Commission proceedings," close quote.

I suggest that you survey California ratepayers and determine how many of them are willing to pay five times the market price in pursuit of a superficial symmetry that treats the SB 846 apple like a PCIA orange.

The tone for this proceeding was set when the assigned commissioner's scoping memo ruled that the prudency and cost effectiveness of Diablo Canyon's extended operations would be out of scope. That was an abdication of your constitutional and statutory responsibilities. Such abdication is all the more unconscionable by your admission two years ago in Decision 23-12-036, Conclusion of Law No. 60, that the Commission did not have, quote, "An adequate foundation upon which to evaluate the cost effectiveness, prudence or reasonableness of DCPP operations," close quote.

The current trajectory of PG&E forecasts has ratepayers paying between 4.5 and $5 billion in above-market costs and taxpayer subsidies to prop up this geriatric plant for its last five years of life.

PG&E is a textbook example of what the financial world calls a "stranded asset." PG&E's management announced nearly 10 years ago that the plant should close for economic reasons. It's about time this Commission started doing its job and update the veracity of that earlier judgment.

Thank you for the opportunity to address you.

ALJ CHANG: Thank you.

Next we'll have Californians for Green Nuclear Power.

ARGUMENT BY MR. MARINAK

Hello. I'm Michael Marinak representing Californians for Green Nuclear Power. Since our founding in 2013, independent, nonprofit Californians for Green Nuclear Power has advocated for extended operations of PG&E's Diablo Canyon Power Plant.

We are one of many groups advocating for the safe, abundant, reliable, cost-effective and zero emissions Diablo Canyon. CGNP's October 20, 2025 comments established that based upon PG&E's Fall Update, Diablo Canyon's 2026 net revenue requirement was projected to be $382 million. CGNP calculated Diablo Canyon's 2026 incremental cost to be a modest $21.3 per megawatt hour or 2.13 cents per kilowatt hour.

With this modest investment, ratepayers will continue to benefit from Diablo's safe, abundant, reliable, nonpolluting power equal to the output of five Hoover Dams.

As a consequence of two rounds of accelerated depreciation, the book value of Diablo is now close to zero, effectively barring Diablo Canyon cost recovery by PG&E. Despite Diablo having a multi-billion dollar market value, SB 846 reduces ratepayer burdens via the prevention of PG&E cost recovery of the plant's capital assets. The plain language of SB 846 establishes that

Diablo Canyon ratepayer obligation is the net of the plant's operational cost less Cal ISO market revenues. CGNP supports the initial ordering paragraph of the proposed decision, which affirms this plain language.

There are three key messages in CGNP's oral argument: One, Diablo Canyon is safe and reliable; two, Diablo is cost effective; and, three, Diablo produces essential synchronous grid inertia, SGI, which plays a vital role in maintaining the stability of California's grid.

Since our first filing in January 2017, CGNP has established that Diablo is a reliable and nonpolluting generator. The safety engineered in depth into Diablo was once again demonstrated on November 18th of this year at 9:54 a.m. when there was a magnitude 4.1 earthquake north of the plant five miles west of Templeton. The epicenter was closer to Diablo than the 2003 San Simeon magnitude 6.3 earthquake that killed two in Paso Robles. Plant operations were unaffected.

The word "safety" appears 19 times in the proposed decision, but none of the instances appear to address the fact that Diablo has maintained an exemplary safety record as recognized by the NRC for four decades. The word "pollution" does not appear. None of the three instances of "emission" mention the zero-emission characteristics of Diablo.

In contrast, Berkshire Hathaway Energy's coal-fired fleet is one of the most polluting in the nation according to the Clean Air Task Force, causing hundreds of premature deaths annually. Berkshire Hathaway hides the exports of its primarily coal-fired electricity to California behind the legal euphemism of "unspecified power."

CGNP previously established that over one-billion dollars of Berkshire Hathaway/PacifiCorp generation has been sold at wholesale to the mostly California entities since November 2014 via the Western Energy Imbalance Market. "Hypocrisy" is CGNP's ongoing characterization of the Commission's role in maintaining Berkshire Hathaway's air and water pollution and advocating for Diablo's unnecessary closure in their 2018 Decision in A.16-08-006, contrary to Commission's charter and California statute.

As noted in the introduction, Diablo is cost effective. Unreliable solar, wind and batteries have much higher unsubsidized cost. Lazard's LCOE-plus metric shows the grid-integration cost for intermittent solar and wind are quite substantial.

Solar and wind cost per megawatt hour, including the essential grid-integration costs, are far in excess of the cost of extended operation of a nuclear power plant. The taxpayer-funded subsidies of solar and wind are large; for example, Berkshire Hathaway uses the taxpayer-funded subsidies of the twin generation fleet to offset taxation of the profits on its large coal-fired generation fleet.

Investments in Diablo Canyon has paid the aforementioned dividends to ratepayers spanning decades of operation. In contrast, California's largest battery storage facility, the Vistra facility at Moss Landing, suffered a catastrophic fire early this year, which burnt uncontrollably for several days. Toxic smoke caused over 1,000 people to be evacuated. This fire destroyed three-quarters of the facility resulting in a loss of $400 million dollars, which is a large fraction of the total investment.

CGNP's written testimony established that providing synchronous grid inertia, SGI, is an essential grid-reliability service. Inadequate mid-day SGI was the cause of the enormous and widespread Iberian Peninsula Blackout on Monday, April 28 of this year, which killed at least eleven people who needed reliable electricity.

Subsequent analysis showed there was too much intermittent solar and wind power with its negligible

SGI resulting in insufficient SGI across the grid at the time of the blackout. The lost productivity and the cost of damaged equipment for the April 28 blackout is denominated in the equivalent of billions of U.S. dollars. Had Spain kept all seven of its nuclear reactors running, this calamitous grid failure would have been avoided. With California's ongoing focus on increasing unreliable solar, wind and batteries, California is on track to emulate Spain's example.

Even though synchronous grid inertia is a critical component of electrical grid reliability, this term does not appear anywhere in the proposed decision. The Commission may consider this omission to be non-significant, but FERC and the Western Electricity Coordinating Council both consider adequate SGI to be essential for grid frequency stability, per standards most recently issued during the Biden Administration.

CGNP has noted that Diablo's huge quantity of synchronous grid inertia stabilizes the California power grid against generation and load-step changes that could cause cascading blackouts. Each of Diablo's twin generators has about a million pounds of rotating turbines and generation components.

Diablo Canyon provides the largest source of SGI of any generator in California. Both of Diablo's generators include power stabilization systems. Important upgrade work on the Diablo PSS systems began in January 2025 and will be complete in 2027.

There are plans to build new nuclear plants around the country and to restart existing ones, as their abundant, reliable, round-the-clock electricity output is an excellent match for new, large-scale AI computer centers, which require prodigious amounts of reliable, round-the-clock power. These immense AI computer centers are increasingly important engines of growth for the 21st century economy.

It is instructive to consider a grid strategies report issued on November 20th, which shows the striking and troubling contrasts between ERCOT and Cal ISO in projected load growth, and hence economic growth, to 2030 associated with these new data centers.

ERCOT will be able to increase generation substantially. California's electricity production, and hence, economic growth, will remain constrained as a consequence of harmful and counterfactual state energy policies, and California natural gas transmission line capability limitations. For all of these reasons we have described, it is necessary to keep Diablo Canyon running.

Thank you.

ALJ CHANG: Thank you.

Next is the Coalition of California Utility Employees, CUE.

ARGUMENT BY MS. JOHNSTON

Good afternoon. My name is Darion Johnston, and I'm here on behalf of the Coalition of California Utility Employees. I'm here to specifically address issues related to the volumetric performance fees, or VPFs. These are issues that CUE has consistently been engaged in litigating over the course of the implementation of Senate Bill 846.

I will keep my comments fairly brief because we believe that the proposed decision gets it absolutely right. The law is right. It's applied correctly, and the PD comes to the correct conclusion that PG&E's 2026 VPF spending plan should be approved because it complies with the requirements and limitations of Senate Bill 846 to accelerate spending on or increase spending on the public purpose priorities identified in the law.

There's one issue I do want to clarify because it's been a point of some confusion over the course of this litigation, which is the meaning of the affordability guiding principle adopted in Phase 2 of the rulemaking implementing the statute.

The affordability guiding principle in our read is an encouragement of PG&E to adopt affordability as a consideration and how they implement and spend volumetric performance fee compensation and while I agree with PG&E that their plan does address affordability and they provide evidence in the record addressing that, this hearing is really about legal issues that could result in a legal error. And the affordability guiding principle does not create a legal basis to reject PG&E's spending plan.

And I want to make that really clear. It says specifically at least four times in the decision, the Phase 2 decision, that PG&E is encouraged to adopt affordability as the guiding principle, and it gives explicit guidance of what it should do in the event it chooses not to do that. So it's not a legal basis to overturn the decision. I'll be here for any additional questions.

Thank you for very much for your time and consideration.

ALJ CHANG: Thank you.

Next is Energy Producers and Users Coalition.

ARGUMENT BY MR. HAFEZ

Thank you, your Honor. Good afternoon, Commissioners. Samir Hafez on behalf of EPUC. Thank you for the opportunity to speak today.

The Commission much reject the proposed decision's endorsement of PG&E's calculation of the 2026 Fixed Management Fee, which uses a cumulative CPI-based escalator applied retroactively to 2022 dollars. This approach ignores the relevant statute, disregards Commission precedent, and if adopted, would wrongly exert unjustified upward pressure on rates by unnecessarily inflating costs by millions of dollars.

The remedy is simple, and there's substantial record support for it: Revise the PD to calculate the 2026 fee by applying an annual adjustment to the most recently adopted Fixed Management Fee for 2025.

When the legislature enacted SB 846, it acknowledged the unique risks of operating an aging nuclear plant and authorized PG&E to collect the Fixed Management Fee as a fixed payment set in 2022 dollars to compensate for that risk.

Public Utilities Code Section 712.8(f)(6)(a) expressly directs you to adjust the fixed payment annually using Commission-approved escalation methodologies and adjustments factors. The purpose of that annual adjustment is clear: To account for inflation between one year and the next; it is not to adjust retroactively to calculate inflation for prior years.

In Decision 24-12-033, you implemented that directive by approving a generation-specific escalator that reflects the Fixed Management Fees' intended purpose; that is, compensation tied to generation asset risk. You then applied that escalator year over year to set the 2024 and 2025 Fixed Management Fees. That means that the 2025 Fixed Management Fee already captured changes in the value of the dollar from 2022 to 2025 based on the data that was available at the time. Let that sink in. PG&E already recovered from ratepayers the cost of inflation from 2022 through 2025.

The proposed decision departs from that framework with little explanation. It endorses PG&E's use of a CPI-based escalator that the Commission has never approved and applies it cumulatively back to 2022.

This approach results in a 2026 Fixed Management Fee of 113.9 million, which is a 15.5 percent increase over the adopted 2025 value. In contrast, the record in this proceeding demonstrates that forecast inflation between 2025 and 2026 is closer to 3 percent.

The disconnect between those values is indefensible, but it's easily corrected, and you need to correct it before you adopt this PD. Rather than address the disconnect, the PD focuses on whether CPI is a reasonable escalator. But that misses the point. The problem is not just the factor; it's the cumulative application of that factor.

PG&E's methodology distorts the level of inflation that you, the Commission, is required to approve and effectively circumvents D.24-12-033 without notice or process. Annual adjustment means adjusting the prior year's adopted value. So taking 2025's value and adjusting it for 2026. Annual adjustment does not mean reopening prior years and layering on cumulative inflation.

As parties in this proceeding warned, allowing PG&E to retroactively apply a new escalator would constitute a de facto modification of D.24-12-033 and create uncertainty that invites PG&E to seek even higher Fixed Management Fees in future applications. You need to stop this cycle now by reaffirming that the escalation applies only to the year-over-year change.

This is important because every unnecessary dollar added to the Fixed Management Fee is an additional dollar paid to PG&E shareholders by customers facing an affordability crisis.

The record shows that applying either the Commission-approved escalator of the generation escalator or a one-year CPI adjustment to the 2025 Fixed Management Fee yields a 2026 value closer to $100 million, which is, roughly, $13 million less than PG&E's proposal that the PD adopts.

This alternative approach complies with law, aligns with precedent and supports affordability. In sum, this is about more than just an escalation factor. It's about upholding the statute, maintaining regulatory certainty, and protecting ratepayers. The PD's approach invites PG&E to maximize shareholder gains in future proceedings at the expense of customers.

You can and should prevent this by reaffirming the principle of annual adjustment and prohibiting cumulative recalculations. Doing so will ensure just and reasonable rates and preserve the integrity of this Commission's decisions.

Thank you again for the opportunity to speak today.]

ALJ CHANG: Thank you.

Next we'll have The Utility Reform Network.

ARGUMENT BY MR. MONSEN

Commissioners and ALJ Chang, my name is Bill Monsen. I'm a principal consultant with MRW & Associates, and I'm TURN's witness in this proceeding. Today I'm speaking on behalf of TURN because TURN's lead attorney on this matter is unavailable.

TURN is disappointed in the PD and requests changes prior to the Commission vote. The PD defers to PG&E on practically every contested issue and does not evaluate or even acknowledge many substantive arguments made by TURN and other intervenors that are backed by significant evidence. TURN urges the Commission to modify the PD to correct the outcome on three issues: fixed management fees, volumetric performance fee spending plan, and transparency in the use of government funding sources. TURN's specific recommendations are spelled out in its comments and brief, and so I won't summarize those here. But I'm going to instead direct my comments to the issues at hand.

First, I want to talk about fixed management fees. Fixed management fee, it's assessed on customers across the state, goes directly to enrich PG&E's shareholders, and does not cover any cost related to the operation of the facility. As indicated by others, the PD would allow a 15-and-a-half percent increase in the fixed management fee escalator between 2025 and 2026, even though escalation is only between 1.9 and 3.3 percent over the same period. This results in about $15 million of additional profits for PG&E in 2026 compared to what TURN recommends.

Regarding the choice of escalators, last year the Commission adopted TURN's recommendations regarding the choice of escalators. But in this proceeding, PG&E proposed and the PD adopts using CPI as an escalator -- escalation factor. The PD's justification for the change in escalation factor relies on the specific PG&E arguments for the CPI that were rejected in the last year's decision. This flip-flop on this issue undermines confidence in the consistency of Commission determinations. The PD invites PG&E to effectively relitigate fixed management fee issues in future proceedings by proposing brand new escalators or approaches if that seems advantageous.

Regarding how the one-year escalator works, TURN recommends escalating the fixed management fee by applying a one-year change in generation capital escalators. This, again, is about a 1.9 percent increase over the current fixed management fee. And as indicated before, PG&E would -- the PD would result in about a 15 percent increase or almost $15 million. This -- applying the escalator as in the PD could result in an additional $75 million in PG&E shareholder profits through 2030.

The PD would encourage PG&E to seek higher fixed management fee in future cost recovery applications by changing escalators and applying escalators for all years back to 2022. The Commission needs to stop this and clarify that the escalation in fixed management fees should be on a year-to-year basis. Given the crisis of affordability and the likely move to lower PG&E's return on equity in its cost of capital proceeding, there's no justification for raising PG&E's profits on Diablo Canyon.

Next, I want to talk about volumetric performance fees. The PD approves PG&E's volumetric performance fee spending plan without modification and applies very little scrutiny to PG&E's proposals for spending $267 million in ratepayer funds on a variety of activities in 2026. Among other things, TURN recommends rejecting the VPF plan specifically regarding contingency for safety and risk and hydroelectric generation. In the alternative, TURN recommends limiting VPF usage to overspending for more aggregated categories of costs than PG&E proposed such as the five major work categories for safety and risk and for all hydro or power generation expenses for the hydro-related VPFs.

TURN also recommends that PG&E should make a more robust showing on the alignment between its plans and the guiding principle of affordability.

The Commission has issued several decisions addressing the process for evaluating VPF plans. The PD ignores or devalues these prior decisions. In D.23-12-036, pursuant to the decision, the Commission allowed VPF plans to be modified or rejected and replaced with proposals made by intervenors. The PD declines to reject or modify PG&E's plans and provides extreme deference to PG&E despite extensive critiques by TURN and other intervenors.

In Decision 25-12-002, the Commission established several additional requirements relating to VPF plans, including directing PG&E to provide additional support for alignment between the plan and affordability goals. In response, PG&E submitted supplementary testimony that provides lip service to the requirements. It makes no changes to its plan and offers no actionable information on how the plan approves affordability. This testimony is just not a good faith effort by PG&E, but the PD approves PG&E's plan and applies none of the requirements from Decision 25-06-002.

The Commission should require PG&E to provide meaningful and comprehensive support for its VPF plans. TURN is particularly concerned that the PD does not address or respond to several of TURN's arguments about the VPF plan. TURN provided extensive evidence and data demonstrating that PG&E's proposed spending for contingencies related to safety and risk and for work on its hydroelectric facilities, which together are about $132 of the $267 million, is not reasonable because there's no evidence the funds will be used to accelerate or increase work as required by the Public Utilities Code.

PG&E's response that the VPF plans work meets the statutory requirement standard because it wasn't specifically forecast in its 2023 GRC is nonsense since the GRC provides no forecast of expense work for 2026. It only provides a forecast for the test year. And PG&E routinely funds work after the test year that was never described in the general rate case budgets.

PG&E also failed to address TURN's showing that -- PG&E's forecast of declining spending on safety and risk in 2023, and it also -- that PG&E has consistently underspent hydrogeneration in prior years. The PD doesn't mention these facts. It doesn't mention that PG&E failed to respond to TURN or TURN's arguments.

One final point on VPFs. In the comments that PG&E made regarding the PD, it -- PG&E argues that it should be allowed to use VPFs even if it underspends costs on a particular major work category. This contradicts PG&E's original proposal to only apply VPF for spending in excess of GRC-authorized forecasts of major work categories. PG&E's proposal would make it impossible to assess whether spending is incremental. The Commission should affirmatively reject PG&E's last-minute proposal.

I'm just about out of time. So I'm basically going to ask to -- for the Commission to look at PG&E's briefs and comments regarding transition costs. Despite TURN's efforts, there's no data in the record that helps ensure that there's no double counting of transition costs. PG&E has played hide the ball with regard to statements that is made in court documents regarding the magnitude of transition costs and how it may use VPFs to pay for these costs. Thank you.

ALJ CHANG: Thank you.

Now we'll move on to replies. Each party will receive five minutes for the replies. We'll start with Alliance for Nuclear Responsibility.

REBUTTAL ARGUMENT BY MR. GEESMAN

Thank you, Judge Chang. Again, John Geesman on behalf of the Alliance for Nuclear Responsibility.

I need to respond to my friends at the Coalition of Utility Employees, a fellow signatory to the 2016 joint proposal, with a reminder of what Hunter Stern speaking on behalf of IBEW 1245 told the legislature in 2022 when SB 846 was being considered:

Quote, "We stand ready to honor our commitment and have the plant closed when we know that the resources are available," close quote.

Well, here we are with 13,728 megawatts of new capacity coming online just between January of 2023 and May of 2025 according to the most recent joint agency reliability assessment. That's more than six times the size of Diablo Canyon. The Alliance For Nuclear Responsibility has strongly supported ever since the joint proposal the extra 25 percent compensation supplement paid to Diablo workers in the employee retention program, but that gravy train can't roll on forever.

I also need to respond to PG&E's defense of its spending plan for the so-called volumetric performance fees. The proposed decision handcuffs itself to an outdated formula for determining when ratepayers are, quote, "not needed for Diablo Canyon," close quote, under SB 846. The problem is when Decision 23-12-036 set that threshold at 115 percent of operating costs, PG&E was still 90 days away from publishing its first forecast of what net operating costs would actually be. No one knew then whether Diablo Canyon's annual market revenues would create a net surplus or a net deficit in operating costs.

Now you're faced with a 2026 net operating deficit of 383 million, and it makes no sense to divert 267 million collected from ratepayers into projects completely unrelated to Diablo Canyon, even if those projects are labeled critical public purpose priorities. It makes even less sense to fund these projects from the $73 million in VPFs collected from the Southern California Edison and San Diego Gas & Electric service territories. You've previously made clear that those ratepayers can't qualify for any critical public purpose priorities. Do you really think that SB 846 encourages you to tax those customers in order to provide benefits exclusively to the PG&E service territory or that you can do so without violating the antidiscrimination provisions of Public Utilities Code Section 453?

TURN's testimony and briefs have documented in minute detail how easy it is for PG&E to launder its VPF expenditures into shareholder money by choosing major work categories that have been underspent from GRC proceeds. Yes, by its very nature, TURN's argument is prospective, and the evidence is entirely circumstantial. The proposed decision dismisses such concerns as, quote, "well intentioned but overly speculative," close quote. This nonchalance is profoundly troubling. As the public has been forced to learn over many years, with PG&E, you don't need a weatherman to know which way the wind blows. California needs a vigilant Commission, not a sleepy night watchman.

Again, I thank you for the opportunity to address you.

ALJ CHANG: Thank you.

Next is Californians for Green Nuclear Power.

MR. MARINAK: CGNP has no additional comments at this time.

ALJ CHANG: Thank you.

Next is Coalition of California Utility Employees.

REBUTTAL ARGUMENT BY MS. JOHNSTON

Hi there. This is Darion on behalf of CUE. A few things to add in response to folks that are raising concerns about volumetric performance fee spending.

I think really what's happening is TURN and A4NR are essentially trying to relitigate how you all have decided how to implement SB 846 and VPFs over two decisions, the Phase 1 and Phase 2 decision in the rulemaking and in the Commission's decision last year in approving PG&E's VPF spending plan. Essentially what they're trying to do is get different requirements and limitations than exist in the current regulatory and legal framework.

That's not what this case is about. We have extensively litigated that. We've heard these arguments time and time again. And we've heard them so many times that the scoping memo for this proceeding explicitly excludes consideration of VPF spending issues beyond determining whether PG&E's plan complies with SB 846 as interpreted in the decision for Phase 1. And beyond that -- that's really the limited scope of what the Commission is doing here.

This is not a standard ratemaking. This is a volumetric performance fee compensation. That's a quote from the statute. It is compensation to PG&E. And the statute specifically and in a detailed manner directs how those funds are meant to be spent.

And I think that TURN and A4NR wish that the statute wasn't written that way. And there are different opinions about that. There have been the entire time the statute was in front of the legislature and has been litigated here. The statute says what it says. And the Commission needs to follow the letter of the law, which, as the Commission has decided time and time again, means that the review of the Commission is limited to ensuring that PG&E's spending plan on a prospective basis will accelerate or increase spending on the public purpose priorities identified in statute.

And those priorities are written very broadly. They include safety and reliability work, improvements to maintenance and operations, customer notifications, worker safety programs, increasing the state's ability to onboard new sources of renewable power. It's a long list. It gives PG&E significant discretion in determining how to spend that compensation.

That is what we're doing here. We're not relitigating or directing PG&E how to spend that money. If you look at the scoping language, that is very clear.

On the specific issue of speculative concerns about PG&E down the road misappropriating these funds, this is another issue that we've seen time and time again that you all have rejected, essentially saying at this point in time it's not actually possible to determine whether PG&E will end up misappropriating or misusing funds that at this stage are being proposed for lawful purposes. You can find language specific to that rejecting recommendations from A4NR and TURN in the Phase 2 decision where the Commission says those concerns are, quote, "moot" because there are significant accountability measures adopted after the fact, including audit requirements and ongoing spending review.

On the specific issues related to hydropower generation, proposals, and the catchall spending category for safety and reliability funds, what TURN continues to not respond to is that these programs were already approved for VPF funding in 2025. They've already been allocated VPF funds. And so it is really nonsensical to adopt a different decision on the same regulatory regime and the same factual record that the Commission saw last year. Those programs have already been funded, and they will be reviewed for compliance in the after-the-fact review as contemplated by the statute.

And, finally, a word about affordability. I think everybody in the room and in California knows how important affordability is. The legislature is acutely aware of that and passed this statute as written, which asks PG&E to increase spending and accelerate spending on specific priorities that support California's goals towards decarbonization, building decarbonization, renewable energy integration, safety, and reliability. Those programs will benefit ratepayers, albeit not necessarily in the way that TURN or A4NR are requesting. That doesn't mean that they're unlawful or there's a legal basis to deny the plan. It means that the PD does the right thing in approving it as written. Thank you.]

ALJ CHANG: Thank you, Energy Producers and Users Coalition.

MR. HAFEZ: Thank you, your Honor.

ALJ CHANG: The Utility Reform Network.

REBUTTAL ARGUMENT BY MR. MONSEN

Thank you. I appreciate the chance to speak some more on these issues. First, I want to talk a little bit about the transition-cost question that I ran out of time to talk about. PG&E indicated that the whole question of transition cost is a little bit gray, that there are costs that might fall into transition costs or might fall into extended-operation costs, but there's not really a bright line, and that's a real problem that faces the Commission because of that uncertainty.

With regard to being able to make a call on those things, the Commission needs more -- more openness and more review of those specific costs. There is a -- the cost associated with transitions, there's a report that DWR puts out. I brought a copy of it. It's four pages, including a cover, that provides almost no detail at all. That's the only information in the record about how those transition costs are being considered, and that's just not enough information. The Commission needs to provide more insight into those and have more review of those costs.

With regard to the discussion of the VPF plan, there's been assertions that the last decision in Diablo Canyon kind of decided these issues, and that's not really true. In fact, the last Commission -- or last decision said that there's were problems with what PG&E proposed and they filed a post-decision advice letter that has not been ruled upon by the Commission. It's been held.

And so we're all kind of waiting to see how the Commission decides that issue of what is incremental, and so that -- it's a little bit -- you know, it's not quite clear that that issue has been decided.

With regard to shareholder benefits, I appreciate the comments from A4NR regarding TURN's testimony and discussion of these issues.

We are kind of reading the tea leaves a little bit with regard to how PG&E could act in the future, but it seems pretty clear that there's a great opportunity, anyway, for PG&E to fund its overfunded projects and to then keep the money that it would have normally used to fund its underfunded projects, and that is a -- I mean, I went into gory detail with regard to how that works, and it's in our testimony and briefs, and I would ask the Commission to consider that more clearly.

Finally, with regard to the comments about the cost effectiveness of the plant by CGNP, the cost of operation of Diablo Canyon is not $21 a megawatt hour. That's clear. And any comparison with localized cost of energy is inappropriate because those levelized cost of energy do not in any way net out costs benefits from sale power. Thank you.

ALJ CHANG: Thank you.

Last, we'll have PG&E.

MR. MARINAK: Could I rebut that last point since I didn't rebut yet?

ALJ CHANG: Yes. Briefly.

REBUTTAL ARGUMENT BY MR. MARINAK

I just wanted to clarify what I said on the record today. I referred to that as a net revenue requirement of 382 million, which was an incremental cost. I didn't say that was the total cost. I just wanted to be clear that's what I said today.

ALJ CHANG: Thank you.

PG&E.

REBUTTAL ARGUMENT BY MS. RAFII

Thank you. On the transition costs, there was no manipulation of the transition costs of either the costs or the schedule. In hearings, our witness explained that the schedules are moved based on plant needs or outages. They're not moved based on funding type. And as explained earlier, aside from costs that are prohibited from customer rates, such as license renewal costs, which are spelled out in the statute. Many costs can be either category depending on the timing of those costs.

For example, dry cast storage cost can be recovered as a transition cost, but they're not precluded from recovery as extended operations cost.

The record in this proceeding demonstrates that PG&E optimized and maximized government funding that is available and is recovering from customers only costs that is incremental to that government funding.

On the VPFs, respectfully, some of the recommendations brought forward by parties are inconsistent with legislative language. TURN assumes that VPF spend will determine whether PG&E earns its authorized rate of return, which is speculative and unsupported.

TURN also disregards testimony from our March testimony that provides a detailed description of our accounting and financial controls that we put in testimony in part because of the concern that we sought in this proceeding. SB 846 imposed several requirements for the VPF spend. Other than those requirements, the legislation gives PG&E discretion, and the CPUC, while adding requirements to those in the statute, also gives PG&E some discretion on implementation.

So to clarify, while not required by the statute, PG&E has agreed regarding the contingency safety and risk programs in the VPF portfolio to only apply VPFs if the MAC code and major work category level are above authorized levels, but, again, that is not a requirement.

And regarding the power generation programs, PG&E has explained that the proposed programs funded by VPFs are wholly outside of the GRC base case; for example, risk reduction work that was prompted only recently by national damn failures over the past year.

The VPF programs are a diverse portfolio; they reflect stakeholder feedback, the evolving needs of the system, and consideration of customer benefits. They're a mix of programs. Some are entirely new and some expand on work previously authorized by the GRC.

On the fixed payment, the fixed payment, to clarify, is the only payment that is directed to shareholders. It is not additional to anything. There is no rate of return earned by DCPP during extended operations. There is no rate base in these extended operation years.

And on the arguments on the escalation being cumulative or retroactive, that is a mischaracterization. SB 846 establishes 2022 as the base year, and each year's payment is a separate payment that has its own relationship to 2022. It is appropriate to recalculate each payment using the base year.

On the review of transition costs, as I've described in the annual proceedings, review in the annual proceedings would not provide additional Commission review because the Commission is already reviewing these costs. Terms -- proposed review would be unnecessary and duplicative of these costs.

This proceeding, which is directed by SB 846 as modeled after the ERRA Forecast basis and the purpose is to review each year's extended operations cost, not transition cost. The legislature did not envision a duplicative process in which the extended operations cases would also review transition cost.

And on the RA market price benchmark, which is being used for RA substitution capacity, A4NR ignores the reasons why the Commission concluded that the market price benchmark is appropriate. PG&E's forward curves are not appropriate to use for RA substitution capacity because they're a snapshot in time and represent expected marginal price for small volume, RA-only transactions. They can change as market conditions, including on a daily basis; for example, if the RA market is thin, procurement of large volumes such as the side with Diablo Canyon can move the market substantially and make it difficult to transact.

Thank you.

ALJ CHANG: Thank you, everybody.

Now I'll invite Commissioner questions.

Commissioner Douglas.

COMMISSIONER DOUGLAS: I'll ask a couple questions, and then I may -- I may have a few more after others get a chance to speak as well. I'll start with a question to PG&E.

Could you speak more to how the volumetric performance peak programs in the application reduce rates or reduce upward pressure on rates, and what kinds of analysis, including quantitative analysis has PG&E conducted on those programs?

MS. RAFII: So the types of programs, the types of affordability benefits are described in our supplemental testimony and they depend on each program. So certain programs, for example, on risk-reduction work to the system benefit just in regard to the increased reliability of risk reduction. Other programs, for example, the low-income programs -- there are a few low-income programs that are relating to building decarbonization are more direct-facing programs to customers, and they provide an expansion of -- expansion of, like, availability to customers who are able to use them.

Other -- for example, the small business building decarbonization program that is a program directed at micro small businesses. So the affordability benefit for that program is for the -- helping small business with their building decarbonization efforts that they would not have been able to do otherwise. That is also an expansion of an existing -- expansion of an existing program.

In regard to the analysis that is provided, that is the -- the decision was issued after our testimony. The workpapers we provided do not include a specific rate analysis, but we saw the encouragement from our decision here, and when possible, we are planning to look at the 2027 suite of programs.

MR. DOUGLAS: All right. Thank you.

We'll move on to another question.

PRESIDENT REYNOLDS: Maybe it's a quick one. And it sounded -- if I heard right, PG&E is saying that it's not using the VPF for -- for GRC accounts where the

MAC (phonetic) hasn't -- that it's not overstepping; in other words, it's using it for categories where the MAC -- it's already gone over the MAC -- right -- you've already gone over the MAC -- right -- the amount?

MS. RAFII: Um, so --

PRESIDENT REYNOLDS: In accounts where there was underspending, you're using it for that with the assertion that it could double-counting or shifting around funds, but I thought I heard you say, no, we did get to that. We've already gotten to the authorized amount, and then we're spending on that.

MS. RAFII: Right. I can clarify. Since this was -- we were litigating this in this case, which is -- that's correct. So there is no requirement that the VPFs can only be applied if a major work category or such level is below the authorized because the requirement is that there's no double recovery in rates, but we did agree for one group of programs -- that's the -- there was a contingency group of programs referred to as "safety and risk," and those are a group of five major work categories of reliability-related programs.

And they are -- they are programs that we have agreed to in -- only apply VPFs if the major work category level and MAC code level are above authorized.

Again, it is a requirement that we've agreed for that program because those are GRC programs, and we will be demonstrating that, but, in general, for example, in the power-gen programs, there is no double recovery rates occurring, but the work that is being proposed is completely separate from what was envisioned in the GRC, completely separate from the normal base case. It's work that has emerged in its own recent years.

PRESIDENT REYNOLDS: So where -- where there's overlap of the GRC, you have already gotten -- already spent the GRC amounts.

MS. RAFII: Not exactly because there are other programs in the suite that are GRC programs in the -- in the -- in the contingency group that I was referring to. The safety and risk are all GRC programs, but there are also some programs that are related to either an expansion of a GRC program that -- or the GRC program that, for example, was maybe started a GRC program, but separated. I'm thinking of there's a battery program -- there's a wildfire-related battery program that's in the GRC, but the VPFs are going to a new program for non-wildfire areas.

So did I answer that? Does that make sense? So that's an example that I'm thinking of. That is a GRC program, but it's not one -- it's not part of my contingency group. The contingency safety and risk group is -- it is separate. It is its own separate set of programs within the suite.

PRESIDENT REYNOLDS: Okay.

COMMISSIONER DOUGLAS: I had another question for PG&E then. A number of parties -- and this came up in oral argument today, but a number of parties have cited an affidavit by a PG&E official in a federal lawsuit showing PG&E has spent 1.487 in the Diablo Canyon transition license renewal costs, which is 150 million more than provided by the Department of Water Resources for such cost after taking into account DWR administrative costs.

And so in the evidentiary hearing for the application, PG&E Witness Brian Ketelsen said PG&E was in the process of a re-prioritization to ensure we utilize the full DWR amount without going over.

Could you describe what's involved in the re-prioritization process regarding transition and license renewal costs, and how can PG&E demonstrate to the Commission that it is not, as is being alleged here, simply reclassifying those costs to enable the ratepayer --

MS. RAFII: Yes. So that declaration -- that's correct. So in hearings our witness explained that that declaration was a snapshot in time from January 2025, and so at that point, this last year's decision had been issued setting up the framework. So in regard to the re-prioritization of costs, using the framework, the -- the -- again, the process is -- again, the process is sort of based on looking at the plant needs and outages, but always at the back of the team's mind on wanting to maximize government funding to make sure that there's -- the use is optimized, and so applying the -- applying the framework to the project cost that had just been approved, the -- the -- project costs are able to -- and the cost -- the transition costs are able to be used for the government funding, and then costs that appropriately extended operational -- extended operations funding are recovered from customers.

What I had mentioned too, though, is that the -- at the end of the day many costs are not by nature either/or. So there's a limited set of costs that are prohibited from customer recovery, but other costs, for example, nuclear fuel costs can be either transition or extended operation depending on its fuel cycle.

So an example like that, this is where the time-line based framework that was approved in December of last year was helpful to us in making those decisions and helping re-prioritize them.

COMMISSIONER BAKER: I just want to make sure I understand it. So the difference between the two numbers, the one in the affidavit lawsuit, like 100-and-some-million, those costs, you're saying, could have been either/or, and today you would, based on the decision we issued this last year, you would classify those as not for -- those were not for ongoing -- or for re- -- just so I understand what you're saying.]

MS. RAFII: Yes. That's correct. So -- so there are costs that are considered transition costs that could be recovered from customer rates reasonably.

And the -- there was a second part to your question that I'm trying to recall. When you were -- yeah. But you were correct -- you're correct in that description that the -- yeah. Sorry. There was a point that I wanted to clarify that you had said, and it escapes me. But overall you're correct that the costs that -- oh, now I remember it, the license renewal.

So the license renewal are fully transition -- so I thought you had mentioned something regarding license renewal. Those costs are fully transition costs recovered from governmental funding sources. But there are other costs that are not license renewal and occur during -- after the end of the retirement date that could have been considered extended operations costs but could be categorized for the purposes of cost recovery as either transition or extended operations. And we have made an effort to maximize usage of the government funding.

COMMISSIONER HOUCK: My question is on a different issue.

COMMISSIONER DOUGLAS: Oh, let's keep on this one. If it's just staying on this topic, I have a question for A4NR that I think is just related to this topic. And so maybe we take it now, if that's all right.

A4NR stated in testimony and comments that PG&E is allegedly pushing back Diablo Canyon project timelines to recover their costs from ratepayers rather than paying for them through the Department of Water Resources loan. And in particular, A4NR has questioned PG&E's use of the incurred after November 3rd, 2024, framework compared to the generally began after November 3rd, 2024, framework in order to distinguish between preparation and operation costs.

What is the distinction A4NR is making between "incurred" and "generally began"? And could you describe why you think it is significant here?

MR. GEESMAN: It's addressed in our comments and on the proposed decision and in our brief in more precision than I'm able to muster verbally. But the point is that since last year's decision approving PG&E's proposed calendar format, PG&E slightly tweaked the threshold date as to how much costs incurred prior to that threshold date would, in fact, be considered preparatory or transition costs.

The challenge here is not as PG&E has described it today in terms of maximizing government funding. They've overspent government funding. That was the point of Mr. Ketelsen's declaration in federal court. They were $157 million in their projection for what they would spend from government funding when compared to the DWR loan. They needed to figure out a way in which to get down to the amount of the DWR loan, so they reprioritized. The way they reprioritized -- in addition to this slight tweak about incurred before November 4th, the way they reprioritized primarily was pushing the schedules around.

In our testimony is an attachment from a Public Advocates Office discovery request that clarifies some $92 million of schedule adjustments, some of which were not in last year's forecast, some of which were originally in this year's forecast. In addition to that, you have Mr. Ketelsen's acknowledgment of the

157 million that needed to be reprioritized. Only one way to reprioritize, and that's to push the projects around on the calendar.

COMMISSIONER DOUGLAS: And maybe this is putting me into my next question exactly for you.

So A4NR states in its comments on the PD that PG&E revealed what are characterized as unexplained timeline alterations to over 47 million in Diablo Canyon costs in a data response to Cal Advocates. And in that data response, PG&E states that the timeline changes represent new or changed work scope, a change in planning order numbers or because the projects were not planned to incur costs for the 2023 to 2025 record period. So in A4NR's view, does that explanation adequately explain the changed timeline? And if not, why not?

MR. GEESMAN: As the Public Advocates Office followed up with the question "Was there any project that you wouldn't change? What about high-risk projects? What about projects that entailed a certain level of safety risk," PG&E's answer was no, none of those projects were exempted from reprioritization.

It's very clear from that that a reasonable inference of the reprioritization was to move project schedules so as to get the government spending down to the level of the DWR loan.

COMMISSIONER DOUGLAS: Let me just see if PG&E would like to speak to that.

MS. RAFII: Thank you. To -- to respond to that point and your question and A4NR's comments, the amount in the declaration is a forecast of spend. So it wasn't actually spent at the point that the federal lawsuit was occurring. And it was a declaration that was an attachment. So PG&E had the ability to take another look at costs following the decision. The fact is some costs -- many of these costs can be considered either transition or extended operations. So that allowed PG&E to maximize government funding. But it is not overspending government funding. And the changes in the schedule are legitimate changes that occur as part of operating a plant.

COMMISSIONER DOUGLAS: Other topics or questions?

COMMISSIONER REYNOLDS: I want to touch on a couple of items, hopefully both pretty briefly.

First, for RA replacement of power for planned outages, I'm just kind of thinking about how generally we don't allow utilities to make or lose money on fuel purchase costs in general. It's essentially a pass-through for customers. And as we have had a debate here about what's the right method to forecast those costs, I wonder why we don't have just a true-up mechanism because this is a -- this is a set of costs that will have actual market transactions backing the need to acquire replacement power that we can look at after the fact.

MS. RAFII: The -- that's correct. There is no money that is made. These are pass-through costs. But the true-up occurs the following year. So once the -- the case is based on a forecast based on the forecast outage schedule and then the forecast market price benchmark. And then the following year, the final market price benchmark is issued. And based on the actual outage schedule, the amount is trued up, and it is reflected in the following year's rates starting January 1st.

MR. GEESMAN: PG&E actually addresses this in their reply comments in response to -- excuse me -- in their response to a petition for modification, which we filed with regard to -- I believe it was D.23-12-036. Because of the sharp revisions made in last year's calculation of the market price benchmark format -- forecast, PG&E agreed with a portion of our proposed petition for modification and suggested that the actual costs ought to be used for forecast purposes as well.

And we think that's a good idea.

COMMISSIONER REYNOLDS: Great. Thank you, both.

And then one other topic I wanted to ask about briefly is escalation. I have to say I'm -- I think about escalation in some of the other venues where we escalate costs, and I do find it a little tricky to think about a situation where we're forecasting for one year and adopting rates or revenue requirement based on that, and in the next year, we're escalating a cost element not from the adopted revenue requirement or -- but actually going back several years in time, which seems very different than how we escalate costs in other venues, including our general rate cases. It's hard for me to imagine us taking, for example, a general rate case in 2030 and going back to the actual costs in 2023 and escalating from there. So I wonder if PG&E and other parties could help me think through this method of escalation.

MS. RAFII: Yes. Thanks. So the escalation -- we looked at the statute that says the fixed payment is in 2022 dollars and each year will have its own relationship to that date. And so the appropriate escalation factor is from 2022. And that is why we think it makes sense to do that in each forecast case.

And here we think the methodology that was selected was the correct methodology of CPI-U.

COMMISSIONER HOUCK: Can you elaborate a little more? Because I'm sharing the same concerns as Commissioner Reynolds. And I do want to see if Mr. Hafez would also want to respond given the arguments he made earlier.

If the statute says it's an annual true-up and if we use a CPI that's looking at, like, a 2.9 percent, are you saying we go back to 2022 every year? And what about the years in between and what was already potentially collected? So I guess I'm having a hard time seeing why it's not cumulative as opposed to incremental, which is what I believe the statute says it should be. So if you could maybe explain it or walk me through the math, I think it would be helpful.

MS. RAFII: So the way we describe it is that the dollars are set in 2022 dollars so that whatever $50 million is in 2022 for each year is what the analysis would be. It wouldn't be cumulative in the sense it's not adding anything. It's not adding '23, '24, '25. It's just from '22 to '26 in this case.

COMMISSIONER HOUCK: So I guess when you're doing the '22 to '26 -- and I don't know if any of the other parties want to chime in and help. How does that relate to -- if the CPI is, say, 2.9, as EPUC had indicated, between '25 and '26, between 2022 and 2025, how are you calculating? What is the, I guess, number you're using? And are you saying that that's a static number that every year we would go back to 2022? Because I guess I'm having the same problem that Commissioner Reynolds has as to why that would be reasonable here.

And maybe that goes to maybe why the CPI in this particular case may not be the right factor or -- and, again, Mr. Hafez, if you wanted to also --

MR. HAFEZ: Yeah. I mean, I would defer to Mr. Monsen, TURN's witness, that addressed this. But we read it the same way that you do, Commissioner. The statute says annual adjustment. It makes sense. The Commission already adjusted that 2022 dollar number from 2022 to 2025. So now this is an incremental increase. What was inflation -- what will inflation be between '25 and '26? And so that's where that -- applying either the annual CPI adjustment escalator or the generation-based escalator is the more appropriate way to apply to that '25 value.

PRESIDENT REYNOLDS: Can you, though, explain how that squares with the statutory language that says that each year there's a volumetric payment equal to

$6.50 in 2022 dollars? That just seems like each year we have to look at 2022 dollars.

MR. HAFEZ: This is for the fixed management fee; right? And so --

PRESIDENT REYNOLDS: Am I looking at the wrong --

MR. HAFEZ: I believe so, Commissioner. It's the --

PRESIDENT REYNOLDS: You referred to -- PG&E referred to the 2022 dollars.

MS. RAFII: That's correct.

MR. HAFEZ: The statute sets it out. It's $50 million per unit in 2022 dollars.

PRESIDENT REYNOLDS: Oh, it's the next section. Yeah. But it says 2022 dollars.

MR. HAFEZ: Right. So in D.24-12-033, the Commission calculated what the 2025 fixed management fee would be escalated from 2022 dollars. So now ratepayers have paid what that payment amount is from 2022 to 2025. The issue here in this proceeding is what the payment should be -- what that value is in 2026 based on the escalation between '25 and '26. It's annual escalation.

MR. MONSEN: I think the issue here is that because PG&E is proposing to change escalators from what was adopted in the last proceeding, it decided to go back and look from 2022 through 2025 and then apply the 2025 CPI increase to 2026.

The problem is when you look at 2022 through 2025 using the CPI, it's significantly higher than the value that was adopted by the Commission last year for fixed management fees. And so that -- that's the disconnect. And that's why I spent some time talking about the concern that suddenly we're opening the door to PG&E potentially deciding, well, maybe we like Producer Price Index. Maybe we like the cost of cotton. Maybe we like something -- some other index, and then we'll go back to 2022 and escalate things forward. And that just is -- it's an absolute can of worms as far as I'm concerned.

PRESIDENT REYNOLDS: Isn't that a disagreement about the index that should be used versus going back to 2022?

MR. MONSEN: Well, it is -- I'm sorry. It is a question about which index but also about how you apply the index. So if you were to say -- and I believe it was -- Cal Advocates recommended a completely different index in this proceeding for going from 2025 to 2026. And that's -- that's a fine argument to have as to which one of those escalators could be used. But to go all the way back to 2022 just means there's an awful lot of potential monkey business that could be done.

COMMISSIONER DOUGLAS: So just as a follow-up question on that. One is that -- I don't know if you saw it. There is a sentence in the PD that says that from hereon forward it would be CPI so that we wouldn't have the shifting of index. And so I have maybe two questions for you because I'm also trying to get to the bottom of is it the index, is it how the index is applied, is it a combination of those that's raising concerns. So I think if you could address the extent to which that sentence -- and that idea that it would be fixed on one index is helpful? Or is the issue which index it is? Or is the issue how it's applied?

And I have a question -- and I hate to hit you with two questions at once, but I just will because it's also on point here, I think.

So in TURN's comments to the PD, TURN proposed an alternative CPI-based method of escalating the fixed management fee by applying it only to the 2025 fee amount rather than applying the CPI starting in 2022. And so the question is whether you see any concerns or challenges with the -- with respect to the fact that the fee would be the result -- or the amount would be the result of two different escalation methods.

MR. MONSEN: I'll try to respond, but tell me if I'm missing what you're asking.

TURN did propose in its testimony that it could use -- the CPI could be used to escalate from 2025 to 2026. That wasn't its preferred method. The preferred method was to continue with the generation capital cost escalators that were adopted last time to go from 2025 to 2026. So the choice of escalators to go from one year to the next from an adopted fixed management fee that's adopted in a decision to the next forecasted fixed management fee, that's a completely fine argument to have with regard to which escalator is the appropriate one at that time.]

Okay. I don't know if that responded to what your question was.

COMMISSIONER DOUGLAS: Maybe partially, but how does that square with the statutory language?

MR. MONSEN: I'm going to have to take a pass on that. It's beyond my pay grade.

COMMISSIONER HOUCK: Maybe Mr. Hafez could answer that because I think it goes to the annual -- maybe Mr. Hafez could address that.

MR. HAFEZ: I mean the Commission escalated it last year to 2025 dollars based on the data available at the time. To come in now and say, well, we're going to now figure it out again that all the way through 2022 --

again, it revisits and clearly attacks what the Commission said was the 2025 value of the Fixed Management Fee. The Commission now comes in and annually adjusts based on the 2025 value.

PRESIDENT REYNOLDS: Don't we have to each year figure out what $50 million is in 2022 dollars?

MR. HAFEZ: I don't think so.

PRESIDENT REYNOLDS: Is that what PG&E was saying?

MS. RAFII: If I can respond. That is correct. So the statute is in 2022 dollars in each year. The analysis is what the amount is from 2022 dollars. On the -- on the -- on the comments on the escalator, I can respond --

PRESIDENT REYNOLDS: Well, can I just ask, I'm not sure how we can ignore it's in 2022 dollars in the statute.

MR. GEESMAN: I don't think you should, Commissioner. I think the question is how do you translate that Fixed Management Fee in 2022 dollars into whatever the current year is.

PRESIDENT REYNOLDS: Yeah.

MR. GEESMAN: This case says, what is it in 2026 dollars? I think the point that TURN and the energy producers and A4NR are making is that you already decided what it was in 2025 dollars. PG&E is seeking to relitigate that. If they want to do that, they ought to file a petition for modification. That's what your Rule 16 says.

COMMISSIONER BAKER: Can I --

PRESIDENT REYNOLDS: That's changing the mechanism --

MR. GEESMAN: Yes.

MS. RAFII: Can I respond to A4NR's comments? PG&E is not trying to undermine last year's decision. That decision was made using the capital generation escalation factor. As we've discussed, regardless of which factor is used, the base year is 2022 dollars. It's set up in the statute, and the capital generation factor, the factor that was used last year, this year has a 20 percent increase. So it is a -- it was a volatile methodology. And, for example, last year it was deflationary; this year it is up 20 percent.

COMMISSIONER BAKER: Before you jump ahead, I just want to make sure. So another way of looking at what you're asking us to do is to instead of going back to 2022 dollars, we want to make sure today we are going back to 2025 dollars.

When -- you know -- which I'm -- which I'm not so -- I don't think that is -- I would argue that -- at least the way I read the plain language of the statute is inconsistent. I do understand the argument by changing the methodology you risk kind of picking and choosing that, but I think that's -- I think those are -- those are two separate arguments. And I think one has, at least in my mind, more merit than the other given that the statute says, you know, we want to make sure this is consistent with 2022 dollars.

COMMISSIONER REYNOLDS: As I'm understanding the argument, it's that by adopting a 2025 revenue requirement, we escalated in -- we escalated in 2022 dollars to 2025 value, and by escalating 2025 to 2026, we would still be starting from 2022 dollars and it would determining what the value is in 2026 in 2022 dollars.

And I also appreciate that changing methodology for calculating escalation year by year is a problem, and I actually don't know that -- I mean, the commissioner was asking her question about whether establishing this decision and that we're going to consistently use CPI creates the -- alleviates some of the problems for the future, and I think that question was directed to TURN, so I will pause there.

MR. MONSEN: Okay. So deciding that we are going to go with CPI as the method for moving forward is a decision that the Commission can make, and it might not be what we would recommend, but to go from 2025 to 2026 using CPI and going forward using CPI, that's -- you know, that's certainly -- that's a decision that the Commission should make based on its understanding of how things should escalate from 2025 to 2026; that's correct.

I guess I did want to say -- I'm jumping up and down; I'm sorry about that. With regard to the point that PG&E made regarding the capital costs escalation for this year, based on the information they provided in their supplemental testimony, escalation from 2025 to 2026 is not 20 percent. It's 1.9 percent. And so I just wanted to make sure we're all clear on that.

MS. RAFII: May I respond? The 20 percent is from the capital generation factors from 2022 to 2026.

MR. MONSEN: And that's right, and that's going back and saying we're going to go back and forget about what we decided last time with regard to the forecast -- adopted forecast for Fixed Management Fees for 2025. We're going to go back and look at history, and, you know, what happened in the past, and that's -- I think that's just a real problematic way to go.

COMMISSIONER DOUGLAS: I got another one on this topic for TURN, so I'll just keep us moving here.

So in testimony and comments, TURN has cited what it says is PG&E's refusal to provide communications it has had with S&P about how and why S&P updated its Quarter 3 2023 nuclear generation forecast capital cost escalators, which is proprietary S&P data.

Does TURN have any concerns that using S&P forecasts to escalate the Fixed Management Fee would provide less transparency?

MR. MONSEN: There's no question that CPI is a widely recognized index. That said, I would note that the CPI forecast that was used by PG&E, in fact, is not the same as the actual CPI for 2024. 2025 is a forecast. We are still in 2025. They're all forecasts, but the fact that the capital cost escalation are produced and used, I'd have to say, by PG&E in the general rate cases, they use those -- they use the same S&P capital cost escalation factors in the general rate case.

And for some reason in this case, it was suddenly felt to be some sort of high -- you know, high-confidential issue that we can't -- we couldn't get, and we had to kind of drag them out of PG&E. And, ultimately, we had to go to the general rate case to find the escalators for hydro and for gas, but PG&E refused to provided the nuclear escalator that we were asking for.

MS. RAFII: If I can respond. The conversations that we had with S&P earlier in the case resulted in them reminding us that we do have a contract with them and our contractual obligation is not to share S&P data without an NDA, but through the course of the proceeding -- this includes the course of the GRC as well -- PG&E negotiated with S&P to allow some subscription data to be shared publicly.

So this was all happening during the pendency of the case. So that is why in the Fall Update the S&P forecast information for our case-specific information was shared. And we understand that it was challenging, and we also experienced those challenges. So we expect it to be smoother next year.

MR. MONSEN: I think your question, though, was going to what happened in 2023 and 2024 to make the capital cost escalators change from what CPI forecast in -- I think it was like July of 2023 to the actual value at the end of 2023.

And we were trying to understand how they moved as far as they did within a six-month period. And we asked PG&E those exact questions, and PG&E said, we can't really tell you. That to me is unsatisfying. I mean in a prior life I did forecasting myself, and you always go back and look at your forecasts -- and say, okay, how'd we do, what happened -- and try to explain what went on.

And that's what we were trying to understand from S&P, but PG&E claimed they couldn't provide that information, but it would surprise -- I mean S&P is a pretty well-known, reputable forecasting shop. So why they couldn't explain the huge variation in that one index, which was the Nuclear Cost Index, which was just a huge miss over a six-month period. That's what we were trying to understand.

COMMISSIONER DOUGLAS: Yeah. That's helpful and part of the reason for the question was just getting at, first, the issue of volatility, and the second, the issue of transparency, which is the proposal in the PD to shift to a different benchmark. And so I'm going to ask one more question on this, even though I feel like we've, perhaps, asked enough questions on this.

I'm going to ask this one to EPUC. So in your comments on the PD, you write:

> Allowing PG&E to escalate the Fixed Management Fee using CPI you started in 2022 is contrary to law and inconsistent with legislative intent.

And you write -- you argue that instead the CPI used methodology that should be applied only starting in 2025, and I think it would help probably all of us to hear you explain to us your vision of legislative intent and how you see it supporting your...

MR. HAFEZ: Thank you. The intent was --

COMMISSIONER DOUGLAS: In plain language. Sorry.

MR. HAFEZ: So the language says -- the legislature said we want PG&E to be able to recover $50 million per unit, and when they enacted that statute, they set it in 2022 dollars because that was when -- they needed to set it to a time; right?

And so the legislature then said that the Commission shall adjust that amount annually based on escalation. The Commission did that last year, and adjusted that 2022 value to 2025 dollars. The language is clear. It says annual adjustment. So now we read the statute to clearly say, adjust that 2025 value to 2026 based on Commission-approved escalation methodology.

COMMISSIONER DOUGLAS: Thank you.

Any other comments on that?

MS. RAFII: I'd like to quickly respond to the comments. In our Fall Update on pages 2 to 3, we do provide some explanation on the changes between the S&P

data. So the rates that were set in January 2025 used Q3 2023 data. And the responses in this proceeding that we provided used updated data from 2025, and so that accounts for the change. There was significant change.

And the explanation for it, which was provided in our Fall Update, relates to certain expectations regarding supply, inventory, and other external items such as federal administration policies, so that -- that is explained in the Fall Update.

MR. MONSEN: I'd like to respond to that. The information that PG&E provided was based on emails between the S&P product manager and PG&E. There are many -- I have to imagine that there are many, many clients that S&P has with regard to these escalators, and the fact that PG&E was unable to provide anything from S&P other than what appeared to be an email dashed off by a product manager is hard for me to believe given what I know about forecasting.

ALJ CHANG: Any further questions from commissioners?

(No response.)

ALJ CHANG: Seeing none, that concludes this oral argument. Thank you all for your participation. We are now off the record. Thank you.]

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(At the hour of 3:32 p.m., this matter having been concluded, the Commission then adjourned.)

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BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE

STATE OF CALIFORNIA

CERTIFICATION OF TRANSCRIPT OF PROCEEDING

I, JACQUELYN HAUPT, CERTIFIED SHORTHAND REPORTER NO. 13964, IN AND FOR THE STATE OF CALIFORNIA, DO HEREBY CERTIFY THAT THE PAGES OF THIS TRANSCRIPT PREPARED BY ME COMPRISE A FULL, TRUE, AND CORRECT TRANSCRIPT OF THE TESTIMONY AND PROCEEDINGS HELD IN THIS MATTER ON DECEMBER 1, 2025.

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JACQUELYN HAUPT
CSR NO. 13964

BEFORE THE PUBLIC UTILITIES COMMISSION

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CSR NO. 8916

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