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DATE:

WITNESS: John Geesman

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

PREPARED TESTIMONY OF JOHN GEESMAN

ON BEHALF OF THE ALLIANCE FOR NUCLEAR RESPONSIBILITY ("A4NR")

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I. INTRODUCTION.

Q01: Please state your name and business address for the record.

A01: My name is John Geesman, and my business address is: Dickson Geesman LLP, 1970 Broadway, Suite 1070, Oakland, CA 94612.

Q02: Are your professional qualifications included in your testimony?

A02: Yes, my professional qualifications are contained as Appendix A to my testimony.

Q03: Was your testimony prepared by you or under your direction?

A03: Yes, it was.

Q04: Insofar as your testimony contains material that is factual in nature, do you believe it to be correct?

A04: Yes, I do.

Q05: Insofar as your testimony contains matters of opinion or judgment, does it represent your best judgment?

A05: Yes, it does.

Q06: Does this written submittal complete your prepared testimony and professional qualifications?

A06: Yes, it does.

II. SUMMARY OF TESTIMONY.

Q07: What is the purpose of your testimony?

A07: The purpose of my testimony is to provide evidence in support of A4NR's challenge to the reasonableness of certain portions of PG&E's proposed revenue requirements for the 2020-2022 rate cycle related to the Diablo Canyon Nuclear Power Plant ("DCNPP").

Q08: How would you summarize your testimony?

A08: Conditions have changed greatly in PG&E's service territory since PG&E, A4NR and others executed the Joint Proposal to Retire DCNPP ("Joint Proposal") on June 20, 2016. A primary inducement for retiring DCNPP, the projected loss of bundled customer load to Community Choice Aggregation ("CCA") and Direct Access ("DA"), has now progressed to levels that the Joint Proposal anticipated would not occur until 2025. Continued reduction in the costs of electricity from solar, wind, and natural gas has rendered DCNPP output economically uncompetitive, and the Power Charge Indifference Adjustment ("PCIA") methodology adopted in D.18-10-019 for calculating above-market costs assigned $410 million to DCNPP for 2018 and projects $523 million for 2019. Nor can PG&E rationalize these above-market costs on the basis of avoided greenhouse gas emissions, since purchasing $523 million in offsets at the AB 32 auction price would more than quadruple the annual emissions savings PG&E claims for DCNPP. DCNPP's inability to be flexibly dispatched in response to steep daily load ramps up and down has made grid operations more difficult, and increased renewable curtailments as more intermittent solar and wind resources come online. Continuing to incur DCNPP costs which are avoidable – like the DCNPP 2020-2022 O&M and Capital expenditure budgets – would be unreasonable and inconsistent with just and reasonable rates. Doing so in the 2020-2022 rate cycle would inflict substantial above-market costs on a dwindling base of bundled customers and unnecessarily penalize former bundled customers, most of whom are now served by CCAs

that foreswear inclusion of nuclear-generated electricity in their portfolios and may be precluded by their charters from doing otherwise. PG&E's wildfire culpability has intensified a search for additional headroom within existing rates from which to fund fire-hardening improvements to its transmission and distribution system. Past precedent would enable an accelerated return of (and reduced return on) DCNPP undepreciated investment in order to recycle such capital to higher priority uses without impacting current rates. Recognition of DCNPP's status as a stranded asset on which further expenditures (other than decommissioning) cannot be rationalized is the first step toward accomplishing such recycling.

III. CONDITIONS HAVE MATERIALLY CHANGED.

Q09: Can you please elaborate on how conditions have changed since the Joint Proposal was executed three years ago?

A09: Yes. PG&E's Opening Brief in A.16-08-006, the proceeding initiated by the Joint Proposal, summarized the underlying rationale for DCNPP's retirement:

> First, the electricity needs of PG&E's bundled customers is decreasing significantly. Ongoing and aggressive EE polices are projected to reduce overall electric consumption, as evidenced by the mandate in SB 350 to double the amount of EE by 2030. Customers are also expected to increase the amount of electricity generated through DG, especially privately-owned solar resources. In addition, PG&E's bundled customer base is likely to significantly decrease as many households and businesses buy their generation from alternate providers, either through DA or CCA. There is a clear downward trend on customer sales that is reducing the need for Diablo Canyon after expiration of its licenses.
>
> Second, California's energy policy is focused on reducing GHG emissions by advancing preferred resources, such as renewable resources, distributed energy resources (primarily rooftop solar), energy storage, CHP, energy efficiency and demand

> response programs. California's energy policies prioritize these types of resources over other available options, including nuclear power. This clear policy preference displaces the need for a significant portion of Diablo Canyon's generation.
>
> Third, as the electric grid in California continues to evolve, so too will the character of resources needed to operate the California electric system reliably. Given California's energy goals that require reliance on renewables – at least 50 percent by 2030—the system will need more flexible resources and less non-renewable, base-load generation. Diablo Canyon is not a good fit under these circumstances. In fact, retirement of Diablo Canyon in 2025 will help reduce the amount of renewable resources expected to be curtailed during overgeneration conditions.[1]

The cornerstone of this rationale, the anticipated significant decrease in PG&E's bundled customer base, has accelerated beyond the A.16-08-006 expectation. Prior to filing A.16-08-006, PG&E conducted an extensive analysis of the cumulative impacts of state policy changes on bundled customer demand and future supply needs, concluding, "These forecasts show that a substantial portion of DCPP's energy is anticipated not to be needed to serve PG&E's bundled electric customers beyond 2025."[2] The forecasts were "anchored" by a Reference Case and included both Low Load and High Load scenarios. While PG&E's bundled sales comprised 82% of its service territory load in 2017, PG&E projected this proportion to decline by 2025 to 56% in the Reference Case, 63% in the High Load scenario, and 44% in the Low Load scenario.[3] PG&E's forecasts anticipated continued erosion of bundled customer base thereafter, envisioning decline by 2030 to 54% of service territory load in the Reference Case, 62% in the High Load scenario, and 42% in the Low Load scenario.[4]

PG&E's responses to data requests by A4NR in this proceeding establish that current erosion of its bundled customer base – now estimated at 47% of service territory load in 2019[5]

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[1] A.16-08-006, PG&E Opening Brief, pp. 17 – 18.
[2] *Id.,* p. 12.
[3] *Id.,* p. 13, citing A.16-08-006 Ex. PG&E-1 at p. 2-10, Table 2-2 (Frazier-Hampton).
[4] *Id.*
[5] GRC-2020-PhI_DR_A4NR_002-Q08.

-- already exceeds the level projected for 2025 which formed the empirical underpinning of the Joint Proposal and A.16-08-006. In fact, 47% represents a greater decay in bundled customer load than any of PG&E's A.16-08-006 scenarios, even for 2030, except Low Load (and, notably, the Low Load scenario was already the most unfavorable for DCNPP). And PG&E's April 2018 projections made for the Commission's PCIA rulemaking, R.17-06-026, anticipated a continuation of this trend: bundled customers would diminish to 45% of service territory load in 2020; 44% of service territory load in 2021; and 42% of service territory load in 2022.[6] The projected 45% bundled customer level for 2020 has been reaffirmed by the January 29, 2019 declaration of Fong Wan, PG&E's Senior Vice President of Energy Policy and Procurement, in the PG&E bankruptcy filing.[7]

PG&E was unequivocal about the significance of its analysis in A.16-08-006: "by 2025 and in 2030 only about 50% of DCPP's energy output is needed. In the Low Load scenario the need for DCPP drops to 26% of the plant's output …"[8] In PG&E's assessment, "the growth of EE [energy efficiency], DG [distributed generation] and CCA/DA combined with the policy priority for preferred resources squeezes out the need for DCPP's energy in 2025 and 2030 under the Reference Case."[9] In response to data requests from A4NR, PG&E declined to provide any update of its A.16-08-006 assumptions for the 2019 – 2022 period.[10] PG&E's responses to six

[6] R.17-06-026, Ex. IOU-1, p. 1-17, Table 1-2, citing "current internal load forecasts."
[7] Case No. 19-03003, U.S. Bankruptcy Court, Northern District of California, San Francisco Division, Document No. 3, ¶ 21.
[8] A.16-08-006, PG&E Opening Brief, p. 15.
[9] *Id.*
[10] GRC-2020-PhI_DR_A4NR_002-Q09, GRC-2020-PhI_DR_A4NR_002-Q10, GRC-2020-PhI_DR_A4NR_002-Q11, and GRC-2020-PhI_DR_A4NR_002-Q12.

data requests from TURN articulated the following rationale for not evaluating a permanent shutdown of Unit 2 at the time of its September 2019 refueling outage:

> PG&E did not consider this option because PG&E agreed in a Joint Proposal filed with the California Public Utilities Commission August 11, 2016, to shut down Diablo Canyon Unit 1 and Unit 2 at the expiration of the current operating licenses in 2024 and 2025, respectively. The CPUC approved the Joint Proposal in D.18-01-022 and the California legislature endorsed those shutdown dates for the Diablo Canyon units when it enacted Senate Bill 1090.[11]

PG&E's explanation requires a material misreading of D.18-01-022. Ordering Paragraph 1 and Conclusion of Law 1 are unambiguous in characterizing 2024 and 2025 as outer limits (see footnote 32 on page 14 below), notwithstanding PG&E's declaration in the Joint Proposal that it intends to operate DCNPP "to the end of its current NRC operating licenses."[12] And SB 1090, enacted after D.18-01-022, makes no reference to specific shutdown dates or years.

As noted in Mr. Wan's declaration to the bankruptcy court, PG&E also anticipates a greater future loss of bundled load to Direct Access than could have been foreseen in the 2016 Joint Proposal and A.16-08-006:

> while DA load has remained relatively consistent since 2015, new legislation passed in 2018 requires the CPUC to increase the current DA cap by 4,000 GWh statewide, apportioned among investor-owned utility ("IOU") service territories, including those of the Debtors, by June 1, 2019. While the CPUC has not yet implemented this statute, the Debtors expect that the DA load in its service area will grow when it does.[13]

[11] GRC-2020-PhI_DR_TURN_064-Q02. Except for the phrase, "PG&E did not consider this option because", PG&E used the same quoted language in GRC-2020-PhI_DR_TURN_064-Q03, GRC-2020-PhI_DR_TURN_064-Q04, GRC-2020-PhI_DR_TURN_064-Q05, GRC-2020-PhI_DR_TURN_064-Q06, andGRC-2020-PhI_DR_TURN_064-Q07.

[12] A.16-08-006, Attachment A to Application of PG&E, Sections 1.2. See also Section 5.1., which uses the phrase, "to the end of its currently authorized NRC license life."

[13] Case No. 19-03003, U.S. Bankruptcy Court, Northern District of California, San Francisco Division, Document No. 3, ¶ 19.

Similar to its outdated projections of retained bundled customer load, PG&E's system planning explanation in A.16-08-006 for the DCNPP retirement decision has been buffeted by headwinds of change. As the utility previously reasoned,

> As the electric grid and CAISO system resource mix continues to evolve, so too will the character of resources needed to operate the grid reliably. Given the 50% RPS by 2030 policy goal, the electric system will need more flexible resources while the need for baseload electricity supply will decrease. By 2030, Diablo Canyon's baseload generating profile does not fit the hourly demand profile associated with PG&E's bundled customers. Figure 2-5 shows the percent of DCPP generation that would be needed by PG&E's bundled customers by hour for each season in 2030. Overall, the need for DCPP's generation is significantly below 100 percent on average in almost all hours. Winter and Fall have the highest need for Diablo Canyon due to higher loads and reduced solar generation, while Spring and Summer have the lowest average need for Diablo Canyon generation. Figure 2-5 reinforces the conclusion that the generation needed for bundled customers in 2030 will need to be flexible throughout the day.[14]

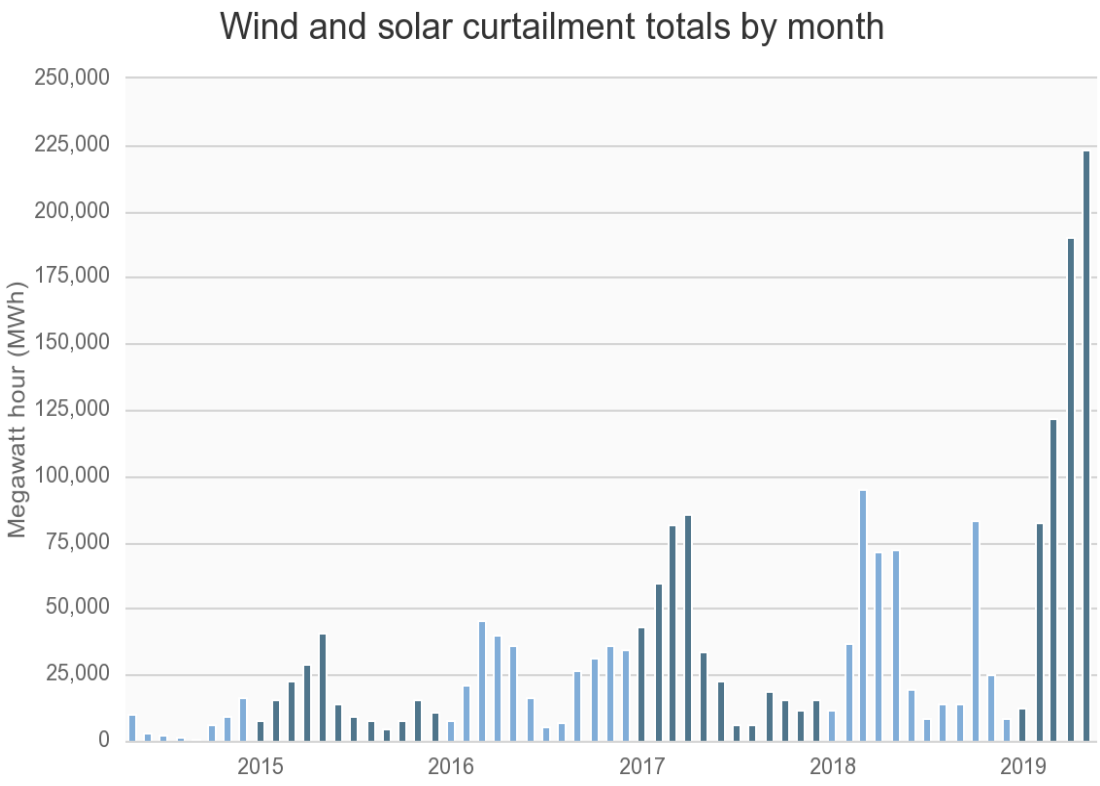
But SB 100, enacted in 2018, moved the 50% renewables target to 2026 from 2030 (and set the 2030 target at 60%). And, the accelerating presence of renewables on the CAISO grid has already exceeded prior expectations. 1,708 MW of utility-scale renewable capacity was brought online in California between July 2017 and December 2018, and the California Energy Commission noted in its 2018 Integrated Energy Policy Report Update:

> As Clyde Loutan with the California ISO reported at the June 20, 2018, IEPR workshop on Renewable Integration and Electric System Flexibility, ramps and minimum loads are four years ahead of the California ISO's original estimates, largely due to the rapid growth in renewable generation. (footnote omitted) Maximum monthly three-hour ramps between January and April 2018 substantially exceeded projections from the prior year in two of the four months …
>
> Managing increasing one- and three-hour upward ramps requires sufficient dispatchable generation, storage, and demand response capacity capable of starting and ramping up quickly. Minimum net loads are falling more quickly than expected, according to Mr. Loutan….

[14] A.16-08-006, PG&E Opening Brief, p. 16.

The drop in minimum net loads contributes to negative market prices and renewable curtailment. Compared to 2016, renewable curtailment and the number of hours with negative prices in the California ISO increased substantially in the first five months of 2017. This increase was due to renewable additions and an increase in hydro generation serving the California ISO from 6,400 GWh in 2016 to more than 10,600 GWh in 2017. (footnote omitted) In 2018, hydro generation returned to 2016 levels (6,700 GWh), which contributed to a reduction in the frequency of negative prices in the first four months of 2018 … Renewable curtailment is greatest in the spring. Curtailment remained at 2017 levels in the first five months of 2018, exceeding those levels in April and May. [15]

The increase in wind and solar curtailments since the 2016 Joint Proposal and A.16-08-006, (2019 is recorded only through May), is vividly displayed on this graph downloaded from the CAISO website[16] on July 2, 2019:



[15] CEC, 2018 Integrated Energy Policy Report Update, p. 93.
[16] http://www.caiso.com/informed/Pages/ManagingOversupply.aspx#dailyCurtailment

The rapid growth in CCAs within PG&E's service territory has also been correlated with a distinct lack of customer appetite for nuclear-generated electricity. A4NR's review of websites and power content labels found none of the CCAs in PG&E's service territory include nuclear-generated electricity in their supply portfolios, and some prominently feature that fact in their marketing. As PG&E itself has pointed out, "the charters of many CCAs flatly prohibit the procurement of nuclear generation."[17] The website for Monterey Bay Community Power, the CCA now joined by all but one of the incorporated cities in the County of San Luis Obispo (home 0f DCNPP), expressly disavows inclusion of nuclear-generated electricity in its portfolio: "Nuclear power is also considered carbon-free. However, MBCP is not including it in its portfolio."[18]

IV. <u>QUITE SIGNIFICANT ABOVE-MARKET COSTS.</u>

Q10: Can you please explain what you mean by "above-market costs" attributable to DCNPP?

A10: After years of controversy, the Commission adopted a detailed methodology in D.18-10-019 revising calculation of the PCIA, "the rate intended to equalize cost sharing between departing load and bundled load."[19]Among the "Final Guiding Principles" articulated in D.18-10-019:

> 1. Any PCIA methodology adopted by the Commission to prevent cost increases for either bundled or departing load:

[17] R.17-06-026, Reply Comments of Pacific Gas and Electric Company (U 39-E), San Diego Gas and Electric Company (U 902-E), and Southern California Edison Company (U 338-E) on Proposed Decision and Alternate Proposed Decision Modifying the Power Charge Indifference Adjustment Methodology, p. 9, citing Exhibit IOU-3, p. 2-25, lines 16-17.

[18] https://www.mbcommunitypower.org/#faqs

[19] D.18-10-019, p. 3.

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h. should only include legitimately unavoidable costs and account for the IOUs' responsibility to prudently manage their generation portfolio and take all reasonable steps to minimize above-market costs;[20]

D.18-10-019 also reiterated the Commission's two regulatory vantage points into the prudent management of IOU supply portfolios: "Utilities are of course required to manage their portfolios prudently. Imprudent management would justify disallowing recovery of portfolio costs, and could be considered in ERRA or General Rate Case (GRC) proceedings."[21]

PG&E's responses to data requests by A4NR in this proceeding identified PCIA charges attributable to DCNPP of $168 million in 2018[22] and $277 million in 2019.[23] Based on PG&E's indication that CCAs and DA providers served 41% of the load in PG&E's service territory in 2018[24] and are forecast to serve 53% in 2019,[25] the Commission-adopted PCIA methodology would assign $410 million (168 divided by .41) in above-market costs to DCNPP in 2018 and forecast $523 million (277 divided by .53) in DCNPP above-market costs in 2019. To the extent that DCNPP's operation contributes to the economic curtailment of renewable electricity generation under contract to PG&E, and such contracts provide for payments by PG&E as if such curtailed output is deemed to have been generated (as PG&E has done since 2015),[26] then DCNPP operation will also add to the annual costs (and PCIA amounts) attributed to those contracts.

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[20] *Id.,* p. 15.
[21] *Id.,* p. 112.
[22] GRC-2020-PhI_DR_A4NR_002-Q02.
[23] GRC-2020-PhI_DR_A4NR_002-Q04.
[24] GRC-2020-PhI_DR_A4NR_002-Q06.
[25] GRC-2020-PhI_DR_A4NR_002-Q08.
[26] PG&E, Presentation by Sandra Burns at the June 20, 2018 IEPR Workshop on Renewable Integration and Electric System Flexibility, https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=18-IEPR-06.

V. UNREASONABLY EXPENSIVE GHG MITIGATION.

Q11: Since operation of DCNPP produces electricity with no incremental greenhouse gas ("GHG") emissions, shouldn't some above-market costs be acceptable pursuant to California's efforts to decarbonize the electricity sector?

A11: Yes, but particularly for a legacy plant in its last years of service like DCNPP, only within some realm of reason. D.18-10-019 expressly rejected a proposed GHG-free adder "untethered to any reliable, observable market premium":

> … applying a GHG-free adder amid scarce data on GHG-free resource transaction premiums is unwarranted. CalCCA's proposed $6.14/MWh (itself a substantial reduction from the $24.16/MWh for PG&E and $25.11/MWh for SCE that CalCCA proposed in testimony) is not tied to any market transactions. TURN offered the limited transaction price data in the record—a $2/MWh premium estimate reported by Sonoma Clean Power in February 2017. The Joint Utilities noted that, for planning purposes, the City of San Diego assumed $3.50/MWh was the GHG-free adder used by the City of San Diego in July 2017 in their [sic] the Short-Term Cost of Service Model included in their CCA Feasibility Study. Neither of these GHG values represent a reliable market value on which to base an additional GHG-free benchmark that would apply to the hydroelectric and nuclear resources in the IOU portfolios.[27]

Using the 18,000 GWh yearly production identified for DCNPP in PG&E's GRC testimony,[28] the $2 – 6.14/MWh levels mentioned above would yield annual amounts of $36 million at $2/MWh; $63 million at $3.50/MWh; and $110.5 million at $6.14/MWh. Alternatively, using the California Air Resources Board's May 2019 Cap-and-Trade Auction settlement price of $17.45 per metric ton,[29] and the 8-million-metric-tons-per-year maximum

[27] D.18-10-019, pp. 150 – 151.
[28] PG&E-5, p. 3-4.
[29] https://ww3.arb.ca.gov/cc/capandtrade/auction/results_summary.pdf

displacement identified for DCNPP in PG&E's GRC testimony,[30] would produce an annual sum of $139.6 million. Reliance on the lower displacement estimate of 6 million metric tons (PG&E assumed 6 – 7 million metric tons in A.16-08-006[31]) would reduce this annual value to $104.7 million. Even the most generous GHG metric would account for no more than 26.7% of DCNPP's above-market costs in 2019, meaning that $523 million could have purchased at the May 2019 Cap-and-Trade auction roughly quadruple the annual GHG emissions savings attributed by PG&E to DCNPP.

VI. GRC IS THE APPROPRIATE FORUM.

Q12: How has the Commission addressed the prospect of changed circumstances affecting the identification of a DCNPP retirement date?

A12: Commission decisions have left that assessment up to PG&E. As noted in D.18-01-022, which approved A.16-08-006,

> Given the relatively early state of the IRP proceeding, the more prudent and conservative approach to balancing this uncertainty tips against a shutdown before 2024 and 2025. As we gain a clearer picture of future developments, such as the relative cost of operating Diablo Canyon, this balance could change. Because there is a possibility that Diablo Canyon may cease operations earlier than 2024 and 2025, PG&E should prepare for that contingency. In the IRP proceeding, PG&E should be prepared to present scenarios assuming Diablo Canyon retirement dates prior to 2024/2025, including ones that demonstrate no more than a de minimis increase in the greenhouse gas emissions of its electric portfolio.

[30] PG&E-5, p. 3-4.
[31] A.16-08-006, PG&E Opening Brief, p. 11, footnote 32.

> Based on the record of this proceeding, PG&E's proposed 2024/2025 retirement schedule for Diablo Canyon provides a reasonable amount of time for the transition process, including further examination of replacement procurement. Accordingly, PG&E's proposed retirement schedule for Diablo Canyon is approved. If in the interim period the facts change in a manner that indicates Diablo Canyon should be retired earlier, the Commission may reconsider this determination.[32]

D.18-02-018, setting requirements for Load Serving Entities filing Integrated Resource Plans, modified the direction to PG&E from "be prepared to present scenarios assuming Diablo Canyon retirement dates prior to 2024/2025" to "we will specifically require that PG&E present alternative portfolios for our consideration in its IRP filing, if it proposes or intends to retire Diablo Canyon at any time prior to the expected 2024/2025 retirement date."[33] To date, PG&E has submitted no such "scenarios" or "alternative portfolios," and until recently the IRP proceeding has focused upon a 2030 time horizon for achieving an annual GHG emissions target of 42 million metric tons. Evaluation of pre-2024/2025 DCNPP retirement scenarios has previously fallen into a blind spot in the Commission's integrated resource planning process, although the June 20, 2019 Assigned Commissioner and Administrative Law Judge's Ruling recently solicited comments on reliability needs in the 2019-2024 period.

Q13: Can continued operation of DCNPP be justified by its contribution to meeting resource adequacy needs?

A13: Perhaps, but it seems unlikely and PG&E has yet to make that argument. The Commission's PCIA methodology has long featured a capacity adder to reflect a plant's

[32] D.18-01-022, p. 15. Conclusion of Law 1 stated, "PG&E's proposal to retire Diablo Canyon Unit 1 **by** 2024 and Unit 2 **by** 2025 is reasonable, and should be approved." (emphasis added) Ordering Paragraph 1 stated, "Pacific Gas and Electric Company's proposal to retire Diablo Canyon Unit 1 **by** 2024 and Unit 2 **by** 2025 is approved." (emphasis added)

[33] D.18-02-018, pp. 154 – 155.

contribution to resource adequacy, and D.18-10-019 modified the methodology to specifically incorporate the value of system, local, and flexible capacity.[34] Adding another $410 – 523 million in annual above-market costs may create an insurmountable barrier to characterizing DCNPP as an economically defensible resource adequacy resource. As the Commission noted in D.18-01-022,

> PG&E's analysis indicates that there is no need to replace Diablo Canyon in order to maintain system reliability. (Transcript Vol. 6 at 957-958.)
>
> PG&E has also been unequivocal that the retirement of Diablo Canyon will not have an adverse impact on local reliability. According to PG&E, because Diablo Canyon's output is exported on the bulk transmission system, Diablo Canyon is considered a system resource only, and is not needed for local reliability: … Unlike San Onofre Nuclear Generating Station, DCPP is considered as a system resource only and is not needed to provide support for local reliability.[35]

Q14: How does the operation of DCNPP during the 2020 – 2022 general rate case cycle relate to the issues in this proceeding?

A14: PG&E has the burden of proving, by a preponderance of evidence, that the revenue requirement it is requesting in A.18-12-009 is reasonable and that the resulting rates will be both just and reasonable. According to its testimony, PG&E is forecasting O&M expenses for DCNPP of $1,039,874,000 in nominal dollars during the 2020 – 2022 rate cycle ($357,731,000 in 2020; $341,595,000 in 2021; and $340,548,000 in 2022).[36] It is forecasting capital expenditures of $84,402,000 in nominal dollars during the 2020 – 2022 rate cycle ($42,881,000 in 2020; $25,173,000 in 2021; and $16,348,000 in 2022).[37] To the extent these planned expenditures are

[34] D.18-10-019, p. 74.
[35] D.18-01-022, pp. 8 – 9.
[36] PG&E-5, p. 3-5, Table 3-1.
[37] *Id.,* p. 3-7, Table 3-2.

contingent upon DCNPP's status as an operating plant (since post-shutdown expenses, including contract cancellation costs, will be paid from the DCNPP decommissioning trusts after a determination of their reasonableness), they cannot be considered "legitimately unavoidable costs" under D.18-10-019 for inclusion in the PCIA unless DCNPP's 2020 – 2022 operation is found prudent. For a plant which generated $523 million in above-market costs in 2019 after experiencing $410 million in above-market costs in 2018 – with no demonstrable reason why this annual trend will not extend through the 2020 – 2022 rate cycle and beyond – proving the reasonableness of incurring more than $1.124 billion (the sum of PG&E's O&M and Capital requests in this GRC proceeding) in additional costs is a substantial evidentiary burden, even excluding the nuclear fuel costs that likely exceed $100 million per year but are outside the scope of this proceeding. Do PG&E's dwindling number of bundled customers deserve such insensitivity from their utility to the cost of the electricity provided?

PG&E's general rate application makes no attempt to justify the reasonableness of running such an uneconomic plant, and the staleness of its prepared testimony is self-evident from the statement, "Approximately 39 percent of PG&E's load is currently served by direct access and CCA providers."[38] In fact, the proportion is more than one-third higher in 2019, as PG&E has subsequently acknowledged,[39] and was projected by PG&E in April 2018 to climb to 58% in 2022.[40] By what standard could it be considered reasonable to incur avoidable above-market costs of such magnitude when a substantial majority of such costs are inflicted on non-bundled customers? For all of the reasons PG&E articulated in A.16-08-006, the conspicuous

[38] *Id.,* p. 6-20.
[39] GRC-2020-PhI_DR_A4NR_002-Q08.
[40] R.17-06-026, Ex. IOU-1, p. 1-17, Table 1-2, citing "current internal load forecasts."

acceleration in its motivating premises should induce a prudently managed utility to update the retirement calendar for DCNPP appropriately. Instead, while encumbering both bundled and non-bundled customers with significant above-market costs, PG&E proposes to increase their economic hardship by incurring additional avoidable costs in massive amounts.

VII. PRELIMINARY CONCLUSIONS.

Q15: What preliminary conclusions do you draw from the evidence presented in your testimony?

A15: Unless PG&E does so in its rebuttal testimony, the utility has failed to meet its burden of proving the reasonableness of including $1,039,874,000 in avoidable DCNPP O&M costs and $84,402,000 in avoidable DCNPP Capital expenditures in calculating the revenue requirement for the 2020 – 2022 general rate case cycle. Including these amounts in rates would be incompatible with just and reasonable rates.

PG&E's refusal to update its analyses from A.16-08-006 is *prima facie* evidence of its failure to prudently manage its supply portfolio and an invitation for the disallowance of above-market DCNPP costs. PG&E's unwillingness to respond to the changing market conditions that have rendered DCNPP a hopelessly stranded asset, saddling both bundled load and departed load with immense annual deadweight losses to produce increasingly unwanted output, compounds the utility's defiance of the Commission's prudent manager standard. Based on its

1 testimony, the only plausible explanation for PG&E's persistence in operation of such an
2 uneconomic plant is to generate a continuing return on its stranded investment. A better
3 approach – consistent with Commission precedent – would allow an accelerated return **of** this
4 investment (albeit at a reduced rate of return **on** such investment) and a recycling of this capital
5 into higher priority fire-hardening investments in the PG&E grid.

6 Q16: Does this conclude your testimony?

7 A16: Yes, it does. A4NR will make a formal recommendation to the Commission in its
8 Opening Brief.

Appendix A

QUALIFICATIONS OF JOHN L. GEESMAN

John L. Geesman is an attorney with the Oakland law firm, Dickson Geesman LLP, and a member in good standing of the California State Bar.

Mr. Geesman served as a member of the California Energy Commission from 2002 to 2008, and was the agency's Executive Director from 1979 to 1983. Between his two tours at the Energy Commission, Mr. Geesman spent nineteen years as an investment banker focused on the U.S. bond markets and served as a financial advisor to municipal electric utilities throughout the West.

Mr. Geesman has a long history of providing leadership on issues related to resource planning, environmental policy, financial management, and risk practices. This is demonstrated by his service in numerous executive capacities, including stints as:

- Co-Chair of the American Council on Renewable Energy;
- Chairman of the California Power Exchange;
- President of the Board of Directors of The Utility Reform Network (nee Toward Utility Rate Normalization);
- Member of the Governing Board of the California Independent System Operator; and,
- Chairman of the California Managed Risk Medical Insurance Board.

Mr. Geesman has previously testified as an expert witness before the California Public Utilities Commission.

Mr. Geesman is a graduate of Yale College and the University of California Berkeley School of Law.