BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE
STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Approval of its 2023 Gas Cost Allocation and Rate Design Proposals for its Gas Transmission and Storage System (U39G)	))))))	Application 21-09-018

Prepared Direct Testimony of R. Thomas Beach on behalf of Calpine Corporation

August 8, 2022

Executive Summary

This testimony presents the position of Calpine Corporation (Calpine) on the application of Pacific Gas and Electric (PG&E) to implement new gas transmission and storage (GT&S) transportation rates to be effective from 2023-2026. Calpine operates the largest fleet of natural gas combined-cycle (NGCC) and combined heat and power (CHP) facilities both in California and the U.S. With roughly 4,500 MW of natural gas-fired generation in PG&E's service territory, Calpine is one of the largest, if not the largest, noncore electric generation (EG) customers on PG&E's gas transportation system and therefore is well aware of the significant increases in PG&E's natural gas rates in recent years. Calpine's power plants take service both from PG&E's local transmission system and directly from PG&E's backbone pipelines. Calpine is also the nation's largest producer of renewable geothermal electricity from its Geysers operations in Northern California.

Calpine continues to be concerned with the substantial rate increases in recent years for noncore shippers on the PG&E system in general, and with the impacts on electric generation (EG) customers such as Calpine in particular. Like other EG customers, Calpine seeks to recover its costs for delivered gas, including both gas commodity costs and intrastate gas transportation charges, in the prices that it receives for its generation in the energy markets on the system of the California Independent System Operator (CAISO) and through contracts with load-serving entities whose prices are closely linked to CAISO energy market prices. As a result, it is ultimately the California electric ratepayers who consume market-priced power from the CAISO system that bear much of these rate increases.

To moderate the proposed rate increases for EG customers and electric ratepayers, Calpine recommends the following:

1. **The Commission should modify the allocation of PG&E's local transmission (local T) costs between core and noncore ratepayers**, in order to ensure that the burdens of the increasing revenue requirement for PG&E's local transmission system are fairly apportioned among PG&E's customer classes. Based on a 1992 decision, PG&E currently allocates its local transmission costs on the basis of peak month throughput in a cold year. This is not the basis on which PG&E designs and incurs costs for its local transmission facilities. PG&E's actual design criteria are the higher of (1) core loads on an Abnormal Peak Day (APD) or (2) total throughput on a Cold Winter Day (CWD). PG&E's testimony proposes to allocate local transmission costs on the basis of the relative amounts of core and noncore loads that the PG&E local transmission system serves on an APD.

   Calpine supports the concept behind PG&E's allocation, but observes that PG&E fails to model accurately the noncore load that its local transmission system would serve on an APD. In comparing core and noncore local transmission loads on an APD, PG&E includes all noncore load. However, a portion of the noncore load on an APD will be EG plants (and a few industrial customers) served directly from the backbone system, without using local transmission facilities. It is not appropriate to allocate local transmission costs to noncore customers based on an assumption that all noncore customers use the local transmission system when, in fact, a significant amount of noncore load is not served on the local transmission system. When this error is corrected, the allocation of local transmission loads on an APD would be 79% core and 21% noncore. Given that the design criteria for local transmission also includes service to all noncore loads on a CWD, and recognizing that all noncore loads are served under most conditions, Calpine recommends increasing the allocation of local transmission costs to the noncore to include all noncore loads served on a CWD. This results in **an allocation of local transmission costs of 77% to the core and 23% to the noncore. This is Calpine's recommendation.** It represents a cost-based allocation of local transmission costs that accurately reflects the level of service that PG&E provides to both core and noncore customers. Such an allocation is fair to both types of customers.

2. **PG&E proposes changes in how inventory management (IM) costs are recovered, and how they are allocated among the customer classes.** PG&E would move the recovery of IM costs from backbone rates to end-use rates. The utility would divide IM costs into separate components for inter-day and intra-day load balancing, and then allocate each of these components between three groups of customers: the core, market-sensitive EGs, and the remaining noncore customers (the "Big 3" market segments). PG&E would base these allocations on the relative inter-day and intra-day imbalances of the Big 3 market segments over a five-year historical period (2016-2020). This would allocate 36% of IM costs to inter-day monthly balancing service and 64% to intra-day balancing.

   Calpine opposes moving inter-day IM costs out of backbone rates. All shippers of gas on the PG&E system receive the same inter-day balancing service under PG&E's G-BAL tariff. Shippers who use balancing services more intensively, and thus who run greater imbalances, but who still stay within the tolerances of G-BAL, should not be charged more than shippers who use balancing less intensively. Further, end use customers do not control the balancing practices of the shippers from whom they may buy gas at the PG&E City-gate or who act as balancing agents for end use customers. For these reasons, all shippers should continue to pay the same rate, as part of backbone rates, for inter-day balancing service.

   Calpine accepts PG&E's proposal to move intra-day IM costs into end-use rates, but the allocation of these costs should reflect the throughput forecast for this case. PG&E's proposed allocation of IM costs is based on the distribution of imbalances among the Big 3 market segments in 2016-2020. However, the relative amounts of throughput in these segments in 2016-2020 is significantly different than the throughput forecast for 2023-2026. In particular, the proportion of EG loads is significantly lower in the forecast period. Assuming the level of imbalances per Dth of throughput remains the same, the allocation of IM costs from 2016-2020 should be revised to reflect the 2023-2026 throughput forecast. This more accurate allocation produces modest changes in the relative IM rates among the market segments, including a small reduction in IM costs for EG customers, compared to PG&E's proposal.

In sum, Calpine recommends the following adjustments to PG&E's backbone, local transmission, and end use rates:

- **Backbone rates.** Calpine proposes to retain inter-day IM costs as part of PG&E's backbone rates. This raises PG&E's proposed backbone rates by about $0.08 per Dth in 2023.

- **Local transmission rates.** The revised allocations of local transmission costs that Calpine recommends would reduce PG&E's proposed noncore local transmission rates for EG-LT customers in 2023 by about $0.63 per Dth, with higher local transmission rates for core customers. See Table 3 of the testimony.

- **End-use rates.** As shown in Tables 7 and 8, keeping a portion of IM costs in backbone rates will reduce the IM component of end-use rates for all customer classes, compared to PG&E's proposal. The use of the throughput forecast to allocate IM costs, as Calpine proposes, will reduce the IM rate for EG customers relative to other customer classes.

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I. INTRODUCTION

Q: Please state for the record your name, position, and business address.

A: My name is R. Thomas Beach. I am principal consultant of the consulting firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 213A, Berkeley, California 94710.

Q: Please describe your experience and qualifications.

A: My experience and qualifications are described in the attached *curriculum vitae* (CV), which is **Attachment RTB-1** to this testimony.

Q: Have you testified previously before this Commission?

A: Yes, I have. A current list of the testimony that I have filed before this Commission is included in my CV.

Q: What is your experience in participating in PG&E Gas Transmission & Storage (GT&S) rate proceedings such as this one?

A: I have participated actively in every PG&E GT&S rate case for the last 25 years, since the original Gas Accord settlement was proposed and approved by this Commission in 1997. Typically I have participated in these rate cases on behalf of parties whose interest is the Commission's approval of reasonable rates for the backbone, local transmission, and storage services that PG&E provides to noncore customers and shippers on its gas system.

Q: On whose behalf are you testifying today?

A: I am appearing on behalf of Calpine Corporation (Calpine).

Calpine operates the largest fleet of natural gas combined-cycle (NGCC) and combined heat and power (CHP) facilities both in California and the U.S. With roughly 4,500 MW of natural gas-fired generation in PG&E's service territory, Calpine is one of the largest, if not the largest, noncore electric generation (EG) customers on PG&E's gas transportation system and therefore is well aware of the significant increases in PG&E's natural gas transportation rates in recent years. Calpine's power plants take service both from PG&E's local transmission system and directly from PG&E's backbone pipelines. Calpine is also the nation's largest producer of renewable geothermal electricity from its Geysers operations in Northern California.

Calpine has participated actively in prior PG&E GT&S rate cases.

II. BACKGROUND

A. Historical Context

Q: Please discuss the origin and purpose of this proceeding.

A: Since 1998, the PG&E gas transmission and storage system has operated under the "Gas Accord" market structure. The Commission and parties have reviewed the Gas Accord structure repeatedly in GT&S rate cases since 1998; these cases have resulted in modest changes to the structure over time. The market structure generally has received positive reviews from end use customers, shippers, PG&E, and the Commission.[1] This application is the GT&S rate case that will set PG&E's gas transmission and storage rates for the four years 2023-2026.

Q: Please provide the context for this PG&E GT&S rate case, in terms of major developments on the California gas system that have influenced PG&E's proposals.

A: This is the third PG&E GT&S rate case to be conducted after the tragic gas pipeline explosion on the PG&E system on September 9, 2010 in San Bruno, California. After the San Bruno incident, the Commission initiated a rulemaking (R. 11-02-019) as "a forward-looking effort to establish a new model of natural gas pipeline safety regulation applicable to all California pipelines." On June 9, 2011, the Commission issued D. 11-06-017 in this rulemaking, directing each of the State's regulated gas utilities, including PG&E, to file an Implementation Plan describing how the utility will "achieve the goal of orderly and cost effectively replacing or testing all natural gas transmission pipeline that have not been pressure tested." The Commission's goal was that, once the plans are implemented, the gas transmission lines of each gas utility will have been pressure tested, will have "traceable, complete, and verifiable records readily available," and if appropriate will be able to be inspected using in-line techniques.[2] Decision (D.) 11-06-017 emphasized that a "key question" was how the plans were to be funded, in other words, whether and how the costs would be recovered in rates. The Commission stressed that "obtaining the greatest amount of safety value, i.e. reducing safety risk, for ratepayer

[1] The Commission has approved or extended the Gas Accord seven times in PG&E GT&S rate cases: three times as a result of all-party settlements, twice (in 1987 and 2011) after partially contested settlements, and three times (in 2003, 2016, and 2019) by Commission decision after a fully litigated rate case. *See* CPUC Decisions (D.) 19-09-025, 16-06-056, 11-04-031, 07-09-045, 04-12-050, 03-12-061, 02-08-070, and 97-08-055. D. 03-12-061, D. 16-06-056, and D. 19-09-025 resolved the three fully-litigated Gas Accord proceedings.

[2] D. 11-06-017, at 19-20.

expenditures will be an overarching Commission goal in reviewing the plans."[3] Further, the California Legislature has also taken action to prioritize gas pipeline safety. In 2011, the Legislature enacted Senate Bill (SB) 705, which declared for the first time that "[i]t is the policy of the state that the commission and each gas corporation place safety of the public and gas corporation employees as the top priority."[4] Notably, SB 705 did not call for safety at any cost but affirmed the traditional standard that rates must be just, reasonable, and based on costs.[5]

PG&E filed its Safety Implementation Plan (Plan) on August 26, 2011. After extensive Commission proceedings on PG&E's Plan, the Commission issued D. 12-12-030 on December 20, 2012. This order adopted a safety implementation plan for PG&E, authorizing increases in PG&E's revenue requirements to be recovered in rates totaling $299 million in 2012-2014.[6] The focus of D. 12-12-030 was on the allocation of cost responsibility between ratepayers and shareholders and on the overall level and pace of ratepayer funding for PG&E's Plan. With respect to the allocation of Plan costs among PG&E's ratepayer classes, the Commission determined that such allocation issues were best addressed in GT&S rate case proceedings.[7]

There have been two prior GT&S rate cases since the San Bruno incident. D. 16-06-056 adopted a 2015 GT&S revenue requirement of $1.05 billion, a 46% increase over

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3 *Ibid.,*at 22. Similarly, the Independent Review Panel (IRP) on the San Bruno incident also emphasized the importance of considering tradeoffs that include ratepayer costs. See "Report of the Independent Review Panel" (IRP Report) on the San Bruno incident, released June 9, 2011, at page 14. Available at http://www.cpuc.ca.gov/PUC/events/110609_sbpanel.htm.

4 P.U. Code Section 963[b][3].

5 P.U. Code Section 963[b][4], for example, "[t]he commission shall take all reasonable and appropriate actions necessary to carry out the safety priority policy of this paragraph consistent with the principle of just and reasonable cost-based rates."

6 D. 12-12-030, at 3.

7 *Ibid.*, at 106 (emphasis added).

the authorized 2014 revenue requirement, plus substantial additional revenue requirement increases for 2016-2018. D. 19-09-025 in the most recent GT&S rate case adopted a 2019 revenue requirement of $1.332 billion, increasing to $1.585 billion in 2022. All told, the authorized GT&S revenue requirement in 2022 is more than triple the authorized 2010 revenue requirement of $462 million at the time of the San Bruno incident.[8]

Q: In addition to the San Bruno incident, what other events have shaped PG&E's proposal in this case?

A: Beginning in October 2015, a major natural gas leak occurred at Southern California Gas Company's (SoCalGas) Aliso Canyon gas storage facility in Porter Ranch, California. The leak was not plugged until February 2016. This incident resulted in evacuations of nearby residents, serious health concerns, and the release in this single incident of methane equivalent to 2.4 MMT of CO_2, or roughly 1.5% of total yearly methane emissions from all U.S. natural gas infrastructure and over 80% of the annual methane emissions from the entire natural gas system in California.[9] This incident spurred the California Geologic Energy Management Division (CalGEM) to promulgate new regulations concerning the operation of the state's gas storage facilities. These regulations have required PG&E to spend significant amounts to upgrade its storage facilities; this spending was another important driver of the revenue requirement increases approved in D. 19-09-025.

D. 19-09-025 also adopted a Natural Gas Storage Strategy for PG&E that reduced the utility's available gas storage capacity, moved to greater reliance on newer independent storage facilities to serve the storage needs of core customers, established a

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[8] For the authorized GT&S 2010 revenue requirements, see D. 07-09-045.

[9] In January 2017, a joint report of the Commission and the California Air Resources Board submitted in R. 15-01-008 estimated the methane emissions from the state's gas storage and delivery infrastructure in 2015 to be 6.6 Bcf, or about 3.0 million metric tons of carbon dioxide equivalent (MMTCO2e). See https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M172/K518/172518969.PDF.

Reserve Capacity set-aside of storage capacity to address certain contingencies, and increased the PG&E storage capacity dedicated to inter-day and intra-day load balancing (or "inventory management" [IM]).

Q: What has been the trajectory of natural gas throughput on the PG&E system since 2010?

A: End use natural gas demand on the PG&E system has been basically flat for the last 20 years, with annual variations depending mostly on hydroelectric conditions. See the black solid line in **Figure 1**, from recorded data in the annual *California Gas Report* (CGR) submitted by the gas utilities to the Commission. PG&E's gas throughput is likely to decline in the future, as California moves away from the use of fossil fuels to meet its greenhouse gas reduction goals, as shown in the most recent throughput forecasts in Figure 1. The figure shows that further significant reductions in gas use, below current forecasts, may be required to meet these goals. The yellow line in Figure 1 shows PG&E's total throughput forecast in this GT&S CARD case; this forecast represents an appreciable decline compared to recorded usage.

Focusing on EG throughput, **Figure 2** below shows PG&E's forecast of EG throughput in this case for 2023-2026 (yellow line), compared to the *2022 CGR* forecast that PG&E made public on August 1, 2022 (orange line) and earlier C*GR* forecasts of PG&E's EG throughput.

Figure 1

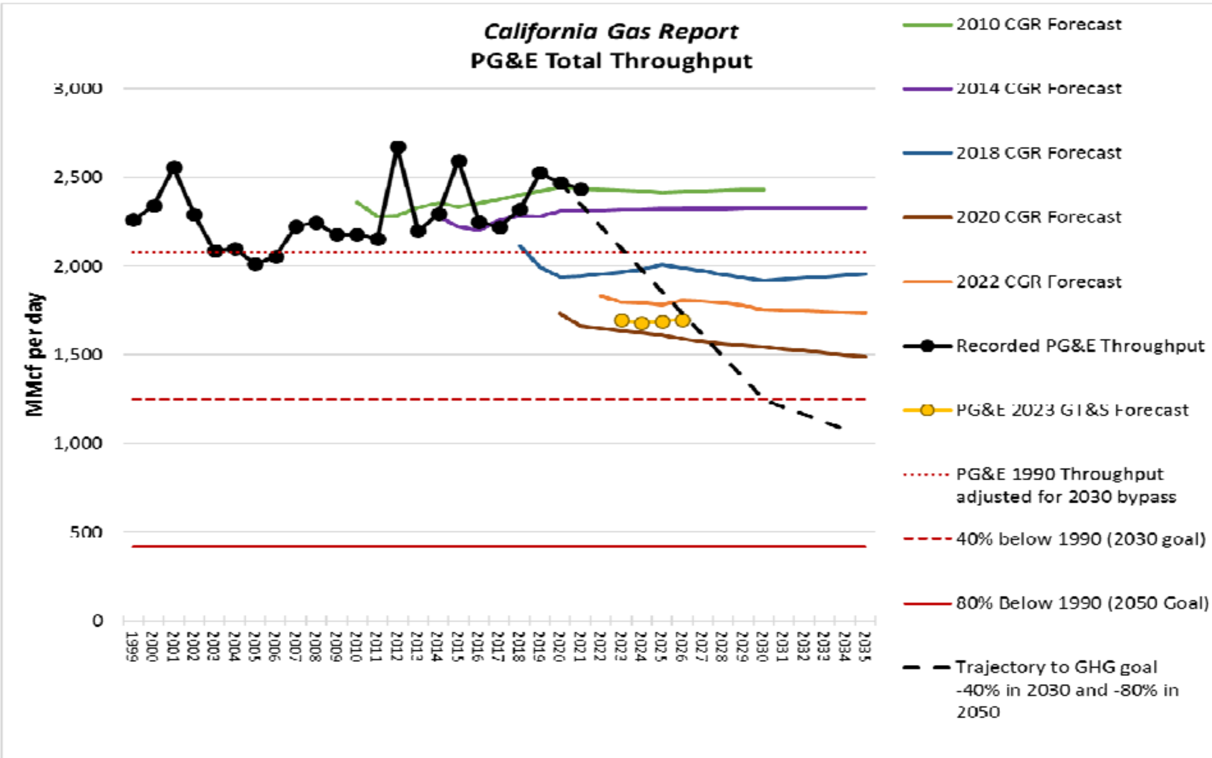
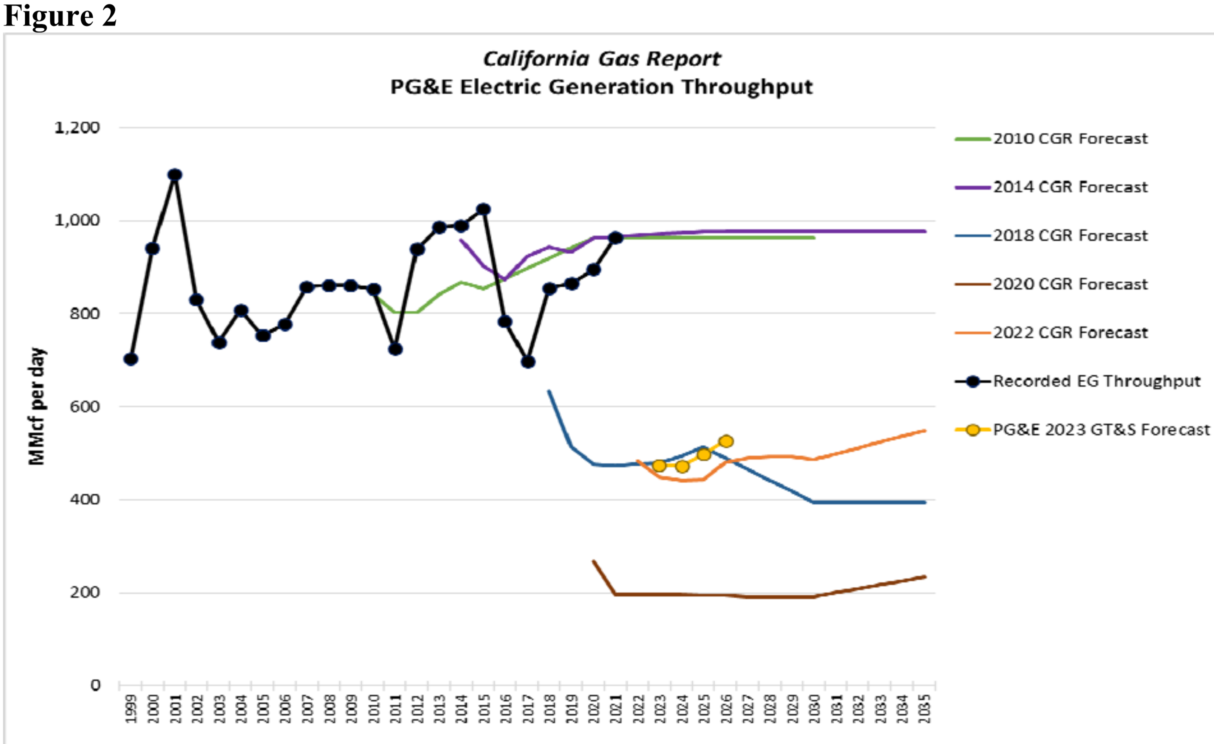


Figure 2



B. Major Rate Increases for Noncore GT&S Customers, including EGs

Q: Please describe the increases in the GT&S revenue requirement that PG&E has proposed in Phase 1 of its general rate case (GRC).

A: PG&E again is proposing very substantial new costs in Phase 1 of its GRC (A. 21-06-021), both for continued safety-related work on the transmission system and for the program to rationalize and upgrade its storage assets approved in D. 19-09-025. From a 2022 GT&S revenue requirement of $1.58 billion, PG&E's GRC Phase 1 application requests that the Commission authorize GT&S revenue requirements of $1.84 billion for 2023 (+16% over 2022), rising to $2.13 billion in 2024 (+35%), $2.27 billion in 2025 (+44%), and $2.44 billion for 2026 (+54%).[10]

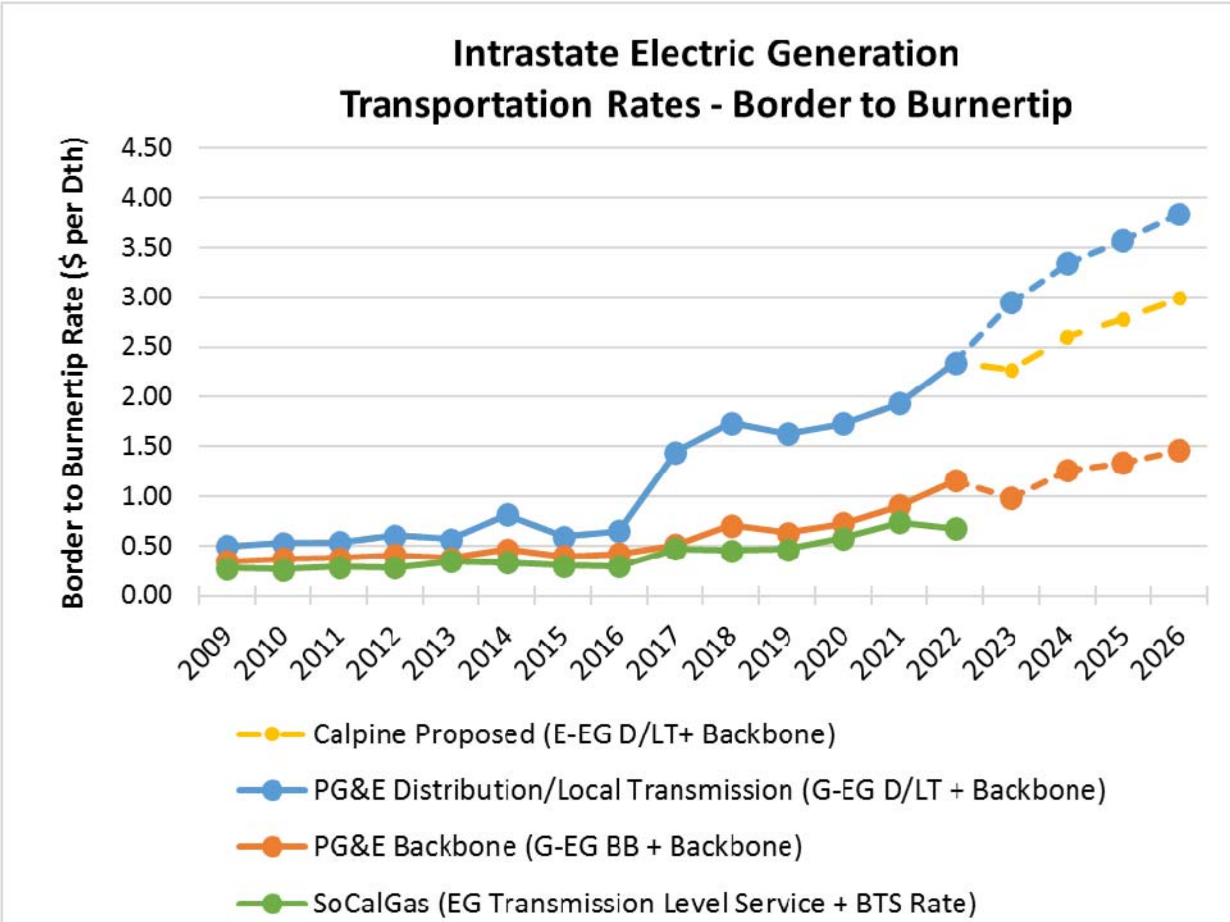
Q: Has the substantial growth in the GT&S revenue requirement resulted in significant increases in gas transportation rates for PG&E ratepayers, including EG customers?

A: Yes. Obviously, with a substantial growth in the revenue requirement and flat throughput, the result has been significant rate increases. Since 2009, PG&E's transportation rates from the California border for electric generators on the local transmission system have increased by 13% per year and by 10% per year for EGs directly connected to the backbone system. The rate increases for core customers also have been significant, but lower, with transportation charges for residential non-CARE customers increasing since 2010 by 9% per year.[11] These major EG rate increases are shown in **Figure 3**; the figure also shows the comparable transportation costs from the California border to large electric generators on the SoCalGas system.

[10] See PG&E Testimony (July 18, 2022 errata), at Table 6-2.

[11] 2010 residential non-CARE transportation-only rate ($5.5561 per Dth) is from A. 17-09-011, PG&E response to Calpine DR 004-Q3a. The January 2022 residential non-CARE transportation-only rate of $16.018 per Dth is from PG&E Testimony (July 18, 2022 errata), at Table 6-3. These core transport-only rates do not include backbone or storage costs.

Figure 3



Under PG&E's proposals in the GRC Phase 1 and this case, from 2023 to 2026, transportation rates from the border to the burnertip for electric generation (EG) customers would increase by 63% (from $2.35 per Dth in 2022 to $3.84 per Dth in 2026) for generators on the distribution/local transmission system (G-EG D/T), and by 26% (from $1.16 to $1.46 per Dth) for generators on the backbone system (G-EG BB). These proposed increases are shown in Figure 3 (the blue and orange dashed lines),[12] which also shows the EG rates for local transmission EG customers that Calpine recommends in this testimony (the yellow dashed line). If all of PG&E's proposals are adopted, the EG transportation rate from the border to EG customers located on the local transmission

[12] See PG&E Testimony (July 18, 2022 errata), at Table 6-3.

system would approach $4.00 per Dth by 2026, possibly exceeding the commodity cost of natural gas.

Q: Why should the Commission be concerned about the very large EG rate increases that PG&E has proposed in this rate case?

A: In the aftermath of the San Bruno and Aliso Canyon incidents, the continuing efforts of PG&E, the Commission, and the state to ensure the safe operation of California's natural gas infrastructure are justified, and PG&E's new emphasis on safety is welcome. Nonetheless, the continued steep increases in transportation rates for electric generators will have a significant and adverse impact on electricity consumers of all sizes. Like other EG customers, Calpine attempts to recover its costs for delivered gas, including both gas commodity costs and intrastate gas transportation charges, in the prices that it receives for its generation. These prices are tied directly or indirectly to those in the energy markets on the system of the California Independent System Operator (CAISO). As a result, it is ultimately the California electric ratepayers who consume market-priced power from the CAISO system that will bear much of these rate increases. The Commission is well aware of the challenges associated with the affordability of electric service in the state, as documented in the *en banc* hearing that the Commission held in February 2021.[13] Sharply rising electric rates present a major challenge for California given that electrification is the state's primary strategy for addressing climate change.

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[13] See the Energy Division white paper presented at that *en banc* hearing, available at: https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/Rates%20En%20Banc_white%20paper_v.2.0.pdf.

III. ALLOCATION OF LOCAL TRANSMISSION COSTS

A. Current Policy

Q: What component of PG&E's gas transmission rates is most impacted by PG&E's proposed spending on safety-related aspects of its gas transmission infrastructure?

A: Much of PG&E's spending for safety improvements has been on its local transmission system. This can be seen in the recent increases for noncore local transmission rate, which have increased from $0.15 per Dth in 2010 to $1.07 per Dth in June 2021. In the GRC Phase 1 and this case, PG&E is proposing further increases in noncore local transmission rates to $2.29 per Dth in 2026 (+114% over 2021, more than doubling this major rate component).[14]

Q: How are PG&E's local transmission costs allocated to customer classes?

A: Local transmission costs are allocated on the basis of each customer class's peak month (December or January) throughput in a cold year. This allocation was set 30 years ago, in 1992 in D. 92-12-058.

Q: Since D. 92-12-058, has the Commission revisited and revised how other types of gas system costs are allocated between the core and noncore market segments?

A: Yes, it has. In fact, the allocation of local transmission costs is the only allocation of gas transmission and storage costs adopted in D. 92-12-058 which has <u>not</u> been changed over the last three decades. The allocators adopted in D. 92-12-058 were chosen for a cost allocation based on long-run marginal costs at a time when all gas transportation and storage services – including backbone transmission, local transmission, storage, distribution, and customer-related services – were provided together on a completely bundled basis. Since that time, GT&S services for transmission and storage have been

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[14] See PG&E Testimony (July 18, 2022 errata), at Table 6-6.

unbundled from gas distribution and the rates for these services are now based on embedded costs. Importantly, in the Gas Accord rate structure, the allocation of backbone transmission and storage costs has changed from the allocations adopted in D. 92-12-058. Today, these allocations are based on the respective backbone and storage capacities used by core and noncore customers. Only the allocation of local transmission costs remains a holdover from 1992.

As discussed below, this aged allocation of local transmission costs does not reflect the cost drivers for PG&E's local transmission system, and dates from a time when the rate design structure and methodology for PG&E's gas transportation rates were very different than today. The magnitudes of the increases in the local transmission costs for noncore customers – both the actual increases since 2010 as well as more-than-doubling of the local transmission rate that PG&E has proposed in the concurrent GRC Phase 1 and this case – also justify a new look at the allocation of these costs. This allocation should reflect cost causation as accurately as possible, should be based directly on PG&E's design criteria for these facilities, and should capture how the respective customer classes benefit from safe and reliable local transmission facilities.

Q: What are the criteria that PG&E uses to design its local transmission facilities?

A: As PG&E has stated in testimony in recent GRCs, the utility designs its local transmission facilities to meet the higher of either (1) core demand on an Abnormal Peak Day (APD), or (2) core and noncore demand on a Cold Winter Day (CWD).[15] Peak month throughput in a cold year, the current allocator for local transmission costs, is <u>not</u> a design criterion for local transmission, and thus the current allocation of local transmission costs does not accurately represent cost causation.

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15 See A. 17-11-019, PG&E Testimony, Chapter 10, at p. 10-11, also A. 21-06-021, Exhibit PG&E-03, Chapter 11, pp. 11-16 to 11-17.

Q: Has the Commission sought to update the allocation of local transmission costs in recent GT&S GRCs?

A: Yes, it has. Although the Commission has continued the use of the cold-year peak-month allocator in its orders in the last two PG&E GT&S GRCs, it has not been satisfied with this outcome. In D. 16-06-056, after rejecting various proposals in the underlying proceeding to modify local transmission cost allocation, the Commission directed PG&E to prepare a study on the allocation of local transmission costs, "accounting for the actual relationships between pipeline capacity, throughput and costs."[16] In the next GT&S GRC (A. 17-11-019), PG&E submitted a study comparing the relative costs of building two separate local pipeline systems, one to serve the core and a second to serve the noncore, and proposed to use the relative costs so modeled as the allocator for local transmission costs. In D. 19-09-025, the Commission did not accept PG&E's study, expressing dissatisfaction with PG&E's modeling of overbuilt system with poorly-supported costs. The Commission also observed that PG&E's study failed to reflect the fact that core and noncore customers share the same local transmission system, with core customers receiving a higher priority of service and with the potential for curtailment of noncore loads during high-demand conditions.[17] The Commission continued the longstanding Cold-Year Peak-Month allocation and ordered PG&E to conduct a workshop process to develop and review new options for this allocation:

> … we find that the cost allocation for PG&E's local transmission service should be studied further to ensure the local transmission costs are being allocated consistent with cost causation principles. Accordingly, we direct PG&E to conduct a workshop with core and non-core customers to identify parameters for a credible transmission study. To facilitate the study, PG&E shall identify industry-standard methodologies used by other public utilities to study pipeline transmission costs. PG&E shall present these methodologies during the first workshop so that it and workshop attendees can discuss which methodologies would be appropriate to study PG&E's local transmission system. For the next rate case, PG&E shall execute a local transmission study using one of the

16 See D. 16-06-056, at p. 316.

17 D. 19-09-025, at pp. 265-266.

methodologies identified in the workshop and submit the study results as its proposal for allocating local transmission costs to ratepayers.[18]

B. PG&E's Proposed Allocation

Q: Please discuss PG&E's proposed allocation of local transmission costs.

A: In this case, PG&E's testimony recaps the discussion and presentations at the workshops ordered by D. 19-09-025, and has extensive testimony on game theory and the opinions of a Nobel economist, apparently in an effort to defend its prior local transmission study. But in the end PG&E does not use that study for its proposal in this case. Instead, PG&E proposes to move to a core / noncore allocation of local transmission costs based on the relative core / noncore demand served from the local transmission system on an Abnormal Peak Day (APD).[19] PG&E claims this allocation would be 65.9% core / 34.1% noncore, essentially very close to the current allocation based on Cold-Year Peak-Month throughput (which is 66.3% core / 33.7% noncore).[20]

PG&E cites a number of reasons to use APD demand on the local transmission system as the allocator for local transmission costs:

- D. 19-09-025 directed PG&E to propose "a nationally used method."[21] A Black & Veatch review presented at the workshop showed that the use of a coincident peak day throughput metric, such as APD, is "the most common method" used nationally.

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18 *Id.*, at pp. 266-267.

19 See PG&E Testimony (July 18, 2022 errata), at p. 4-29 to 4-30 and Table 4-10: "PG&E's proposed APD methodology… only uses the Core and Non-Core demand served under APD conditions to calculate local transmission allocation rates and excludes the amount that Non-Core is curtailed."

20 *Id*, at p. 4-37 (Table 4-15).

21 See D. 19-09-025, at p. 266: "PG&E shall identify industry-standard methodologies used by other public utilities to study pipeline transmission costs."

- The use of APD reflects the design criteria for PG&E's local transmission system: "The APD method is used to determine gas capacity requirements for Core customers."[22]
- Although APD conditions are expected to occur only once in 90 years, the risk of APD conditions remains, given that climate change will result in more extreme weather events, both hot and cold.[23]
- Parties representing both core and noncore customers proposed variations on the use of APD throughput as the local transmission allocator.[24]

C. Critique of PG&E's Proposal

Q: Do you agree that the use of the relative core / noncore throughput on the local transmission system on an APD would be reasonably consistent with the design standards for the PG&E local transmission system?

A: Yes. The local transmission system is designed to serve core loads on an APD, with noncore loads served from the remaining available system capacity. PG&E's forecasts of APD loads show that about 92% of the noncore demand on an APD could be served given PG&E's system capacity on an APD.[25]

Q: What is your understanding of PG&E's APD demand and the system capacity available to serve that demand under APD (1 day-in-90-year) cold conditions?

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22 See PG&E Testimony (July 18, 2022 errata), at p. 4-38.

23 *Id*.

24 *Id*., at pp. 4-38 and 4-39.

25 *Id*., at pp. 4-28.

A: PG&E revised its APD forecast in its May 10, 2022 updated testimony in this case.[26] On an APD, the full capacity of the PG&E gas system would be used, with about 8% of noncore load curtailed. PG&E recently has provided the design day capacities of its backbone pipeline and storage system in Table 7-15 in Exhibit PG&E-3 in the GRC Phase 1. These design day capacities are calculated on the basis of 1 day-in-10-year conditions, but the total design day capacity is similar to, and only slightly lower than, PG&E's modeling of the demand that it can serve on an APD.[27] **Table 1** summarizes this data.

Table 1: *PG&E APD Demand and Design Day Supply*

APD Demand (1-in-90)		**Design Day Supply (1-in-10)**	
Market	*MMcfd*	**Sources**	*MMcfd*
Core	3,040	Redwood Path (including ISPs)	2,700
Noncore	1,570	Baja Path (including Gill Ranch)	998
Total System Demand Served on APD	4,610	PG&E Storage	750
		California gas	35
Curtailment on an APD	146	Total System Supply to PG&E market	4,473

PG&E proposes to use the relative amounts of core (3,040 MMcfd, or 66%) and noncore (1,570 MMcfd, or 34%) demand served on an APD as the basic allocator for local transmission costs.[28]

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26 *Id.*, at pp. 4-30 and 4-31. PG&E also included an APD forecast in Table 19 of the *2022 CGR* (released on August 1, 2022). The core demand of 3,057 MMcfd in the *2022 CGR* APD forecast is very close to the core APD forecast in Table 1.

27 Table 19 of the *2022 CGR* includes data on the "Projected Resources to Meet Demands" on an APD of 4.232 MMcfd in 2022-2023, 4,193 MMcfd in 2023-2024, and 4,108 MMcfd in 2024-2025. The *CGR* table notes that these available supply capacities are calculated on a 1-day-in-10-year basis. They are lower than the 4,473 MMcfd of 1-day-in-10-year supply capacity shown in Table 1, from PG&E's GRC Phase 1 testimony.

28 See Id., at p. 4-29: "PG&E's proposed APD methodology… only uses the Core and Non-Core demand served under APD conditions to calculate local transmission allocation rates and excludes the amount that Non-Core is curtailed."

Q: Do you have any concerns with PG&E's proposed APD-based allocation of local transmission costs?

A: Yes. My concern is that PG&E's proposal ignores the fact that a significant portion of PG&E's noncore demand on an APD will not use the local transmission system, but will be backbone-level EG usage served directly from the backbone system, upstream of the local transmission system. Thus, the actual amount of service on the local transmission system that noncore customers will use on an APD is substantially lower than the 1,570 MMcfd shown in PG&E's APD forecast. Noncore customers should not pay for local transmission capacity that they are not going to use.

Q: Does PG&E's APD forecast recognize that a portion of the noncore demand on an APD will not use the local transmission system?

A: No, it does not. When asked in discovery to provide "for EG, the amount of APD demand that takes local transmission service, and how much EG demand on the APD takes backbone-only service from PG&E," PG&E did not provide any data, stating:

> Backbone pipelines employ a different planning methodology than local transmission systems. As such, there is no APD load for backbone EG customers.[29]

PG&E appears to be asserting that its APD planning looks at the <u>capacity</u> of the local transmission system to serve noncore loads under those conditions. This is also confirmed by PG&E's discussion of the hydraulic modeling used to determine service on an APD.[30] However, not all of this local transmission capacity will be used on an APD. Although the PG&E local transmission system might be able to deliver to noncore customers on an APD the volumes that PG&E states, in reality PG&E will never deliver those full volumes to noncore customers on the local transmission system, because a significant share of EG loads, and a small amount of industrial demand, on an APD will

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[29] PG&E Response to Calpine Data Request (DR) 001-Q11[d]. See also PG&E Response to Calpine DR 003-Q8[d]: "PG&E does not forecast EG APD demands for the population of plants served directly from the backbone system." Both responses are included in **Attachment RTB-2**.

[30] See PG&E Testimony (July 18, 2022 errata), at p. 4-5.

be served directly from the backbone system, without the use of local transmission facilities. In discovery, PG&E appeared to confirm this, stating "The sum of the APD demands that can be served on all the LT systems is not necessarily the systemwide demand on a 1:90 peak day for the system."[31] In sum, PG&E's backbone and storage system has limited capacity on an APD, and some of this limited capacity will be used to serve loads directly connected to the backbone. These backbone-level loads are upstream of much of the local transmission system, and thus they will reduce the amount of gas that could be delivered to noncore customers on the local transmission system on an APD.

Q: Is it plausible that there would be zero loads from backbone EG customers on an APD?

A: No. Today, a significant majority of PG&E's EG loads are from plants served directly from the backbone:

- Over the historical period January 2018 to June 2021, 55% of PG&E's market-responsive EG loads were served directly from the backbone.[32] This was generally a period of dry hydro conditions and higher EG loads.
- PG&E's throughput forecast in this case shows an even higher percentage – 82% – of market-responsive EG loads from backbone-level plants.[33]
- In discovery, PG&E produced a 1-day-in-35-year EG throughput forecast for 2022-2026 based on PLEXOS production cost modeling that shows 69% of overall EG loads on the peak winter days in December and January will be from backbone-level EG plants.[34]

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31 PG&E Response to Calpine DR 003-Q8[e], included in **Attachment RTB-2**.

32 See PG&E Chapter 5 workpapers, Table WP5-3.

33 PG&E Testimony (July 18, 2022 errata), at p. 2A-4. A summary of PG&E's EG throughput forecast is also in PG&E Response to TURN DR 3, Q1, Attachment 1.

34 This 1-in-35 EG forecast is also included in PG&E Response to TURN DR 3, Q1, Attachment 1.

- Backbone-level EG plants pay lower intrastate transportation rates than EG plants on the PG&E local transmission system, and thus are likely to be dispatched in the CAISO energy market in preference to higher-cost local transmission plants.

D. Calpine's Proposed Allocation

Q: What would be the effect of removing expected backbone-level EG loads from the APD forecast, in terms of the relative amounts of core and noncore service from the local transmission system on an APD?

A: I have corrected PG&E's APD forecast to remove backbone-level EGs, based on the amount of backbone-level, market-responsive EG loads on winter peak days in PG&E's detailed 1-in-35 EG forecast, plus PG&E's forecast of the small amount of backbone-level industrial loads.[35] This calculation is shown in **Table 2**. This changes the APD forecast of local transmission service to 7**8.8% core, 21.1% noncore**, as shown in the yellow-shaded lines in Table 2 This should be the allocation of local transmission costs if the allocation is based on local transmission service on the APD, as PG&E has proposed.

Table 2: *2023-2026 APD Allocations (MMcf/d)*

	Core	Noncore	Total Load
APD Demand *Allocation*	3,041 ***65.9%***	1,570 ***34.1%***	4,610 ***100%***
less Industrial Backbone	-	(6)	(6)
less EG Backbone	-	(746)	(746)
Net APD Load (LT) *Allocation*	3,041 ***78.8%***	818 ***21.2%***	3,859 ***100%***
Curtailed Demand (LT)	-	76	76
APD Demand *Allocation*	3,041 ***77.3%***	894 ***22.7%***	3,935 ***100%***

[35] The amount of backbone-level EG loads removed from the APD forecast is the average of the three highest daily backbone-level EG loads in December or January for the years 2023 – 2026 in PG&E's 1-in-35 EG forecast produced in response to TURN DR 3, Q1.

Q: As the Commission observed in D. 19-09-025, noncore service is almost never curtailed.[36] When core demand is below the APD level, the additional capacity is available to serve noncore loads. Further, another of the design criteria for local transmission facilities is serving all noncore loads on a cold winter day (CWD). How could the 79% core / 21% noncore allocation be adjusted to reflect these considerations?

A: A logical way to do this would be to use an allocation based on (1) the core demand on an APD and (2) noncore demand on the local transmission system on a peak winter day. A reasonable peak winter day demand forecast would be the full noncore demand for local transmission service on the APD, including the loads that would be curtailed to make way for full core service on the APD. According to PG&E's updated forecast, this would result in an allocation of local transmission costs of **77% core, 23% noncore,** as shown in the blue-shaded lines in Table 2. This is Calpine's recommendation.

Q: Why would this allocation of local transmission costs be reasonable?

A: This allocation is reasonable because it would accurately align the allocation of these costs with how PG&E designs its system and with the core and noncore usage that determines the need for local transmission capacity. Today's allocator, cold-year peak-month throughput, is not based on PG&E's design criteria for local transmission and allocates too many local transmission costs to noncore customers, forcing them to subsidize the core. The need to address this subsidy is magnified by the size of the increases in PG&E's local transmission costs since 2010 and as proposed by PG&E in this proceeding.

Q: Would such a change be fair to core customers?

A: Yes, it would, because it would more accurately reflect cost causation.

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[36] See D. 19-09-025, at p. 266: "Under PG&E's tariff, non-core customers have a lower quality of service than core customers, as service to non-core customers can be curtailed; however, in practice, non-core customers are rarely curtailed."

Q: Would the allocation of local transmission costs that you have proposed be more consistent with the capacity-based allocation of other GT&S costs for backbone transmission and storage?

A: Yes, it would, because these are the design criteria which PG&E uses to determine how much local transmission capacity is needed to serve the capacity-related demands of each class for service under peak demand conditions. This would be consistent with the current capacity-based allocation of backbone transmission and storage costs.

Q: Please present your calculation of PG&E's proposed local transmission rates using Calpine's recommended allocation and compare it to PG&E's proposal.

A: **Table 3** shows both PG&E's and Calpine's proposed local transmission rates, and the core / noncore allocation that is used in each.

Table 3: *Local Transmission Rates ($/MDth)*

	PG&E		**Calpine**		**% Change**	
	Core	Noncore	Core	Noncore	Core	Noncore
Allocation:	**66%**	**34%**	**77%**	**23%**		
2023	3.6294	1.8830	4.2583	1.2497	17%	-34%
2024	3.9103	1.9921	4.5878	1.3222	17%	-34%
2025	4.2878	2.1440	5.0308	1.4233	17%	-34%
2026	4.6853	2.2887	5.4971	1.5195	17%	-34%

IV. ALLOCATION OF INVENTORY MANAGEMENT COSTS

A. PG&E's Proposal

Q: PG&E proposes to move the recovery of inventory management (IM) costs from backbone rates to end-use transportation rates, and then to allocate these costs

among end-use customer classes using a method based on how each class uses IM resources. How are IM costs recovered today?

A: A portion of PG&E's storage capacity is allocated to IM in order to serve fluctuating demand while maintaining safe and reliable pressures on the gas system, on both an hourly and daily basis. Today, IM costs are recovered as a common cost in PG&E's backbone transmission rates, with all types of customers paying for IM service effectively based on their use of PG&E's backbone transmission system.

Q: Please comment on the different time scales over which PG&E provides IM service.

A: On a time scale of days, PG&E provides a monthly balancing service for all shippers on its system, based on the daily amounts of gas delivered into and taken out of the system. Importantly, the entities subject to this "inter-day" service are not just end-use customers, but also the gas suppliers who hold capacity on PG&E's backbone system in order to sell or supply gas to customers at the PG&E City-gate. PG&E provides this inter-day balancing service pursuant to its G-BAL tariff; all shippers who are transporting their own gas supplies are subject to this tariff, regardless of the type of end-use customer who ultimately consumes the gas.[37] Generally, the G-BAL tariff requires shippers, each day and month, to schedule quantities of gas into the PG&E system that are similar to the quantities that they remove from the system, subject to certain tolerances and penalties for violating these tolerances. These tolerances can be tightened as necessary to keep the system in balance, through PG&E calling operational flow orders (OFOs). End-use customers are not necessarily responsible for managing their imbalances, as G-BAL allows noncore customers to elect to assign their balancing obligations to a Balancing Agent, who may be a gas supplier that is the Balancing Agent for multiple customers.

Within each gas day, on an hourly basis, there are no balancing rules, but PG&E requires and uses IM storage resources to accommodate customers whose end use of natural gas

[37] PG&E's current G-BAL tariff is provided for the record in **Attachment RTB-3**.

fluctuates on an hourly basis. This is the "intra-day" balancing component of the overall IM service that PG&E provides.

Q: How does PG&E propose to change the allocation of IM costs?

A: PG&E would divide IM costs into inter-day and intra-day components and allocate each of these components between three groups of customers: the core, market-sensitive EGs, and the remaining noncore customers (the "Big 3" market segments). PG&E would base these allocations on the relative inter-day and intra-day imbalances of the Big 3 market segments over a five-year historical period (2016-2020). The utility also proposes a split of IM costs of 36% to inter-day monthly balancing service and 64% to intra-day balancing, based on the ratio of customer class imbalance volumes from 2016-2020.

PG&E would then allocate both inter-day and intra-day IM costs to individual rate schedules within the Big 3 market segments, using the seasonal variance in usage by the customers on each rate schedule as the allocator.[38]

B. Calpine's Proposed Modifications to PG&E's Proposal

Q: As a threshold issue, does Calpine support removing both inter-day and intra-day IM costs from backbone rates?

A: No. Inter-day balancing costs should remain bundled in backbone rates. All shippers of gas on the PG&E system receive the same inter-day balancing service pursuant to the single G-BAL tariff, and should pay the same price for this service. G-BAL allows shippers to run a certain level of inter-day imbalances between their receipts into and deliveries out of the system, without additional charge, and levies specific penalties if the tariff's tolerances are violated. Shippers are able to use as much or as little of PG&E's inter-day balancing services as they wish, with no extra charges, so long as they remain within the prescribed tolerances of the G-BAL tariff. PG&E's proposal to allocate inter-day IM costs among market segments based on their historical daily imbalances would penalize certain types of customers – specifically, core customers and EGs – who made greater use of the available tolerances under G-BAL than other market segments, even though all types of customers and shippers operated within the uniform G-BAL rules.

In addition, there are a substantial number of shippers on the PG&E system who are not end use customers, but are gas suppliers or marketers who sell gas, for example, at the PG&E City-gate. These suppliers can be shippers in their own name on the backbone system upstream of the City-gate, and can act as Balancing Agents under G-BAL for multiple end-use customers. It is unclear how PG&E considered the imbalances of these non-end-use shippers in its allocation of inter-day IM costs. They may not have been considered at all, given that PG&E said in discovery that its allocation proposal for IM costs "is focused on end-use customers including backbone connected end-use customers."[39] Such supplier/shippers may serve a diverse portfolio of end use customers that include customers in different market segments. Moreover, end users have little control over the balancing performance of these suppliers and balancing agents, and, to the extent that PG&E's inter-day imbalance calculations do consider these supplier imbalances, then it would be unfair to penalize end use customers now if their suppliers or agents made more use of G-BAL than other shippers or customer types while remaining within the G-BAL tolerances.

Q: Does Calpine support the transfer of intra-day IM costs from backbone to end-use rates?

A: Yes. Within each day, end use customers obviously determine and control their hourly use of natural gas. Accordingly, it makes sense for intra-day IM costs to be allocated

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[38] The use of the seasonal variance in usage would be a proxy, as PG&E does not have imbalance data by customer class.

[39] See PG&E response to Calpine DR 001, Q21, included in **Attachment RTB-2**.

based on the variation of each market segment from a constant hourly use of gas. For the purposes of this case, I also accept PG&E's proposed allocation of 64% of IM costs to intra-day balancing, to be recovered in end-use rates. This allocation should be reviewed in the next GT&S CARD case, given the uncertainty in how PG&E has treated inter-day imbalances of shippers who are not end users.

Q: Do you have other concerns with PG&E's proposed allocation of intra-day IM costs?

A: Yes. PG&E's allocation of intra-day IM costs to the "Big 3" market segments is based on historical data (2016-2020). The relative allocation of intra-day IM costs thus reflects the relative throughput of the Big 3 segments over that period. This historical period included abnormally high EG loads as a result of below-normal hydro conditions. However, the throughput forecast for this case shows a very different mix of throughput among these market segments. The throughput forecast for this case is the best available estimate of the relative amounts of gas service that each of the Big 3 market segments will take during the forecast period. Thus, the adopted throughput forecast should be the basis for the allocation of IM costs.

Q: Have you quantified the effects of your proposals, first, to only shift intra-day IM costs to end-use rates and, second, to use the throughput forecast for this case to allocate IM costs among the Big 3 market segments?

A: Yes. PG&E's IM rate analysis makes use of the following allocation of intra-day imbalances to allocate costs.

Table 4: *PG&E "Big 3" 2016-2020 Intra-day Imbalances (MMcfd)*

Big 3 Market Segment	Intra-day Imbalances	Allocation (%)
Market-sensitive EG	106	33%
Other Noncore	13	4%
Core	201	63%
Total	319	100%

Table 2B-1 of PG&E's testimony summarizes historical 2020 and forecast 2023-2026 throughput. See **Table 5** below. It shows that EG throughput is expected to decrease by 44%, while the other classes' throughputs change by much smaller amounts.

Table 5: *PG&E 2020 Actual and 2023-2026 Forecasted Throughput (MMcfd)*

Big 3 Market Segment	Actual 2020	Forecasted 2023-2026	% Change
Market-sensitive EG	817	459	-44%
Other Noncore	482	489	+1%
Core	723	686	-5%

We have adjusted the imbalances shown in Table 4 based on the expected change in throughput from recorded 2020 volumes to the 2023-2026 throughput forecast for this case, assuming that each market segment continues to have the same level of imbalances per Dth of throughput that it had in 2020. The resulting allocation of imbalances for the 2023-2026 forecast period is shown in **Table 6**.

Table 6: *Revised "Big 3" Intra-Day Imbalances for 2023-2026 (MMcfd)*

Big 3 Market Segment	Intra-day Imbalances	Allocation (%)
Market-sensitive EG	69	25%
Other Noncore	13	5%
Core	188	70%
Total	270	100%

Limiting the IM costs in end use rates to intra-day IM costs only, and applying the revised allocation shown in **Table 6,** results in the IM rates in 2023 and in 2023-2026 shown in **Tables 7 and 8**. These tables are Calpine's primary recommendation for the IM component of PG&E's end-use rates.

Table 7: *Inventory Management Rates in 2023 ($/Dth)*

Class	PG&E	Calpine
Core	0.168	0.155
EG-LT	0.189	0.085
EG-BB	0.178	0.080
Noncore C&I	0.042	0.011
Total	0.136	0.090

Table 8: *Calpine Proposed Inventory Management Rates for 2023-2026 ($/Dth)*

Class	2023	2024	2025	2026
Residential and Small Commercial	0.155	0.237	0.246	0.279
Large Commercial and Industrial Distribution	0.003	0.004	0.004	0.005
Industrial Transmission	0.014	0.021	0.022	0.025
EG-LT	0.085	0.129	0.134	0.152
EG-BB	0.080	0.122	0.126	0.143
Total	0.090	0.137	0.142	0.161

Q: If the Commission decides to include both inter-day and intra-day IM costs in end-use rates, should the allocation of inter-day IM costs also be revised based on the changing throughput forecast in 2023-2026 compared to 2016-2020?

A: Yes. If the Commission decides to include both inter-day and intra-day IM costs in end-use rates, then **Table 9** shows the IM rates for 2023-2026 that Calpine recommends as a second-best outcome, with the adjustment for the changing throughput forecast.

Table 9: *Calpine's Alternative IM Rates – Including All IM Costs ($/Dth)*

Class	2023	2024	2025	2026
Residential and Small Commercial	0.192	0.293	0.304	0.345
Large Commercial and Industrial Distribution	0.012	0.018	0.019	0.022
Industrial Transmission	0.064	0.098	0.102	0.115
EG-LT	0.142	0.217	0.225	0.255
EG-BB	0.134	0.205	0.212	0.240
Total	0.136	0.207	0.215	0.243

V. RATE DESIGN

Q: PG&E is proposing no changes in the design of the GT&S transportation rates applicable to EG customers. Do you support the continuation of the existing EG rate design?

A Yes. Calpine will respond in rebuttal to any proposals to revise the structure of the GT&S transportation rates applicable to EG customers.

VI. RATE IMPACTS OF CALPINE'S PROPOSALS

Q: Have you estimated the impacts of the recommendations in this testimony on PG&E's backbone, local transmission, and end use rates for core and noncore customers?

A: Yes, I have.

- **Backbone rates.** Calpine's proposal to keep inter-day IM costs in backbone rates would increase PG&E's proposed backbone rates by about $0.08 per Dth.

- **Local transmission rates.** The revised allocation of local transmission and IM costs that Calpine proposes would reduce PG&E's proposed noncore local transmission rates in 2023 by about $0.63 per Dth for noncore customers. For example, for EG customers who take service from the local transmission system, Calpine recommends a noncore local transmission rate in 2023 of $1.25 per Dth, compared to PG&E's proposed $1.88 per Dth (see Table 3).

- **End-use rates.** Calpine's proposal to limit the IM costs in end-use rates to intra-day IM costs would reduce all of PG&E's end-use rates, as shown in Table 7, compared to PG&E's proposal. The use of the adopted throughput forecast to allocate IM costs, as Calpine proposes, will result in the most accurate allocation of IM costs over the forecast period and will reduce the IM rate for EG customers relative to other customer classes.

Q: Does this complete your prepared direct testimony in this case?

A: Yes, it does.

Attachment RTB-1

Experience and Qualifications of R. Thomas Beach

Mr. Beach is principal consultant with the consulting firm Crossborder Energy. Crossborder Energy provides economic consulting services and strategic advice on market and regulatory issues concerning the natural gas and electric industries. The firm is based in Berkeley, California, and its practice focuses on the energy markets in California, the U.S., and Canada.

Since 1989, Mr. Beach has had an active consulting practice on policy, economic, and ratemaking issues concerning renewable energy development, the restructuring of the gas and electric industries, the addition of new natural gas pipeline and storage capacity, and a wide range of issues concerning independent power generation. From 1981 through 1989 he served at the California Public Utilities Commission, including five years as an advisor to three CPUC commissioners. While at the CPUC, he was a key advisor on the CPUC's restructuring of the natural gas industry in California, and worked extensively on the state's implementation of the Public Utilities Regulatory Policies Act of 1978.

AREAS OF EXPERTISE

- *Renewable Energy Issues:* extensive experience assisting clients with issues concerning Renewable Portfolio Standard programs, including program structure and rate impacts. He has also worked for the solar industry on rate design and net energy metering issues, on the creation of the California Solar Initiative, as well as on a wide range of solar issues in many other states.

- *Restructuring the Natural Gas and Electric Industries:* consulting and expert testimony on numerous issues involving the restructuring of the electric industry, including the 2000 - 2001 Western energy crisis.

- *Energy Markets:* studies and consultation on the dynamics of natural gas and electric markets, including the impacts of new pipeline capacity on natural gas prices and of electric restructuring on wholesale electric prices.

- *Qualifying Facility Issues:* consulting with QF clients on a broad range of issues involving independent power facilities in the Western U.S. He is one of the leading experts in California on the calculation of avoided cost prices. Other QF issues on which he has worked include complex QF contract restructurings, standby rates, greenhouse gas emission regulations, and natural gas rates for cogenerators. Crossborder Energy's QF clients include the full range of QF technologies, both fossil-fueled and renewable.

- *Pricing Policy in Regulated Industries:* consulting and expert testimony on natural gas pipeline rates and on marginal cost-based rates for natural gas and electric utilities.

EDUCATION

Mr. Beach holds a B.A. in English and physics from Dartmouth College, and an M.E. in mechanical engineering from the University of California at Berkeley.

ACADEMIC HONORS

Graduated from Dartmouth with high honors in physics and honors in English.
Chevron Fellowship, U.C. Berkeley, 1978-79

PROFESSIONAL ACCREDITATION

Registered professional engineer in the state of California.

EXPERT WITNESS TESTIMONY BEFORE THE CALIFORNIA PUBLIC UTILITIES COMMISSION

1. Prepared Direct Testimony on Behalf of **Pacific Gas & Electric Company/Pacific Gas Transmission** (I. 88-12-027 — July 15, 1989)

    - *Competitive and environmental benefits of new natural gas pipeline capacity to California.*

2. a. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 10, 1989)
   b. Prepared Rebuttal Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 30, 1989)

    - *Natural gas procurement policy; gas cost forecasting.*

3. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (R. 88-08-018 — December 7, 1989)

    - *Brokering of interstate pipeline capacity.*

4. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029 — November 1, 1990)

    - *Natural gas procurement policy; gas cost forecasting; brokerage fees.*

5. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission and the Canadian Producer Group** (I. 86-06-005 — December 21, 1990)

    - *Firm and interruptible rates for noncore natural gas users*

6. a. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — January 25, 1991)
   b. Prepared Responsive Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — March 29, 1991)

   - *Brokering of interstate pipeline capacity; intrastate transportation policies.*

7. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029/Phase II — April 17, 1991)

   - *Natural gas brokerage and transport fees.*

8. Prepared Direct Testimony on Behalf of **LUZ Partnership Management** (A. 91-01-027 — July 15, 1991)

   - *Natural gas parity rates for cogenerators and solar thermal power plants.*

9. Prepared Joint Testimony of R. Thomas Beach and Dr. Robert B. Weisenmiller on Behalf of the **California Cogeneration Council** (I. 89-07-004 — July 15, 1991)

   - *Avoided cost pricing; use of published natural gas price indices to set avoided cost prices for qualifying facilities.*

10. a. Prepared Direct Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-033 — October 28, 1991)
    b. Prepared Rebuttal Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-0033 — November 26,1991)

   - *Natural gas pipeline rate design; cost/benefit analysis of rolled-in rates.*

11. Prepared Direct Testimony on Behalf of the **Independent Petroleum Association of Canada** (A. 91-04-003 — January 17, 1992)

   - *Natural gas procurement policy; prudence of past gas purchases.*

12. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (I.86-06-005/Phase II — June 18, 1992)
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council** (I. 86-06-005/Phase II — July 2, 1992)

   - *Long-Run Marginal Cost (LRMC) rate design for natural gas utilities.*

13. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 92-10-017 — February 19, 1993)

   - *Performance-based ratemaking for electric utilities.*

14. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-02-014/A. 93-03-053 — May 21, 1993)

    - *Natural gas transportation service for wholesale customers.*

15
    a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — June 28, 1993)
    b. Prepared Rebuttal Testimony of Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — July 8, 1993)

    - *Natural gas pipeline rate design issues.*

16.
    a. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — November 10, 1993)
    b. Prepared Rebuttal Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — January 10, 1994)

    - *Utility overcharges for natural gas service; cogeneration parity issues.*

17. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 93-09-006/A. 93-08-022/A. 93-09-048 — June 17, 1994)

    - *Natural gas rate design for wholesale customers; retail competition issues.*

18. Prepared Direct Testimony of R. Thomas Beach on Behalf of the **SEGS Projects** (A. 94-01-021 — August 5, 1994)

    - *Natural gas rate design issues; rate parity for solar thermal power plants.*

19. Prepared Direct Testimony on Transition Cost Issues on Behalf of **Watson Cogeneration Company** (R. 94-04-031/I. 94-04-032 — December 5, 1994)

    - *Policy issues concerning the calculation, allocation, and recovery of transition costs associated with electric industry restructuring.*

20. Prepared Direct Testimony on Nuclear Cost Recovery Issues on Behalf of the **California Cogeneration Council** (A. 93-12-025/I. 94-02-002 — February 14, 1995)

    - *Recovery of above-market nuclear plant costs under electric restructuring.*

21. Prepared Direct Testimony on Behalf of the **Sacramento Municipal Utility District** (A. 94-11-015 — June 16, 1995)

    - *Natural gas rate design; unbundled mainline transportation rates.*

22. Prepared Direct Testimony on Behalf of **Watson Cogeneration Company** (A. 95-05-049 — September 11, 1995)

    - *Incremental Energy Rates; air quality compliance costs.*

23. a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — January 30, 1996)
    b. Prepared Rebuttal Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — February 28, 1996)

    - *Natural gas market dynamics; gas pipeline rate design.*

24. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 96-03-031 — July 12, 1996)

    - *Natural gas rate design: parity rates for cogenerators.*

25. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 96-10-038 — August 6, 1997)

    - *Impacts of a major utility merger on competition in natural gas and electric markets.*

26. a. Prepared Direct Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — December 18, 1997)
    b. Prepared Rebuttal Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — January 9, 1998)

    - *Natural gas rate design for gas-fired electric generators.*

27. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 97-03-015 — January 16, 1998)

    - *Natural gas service to Baja, California, Mexico.*

28. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 98-10-012/A. 98-10-031/A. 98-07-005 — March 4, 1999).
    b. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — March 15, 1999).
    c. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — June 25, 1999).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

29. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — February 11, 2000).
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — March 6, 2000).
    c. Prepared Direct Testimony on Line Loss Issues of behalf of the **California Cogeneration Council** (R. 99-11-022 — April 28, 2000).
    d. Supplemental Direct Testimony in Response to ALJ Cooke's Request on behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — April 28, 2000).
    e. Prepared Rebuttal Testimony on Line Loss Issues on behalf of the **California Cogeneration Council** (R. 99-11-022 — May 8, 2000).

    - *Market-based, avoided cost pricing for the electric output of gas-fired cogeneration facilities in the California market; electric line losses.*

30. a. Direct Testimony on behalf of the **Indicated Electric Generators** in Support of the Comprehensive Gas OII Settlement Agreement for Southern California Gas Company and San Diego Gas & Electric Company (I. 99-07-003 — May 5, 2000).
    b. Rebuttal Testimony in Support of the Comprehensive Settlement Agreement on behalf of the **Indicated Electric Generators** (I. 99-07-003 — May 19, 2000).

    - *Testimony in support of a comprehensive restructuring of natural gas rates and services on the Southern California Gas Company system. Natural gas cost allocation and rate design for gas-fired electric generators.*

31. a. Prepared Direct Testimony on the Cogeneration Gas Allowance on behalf of the **California Cogeneration Council** (A. 00-04-002 — September 1, 2000).
    b. Prepared Direct Testimony on behalf of **Southern Energy California** (A. 00-04-002 — September 1, 2000).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

32. a. Prepared Direct Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — September 18, 2000).
    b. Prepared Rebuttal Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — October 6, 2000).

    - *Rate design for a natural gas "peaking service."*

33. a. Prepared Direct Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—April 25, 2001).
    b. Prepared Rebuttal Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—May 15, 2001).

    - *Terms and conditions of natural gas service to electric generators; gas curtailment policies.*

34. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 7, 2001).
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 30, 2001).

    - *Avoided cost pricing for alternative energy producers in California.*

35. a. Prepared Direct Testimony of R. Thomas Beach in Support of the Application of **Wild Goose Storage Inc.** (A. 01-06-029—June 18, 2001).
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Wild Goose Storage** (A. 01-06-029—November 2, 2001)

    - *Consumer benefits from expanded natural gas storage capacity in California.*

36. Prepared Direct Testimony on behalf of the **County of San Bernardino** (I. 01-06-047—December 14, 2001)

    - *Reasonableness review of a natural gas utility's procurement practices and storage operations.*

37. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)
    b. Prepared Supplemental Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)

    - *Electric procurement policies for California's electric utilities in the aftermath of the California energy crisis.*

38. Prepared Direct Testimony on behalf of the **California Manufacturers & Technology Association** (R. 02-01-011—June 6, 2002)

    - *"Exit fees" for direct access customers in California.*

39. Prepared Direct Testimony on behalf of the **County of San Bernardino** (A. 02-02-012 — August 5, 2002)

    - *General rate case issues for a natural gas utility; reasonableness review of a natural gas utility's procurement practices.*

40. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association** (A. 98-07-003 — February 7, 2003)

    - *Recovery of past utility procurement costs from direct access customers.*

41. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — February 28, 2003)
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — March 24, 2003)

    - *Rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord II).*

42. a. Prepared Direct Testimony on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — March 21, 2003)
    b. Prepared Rebuttal Testimony on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — April 4, 2003)

    - *Cost allocation of above-market interstate pipeline costs for the California natural gas utilities.*

43. Prepared Direct Testimony of R. Thomas Beach and Nancy Rader on behalf of the **California Wind Energy Association** (R. 01-10-024 — April 1, 2003)

    - *Design and implementation of a Renewable Portfolio Standard in California.*

44. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 23, 2003)
    b. Prepared Supplemental Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 29, 2003)

    - *Power procurement policies for electric utilities in California.*

45. Prepared Direct Testimony on behalf of the **Indicated Commercial Parties** (02-05-004 — August 29, 2003)

    - *Electric revenue allocation and rate design for commercial customers in southern California.*

46. a. Prepared Direct Testimony on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 16, 2004)
    b. Prepared Rebuttal Testimony on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 26, 2004)

    - *Policy and rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord III).*

47. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (A. 04-04-003 — August 6, 2004)

    - *Policy and contract issues concerning cogeneration QFs in California.*

48. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 11, 2005)
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 28, 2005)

    - *Natural gas cost allocation and rate design for large transportation customers in northern California.*

49. a. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — March 7, 2005)
    b. Prepared Rebuttal Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — April 26, 2005)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

50. Prepared Direct Testimony on behalf of the **California Solar Energy Industries Association** (R. 04-03-017 — April 28, 2005)

- *Cost-effectiveness of the Million Solar Roofs Program.*

51. Prepared Direct Testimony on behalf of **Watson Cogeneration Company, the Indicated Producers, and the California Manufacturing and Technology Association** (A. 04-12-004 — July 29, 2005)

- *Natural gas rate design policy; integration of gas utility systems.*

52. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — August 31, 2005)
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — October 28, 2005)

- *Avoided cost rates and contracting policies for QFs in California*

53. a. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — January 20, 2006)
    b. Prepared Rebuttal Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — February 24, 2006)

- *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in southern California.*

54. a. Prepared Direct Testimony on behalf of the **California Producers** (R. 04-08-018 – January 30, 2006)
    b. Prepared Rebuttal Testimony on behalf of the **California Producers** (R. 04-08-018 – February 21, 2006)

- *Transportation and balancing issues concerning California gas production.*

55. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 06-03-005 — October 27, 2006)

- *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

56. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (A. 05-12-030 — March 29, 2006)

- *Review and approval of a new contract with a gas-fired cogeneration project.*

57. a. Prepared Direct Testimony on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 14, 2006)
    b. Prepared Rebuttal Testimony on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 31, 2006)

    - *Restructuring of the natural gas system in southern California to include firm capacity rights; unbundling of natural gas services; risk/reward issues for natural gas utilities.*

58. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 06-02-013 — March 2, 2007)

    - *Utility procurement policies concerning gas-fired cogeneration facilities.*

59. a. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 07-01-047 — August 10, 2007)
    b. Prepared Rebuttal Testimony on behalf of the **Solar Alliance** (A. 07-01-047 — September 24, 2007)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems.*

60. a. Prepared Direct Testimony on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — May 15, 2008)
    b. Prepared Rebuttal Testimony on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — June 13, 2008)

    - *Utility subscription to new natural gas pipeline capacity serving California.*

61. a. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 08-03-015 — September 12, 2008)
    b. Prepared Rebuttal Testimony on behalf of the **Solar Alliance** (A. 08-03-015 — October 3, 2008)

    - *Issues concerning the design of a utility-sponsored program to install 500 MW of utility- and independently-owned solar photovoltaic systems.*

62. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 08-03-002 — October 31, 2008)

- *Electric rate design issues that impact customers installing solar photovoltaic systems*.

63. a. Phase II Direct Testimony on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — December 23, 2008)
    b. Phase II Rebuttal Testimony on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — January 27, 2009)

- *Natural gas cost allocation and rate design issues for large customers.*

64. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (A. 09-05-026 — November 4, 2009)

- *Natural gas cost allocation and rate design issues for large customers.*

65. a. Prepared Direct Testimony on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 5, 2010)
    b. Prepared Rebuttal Testimony on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 26, 2010)

- *Revisions to a program of firm backbone capacity rights on natural gas pipelines.*

66. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 10-03-014 — October 6, 2010)

- *Electric rate design issues that impact customers installing solar photovoltaic systems*.

67. Prepared Rebuttal Testimony on behalf of the **Indicated Settling Parties** (A. 09-09-013 — October 11, 2010)

- *Testimony on proposed modifications to a broad-based settlement of rate-related issues on the Pacific Gas & Electric natural gas pipeline system.*

68. a. Supplemental Prepared Direct Testimony on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 6, 2010)
    b. Supplemental Prepared Rebuttal Testimony on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 13, 2010)
    c. Supplemental Prepared Reply Testimony on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 20, 2010)

    - *Local reliability benefits of a new natural gas storage facility.*

69. Prepared Direct Testimony on behalf of **The Vote Solar Initiative** (A. 10-11-015—June 1, 2011)

    - *Distributed generation policies; utility distribution planning.*

70. Prepared Reply Testimony on behalf of the **Solar Alliance** (A. 10-03-014—August 5, 2011)

    - *Electric rate design for commercial & industrial solar customers.*

71. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 11-06-007—February 6, 2012)

    - *Electric rate design for solar customers; marginal costs.*

72. a. Prepared Direct Testimony on behalf of the **Northern California Indicated Producers** (R.11-02-019—January 31, 2012)
    b. Prepared Rebuttal Testimony on behalf of the **Northern California Indicated Producers** (R. 11-02-019—February 28, 2012)

    - *Natural gas pipeline safety policies and costs*

73. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 11-10-002—June 12, 2012)

    - *Electric rate design for solar customers; marginal costs.*

74. Prepared Direct Testimony on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002—June 19, 2012)

    - *Natural gas pipeline safety policies and costs*

75. a. Testimony on behalf of the **California Cogeneration Council** (R. 12-03-014—June 25, 2012)
    b. Reply Testimony on behalf of the **California Cogeneration Council** (R. 12-03-014—July 23, 2012)

    - *Ability of combined heat and power resources to serve local reliability needs in southern California.*

76. a. Prepared Testimony on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002, Phase 2—November 16, 2012)
    b. Prepared Rebuttal Testimony on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002, Phase 2—December 14, 2012)

    - *Allocation and recovery of natural gas pipeline safety costs.*

77. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 12-12-002—May 10, 2013)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

78. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 13-04-012—December 13, 2013)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

79. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 13-12-015—June 30, 2014)

    - *Electric rate design for commercial & industrial solar customers; residential time-of-use rate design issues.*

80. a. Prepared Direct Testimony on behalf of **Calpine Corporation** and the **Indicated Shippers** (A. 13-12-012—August 11, 2014)
    b. Prepared Direct Testimony on behalf of **Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest,** and **the City of Palo Alto** (A. 13-12-012—August 11, 2014)
    c. Prepared Rebuttal Testimony on behalf of **Calpine Corporation** (A. 13-12-012—September 15, 2014)
    d. Prepared Rebuttal Testimony on behalf of **Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest,** and **the City of Palo Alto** (A. 13-12-012—September 15, 2014)

    - *Rate design, cost allocation, and revenue requirement issues for the gas transmission system of a major natural gas utility.*

81. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (R. 12-06-013—September 15, 2014)

    - *Comprehensive review of policies for rate design for residential electric customers in California.*

82. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 14-06-014—March 13, 2015)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

83. a. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A.14-11-014—May 1, 2015)
    b. Prepared Rebuttal Testimony on behalf of the **Solar Energy Industries Association** (A. 14-11-014—May 26, 2015)

    - *Time-of-use periods for residential TOU rates.*

84. Prepared Rebuttal Testimony on behalf of the **Joint Solar Parties** (R. 14-07-002 — September 30, 2015)

    - *Electric rate design issues concerning proposals for the net energy metering successor tariff in California.*

85. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 15-04-012—July 5, 2016)

    - *Selection of Time-of-Use periods, and rate design issues for solar customers.*

86. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 16-09-003 — April 28, 2017)

    - *Selection of Time-of-Use periods, and rate design issues for solar customers.*

87. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 17-06-030 — March 23, 2018)

    - *Selection of Time-of-Use periods, and rate design issues for solar customers.*

88. Prepared Direct and Rebuttal Testimony on behalf of **Calpine Corporation** (A. 17-11-009 – July 20 and August 20, 2018)

    - *Gas transportation rates for electric generators, gas storage and balancing issues*

89. Prepared Direct Testimony on behalf of **Gas Transmission Northwest LLC** and the **City of Palo Alto** (A. 17-11-009 – July 20, 2018)

    - *Rate design for intrastate backbone gas transportation rates*

90. Prepared Direct Testimony on behalf of **EVgo** (A. 18-11-003 – April 5, 2019)

    - *Electric rate design for commercial electric vehicle charging*

91. Prepared Direct and Rebuttal Testimony on behalf of **Vote Solar** and the **Solar Energy Industries Association** (R. 14-10-003 — October 7 and 21, 2019)

    - *Avoided cost issues for distributed energy resources*

92. Prepared Direct and Rebuttal Testimony on behalf of **EVgo** (A. 19-07-006 – January 13 and February 20, 2020)

    - *Electric rate design for commercial electric vehicle charging*

93. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 19-03-002 — March 17, 2020)

    - *Electric rate design issues for solar and storage customers*

EXPERT WITNESS TESTIMONY BEFORE THE ARIZONA CORPORATION COMMISSION

1. Prepared Direct, Rebuttal, and Supplemental Testimony on behalf of **The Alliance for Solar Choice (TASC)**, (Docket No. E-00000J-14-0023, February 27, April 7, and June 22, 2016).

    - *Development of a benefit-cost methodology for distributed, net metered solar resources in Arizona.*

2. Prepared Surrebuttal and Responsive Testimony on behalf of the **Energy Freedom Coalition of America** (Docket No. E-01933A-15-0239 – March 10 and September 15, 2016).

    - *Critique of a utility-owned solar program; comments on a fixed rate credit to replace net energy metering.*

3. Direct Testimony on behalf of the **Solar Energy Industries Association** (Docket No. E-01345A-16-0036, February 3, 2017).

4. Direct and Surrebuttal Testimony on behalf of **The Alliance for Solar Choice and the Energy Freedom Coalition of America** (Docket Nos. E-01933A-15-0239 (TEP), E-01933A-15-0322 (TEP), and E-04204A-15-0142 (UNSE) – May 17 and September 29, 2017).

EXPERT WITNESS TESTIMONY BEFORE THE COLORADO PUBLIC UTILITIES COMMISSION

1. Direct Testimony and Exhibits on behalf of the **Colorado Solar Energy Industries Association** and the **Solar Alliance**, (Docket No. 09AL-299E – October 2, 2009). https://www.dora.state.co.us/pls/efi/DDMS_Public.Display_Document?p_section=PUC&p_source=EFI_PRIVATE&p_doc_id=3470190&p_doc_key=0CD8F7FCDB673F1043928849D9D8CAB1&p_handle_not_found=Y

    - *Electric rate design policies to encourage the use of distributed solar generation.*

2. Direct Testimony and Exhibits on behalf of the **Vote Solar Initiative** and the **Interstate Renewable Energy Council**, (Docket No. 11A-418E – September 21, 2011).

    - *Development of a community solar program for Xcel Energy.*

3. Answer Testimony and Exhibits, plus Opening Testimony on Settlement, on behalf of the **Solar Energy Industries Association**, (Docket No. 16AL-0048E [Phase II] – June 6 and September 2, 2016).

    - *Rate design issues related to residential customers and solar distributed generation in a Public Service of Colorado general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

1. Direct Testimony on behalf of **Georgia Interfaith Power & Light and Southface Energy Institute, Inc.** (Docket No. 40161 – May 3, 2016).

    - *Development of a cost-effectiveness methodology for solar resources in Georgia.*

EXPERT WITNESS TESTIMONY BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

1. Direct Testimony on behalf of the **Idaho Conservation League** (Case No. IPC-E-12-27—May 10, 2013)

    - *Costs and benefits of net energy metering in Idaho.*

2. a. Direct Testimony on behalf of the **Idaho Conservation League and the Sierra Club** (Case Nos. IPC-E-15-01/AVU-4-15-01/PAC-E-15-03 — April 23, 2015)
   b. Rebuttal Testimony on behalf of the **Idaho Conservation League and the Sierra Club** (Case Nos. IPC-E-15-01/AVU-4-15-01/PAC-E-15-03 — May 14, 2015)

    - *Issues concerning the term of PURPA contracts in Idaho.*

2. a. Direct Testimony on behalf of the **Sierra Club** (Case No. IPC-E-17-13 — December 22, 2017)
   b. Rebuttal Testimony on behalf of the **Sierra Club** (Case No. IPC-E-17-13 — January 26, 2018)

EXPERT WITNESS TESTIMONY BEFORE THE MASSACHUSETTS DEPARTMENT OF PUBLIC UTILITIES

1. Direct and Rebuttal Testimony on behalf of **Northeast Clean Energy Council, Inc.** (Docket D.P.U. 15-155, March 18 and April 28, 2016)

    - *Residential rate design and access fee proposals related to distributed generation in a National Grid general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

1. Prepared Direct Testimony on behalf of **Vote Solar** (Case No. U-18419—January 12, 2018)

2. Prepared Rebuttal Testimony on behalf of the **Environmental Law and Policy Center, the Ecology Center, the Solar energy Industries Association, Vote Solar, and the Union of Concerned Scientists** (Case No. U-18419 — February 2, 2018)

EXPERT WITNESS TESTIMONY BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

1. Direct and Rebuttal Testimony on Behalf of **Geronimo Energy, LLC**. (In the Matter of the Petition of Northern States Power Company to Initiate a Competitive Resource Acquisition Process [OAH Docket No. 8-2500-30760, MPUC Docket No. E002/CN-12-1240, September 27 and October 18, 2013])

    - *Testimony in support of a competitive bid from a distributed solar project in an all-source solicitation for generating capacity.*

EXPERT WITNESS TESTIMONY BEFORE THE MONTANA PUBLIC SERVICE COMMISSION

1. Pre-filed Direct and Supplemental Testimony on Behalf of **Vote Solar and the Montana Environmental Information Center** (Docket No. D2016.5.39, October 14 and November 9, 2016).

    - *Avoided cost pricing issues for solar QFs in Montana.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

1. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 97-2001—May 28, 1997)

    - *Avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

2. Pre-filed Direct Testimony on Behalf of **Nevada Sun-Peak Limited Partnership** (Docket No. 97-6008—September 5, 1997)

    - *QF pricing issues in Nevada.*

3. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 98-2002 — June 18, 1998)

    - *Market-based, avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

4. a. Prepared Direct Testimony on behalf of **The Alliance for Solar Choice (TASC)**, (Docket Nos. 15-07041 and 15-07042 –October 27, 2015).
   b. Prepared Direct Testimony on Grandfathering Issues on behalf of **TASC**, (Docket Nos. 15-07041 and 15-07042 –February 1, 2016).

c. Prepared Rebuttal Testimony on Grandfathering Issues on behalf of **TASC**, (Docket Nos. 15-07041 and 15-07042 –February 5, 2016).

- *Net energy metering and rate design issues in Nevada.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

1. Prepared Direct and Rebuttal Testimony on behalf of **The Alliance for Solar Choice (TASC)**, (Docket No. DE 16-576, October 24 and December 21, 2016).

   - *Net energy metering and rate design issues in New Hampshire.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

1. Direct Testimony on Behalf of the **Interstate Renewable Energy Council** (Case No. 10-00086-UT—February 28, 2011) http://164.64.85.108/infodocs/2011/3/PRS20156810DOC.PDF

   - *Testimony on proposed standby rates for new distributed generation projects; cost-effectiveness of DG in New Mexico.*

2. Direct Testimony and Exhibits on behalf of the **New Mexico Independent Power Producers** (Case No. 11-00265-UT, October 3, 2011)

   - *Cost cap for the Renewable Portfolio Standard program in New Mexico*

EXPERT WITNESS TESTIMONY BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

1. Direct, Response, and Rebuttal Testimony on Behalf of the North Carolina Sustainable Energy Association. (In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2014; Docket E-100 Sub 140; April 25, May 30, and June 20, 2014)

   - *Testimony on avoided cost issues related to solar and renewable qualifying facilities in North Carolina.*

April 25, 2014: http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=89f3b50f-17cb-4218-87bd-c743e1238bc1
May 30, 2014: http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=19e0b58d-a7f6-4d0d-9f4a-08260e561443
June 20, 2104: http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=bd549755-d1b8-4c9b-b4a1-fc6e0bd2f9a2

2. Direct Testimony on Behalf of the North Carolina Sustainable Energy Association. (In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2018; Docket E-100 Sub 158; June 21, 2019)

    - *Testimony on avoided cost issues related to solar and renewable qualifying facilities in North Carolina.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF OREGON

1. a. Direct Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — August 3, 2004)
   b. Surrebuttal Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — October 14, 2004)

2. a. Direct Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — February 27, 2006)
   b. Rebuttal Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — April 7, 2006)

    - *Policies to promote the development of cogeneration and other qualifying facilities in Oregon.*

3. Direct Testimony on Behalf of the **Oregon Solar Energy Industries Association** (UM 1910,01911, and 1912 — March 16, 2018).

    - *Resource value of solar resources in Oregon*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

1. Direct Testimony and Exhibits on behalf of **The Alliance for Solar Choice** (Docket No. 2014-246-E – December 11, 2014)
https://dms.psc.sc.gov/attachments/matter/B7BACF7A-155D-141F-236BC437749BEF85

    - *Methodology for evaluating the cost-effectiveness of net energy metering*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF TEXAS

1. Direct Testimony on behalf of the **Solar Energy Industries Association** (SEIA) (Docket No. 44941 – December 11, 2015)

    - *Rate design issues concerning net metering and renewable distributed generation in an El Paso Electric general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

1. Direct Testimony on behalf of the **Sierra Club** (Docket No. 15-035-53—September 15, 2015)

    - *Issues concerning the term of PURPA contracts in Idaho.*

EXPERT WITNESS TESTIMONY BEFORE THE VERMONT PUBLIC SERVICE BOARD

1. Pre-filed Testimony of R. Thomas Beach and Patrick McGuire on Behalf of **Allco Renewable Energy Limited** (Docket No. 8010 — September 26, 2014)

    - *Avoided cost pricing issues in Vermont*

EXPERT WITNESS TESTIMONY BEFORE THE VIRGINIA CORPORATION COMMISSION

Direct Testimony and Exhibits on Behalf of the Maryland – District of Columbia – Virginia Solar Energy Industries Association, (Case No. PUE-2011-00088, October 11, 2011) http://www.scc.virginia.gov/docketsearch/DOCS/2gx%2501!.PDF

- *Cost-effectiveness of, and standby rates for, net-metered solar customers.*

LITIGATION EXPERIENCE

Mr. Beach has been retained as an expert in a variety of civil litigation matters. His work has included the preparation of reports on the following topics:

- The calculation of damages in disputes over the pricing terms of natural gas sales contracts (2 separate cases).
- The valuation of a contract for the purchase of power produced from wind generators.
- The compliance of cogeneration facilities with the policies and regulations applicable to Qualifying Facilities (QFs) under PURPA in California.
- Audit reports on the obligations of buyers and sellers under direct access electric contracts in the California market (2 separate cases).
- The valuation of interstate pipeline capacity contracts (3 separate cases).

In several of these matters, Mr. Beach was deposed by opposing counsel. Mr. Beach has also testified at trial in the bankruptcy of a major U.S. energy company, and has been retained as a consultant in anti-trust litigation concerning the California natural gas market in the period prior to and during the 2000-2001 California energy crisis.

Attachment RTB-2

PG&E Responses to Selected Data Requests

PACIFIC GAS AND ELECTRIC COMPANY
GTS – Cost Allocation and Rate Design (CARD) 2023
Application 21-09-018
Data Response

PG&E Data Request No.:	Calpine_001-Q011		
PG&E File Name:	GTS-CARD-2023_DR_Calpine_001-Q011		
Request Date:	January 24, 2022	Requester DR No.:	001
Date Sent:	February 11, 2022	Requesting Party:	Calpine Corporation
PG&E Witness:	Annette Taylor	Requester:	Joseph M. Karp

This data request refers to the direct testimony that PG&E served in this proceeding on September 30, 2021.

Local Transmission

QUESTION 011

This question concerns PG&E Abnormal Peak Day (APD) forecast, which Calpine understands PG&E is revising due to data issues.

a. Please provide the APD demand forecast, by customer class, which results in the 63% core/37% noncore cost allocation proposed by PG&E.

b. Please quantify how much noncore industrial and noncore EG throughput is curtailed in the APD forecast.

c. Please describe how the EG throughput forecast on the APD is calculated.

d. Please include, for EG, the amount of APD demand that takes local transmission service, and how much EG demand on the APD takes backbone-only service from PG&E.

e. Please provide an explanation of the errors in the APD forecast and the changes that PG&E plans to make. Please provide the revised testimony/workpapers based on these changes, when available.

ANSWER 011

11.a

The APD demand forecast by customer class that results in the 63%/37% allocation is not available since the underlying data has been overwritten with the revised APD forecast. (Please see Answer 11e) Therefore, this response uses the most current data available – winter 2021-2022.

The local transmission APD load components for the winter of 2021-2022 are: Core Residential – 2,145,887 Mcfd, Core Commercial – 856,124 Mcfd, and Noncore All – 1,778,192 Mcfd.

11.b

The projected APD non-core curtailment volume for the 2021-2022 winter is 179,758 Mcfd. Separating non-core, local transmission EG demand is not easily attainable as the data source used for local transmission curtailment planning cannot accurately split noncore EG load from other noncore demand for all customers. For instance, some customers use some of their gas for EG and the balance for non-EG purposes (refineries are a good example). This gas runs through the same meter and is somehow back-calculated in the billing process. The database that is used to retrieve this information cannot accurately split this usage, so the segregated EG demand would be under or overrepresented depending on the class assigned to that customer.

11.c

The following is a description of how the EG throughput forecast on the APD is calculated. PG&E uses a probabilistic loading methodology for all non-temperature dependent, noncore demand on the local transmission system. Customers are first assigned to a curtailment zone based on system hydraulics. An APD demand for each non-core customer (non-temperature dependent) is then developed from the load diversity process. If the potential magnitude of a noncore, non-temperature dependent customer's demand is high enough to risk the safety of a particular system, the demand is analyzed separately and an APD projection is subsequently developed.

11.d

Backbone pipelines employ a different planning methodology than local transmission systems. As such, there is no APD load for backbone EG customers. As stated above, separating non-core, local transmission EG demand is not easily attainable as the data source used for local transmission curtailment planning cannot accurately split noncore EG load other noncore demand for all customers.

11.e

The APD forecast was revised to incorporate more recently available data, and not because of errors in the prior forecast In responding to a discovery request, PG&E revised the 2020 – 2021 APD Winter forecast values that PG&E filed for the CARD proceeding. The original 2020-2021 Winter forecast that was served with PG&E's direct testimony, Chapter 4, on September 30, 2021 came from information created in Nov 2020 for the upcoming 2020-2021 Winter season. As part of the Gas System Planning Engineering team's winter planning process, the design day estimates (APD, CWD) for large customers are reviewed immediately prior to the upcoming winter. Several local transmission customers in the East Bay had their projected usage adjusted after the original filing. The usage also changed for other local transmission areas through this process, but the changes in the East Bay are overwhelmingly responsible for the difference between the original and revised forecast.

PACIFIC GAS AND ELECTRIC COMPANY
GTS – Cost Allocation and Rate Design (CARD) 2023
Application 21-09-018
Data Response

PG&E Data Request No.:	Calpine_001-Q021		
PG&E File Name:	GTS-CARD-2023_DR_Calpine_001-Q021		
Request Date:	January 24, 2022	Requester DR No.:	001
Date Sent:	February 11, 2022	Requesting Party:	Calpine Corporation
PG&E Witness:		Requester:	Joseph M. Karp

This data request refers to the direct testimony that PG&E served in this proceeding on September 30, 2021.

Inventory Management

QUESTION 021

PG&E states that off-system customers currently pay for inventory management in backbone rates despite not being end-use customers and not contributing to imbalances. See page 6-17. Is it PG&E's position that only on-system end-use customers cause imbalances? Is inventory management meant to focus only on customers served from the distribution and local transmission systems, and not from the backbone system?

ANSWER 021

Inventory management is focused on end-use customers including backbone connected end-use customers. Backbone connected end-use customers are allocated a portion of the cost of Inventory Management on the same basis as distribution and local transmission customers.

In general, interconnecting pipelines, including off-system deliveries to the SoCalGas system are done evenly throughout the day. Any deviation from ratable flows is mutually agreed upon by the two operators. The same is generally true for daily imbalances.

PACIFIC GAS AND ELECTRIC COMPANY
GTS – Cost Allocation and Rate Design (CARD) 2023
Application 21-09-018
Data Response

PG&E Data Request No.:	Calpine_002-Q010		
PG&E File Name:	GTS-CARD-2023_DR_Calpine_002-Q010		
Request Date:	May 6, 2022	Requester DR No.:	002
Date Sent:	May 27, 2022	Requesting Party:	Calpine Corporation
PG&E Witness:	Patricia Gideon	Requester:	R. Thomas Beach

SUBJECT: INVENTORY MANAGEMENT

QUESTION 010

PG&E has used both 2016-2020 and 2023-2026 throughputs in its workpapers. EG throughput is lower in the latter period.

a. Has PG&E made any adjustments to its inventory management rate calculations to recognize that cost allocation based on EG shares of total system inter-day and intra-day imbalances may be lower in 2023-2026 than in 2016-2020?

b. Please provide versions of Table 6-4 that are based on each year from 2016 to 2020, rather than on 2016-2020 combined.

ANSWER 010

a. No, PG&E did not make any adjustments and applied the “Big Three” 2016-2020 historic shares of inter-day and intra-day imbalances as is when calculating the further segmentation of the allocations by end-use customer classes.

b. Below are versions of Table 6-4 that are based on each year from 2016 to 2020, rather than on 2016-2020 combined.

1/1/2016 – 12/31/2016

				Allocation based on Weighting of Inter vs Intra-day Results	
				Secondary Method	Proposed Method
	Status-quo	Inter-day	Intra-day	50% - 50%	37% - 63%
Core	31.5%	26.2%	64.5%	45.3%	50.3%
Ind	37.3%	29.7%	3.7%	16.7%	13.4%
EG	21.9%	44.1%	31.8%	38.0%	36.4%
off-system	9.3%	0.0%	0.0%	0.0%	0.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%

1/1/2017 – 12/31/2017

				Allocation based on Weighting of Inter vs Intra-day Results	
				Secondary Method	Proposed Method
	Status-quo	Inter-day	Intra-day	50% - 50%	37% - 63%
Core	34.2%	26.7%	63.3%	45.0%	49.6%
Ind	36.2%	32.9%	4.0%	18.5%	14.8%
EG	19.3%	40.4%	32.7%	36.6%	35.6%
off-system	10.3%	0.0%	0.0%	0.0%	0.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%

1/1/2018 – 12/31/2018

				Allocation based on Weighting of Inter vs Intra-day Results	
				Secondary Method	Proposed Method
	Status-quo	Inter-day	Intra-day	50% - 50%	37% - 63%
Core	31.6%	26.8%	65.7%	46.2%	50.8%
Ind	34.0%	26.3%	4.1%	15.2%	12.6%
EG	23.6%	46.9%	30.2%	38.6%	36.6%
off-system	10.8%	0.0%	0.0%	0.0%	0.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%

1/1/2019 – 12/31/2019

				Allocation based on Weighting of Inter vs Intra-day Results	
				Secondary Method	Proposed Method
	Status-quo	Inter-day	Intra-day	50% - 50%	37% - 63%
Core	32.7%	29.2%	61.8%	45.5%	50.8%
Ind	34.1%	23.9%	3.9%	13.9%	10.7%
EG	24.2%	46.9%	34.3%	40.6%	38.6%
off-system	9.0%	0.0%	0.0%	0.0%	0.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%

1/1/2020 – 12/31/2020

				Allocation based on Weighting of Inter vs Intra-day Results	
				Secondary Method	Proposed Method
	Status-quo	Inter-day	Intra-day	50% - 50%	37% - 63%
Core	31.6%	27.7%	59.3%	43.5%	48.6%
Ind	32.5%	23.5%	4.0%	13.7%	10.6%
EG	26.0%	48.8%	36.7%	42.7%	40.8%
off-system	9.9%	0.0%	0.0%	0.0%	0.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%

PACIFIC GAS AND ELECTRIC COMPANY
GTS – Cost Allocation and Rate Design (CARD) 2023
Application 21-09-018
Data Response

PG&E Data Request No.:	Calpine_003-Q008		
PG&E File Name:	GTS-CARD-2023_DR_Calpine_003-Q008		
Request Date:	July 15, 2022	Requester DR No.:	003
Date Sent:	July 29, 2022	Requesting Party:	Calpine Corporation
PG&E Witness:	James Chen	Requester:	R. Thomas Beach

SUBJECT: LOCAL TRANSMISSION COST ALLOCATION

QUESTION 008

Table 4-1 of Chapter 4 (Local Transmission Allocation Study) of PG&E’s revised testimony indicates that the combined Local Transmission Core and Noncore demands that can be served on an Abnormal Peak Day (“APD”) is 46,104 Mths/Peak Day. Please provide the following information:

a. Please confirm that the Core APD demand of 30,405 MThs/Peak Day constitutes 100% service to core customers.

b. Please allocate the Noncore APD demand of 15,699 MThs/Peak Day that is served from the LT system into the various noncore customer classes – Industrial D/T, EG D/T, and Wholesale.

c. Please provide the assumed level of Noncore APD demand on the LT system that is curtailed on an APD, again broken down by the various noncore customer classes – Industrial D/T, EG D/T, and Wholesale.

d. On an APD, what is PG&E’s assumption for the amount of EG load (in MThs/Peak Day) that will be served directly from the backbone system? Does PG&E assume any curtailments of EG service to backbone-level EG customers on an APD? If it does, what would be the level of those curtailments? If there would be excess capacity to serve backbone-level EGs on an APD, please indicate what that excess capacity would be, in MThs/Peak Day.

e. Please confirm that the PG&E system can actually accommodate simultaneous Core and Noncore demands on an APD on the LT system equal to 46,104 Mths/Peak Day, plus the backbone-level EG loads on an APD referenced in PG&E’s response to Part [d] of this question. If this cannot be confirmed, please explain in detail.

ANSWER 008

a. Table 4-1 lists 30,405 Mcf/d of core demand. This demand represents all core loads modeled on our local transmission hydraulic models and is not curtailed under APD conditions.
b. As answered in question 11.b from the first data request of Calpine, some noncore customer bills include both EG and non-EG components. As such, it is

difficult to split these components accurately. However, the noncore allowable split between local transmission customers with 100% EG demand and all other noncore customers is approximately 37% EG vs. 63% industrial (customers with both EG and non-EG load are bundled in the industrial customer category). Since customers with both EG and EG billing components are categorized as industrial, some EG demand is underrepresented in this ratio. This allocation percentage is a correct approximation as of the date of this data response. Due to the size of customers in this class, any new connects or disconnects could skew these allocation percentages.

c. PG&E cannot accurately calculate a breakdown of curtailment levels for the requested detailed level. As noted in the answer to question 7b, PG&E cannot accurately split curtailment levels for local transmission customers billed with both EG and non-EG components.
d. PG&E does not forecast EG APD demands for the population of plants served directly from the backbone system. APD is not a peak day standard on the backbone, so PG&E does not have details on a system-wide APD event.
e. The sum of the APD demands that can be served on all the LT systems is not necessarily the systemwide demand on a 1:90 peak day for the system. We do not expect every LT system to be in an APD condition at the same time. A 1:90 is not a peak day standard on the backbone, so PG&E does not have details on a backbone 1:90 event.

PACIFIC GAS AND ELECTRIC COMPANY
GTS – Cost Allocation and Rate Design (CARD) 2023
Application 21-09-018
Data Response

PG&E Data Request No.:	Calpine_005-Q001		
PG&E File Name:	GTS-CARD-2023_DR_Calpine_005-Q001		
Request Date:	July 22, 2022	Requester DR No.:	005
Date Sent:	August 5, 2022	Requesting Party:	Calpine Corporation
PG&E Witness:	James Chen	Requester:	Tom Beach

SUBJECT: LOCAL TRANSMISSION COST ALLOCATION

QUESTION 001

The *2020 California Gas Report* (*2020 CGR*) states, at page 83, that

> "PG&E projects that noncore demand served by pipeline and storage withdrawals, including gas-fired EG, on an APD would be approximately 1.4-1.6 Bcf/d in the near term."

a. Please confirm that the "1.4-1.6 Bcf/d" of noncore demand served on an APD would include demand on an APD from backbone-level EG customers directly connected to PG&E's backbone pipeline system. Please provide PG&E's estimate of this APD demand from backbone-level EG customers directly connected to PG&E's backbone pipeline system.

b. The *2020 CGR*, at page 84, includes this Table 21:

TABLE 21 – FORECAST OF CORE GAS DEMAND AND SUPPLY ON AN APD (MMcf/d)

Line No.		2020-21	2021-22	2022-23
1	APD Core Demand (1)	3,031	3,043	3,055
2	Independent Storage Provider Withdrawal (2)	2,190	2,190	2,190
3	Firm Flowing Supply (3)	3,055	3,055	3,055
4	Total Resources to Meet Demands (4)	4,067	4,067	4,067

Notes:

(1) Includes PG&E's Gas Procurement Department's and other Core Aggregator's core customer demands. APD core demand forecast is calculated for 28.3 degrees F system composite temperature, corresponding to 1-in-90 year cold temperature event.1 PG&E uses a system composite temperature based on six weather sites.

(2) The Independent Storage Provider Withdrawal is based on information provided by the Independent Storage Providers to PG&E.

(3) The Firm Flowing Supply includes firm Redwood and Baja capacities and nominal amounts of California gas production. These values are those currently approved for use within PG&E.

(4) The Total Resources to Meet Demands (Line No. 4) are less than the sum of Independent Storage Provider Withdrawal (Line No. 2) and Firm Flowing Supply (Line No. 3) because PG&E's system cannot simultaneously accommodate all flowing supplies and all storage withdrawals.

Does the 4,067 MMcf/d of "Total Resources to Meet Demands" include all resources to meet both core and noncore demand on an APD? If any available resources used to meet noncore demand on an APD are not included in Table 21, please specify what those resources are, in MMcf/d. For example, are PG&E-owned storage resources not shown in Table 21 available to serve noncore demand on an APD?

c. If the 4,067 MMcf/d of "Total Resources to Meet Demands" include all resources planned to meet both core and noncore demand on an APD, and core APD demand in 2022-2023 is 3,055 MMcf/d as shown, then this suggests that only 1,012 MMcf/d of pipeline and storage resources are planned to be available to serve noncore demand on an APD. This appears to contradict PG&E's statement on page 83 that "noncore demand served by pipeline and storage withdrawals, including gas-fired EG, on an APD would be approximately 1.4-1.6 Bcf/d in the near term."
    i. If this conclusion that PG&E only plans to have resources to serve 1,012 MMcf/d of noncore load on an APD is incorrect, please explain why it is incorrect.
    ii. Calpine understands that, from PG&E's response to Indicated Shippers 002-Q002, that the 4,067 MMcf/d of "Total Resources to Meet Demands" in Table 21 is based on the 1-in-10 year planning standard for backbone pipelines. Please provide any studies or analysis that PG&E has performed of the additional capacity or deliverability (in MMcf/d) of its backbone system on a 1-in-35 cold winter day or 1-in-90 APD, beyond the 1-in-10 planning standard for backbone pipelines.
d. The submission of the *2022 California Gas Report* (*2022 CGR*) has been delayed, at the request of Southern California Gas Company. If PG&E has finalized its section of the *2022 CGR* on APD Demand and Supply, comparable to pages 82-84 of the *2020 CGR*, please provide that complete section of the *2022 CGR.*

ANSWER 001

PG&E objects to the request to the extent that it seeks information relating to a California Gas Report that is not relevant or calculated to lead to the discovery of relevant evidence to this CARD proceeding. With these objections, and without waiver, PG&E responds as follows:

a) PG&E has conducted a reasonable search for information identified in this request, and we no longer have the knowledge of how this number was determined. Furthermore, this number will be removed from future California Gas Reports. APD is not a backbone standard, so PG&E does not have these details on what the backbone system would look like on an APD.

b) 4067 mmcfd is the amount the backbone can supply on a 1:10 peak day. Note 4 in the CGR should have stated that the 4067 is a 1:10 peak day number. APD is not a backbone standard, so PG&E does not have details on what the backbone system would look like on an APD.

c) i: As stated in the response to question 1b, the 4067 mmcfd value is for a 1:10 peak day. APD is not a backbone standard, so PG&E does not have details on what the backbone system would look like on an APD.

ii: 1-in-10 is the standard for the backbone. PG&E does not have details on how the backbone would look on a 1-in-35 peak day or 1-in-90 peak day.

d) The 2022 California Gas Report is now available from the following link: https://www.pge.com/pipeline/library/regulatory/cgr/index.page

PACIFIC GAS AND ELECTRIC COMPANY
GTS – Cost Allocation and Rate Design (CARD) 2023
Application 21-09-018
Data Response

PG&E Data Request No.:	Calpine_005-Q002		
PG&E File Name:	GTS-CARD-2023_DR_Calpine_005-Q002		
Request Date:	July 22, 2022	Requester DR No.:	005
Date Sent:	August 8, 2022	Requesting Party:	Calpine Corporation
PG&E Witness:	Andrew Klingler, Todd Peterson, Annette Taylor	Requester:	Tom Beach

SUBJECT: LOCAL TRANSMISSION COST ALLOCATION

QUESTION 002

This question follows up PG&E's response to Calpine Data Request 001-011(d). In this question, Calpine directly requested "for EG, the amount of APD demand that takes local transmission service, and how much EG demand on the APD takes backbone-only service from PG&E." PG&E did not provide data in response, but stated "Backbone pipelines employ a different planning methodology than local transmission systems. As such, there is no APD load for backbone EG customers."

a. Does the statement "there is no APD load for backbone EG customers" mean that the PG&E gas system is physically incapable of serving backbone-level EG customers on an APD? If the PG&E gas system is physically incapable of serving backbone-level EG customers on an APD, please explain why.

b. On an APD, does PG&E expect to serve EG gas demand solely via EG plants located on the local transmission system? If PG&E does so expect, please explain why.

c. Does the statement "there is no APD load for backbone EG customers" mean that PG&E has not planned or studied the relative amounts of EG gas demand from backbone versus local transmission EG customers on an APD?

d. If the answer to Question 2(c) is that PG&E has not planned or studied the relative amounts of EG gas demand from backbone versus local transmission EG customers on an APD, please explain why it is reasonable to assume that all noncore load on an APD would be served from the local transmission system, as is implied by PG&E's response to Calpine DR 001-011(d).

e. Does PG&E agree that the relative proportions of EG gas demand served from the backbone and local transmission systems on a 1-in-35 cold winter peak day would be representative of the relative amounts of EG gas demand on the backbone and local transmission systems that might be expected on an APD? If not, why not?

f. PG&E provided 1-in-35 cold winter daily EG demand, for 2021-2026, in response to TURN DR 003-Q001, based on PLEXOS modeling.

    i. Is it accurate to assume that a 1-in-35 cold winter <u>peak day</u> forecast of EG demand can be derived from the highest total daily EG demand each year in this series of daily EG gas demands? If not, why not?

ii. Please provide PG&E's comparable 1-in-35 cold winter peak day forecast of noncore, non-EG loads. If these loads are assumed not to be temperature sensitive, please provide the average-year forecast. Calpine also expects that PG&E may not have a daily forecast of noncore, non-EG loads similar to the daily forecast of EG loads from PLEXOS; in that event, please provide PG&E's monthly forecast of daily average noncore, non-EG demand for 2021-2026.

ANSWER 002

a) APD is a local transmission standard, so analyses have been done to assess the local transmission systems on an APD. These analyses do not include customers directly connected to the backbone system. The backbone system has adequate capacity to serve all end-use customers connected directly to the backbone under an APD condition based on their maximum load stated in their application for service. However, PG&E does not forecast what that actual APD demand will be for those backbone customers since APD is not a planning standard for the backbone. Although there is enough capacity to serve backbone customers, supplies on the backbone could be limited on an APD, so the number of EG customers served on local transmission versus backbone could be affected by who is able to secure supplies.

b) APD is not a standard on the backbone, so PG&E does not have detailed information on what an APD on the backbone would look like.

c) Yes.

d) Since local transmission and backbone have different planning standards, the APD local transmission analysis does not include demands directly connected to the backbone. As a result, there are no backbone demands included in the local transmission analysis. The local transmission analysis includes all noncore loads on the local transmission system.

e) A 1-in-35 peak day is not a standard on the backbone or local transmission system, so we do not know what these systems would look like on a 1-in-35 peak day.

f.i.: It may not be accurate to make this assumption. The highest total daily EG demand for each year in the series of daily EG gas demands in TURN DR 003-Q001 does not represent the highest peak day the PG&E system could experience. For example, this EG gas demand forecast assumes average hydroelectric conditions (hydro). If hydro is dry, EG gas demand could be higher.

f.ii.: Calpine is correct that PG&E does not have a daily forecast of noncore, non-EG loads. We supply average daily values by month for the 1-in-35 case. For reference, these values average by year to the non-core non-EG values in Table 2B-2.

Daily Average Noncore NonEG 1 in 35 Forecast												
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2023	476	458	449	441	444	446	518	612	611	499	473	489
2024	482	447	452	442	444	445	515	610	608	497	470	487
2025	480	460	450	440	442	443	513	607	606	495	468	484
2026	478	458	447	437	439	440	510	605	603	492	465	482

Attachment RTB-3

PG&E Gas Schedule G-BAL

GAS SCHEDULE G-BAL

Sheet 1

GAS BALANCING SERVICE FOR INTRASTATE TRANSPORTATION CUSTOMERS

APPLICABILITY: This rate schedule* provides the terms and conditions pursuant to which PG&E will endeavor to balance volumes of gas it receives into its pipeline system with the volume it delivers to End-Use Customers and to Off-System Delivery Points. In addition, this schedule provides for balancing PG&E's Market Center volumes. Under this schedule, PG&E will calculate, maintain, and carry imbalances; provide incentives for Customers to avoid and minimize imbalances; facilitate elimination of imbalances; and cash out imbalances. Schedule G-BAL applies to PG&E's Core Gas Supply department transactions on behalf of PG&E's core procurement Customers, and to all Customers taking services under Schedules G-CT (or other core rate schedule(s) where procurement service is provided by a third party), to Schedules G-NT, G-EG, G-NGV4, G-WSL, G-LNG, G-AFT, G-SFT, G-NFT, G-AA, G-NAA, G-AFTOFF, G-AAOFF, G-NFTOFF, G-NAAOFF, G-PARK, and G-LEND. (T)

Imbalances generally will be maintained at the delivery point.

This schedule is the default supply schedule for Noncore End-Use Customers who do not execute a Natural Gas Service Agreement (NGSA) (Form No. 79-756), pursuant to the terms of Schedule G-NT.

TERRITORY: Schedule G-BAL applies everywhere within PG&E's natural gas Service Territory.

BALANCING AGGREGATION: Noncore End-Use Customers may elect to aggregate Cumulative Imbalances for multiple premises, or they may assign their balancing obligations to a Balancing Agent, as described below. If the Cumulative Imbalances are aggregated or assigned to a Balancing Agent, PG&E will aggregate individual Balancing Service accounts into a single Balancing Service account, with both the usage and the deliveries aggregated. A single Monthly Tolerance Band, as defined below, shall apply to the aggregated quantities.

BALANCING AGENT: The Balancing Agent is the party financially responsible for managing and clearing imbalances described in Schedule G-BAL. The Balancing Agent shall be responsible for all applicable balancing and Rule 14 Operational Flow Order, Emergency Flow Order and diversion noncompliance charges. The following are Balancing Agents: Core Transport Agent (CTA), PG&E Core Gas Supply department, Noncore Balancing Aggregation Agreement (NBAA) Agent, a Noncore End-Use Customer or Wholesale/Resale Customer that is not part of an NBAA. All Balancing Agents are subject to creditworthiness requirements. (T)

For deliveries to a Core Transport Group, the CTA will be responsible for any imbalances. For deliveries to storage and to off-system points, the Customer holding the Gas Transmission Service Agreement (GTSA) (Form No. 79-866) will be responsible for imbalances.

For deliveries made to Noncore End-Use Customers, the Noncore End-Use Customer will be responsible for imbalances; however, Noncore End-Use Customers may designate a Balancing Agent to manage and assume responsibility for the Noncore End-Use Customer's obligations under this schedule.

A Noncore End-Use Customer may change its Balancing Agent no more than once per month.

* PG&E's gas tariffs are available on-line at www.pge.com.

(Continued)

GAS SCHEDULE G-BAL Sheet 2

GAS BALANCING SERVICE FOR INTRASTATE TRANSPORTATION CUSTOMERS

BALANCING AGENT: (Cont'd.)

Noncore End-Use Customer designation of a Balancing Agent, changing of one Balancing Agent for another Balancing Agent, or terminating the services of a Balancing Agent, will take effect on the first day of the month following PG&E's receipt of an executed Noncore Balancing Aggregation Agreement (NBAA) (Form No. 79-869), or Exhibit A or Exhibit B of the NBAA. The request must be received by PG&E by the last business day prior to the first day of the month the designation or change is to take effect. Requests that are not received by PG&E by the last business day prior to the first day of the month will not take effect until the first day of the second month following such request.

For End-Use Customers whose imbalances were previously not handled under an NBAA, upon designating a Balancing Agent and executing an NBAA, any existing imbalances and/or adjustments to past imbalances will also become the responsibility of such Balancing Agent upon the effective date of the NBAA.

The Balancing Agent may nominate transportation deliveries to PG&E on behalf of the Customer, in accordance with the provisions of gas Rule 21.*

BALANCING OPTIONS:

PG&E will provide Balancing Service to accommodate any imbalances between Customer usage and gas delivered to PG&E for the Customer. Only one balancing option may apply to an individual End-Use Customer at any time. The Monthly (T)
Balancing Option remains the default balancing option for any Balancing Agent who (T)
does not elect Self-Balancing. In accordance with gas Rule 21, all Balancing Agents must endeavor to ensure that daily gas deliveries match daily gas usage.

MONTHLY BALANCING OPTION:

MONTHLY TOLERANCE BAND:

The Monthly Tolerance Band is equal to plus or minus five percent (± 5%) of the usage in the month in which the imbalance occurred. PG&E will provide Monthly Balancing Service at no additional charge if the Balancing Agent's Cumulative Imbalance is less than or equal to the Monthly Tolerance Band limit. (T)

If a Balancing Agent has a month-end imbalance that exceeds the Monthly Tolerance Band, this amount may be traded or will be cashed out as provided below. Unlike the Self-Balancing Option, there is no specific noncompliance charge for exceeding the balancing limit of the Monthly Tolerance Band.

If at any time the aggregate imbalance of all of PG&E's On-System Customers has exceeded plus or minus three percent (±3%) of that month's aggregate deliveries for any two (2) months in the preceding twelve (12) month period, PG&E may decrease the limit of the Monthly Tolerance Band by one percent (1%) after a minimum of thirty (T)
(30) days' notice to Customers. The Monthly Tolerance Band may not be adjusted |
more than once in any twelve (12) month period. The Monthly Tolerance Band may not (T)
be set below three percent (3%) without prior CPUC approval.

DAILY USAGE MEASUREMENT:

For purposes of determining daily usage, Noncore End-Use Customers are required to have daily metering. Telemetering will be installed on Noncore End-Use Customers' meters, where PG&E determines that it is cost-effective.

(Continued)

GAS SCHEDULE G-BAL Sheet 3

GAS BALANCING SERVICE FOR INTRASTATE TRANSPORTATION CUSTOMERS

MONTHLY BALANCING OPTION: (Cont'd.)

CUMULATIVE IMBALANCE FOR NONCORE CUSTOMERS:

A Balancing Agent's Cumulative Imbalance shall be the difference, for each calendar month, between metered usage (adjusted for shrinkage) and the actual monthly gas deliveries, plus any adjustments and tolerance carried forward from prior months.

A Cumulative Imbalance quantity will be stated each month on the Cumulative Imbalance Statement.

CUMULATIVE IMBALANCE FOR CORE PROCUREMENT GROUPS:

For a Core Procurement Group (which includes PG&E's Core Gas Supply department and Core Transport Groups (CTA Group), as defined in gas Rule 1 (CP Group)), PG&E will determine the Cumulative Imbalance as follows:

PG&E will provide each CP Group with Core Load Forecasting and Determination Service, which will include 24-hour and 48-hour forecasts prior to the Gas Day. As part of this service, PG&E will also provide a Gas Day estimated usage (Determined Usage) for the CP Group. Determined Usage will be based on the historical usage of the CP Group's customer mix, adjusted for climatic and operational conditions.

For a CP Group, the Cumulative Imbalance shall be the difference, for each calendar month, between Determined Usage (adjusted for shrinkage) and the actual monthly gas deliveries plus any Operating Imbalance, plus tolerance carried forward from prior months. (T)

OPERATING IMBALANCE FOR CORE PROCUREMENT GROUPS:

For CP Groups, each Core End-Use Customer's cycle billed usage will be divided by the number of days within the billing cycle, then weighted on a daily basis to match the daily fluctuations of the CP Group's Determined Usage within the same billing cycle (Daily Weighted Usage).

The Operating Imbalance for each CP Group is the difference between the sum of each day's Determined Usage* within a calendar month and the sum of each day's Daily Weighted Usage for each of the Core End-Use Customers for that calendar month. The Operating Imbalance Carryover is the accumulation of untraded monthly Operating Imbalances plus prior month accounting adjustments.

Each month, PG&E will provide the CP Group with an Operating Imbalance Statement. That Operating Imbalance Statement will be processed within two (2) months following the processing of the Cumulative Imbalance Statement for the same month. The processing delay ensures that most of the billing cycle usage for the calendar month has been measured and billed. If a CP Group incurs a Cumulative Imbalance cashout and the subsequent Operating Imbalance indicates that the Group's deliveries more closely matched the Group's actual gas use, then PG&E will reverse the cashout to the extent applicable.

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*Based on the most recent Determined Usage which has a date and time of less than or equal to 7:15:00 AM on the current gas day and was communicated to CTAs. If the Determined Usage has a date and time greater than 7:15:00 AM on the current gas day or the Determined Usage was not generated, the most recent previous forecast for the current gas day will be used. (T)

(Continued)

GAS SCHEDULE G-BAL Sheet 4
GAS BALANCING SERVICE FOR INTRASTATE TRANSPORTATION CUSTOMERS

MONTHLY BALANCING OPTIONS: (Cont'd.)

CASHOUT FOR MONTHLY BALANCING:

Monthly imbalances after trading is completed, which exceed the Monthly Tolerance Band are cashed out for both the commodity component and the transportation component.

The Commodity Cashout for each month is based on the following four (4) imbalance categories: Over-deliveries and under-deliveries in the imbalance range of greater than five percent (5%) and less than or equal to ten percent (10%) of usage (Tier I Cashout), and over-deliveries and under-deliveries in the imbalance range of greater than ten percent (10%) of usage (Tier II Cashout). The amount of gas in each category is multiplied by the appropriate price as determined below to calculate the commodity cashout portion of the bill.

The Transportation Cashout for each month is based only on the under or over-delivery greater than five percent (5%). This amount is multiplied by the appropriate transportation cashout price as determined below to calculate the transportation cashout portion of the bill. In the case of an overdelivery, this will be a credit.

SELF-BALANCING OPTION:

The Self-Balancing option requires daily balancing within specified limits. To participate in Self-Balancing, the Balancing Agent must have an NBAA or CTA Group.

To elect Self-Balancing, the Balancing Agent must sign a Self-Balancing Amendment (Form No. 79-971) and the NBAA or the Core Gas Aggregation Service Agreement (CTA Agreement) will be subject to the terms of Self-Balancing for the period identified in the Amendment.

SELF-BALANCING CREDIT:

The Self-Balancing option allows a Balancing Agent to receive a credit. The Self-Balancing credit is $0.0368 (I) per Decatherm multiplied by the actual recorded monthly usage. Credits will be provided to the Balancing Agent on a monthly basis, subject to adjustments. (T)

LIMIT ON SELF-BALANCING PARTICIPATION:

When a Balancing Agent elects Self-Balancing, their share of the balancing storage assets will be assigned to and marketed through PG&E's at-risk unbundled storage program. The amount of storage assets allocated to PG&E's at-risk unbundled storage program is based on the Balancing Agent's End-Use Customer's annual average usage as a percentage of PG&E's average annual system usage. PG&E will allow the election of Self-Balancing until the storage balancing assets of 1.1 Bcf of inventory, 25 MMcf per day of injection and 35 MMcf per day of withdrawal are reached. If these limits are reached, PG&E will restrict further elections for Self-Balancing until capacity is made available or the OFO Forum raises the limits.

(Continued)

SELF-BALANCING OPTION: (Cont'd.)

DAILY IMBALANCE LIMITS FOR SELF-BALANCING:

A Balancing Agent electing Self-Balancing will be subject to two (2) imbalance limits each day:

1. The Daily Imbalance cannot exceed plus or minus ten percent (±10%) of that day's metered usage for an NBAA or 24-hour forecast usage for a CTA Group, except on OFO or EFO days. On OFO or EFO days the applicable OFO or EFO tolerance band and noncompliance charge will apply.

2. A Balancing Agent must also maintain an Accumulated Daily Imbalance less than, or equal to, plus or minus one percent (±1%) of the Pre-Determined Monthly Usage for that month.

The Pre-Determined Monthly Usage (PDMU) for Noncore End-Use Customers will be equal to the Monthly Contract Quantity specified in the Exhibit B of their NGSA. PG&E will provide the Self-Balancing CTA with a PDMU at least 5 days prior to the first of each month. The PDMU for CTA Groups will be determined by PG&E as a function of the sum of the actual usage of the End-Use Customers within the CTA Group in the same month of the prior year. Adjustments may be applied for missing usage information for the prior year, mid-month starts and stops of service by the Balancing Agent, and for weather effects.

SELF-BALANCING NONCOMPLIANCE CHARGES:

Self-Balancing Noncompliance charges will be calculated as the sum of the following:

1. Daily Noncompliance Charge: For each non-OFO or non-EFO day, a noncompliance charge equal to fifty percent (50%) of the Monthly Citygate Index (MCI) per Decatherm for the portion of the daily imbalance that exceeds plus or minus ten percent (±10%) of the daily metered usage for customers in an NBAA or 24-hour forecast usage for a CTA Group per day. The MCI is the higher of the highest daily price during the month, or the monthly PG&E Citygate Index price published in *Gas Daily*, rounded up to the next whole dollar. If no price is published on a given day, the previously published price will be applied. On OFO or EFO days the corresponding tolerance band and OFO or EFO charge will apply. (T) (T) (T) | | (T)

2. Accumulated Daily Imbalance Noncompliance Charge: For each day, including OFO and EFO days, a noncompliance charge equal to fifty percent (50%) of the Monthly Citygate Index (MCI) per Decatherm per day for each day when the Accumulated Daily Imbalance exceeds plus or minus one percent (±1%) of the Pre-Determined Monthly Usage. The MCI is the higher of the highest daily price during the month, or the monthly PG&E Citygate Index price published in *Gas Daily*, rounded up to the next whole dollar. If no price is published on a given day, the previously published price will be applied. (See gas Rule 14 for possible exemptions from noncompliance charges on OFO days.) (T) (T) (T) | | (T)

(Continued)

SELF-BALANCING OPTION: (Cont'd.)

ANNUAL SELF-BALANCING ELECTION PERIOD:

A Balancing Agent may elect the Self-Balancing option annually in February. The election is effective for a minimum term of one year that begins on April 1, and ending on the following March 31. Election requests for Self-Balancing will be accepted on a first-come, first-served basis. A Balancing Agent may not combine Self-Balancing and Monthly Balancing Customers in a single group.

CHANGES TO A BALANCING GROUP AFTER THE ELECTION PERIOD:

Circumstances may arise which would require the release of an End-Use Customer from a Self-Balancing Group during the year. PG&E will agree to changes that result from, but are not limited to, the following: failure of the business, change in core or noncore status, change of ownership, End-Use Customer changing Balancing Agents, and the termination of a Natural Gas Service Agreement, CTA Agreement, or NBAA. A Balancing Agent may not elect to move End-Use Customers from their Self-Balancing group to their Monthly Balancing group after the election period has ended nor may a Balancing Agent add a customer from their Monthly Balancing group to their Self-Balancing Group. End-Use Customers may be added to a Balancing Agent's Self-Balancing group if the End-Use Customer is not currently served by that same Balancing Agent under Monthly Balancing. All additions or deletions to a Self-Balancing group after the Election Period has ended must be agreed to by PG&E prior to the effective date of the change. (T) (T)

REQUIREMENT FOR DAILY USAGE RECORDING GAS METERS:

Noncore End-Use Customers must have a minimum of one daily usage recording meter prior to the Annual Self-Balancing Election Period. The cost of adding daily usage recording devices and/or data access is the responsibility of the customer. Noncore End-Use Customers who add daily usage recording devices after the election period will be allowed to convert to Self-Balancing during the next election period, if capacity is available. (See Limit on Self-Balancing Participation.) Meters with a capacity less than 100 Dth per day at a customer premises with large hourly recording meters are exempted from the hourly recording requirement. The average daily usage of these meters will be included in the daily calculations. (T) (T)

(Continued)

SELF-BALANCING OPTION: (Cont'd.)

MEASUREMENT OF DAILY USAGE AND IMBALANCES:

Balancing Agents will be responsible for tracking their own daily imbalance position. PG&E will not provide notice to a Balancing Agent if their imbalances are exceeding the daily tolerance levels. The daily usage for Noncore End-Use Customers who qualify for exemption from the hourly recording requirement in the Requirement for Daily Usage (T) Recording Gas Meters provision, specified above, will be based on the sum of the (T) average daily use plus any actual daily recorded usage. Average daily usage is equal to the monthly recorded usage divided by the number of days within the month. Daily usage for all other noncore End-Use Customers will be based on the actual recorded volumes. If the daily usage recording device fails, average daily use will be used for those days where daily-recorded use is unavailable or missing.

Daily usage for CTA Groups will be based on a forecast of their customers' gas usage, as provided by PG&E. For CTA Groups with an annual demand less than three percent (3%) of the total core market's annual demand, daily usage will be determined using the first 24-hour forecast available each day. For CTA Groups with an annual demand greater than or equal to three percent (3%) of the total core market, daily usage will be determined using an end of the gas day forecast. For any CTA Group electing Self-Balancing, the applicable daily usage forecast will also be used to calculate its monthly Cumulative Imbalance. If the annual demand of any CTA Group participating in Self-Balancing exceeds ten percent (10%) of the total core market annual demand, then the largest CTA Group(s) will have their daily usage determined based on the end of the gas day forecast, such that the sum of the demands for the remaining Self-Balancing CTA Groups continuing to use the 24-hour forecast does not exceed the ten percent (10%) limit.

CUMULATIVE IMBALANCE FOR SELF-BALANCING NONCORE CUSTOMERS:

A Balancing Agent's Cumulative Imbalance under the Self-Balancing option is the same as under the Monthly Balancing Option, and is the difference, for each calendar month, between metered usage (adjusted for shrinkage) and the actual monthly gas deliveries plus any adjustments and tolerance carried forward from a prior month.

A Cumulative Imbalance quantity will be stated each month on the Cumulative Imbalance Statement.

CUMULATIVE IMBALANCE FOR SELF-BALANCING CTA GROUPS:

The Cumulative Imbalance for a CTA Group that elects the Self-Balancing option shall be the difference between the sum of each day's 24-hour Core Load Forecast and the actual monthly gas deliveries including any Operating Imbalance or tolerance carried forward from a prior month, plus any under-delivery of gas by a CTA Group resulting from the failure to meet the Injection Period Month-End Minimum Inventory Target Level as specified in Schedule G-CFS.

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GAS SCHEDULE G-BAL Sheet 8
GAS BALANCING SERVICE FOR INTRASTATE TRANSPORTATION CUSTOMERS

SELF-BALANCING OPTION: (Cont'd.)

OPERATING IMBALANCE FOR SELF-BALANCING CTA GROUPS:

The Operating Imbalance for each CTA Group that elects the Self-Balancing option shall be the difference between the sum of each day's 24-hour Core Load Forecast and the sum of each day's Daily Weighted Usage of the Core End-Use Customers included in that CTA Group for that calendar month.

CASHOUT FOR SELF-BALANCING:

For those balancing groups subject to Self-Balancing, any gas imbalances remaining after the Imbalance Trading Period that are in excess of plus or minus one percent (T)
(±1%) of the Pre-Determined Monthly Usage will be cashed out for both the commodity component and the transportation component. The commodity cashout is at the appropriate Tier II Cashout price as determined below. Any remaining gas imbalances within the tolerance band (±1%) will be included in Accumulated Daily Imbalance calculated for the first day of the month following trading period. The transportation cashout is at the appropriate price as determined below.

IMBALANCE TRADING:

A Balancing Agent may trade its Cumulative or Operating Imbalances with another Balancing Agent that has a Cumulative or Operating Imbalance from the same statement period.

Executing an Imbalance trade consists of both parties to the trade completing an Imbalance Trading Form for Schedule G-BAL Service (Form No. 79-762), or electronic equivalent, and submitting the form to PG&E.

IMBALANCE TRADING CRITERIA:

Each Cumulative Imbalance trade must meet at least one of the following criteria:

1. The trade moves the trading party's Cumulative Imbalance towards zero; and/or

2. The trade results in a Cumulative Imbalance that is within the range of plus or minus three percent (3%) of usage past zero.

The following table sets forth the range of acceptable Cumulative Imbalance trades. Imbalances are described as a percentage of usage. Each trade will be deemed to have a Beginning Imbalance (the imbalance, positive or negative, existing immediately prior to the trade) and an Ending Imbalance (the imbalance, positive or negative, resulting from the trade).

If Beginning Imbalance is:	Ending Imbalance must be:
Greater than -3% (in the negative direction)	Between the Beginning Imbalance and +3%
Equal to or between –3% and +3%	Equal to or between -3% and +3%
Greater than +3% (in the positive direction)	Between -3% and the Beginning Imbalance

Each Operating Imbalance trade must move the CP Groups' Operating Imbalance Carryover toward zero.

(Continued)

IMBALANCE TRADING: (Cont'd.)

IMBALANCE TRADING PERIOD:

PG&E will issue Cumulative Imbalance statements no later than the fifteenth (15) day of the first subsequent month following the month in which the Cumulative Imbalance occurred. PG&E will issue Operating Imbalance Statements no later than the fifteenth (15) day of the second subsequent month following the month in which the Cumulative Imbalance Statement for the same period was issued. Thereafter, Balancing Agents may trade all or a portion of their Cumulative and/or Operating Imbalance quantity by executing an imbalance trade by 5:00 p.m. Pacific Time on the closing date for New York Mercantile Exchange (NYMEX) Henry Hub Gas Futures contracts for the following month. If necessary, PG&E will extend the Cumulative and Operating Imbalance trading deadline beyond the NYMEX close date to ensure that the trading period lasts a minimum of five (5) business days.

TRADING IMBALANCES USING STORAGE ACCOUNTS:

During the imbalance Trading Period, Balancing Agents may manage both Cumulative and Operating Imbalances by trading into or out of storage accounts at on-system storage facilities. The owner of the storage account is not required to purchase storage injection or storage withdrawal capacity from PG&E to effect an imbalance trade.

The owner of the storage account must have, at the time of the trade, the inventory capacity to accept a trade into storage or the gas in inventory to trade out of storage. A CTA that uses its core storage account for managing Cumulative or Operating Imbalances must adhere to the end-of-month inventory target levels, as specified in Schedule G-CT. Owners of a third-party storage account must provide documentation of their inventory capacity or gas in inventory. Subject to system load balancing and/or operational constraints, Balancing Agents may trade as much of their Cumulative and/or Operating Imbalance quantity as their storage inventory/capacity allows.

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GAS SCHEDULE G-BAL Sheet 10
GAS BALANCING SERVICE FOR INTRASTATE TRANSPORTATION CUSTOMERS

IMBALANCE TRADING: (Cont'd.)

MANAGING REMAINING IMBALANCES AFTER TRADING:

After the imbalance trading deadline, any remaining Cumulative Imbalance, within the Monthly Tolerance Band, and any Operating Imbalance Carryover, as specified below, will be considered the first transaction during the calendar month following the just-completed trading period. Any remaining Cumulative Imbalance in excess of the Monthly Tolerance Band will be automatically cashed out. Cashouts will include a Commodity Cashout component and a Transmission Cashout component. (T) (T)

After the imbalance trading deadline, any remaining Operating Imbalance will be managed as follows:

1. The Operating Imbalance remaining after trading will be added to the Operating Imbalance Carryover.

2. One-twelfth (1/12) of the Operating Imbalance Carryover will be considered part of the first transaction for the CP Group during the calendar month following the just completed trading period.

3. A CP Group may also make a monthly election to clear its entire Operating Imbalance Carryover if it is less than 5,000 Dth. This will be considered the first transaction during the calendar month following PG&E's receipt of written notification, and will set the Operating Imbalance Carryover to zero.

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GAS SCHEDULE G-BAL Sheet 11

GAS BALANCING SERVICE FOR INTRASTATE TRANSPORTATION CUSTOMERS

CASHOUT PRICING:

COMMODITY CASHOUT PRICING: (L)

Each commodity cashout price is based on a two-step calculation: First, a cashout index is determined based on an average of the published price data from Natural Gas Intelligence (NGI) and the BTU Daily Gas Wire for the PG&E interconnect points of Malin (Northern California Border) and Topock (Southern California Border). Second, that index is adjusted to arrive at the cashout price for that imbalance category.

Tier I Commodity Cashout – Imbalances greater than five percent (5%) and less than or equal to ten percent (10%) of usage: (T) (T)

1. Over-deliveries:
   a. The Weighted Over Delivery (WOD) Index equals the lower of the Bid Week monthly index price or the average of the five (5) lowest average published daily prices, weighted by the supply mix of all gas received at Malin and Topock for on-system End-Use Customers during the month in which the imbalance occurred.
   b. The cashout price equals seventy-five percent (75%) of the WOD Index. (T)
2. Under-deliveries:
   a. The Weighted Under Delivery (WUD) Index equals the higher of the Bid Week monthly index price or the average of the five highest average published daily prices, weighted by the supply mix of all gas received at Malin and Topock for on-system End-Use Customers during the month in which the imbalance occurred.
   b. The cashout price equals one hundred twenty-five percent (125%) of the WUD Index. (T)

Tier II Commodity Cashout – Imbalances greater than ten percent (10%) of usage: (T)

1. Over-deliveries:
   a. The Over Delivery (OD) Index equals the lowest average published daily price at either Malin or Topock.
   b. The cashout price equals fifty percent (50%) of the OD Index. (T)
2. Under-deliveries:
   a. The Under-Delivery (UD) Index is defined as the highest average published daily price at either Malin or Topock.
   b. The cashout price equals one hundred fifty percent (150%) of the UD Index. (T) (L)

(L)

(L)

(Continued)

CASHOUT PRICING:

If no published daily price is reported on a given day, the prior published daily price from that index service will continue to apply for that day. If an index service is no longer available, PG&E reserves the right to choose another nationally recognized index to replace it.

TRANSPORTATION CASHOUT PRICING:

The Transportation Cashout price for under-deliveries is based on the Usage Charge as specified in Schedule G-AA. Over-deliveries will receive a transmission credit based on the Modified Fixed Variable (MFV) Usage Charge as specified in Schedule G-AFT. The Transportation Cashout price or credit is determined by weighting the path specific rates by the supply mix percentages of all gas received by PG&E, for on-system End-Use Customers, during the month.

MARKET CENTER IMBALANCES:

A Customer may have a positive or negative balance when a Market Center account expires. This balance becomes a Market Center Imbalance after the end date specified on the Market Center Exhibit.

Negative Imbalances:

For a Customer with a negative imbalance ranging from 1 Dth to 1,000 Dth, after thirty (30) calendar days from the termination of the exhibit resulting from Customer's under-delivery of gas to the Market Center, automatic reimbursement will occur. (T)

For a Customer with an imbalance greater than 1,000 Dth, the Customer shall have thirty (30) calendar days resulting from Customer's under-delivery of gas to the Market Center to clear the imbalance as follows:

1. Customer shall reach agreement with PG&E to make up such imbalance in-kind during a specified period and at a specific rate; or

2. Customer shall reimburse PG&E at the rate of one hundred fifty percent (150%) of the Under-Delivery Index, defined as the highest average published daily price at the same Market Center location specified in the Exhibit for the same time period.

If the Customer fails to establish the terms of resolving the Market Center Imbalance within the thirty (30) day period:

1. PG&E shall charge the Customer the maximum daily rate, as specified in Schedule G-LEND, for each day of the Market Center imbalance; and

2. Customer shall reimburse PG&E at the rate of one hundred fifty percent (150%) of the Under-Delivery Index, defined as the highest average published daily price at the same Market Center location specified in the Exhibit for the same time period.

Positive Imbalances:

If a Customer has a positive imbalance ranging from 1 Dth to 1,000 Dth, after thirty (30) calendar days from the termination of the exhibit resulting from Customer's over-delivery of gas to the Market Center automatic reimbursement will occur. (T)

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GAS SCHEDULE G-BAL Sheet 13
GAS BALANCING SERVICE FOR INTRASTATE TRANSPORTATION CUSTOMERS

MARKET CENTER IMBALANCES: (Cont'd.)

If a Customer has an imbalance greater than 1,000 Dth, the Customer shall have thirty (30) calendar days after the termination of the exhibit resulting from Customer's over-delivery of gas to the Market Center to clear the imbalance as follows:

1. Customer shall reach agreement with PG&E to use up such imbalance in-kind during a specified period and at a specific rate; or

2. Customer shall be reimbursed by PG&E at the rate of fifty percent (50%) of the <u>lowest</u> monthly Over-Delivery Index, at the same Market Center location specified in the Exhibit for the same time period.

If the Customer fails to establish the terms of resolving the Market Center Imbalance within the thirty (30) day period: (T)

1. PG&E shall charge the Customer the maximum daily rate for each day of the Market Center imbalance specified in Schedule G-PARK.; and

2. The Customer's imbalance shall be reimbursed by PG&E at the rate of fifty percent (50%) of the lowest monthly Over-Delivery Index at the same Market Center location specified in the Exhibit for the same time period. (T)

TRANSMISSION CUSTOMER IMBALANCE:

Transmission Customer Imbalance can occur for gas delivered to Off-System Delivery Points or On-System Storage Facilities, and is defined as the difference between the final scheduled volume on the day of flow at the PG&E system Receipt Point, and the quantity of gas which was actually delivered at the receipt point.

A Transmission Customer Imbalance may be made up in-kind at a later date as agreed upon between the Customer on whose contract the imbalance occurs and PG&E. If no agreement can be reached by the end of the month following the month in which PG&E sends notification of the imbalance to the Customer, then PG&E shall resolve the imbalance in the following manner:

1. For positive imbalances, PG&E shall cashout the entire positive imbalance quantity at the <u>lowe</u>st daily commodity price at Malin or Topock, as published in Gas Daily, during the month in which the imbalance occurred; and

2. For negative imbalances, PG&E shall account for the entire negative imbalance quantity as the first transaction during the second calendar month following the date of notification of the imbalance.

(Continued)

GAS SCHEDULE G-BAL Sheet 14
GAS BALANCING SERVICE FOR INTRASTATE TRANSPORTATION CUSTOMERS

ACCOUNTING ADJUSTMENTS: If subsequent accounting adjustments change a previous Cumulative or Operating Imbalance, then:

1. If any portion of the adjusted quantity was previously subject to an imbalance cashout, the adjusted portion of the cashout will be reversed.

2. For noncore Cumulative Imbalances, any remaining adjustment quantity will be considered the first transaction during the calendar month following the date of notification of the adjustment, and reported on the Cumulative Imbalance Statement, unless otherwise agreed to by PG&E.

3. For Core Procurement Groups, adjustment quantities will be included in the Operating Imbalance Carryover.

4. Adjustments are limited to a maximum three year period. (N)

CURTAILMENT OF SERVICE: Service under this schedule may be curtailed. Details are provided in gas Rule 14.

TERMINATION: Upon termination of a Customer's GTSA, NGSA, NBAA, CTA Agreement, and/or CPBA, any remaining Cumulative Imbalance and/or Operating Imbalance Carryover must be traded, toward zero, during the first Imbalance Trading Period following notice of termination. Following the Imbalance Trading Period, any remaining negative Cumulative and Operating Imbalances will be cashed out at the applicable MCI. The MCI is the higher of the highest daily price during the month, or the monthly PG&E Citygate Index Price of gas in the daily range, as published in *Gas Daily*, rounded up to the next whole dollar. If there is no price published on a given day the previously published price will be applied. Any remaining positive Cumulative and Operating Imbalances will be cashed out at the applicable Lowest Citygate Index (LCI). The LCI is the lower of the lowest daily price during the month, or the monthly PG&E Citygate Index Price as published in *Gas Daily*, rounded down to the next whole dollar. If there is no price published on a given day the previously published price will be applied.