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

Application of Pacific Gas and Electric Company Proposing Cost of Service and Rates for Gas Transmission and Storage Service for the Period 2015 - 2017. (U39G)	)))))	A. 13-12-012 (Filed September 18, 2009)

Prepared Direct Testimony of R. Thomas Beach on behalf of Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest, and the City of Palo Alto

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Prepared Direct Testimony of R. Thomas Beach on behalf of Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest, and the City of Palo Alto

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: On whose behalf are you testifying today?

A: I am appearing on behalf of Calpine Corporation, the Canadian Association of Petroleum Producers, TransCanada's Gas Transmission Northwest (GTN) pipeline, and the City of Palo Alto (Palo Alto).

Calpine develops, builds, and operates electric generating plants in California and throughout the United States. Calpine owns and operates 4,500 MWs of gas-fired power plants in northern California that receive noncore gas transportation services from PG&E. Calpine is one of the largest noncore gas transportation customers on the Pacific Gas and Electric (PG&E) system.

The Canadian Association of Petroleum Producers (CAPP) represents companies, large and small, that explore for, develop and produce natural gas and crude oil throughout Canada. CAPP's member companies produce about 90 per cent of Canada's natural gas and crude oil, and its associate members provide a wide range of services that support the upstream crude oil and natural gas industry. PG&E receives a significant portion of its gas supply requirements from Canada. The vast majority of this gas is supplied by producers who are members of CAPP.

GTN owns and operates the interstate natural gas pipeline system that delivers Canadian and Rocky Mountain gas supplies to portions of the Pacific Northwest and to the California / Oregon border at Malin, Oregon, where GTN interconnects with PG&E's backbone pipeline system (Lines 400 and 401, or the Redwood path).

Palo Alto operates municipal gas and electric utilities that provide service to approximately 28,000 customers in Palo Alto. Average daily natural gas requirements are currently approximately 9 million cubic feet per day (MMcfd), 100 percent of which is classified as core. Palo Alto is the largest wholesale natural gas customer on the PG&E system. Palo Alto holds an allocation of capacity rights for vintage Core Redwood capacity (under Rate Schedule G-AFT) and is also subject to PG&E's Local Transmission rates.

II. SUMMARY

Q: Please summarize the key points presented in your testimony.

A: For the past sixteen years, the PG&E natural gas system has operated under the "Gas Accord" market structure first implemented in 1998. Generally, the Gas Accord market structure has been well-received by end use customers, shippers, PG&E, and the Commission. The Commission has approved or extended the Gas Accord six times in PG&E Gas Transmission & Storage (GT&S) rate cases: three times as a result of all-party settlements, twice (in 1997 and 2011) after partially contested settlements, and once (in 2003) by a Commission decision after a fully litigated rate case.[1]

A key feature of the Gas Accord is the adoption of path-specific rates for PG&E's backbone system based on the costs of the pipeline facilities that comprise each path. The Gas Accord's backbone rate design was the result of the application to the PG&E system of the incremental rate policies that the Commission developed in response to the pipeline expansions of the late 1980s. The Commission has maintained these policies consistently for the past 25 years, *i.e.* since 1988. For the initial ten years of the Gas Accord, backbone rates on the Redwood path (Lines 400 and 401) were higher than rates on the competing Baja path (Line 300), as a result of the incremental rate treatment of the costs of the Line 401 expansion project completed in 1993. The Commission has allowed the incremental costs of Line 401 to be rolled-in with the costs of other lines only to the extent that the affected customers agreed in a settlement to such a combination, as noncore customers did in the original Gas Accord settlement in allowing the partial roll-in of Lines 400 and 401. Today, the costs of Line 401 are significantly depreciated, while aging facilities on Lines 300 and 400 require additional capital spending. In addition, the extensive safety-related work that PG&E is proposing for its backbone and local transmission systems focuses on the older pipelines on the PG&E system, including

Lines 300 and 400. As a result, under the standard Gas Accord rate design used since 1998, Baja rates now exceed Redwood rates. This appropriately reflects today's cost of service on these two competing paths to the PG&E City-gate market.

In the instant case, PG&E has proposed to combine, or "roll-in," Redwood and Baja costs to create "postage-stamp" rates applicable to core and noncore customers. This rolling-in of costs effectively would shift Baja path costs to Redwood shippers. Such a step would be inconsistent with cost causation and the longstanding Gas Accord rate design, and would be manifestly unfair to Redwood shippers who for a full decade bore the higher incremental costs of Line 401 without shifting any of those costs to Baja shippers. In the past, the Commission has allowed the higher costs of Line 401 to be rolled into the rates of lower cost lines only with the agreement of the affected shippers, or upon a persuasive showing that the benefits to the affected customers outweigh the higher costs. No such agreement has been reached in this case, nor has PG&E presented convincing testimony on the net customer benefits from its rolled-in rate design proposal. From a broad policy perspective, PG&E's rolled-in rate design would undermine the Commission's consistent application of its incremental rate policy, sending a cautionary signal to parties considering future investments in the state's gas infrastructure.

PG&E's attempt to roll-in the costs of the Redwood and Baja paths is a first step toward fully rolled-in rates for all customers, which would undo the Gas Accord's adoption of a set-aside of Line 400 capacity for core customers. A full roll-in of all of PG&E's backbone costs would raise rates for core customers by about $12.6 million per year. The partial roll-in that PG&E has proposed in this case also will increase costs for core customers, by an estimated $1.1 million over the next three years, because PG&E is expected to use the Redwood path in preference to Baja capacity to serve core customers.

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[1] *See* CPUC Decisions (D.) 11-04-031, D. 07-09-045, D. 04-12-050, D. 03-12-061, D. 02-08-070, and D. 97-08-055. D. 03-12-061 resolved the one fully-litigated Gas Accord proceeding.

As a result, shifting Baja costs to the Redwood path will increase costs for core customers.

The standard Gas Accord rate design calculates backbone rates using, in the numerator, the path-specific revenue requirement and, in the denominator, the product of the path's capacity times a single system load factor that is used for all paths. PG&E's backbone rate design proposes to continue to use the system load factor in the denominator of the rate calculation. The Gas Accord rate design has used the single system load factor in order to avoid the issue of forecasting path-specific throughput, which, depending on market conditions, could be contentious. In addition, the use of the single system load factor has been justified based on the argument that the PG&E gas system is a partially integrated system, especially in the Bay Area load center and in the contractual sense that a shipper holding capacity on any one path can deliver gas to any backbone delivery point on the system. The PG&E backbone system is only partially integrated as a result of its principal feature of the two long pipelines to the north and south accessing the distinct markets and receipt points at Malin, Oregon and Topock, Arizona.

This is not the first time that the Commission has considered proposals to modify the Gas Accord's backbone rate design. In 2003, in the one fully-litigated Gas Accord case, the Commission considered both a proposal for a rolled-in, postage-stamp rate design, similar to PG&E's proposal in this case, and a proposal to use path-specific load factors. The Commission rejected both of those proposals in D. 03-12-061, for some of the same reasons that this testimony recommends rejection today of PG&E's proposal. The circumstances of PG&E's backbone system have not changed significantly since 2003, and there is no reason today to abandon a backbone rate design that has served northern and central California well since 1998. The Commission should retain the use of the standard Gas Accord backbone rate design.

III. BACKBONE RATE DESIGN POLICIES UNDER THE PG&E GAS ACCORD

Q: Please describe the Commission policies and market circumstances that led to the "path-based" structure for PG&E's backbone rates that the Commission adopted in 1997 and implemented in the first Gas Accord settlement in 1998.

A: In the late 1980s, California faced a rapidly-growing natural gas market and a shortage of interstate pipeline capacity to the state. At least five major interstate pipeline projects were proposed to serve the growing California market, and the Commission had to establish a fundamental policy on how to choose among the new gas supply options that were competing in the "Great Pipeline Race" to California. In I. 88-12-027 and D. 90-02-016, the Commission adopted the general parameters of its "let the market decide" policy for new pipeline infrastructure. In these orders, the Commission wisely refrained from substituting its own judgment for that of the market and from trying to pick the "best" project. Instead, the Commission set forth the goals that it sought from the competing pipelines,[2] committed to support through the federal certification process the projects that met those criteria,[3] and then stepped back to let the market for shipper subscriptions determine the projects that could be financed and built. In exchange for this deference to the market, the Commission expected pipeline sponsors to bear the full risks associated with project development, including the risks of fully subscribing project capacity at rates that recovered the incremental costs of a project.[4]

One of the successful competing projects was PG&E's Line 401, a major expansion of its pipeline system south from Malin, Oregon, completed in conjunction with a parallel expansion of the upstream GTN system through Oregon and Washington, then owned by Pacific Gas Transmission Company, a PG&E affiliate. Line 401 was a complete looping of the existing Line 400 south of Malin. The Commission certificated Line 401 in 1989

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[2] *See* D. 90-02-016, mimeo at 89-102.

[3] *See*, for example, D. 90-10-034 (finding that the Kern River and Mojave projects had met the CPUC's criteria for new pipeline capacity) and D. 91-01-031 (finding that the Altamont project met the CPUC's criteria).

under the "let the market decide" policy, without reviewing the need for the new capacity, based on a firm commitment that an incremental rate design would be used to assign the costs of Line 401 to the shippers who used the line. The Commission actually affirmed this decision twice, first in the original certification decision for Line 401 in 1989[5] and again in a comprehensive rehearing of the project's rate design in 1992.[6] In the latter case, the Commission decisively rejected a rolled-in rate design for the Line 401 capacity serving noncore customers, notwithstanding a proposal from PG&E for the partial roll-in of Line 401 costs for noncore customers and a showing that the benefits to PG&E's customers from the new Line 401 capacity exceeded the higher transportation costs resulting from the roll-in.[7]

Thus, a policy of incremental rates on new, competing pipelines was an essential element of the "let the market decide" policy. In November 1993, PG&E placed Line 401 into service, adding 851 MMcf/d of capacity to PG&E's backbone system.

Q: Please describe the issues that motivated the original Gas Accord settlement.

A: Once Line 401 entered service, issues arose concerning PG&E's marketing and operating practices for the new line. U.S. Southwest pipelines and core consumer interests accused PG&E of a conflict of interest that favored the transportation of gas on Line 401 over other routes, because PG&E shareholders were 100% at risk for recovery of Line 401 costs, while PG&E ratepayers were at risk for cost recovery on the other lines. In addition, there were unresolved issues concerning the reasonableness of PG&E's decision to build the line and of the project's construction costs. Facing a thicket of litigation on these issues, PG&E and a broad spectrum of parties negotiated the Gas Accord in 1996, a settlement that the Commission approved in 1997 in D. 97-08-055 and implemented in 1998.

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[4] *Ibid.*, mimeo at 100 - 101.
[5] D. 90-12-119.
[6] D. 92-10-056.

The Gas Accord unbundled PG&E's backbone system into four "paths" based on the fundamental geography of the system: two long "straws" – the Redwood path north to the California / Oregon border at Malin and the Baja path south to the California / Arizona border at Topock, plus two shorter straws – the Silverado path to access California production within PG&E's service territory and the Mission path into and out of storage fields in PG&E's territory. This unbundling created a new market – the PG&E City-gate – at the virtual point downstream from each path wherever gas moved from a backbone pipeline into PG&E's local transmission system. The Gas Accord structure addressed PG&E's pre-Accord "conflict of interest" and the other contested issues in the following ways:

- PG&E assumed 100% risk for recovery of all backbone costs, on all paths, not just on Line 401.

- The Redwood path rate for noncore shippers was set as a rolled-in combination of the Line 400 and Line 401 capacity used to serve the noncore market, eliminating the complex and controversial procedures used to determine which gas volumes could flow on the much less expensive Line 400. Noncore shippers agreed to this partial roll-in in recognition that both lines were needed to serve the market and in exchange for other concessions.

- The deal preserved for the core the rate benefits of the low-cost Line 400 capacity historically used by the core, through a separate rate for the Redwood-core path. Line 400 rates were low because it was an older pipeline, with a substantially depreciated rate base.

- The backbone rate for each path was set using the path-specific revenue requirement in the numerator and a denominator that was the product of (1) the path's capacity times (2) a single system load factor that was used for all paths times (3) 365 days, as follows:

$$\textit{Path-specific Backbone Rate} = \frac{\textit{Path-specific Revenue Requirement}}{\textit{Path Capacity x System Load Factor x 365 days}}$$

[7] D. 90-12-119, at 12, 37-38, 98-99 and 106-109; D. 92-10-056, at 8-14.

The path-specific revenue requirement for each path included an allocation of the costs of PG&E's "common," networked backbone system in the Bay Area.

In the denominator, the CPUC approved the use of the single system load factor for all paths to provide backbone rates that were unbiased by forecasts of higher throughput on one path compared to another and that recognized the potential for throughput to swing from one path to another as market conditions changed. Further, the Commission's approval of the single system load factor recognized the partial, contractual integration of the PG&E system under the Gas Accord, whereby a customer interconnected to the facilities of one path could receive service from another path, via displacement, simply by paying the costs of the path from which he took service.

- Backbone rates were set for the entire five-year Gas Accord period, to provide rate certainty and to avoid rate volatility based on throughput fluctuations.

- The settlement included rules designed to ensure that PG&E did not grant transportation discounts preferentially to the higher-priced paths.

- PG&E agreed to financial concessions to resolve reasonableness issues associated with Line 401's development and construction.

Q: In approving the Gas Accord, did the Commission reaffirm its incremental rate policy?

A: Yes, it did. In D. 97-08-055, the Commission carefully explained, as follows, that the partial roll-in of Line 400 and Line 401 costs into Redwood-noncore rates was a limited exception from its incremental rate policies:

> Although we are approving the Gas Accord, we remain concerned that the partially rolled-in rates for Line 400 and Line 401 are contrary to our incremental ratemaking principles. PG&E was authorized to build Line 401 based upon its pledge to utilize incremental rates, and PG&E assured us at that time that PG&E's existing customers would not have to pay for Line 401 costs. Approval of partially rolled-in rates for noncore customers is reasonable here, but *only* because noncore representatives have agreed to it in the Gas Accord, presumably in return for other benefits. Full roll-in of Line 401 costs would increase core rates and would significantly conflict with our policies. However, the Gas Accord does not provide for fully rolled-in rates; it protects core retail and core wholesale ratepayers from the unjustifiable increase in rates which would result from the rolled-in rates. Therefore, our finding that the Gas Accord

> is in the public interest is predicated of the fact that the core retail and core wholesale customers will continue to benefit from low, vintaged rates on Line 400 and will not have to pay for Line 401 costs. We would strongly disfavor any future PG&E request for full roll-in of Line 401 costs if such roll-in would increase either core or noncore rates (absent an all-party settlement), whether such a request occurred before or at the expiration of the Gas Accord.[8]

Q: Have Gas Accord rate cases subsequent to the original settlement maintained this basic structure for PG&E's backbone rates?

A: Yes, they have. The Gas Accord II settlement, approved in D. 02-08-070, extended the original Gas Accord market structure for one year (2003), using 2002 Gas Accord rates. Gas Accord rates for 2004 were fully litigated in A. 01-10-011, resulting in D. 03-12-061. This order strongly affirmed the Gas Accord market structure and rejected several proposals for fundamental changes to the Gas Accord's backbone rate design. The decision turned down proposals to roll-in Line 401 costs into core rates, and again dismissed attempts to show that the benefits of Line 401 capacity exceeded the costs of the roll-in. The decision also rejected a proposal for equalized, postage-stamp rates on all backbone paths. I will discuss this order in more detail below. The next two Gas Accord cases, A. 04-03-021 and A. 07-03-012, resulted in settlements that continued the Gas Accord market structure for two successive three-year periods, 2005-2007 and 2008-2010. The Commission approved these Gas Accord III and IV settlements in D. 04-12-050 and D. 07-09-045, respectively. Both of these settlements relied on the same basic structure for PG&E's backbone rates that had been adopted in the first Gas Accord; in other words, backbone rates were based on the path-specific revenue requirement in the numerator and a denominator that used the path-specific capacity times a single system load factor. In D. 11-04-031, the Commission approved the most recent Gas Accord settlement, Gas Accord V, a settlement supported by most, but not all, of the parties to A.

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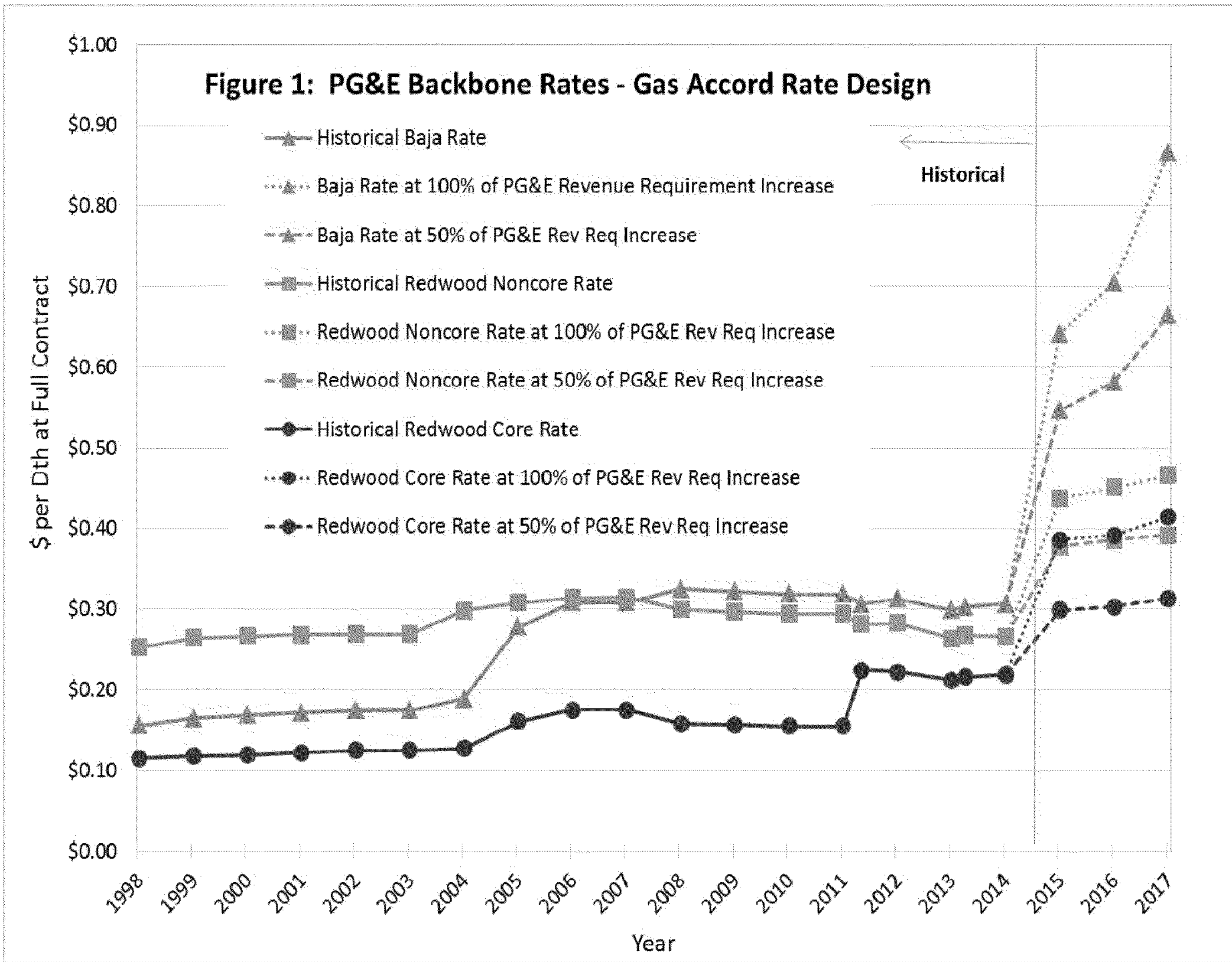
[8] D. 97-08-055, at 40-41.

09-09-013. This settlement included rates covering a four-year period, 2011-2014, and also continued the traditional Gas Accord backbone rate structure.[9]

PG&E's Redwood and Baja backbone rates since the original Gas Accord settlement in 1998 are shown in the historical section of **Figure 1**. From 1998 - 2007, noncore Redwood rates combining the costs of Lines 400 and 401 were higher than Baja rates, as a result of the higher costs of the relatively new Line 401. The figure also shows clearly that core customers have obtained substantial benefits from the incremental rate policy that has maintained a low rate for vintage capacity on Line 400 (the Redwood-core path).

[9] The Gas Accord IV and V settlements deviated slightly from prior Gas Accord settlements in that the differential between the Redwood-noncore and Baja path rates was set at negotiated levels. For example, *see* the Gas Accord IV settlement, attached to D. 07-09-045, at Section 8.2, page 6.



Q: Has the Commission continued to follow the "let the market decide" and incremental rate policies with respect to more recent gas infrastructure expansions?

A: Yes, it has. The Commission was very careful to refrain from "picking a winner" among both the pipeline infrastructure expansions of 2001-2003 and the liquefied natural gas (LNG) projects that were proposed in 2004-2008 to serve the California market. For example, in D. 04-09-022, the Commission directed PG&E, SoCalGas and SDG&E to submit non-discriminatory open access tariffs for all new sources of supply, including potential LNG supplies.[10] More recently, in R. 07-11-001, a rulemaking on LNG contracts, the Commission re-iterated that "we will not be choosing LNG projects."[11] Consistent with the "let the market decide" policy, the Commission insisted that project developers must bear the full incremental costs associated with their projects, without support from core ratepayers. For example, in D. 04-09-022, the Commission stated "we will therefore adopt a policy that presumes LNG suppliers will pay the actual system infrastructure costs associated with their projects."[12] The Commission also reaffirmed the "let the market decide" policy as recently as 2008, in D. 08-11-032, which approved PG&E's subscription to long-term capacity on the new Ruby Pipeline. In particular, in the Ruby decision the Commission again affirmed, as part of the "let the market decide" policy, the cost causation principle that "[c]ost responsibility for the new pipeline should flow to those customer groups that benefit from the pipeline."[13]

IV. PG&E'S BACKBONE RATE PROPOSAL VS. STANDARD GAS ACCORD RATES

Q: Please summarize PG&E's proposal for backbone rate design.

A: PG&E's testimony proposes, starting in 2015, to equalize Baja and Redwood path rates for core and noncore customers – in other words, a rate design with the costs for the Redwood and Baja paths "rolled-in" together. Significantly, however, rates for service to core and noncore shippers would not be equal, but Redwood and Baja path rates would be the same for each class (core and noncore). Core rates would include a discount that PG&E asserts would continue to reflect the core's preferential use of highly depreciated capacity on Line 400, although PG&E expects Line 400's costs to increase as a result of the need to perform safety-related work and to replace aging equipment on this line.

[10] D. 04-09-022, at 64.
[11] R. 07-11-001, at 12.
[12] D. 04-09-022, at 68, Finding of Fact 45, and Conclusion of Law 19.

Table 1 summarizes PG&E's proposed transportation and storage rates for 2015-2017, with rolled-in Redwood and Baja rates. 2014 rates under the adopted Gas Accord V settlement also are shown.

Table 1: *PG&E Proposed Transportation and Storage Rates ($/Dth, G-AFT at Full Contract)*

	Present	Proposed		
Service	**2014 (with PSEP)**	**2015**	**2016**	**2017**
Core Redwood	0.257	0.460	0.482	0.544
Core Baja	0.297	0.460	0.482	0.544
Noncore Redwood	0.298	0.512	0.543	0.608
Noncore Baja	0.338	0.512	0.543	0.608
Silverado/Mission	0.188	0.323	0.346	0.386
G-XF	0.186	0.204	0.205	0.204
Local Transmission Core	0.680	1.959	2.109	2.371
Local Transmission Noncore	0.332	0.875	0.919	1.057
Core Firm Storage Reservation Charge ($/Dth/Month)	0.126	0.175	0.173	0.180
Standard Firm Storage Reservation Charge ($/Dth/Month)	0.240	0.326	0.320	0.314

Q: Have you also calculated backbone rates under the standard Gas Accord rate design used since 1998?

A: Yes. **Table 2** shows the rates that would result from a continuation of the standard Gas Accord rate design. Because the unprecedented rate increases which PG&E is requesting in this case are sure to be contested, Table 2 also shows the standard Gas Accord rates assuming Commission approval of only 50% of PG&E's proposed backbone revenue requirement rate increase (above the 2014 backbone revenue requirement plus the PSEP surcharge). The rates in Table 2 are also shown graphically in the "forecast" section of Figure 1.

[13] *See* D. 08-11-032, at 64-68, citing D.90-02-016.

Table 2: *Traditional* Redwood and Baja Path Transportation Rates ($/Dth at Full Contract)*

Service	2015	2016	2017
At PG&E's Proposed Revenue Requirement:			
Core Redwood	0.383	0.388	0.410
Core Baja	0.637	0.698	0.858
Noncore Redwood	0.434	0.447	0.462
Noncore Baja	0.637	0.698	0.858
At 50% of PG&E's Proposed Revenue Requirement Increase:			
Core Redwood	0.297	0.300	0.311
Core Baja	0.542	0.576	0.658
Noncore Redwood	0.375	0.382	0.388
Noncore Baja	0.542	0.576	0.658

*Assumes No Equalization of the Redwood and Baja Path Backbone Rates. Also uses system load factors without any adjustment for disproportionate path flows – see page 32 of this testimony.

The next sections of my testimony analyze PG&E's preferred rolled-in rate design, as well as another alternative approach – the use of path-specific load factors in the denominator of the backbone rate calculation. I compare each of these alternatives to the standard Gas Accord rate design.

V. ANALYSIS OF ALTERNATIVES TO THE TRADITIONAL GAS ACCORD RATE DESIGN FOR THE REDWOOD AND BAJA PATHS

A. Comparing PG&E's Past and Present Proposals for Equalized, Rolled-in Redwood and Baja Rates

Q: What arguments does PG&E advance in support of its "preferred" proposal for equalized, rolled-in Redwood and Baja rates?

A: PG&E asserts that equalizing Redwood and Baja rates will result in "downward pressure" on prices at the PG&E City-gate. Because gas moved over the more expensive Baja path is presently the marginal source of supply at the PG&E City-gate, PG&E argues that, if Baja rates are set higher than Redwood rates, prices at the PG&E City-gate will be higher than if rates on the two paths are equalized. PG&E also cites the "contractual integration" of its system, which allows any PG&E customer, at any location, to receive gas regardless of the path into which the customer's gas is received, and the fact that at times gas received into the Redwood path at Malin can physically flow onto a portion of the Baja Path's facilities, and vice versa, depending on system demand conditions. Finally, PG&E cites the single, postage-stamp backbone rate used on the Southern California Gas system.[14]

Q: What is your overall reaction to PG&E's proposal?

A: My assessment of PG&E's backbone rate proposal is that it contradicts cost causation principles, is unfair to Redwood path shippers, unwisely attempts to use backbone rate design to manipulate the gas market at the PG&E City-gate, will discourage the development of new supply sources, and may undermine the Gas Accord's vintage rate protections for core customers. PG&E has made no showing that the benefits to Redwood customers from rolling-in Redwood and Baja rates exceed the costs for those shippers. Finally, the proposal is directly contrary to 25 years of consistent CPUC policy favoring incremental rates. I discuss my assessment in detail in the following sections.

Q: Is this the first case in which PG&E has sought to equalize Redwood and Baja rates?

A: No, it is not. PG&E made the same proposal in the last Gas Accord proceeding, A. 09-09-013. However, the circumstances at that time were different than today: at that point in time the Redwood path was the marginal source of gas. As a result, raising the Redwood path rate by implementing a rolled-in backbone rate at that time would have <u>increased</u> PG&E City-gate prices. Unable to argue that rate equalization would reduce PG&E City-gate prices, the utility instead asserted that the change would "level the playing field" by setting equal rates on the two transportation paths, thus avoiding a "bias" for a particular gas supply source.[15] As I will discuss at length below, PG&E's inconsistent and changing reasons for equalizing Redwood and Baja rates between the

[14] PG&E Testimony in A. 09-09-013, at 10-21.

2009 Gas Accord case and this proceeding help to illustrate the fundamental weakness of the utility's proposal.

1. Cost causation and equity for backbone shippers

Q: Would a major change in rate design – to rolled-in Redwood and Baja rates – be fair to shippers on the Redwood path who for many years paid Redwood rates that were higher than Baja rates, as a result of including Line 401 costs in Redwood rates?

A: No. Today, the costs of Line 401 at last are substantially depreciated, while the costs of the vintage capacity on both Lines 400 and 300 are increasing as aging equipment on those lines must be replaced. In the last Gas Accord case, filed in 2009, just when the reduction in Line 401's costs caused overall Redwood path costs to fall below those of the competing Baja path, PG&E proposed a fundamental change in rate design policy. PG&E's rolled-in rate proposal would combine the now-low costs of Line 401 capacity with the increasingly expensive Line 300 capacity, thus shifting the burden of these new Line 300 costs to large noncore customers and shippers on the Redwood path – the same group that has borne the impact of high incremental Line 401 rates since 1993. Under the Gas Accord, Redwood shippers bore the burden of high Line 401 costs for a full decade, from 1998 – 2007. I calculate that they paid an additional $159 million over this decade compared to what they would have paid if Redwood and Baja rates had been equalized beginning in 1998. The Commission found this result to be consistent with both cost causation principles and the "let the market decide" policy, because Redwood shippers used that path and it was their commitment to Line 401 capacity which enabled that expansion to be built.

[15] A. 09-09-013, at 13-14, also PG&E Testimony in A. 09-09-013, at 1-12 to 1-14.

Clearly, it would be contrary to cost causation and unfair to Redwood shippers to roll-in Redwood and Baja rates now, when Redwood costs have fallen below Baja costs. This would force Redwood shippers to bear a share of today's high Baja costs, despite the fact that they do not use that path, and Baja shippers did not bear any of the high Redwood costs from 1998-2007. PG&E's proposed rolled-in rates for 2015-2017 would require Redwood shippers to subsidize Baja shippers by a total of $102 million over the three-year period. This calculation is based on comparing rates under PG&E's equalization rate proposal (Table 1) to rates calculated using the standard Gas Accord rate design (Table 2).

2. Impact on City-gate prices paid by gas consumers

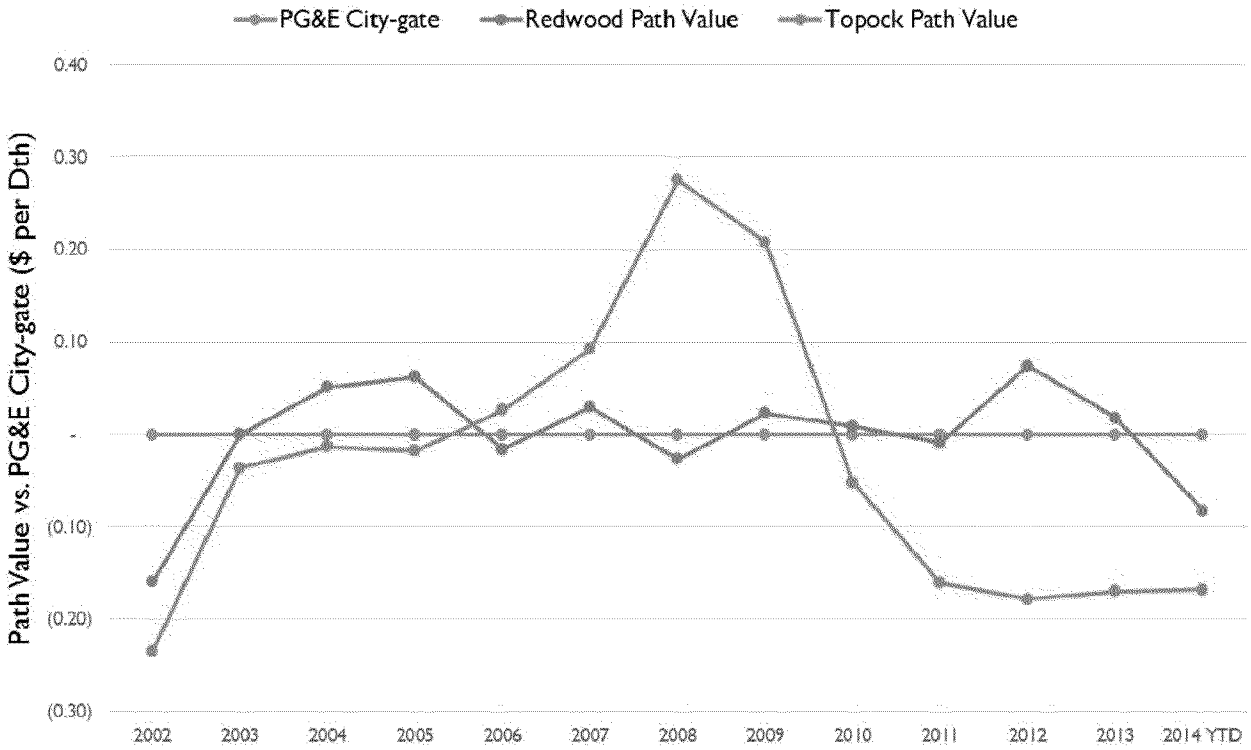
Q: PG&E asserts that equalized, rolled-in backbone rates will reduce prices at the PG&E City-gate. Please respond.

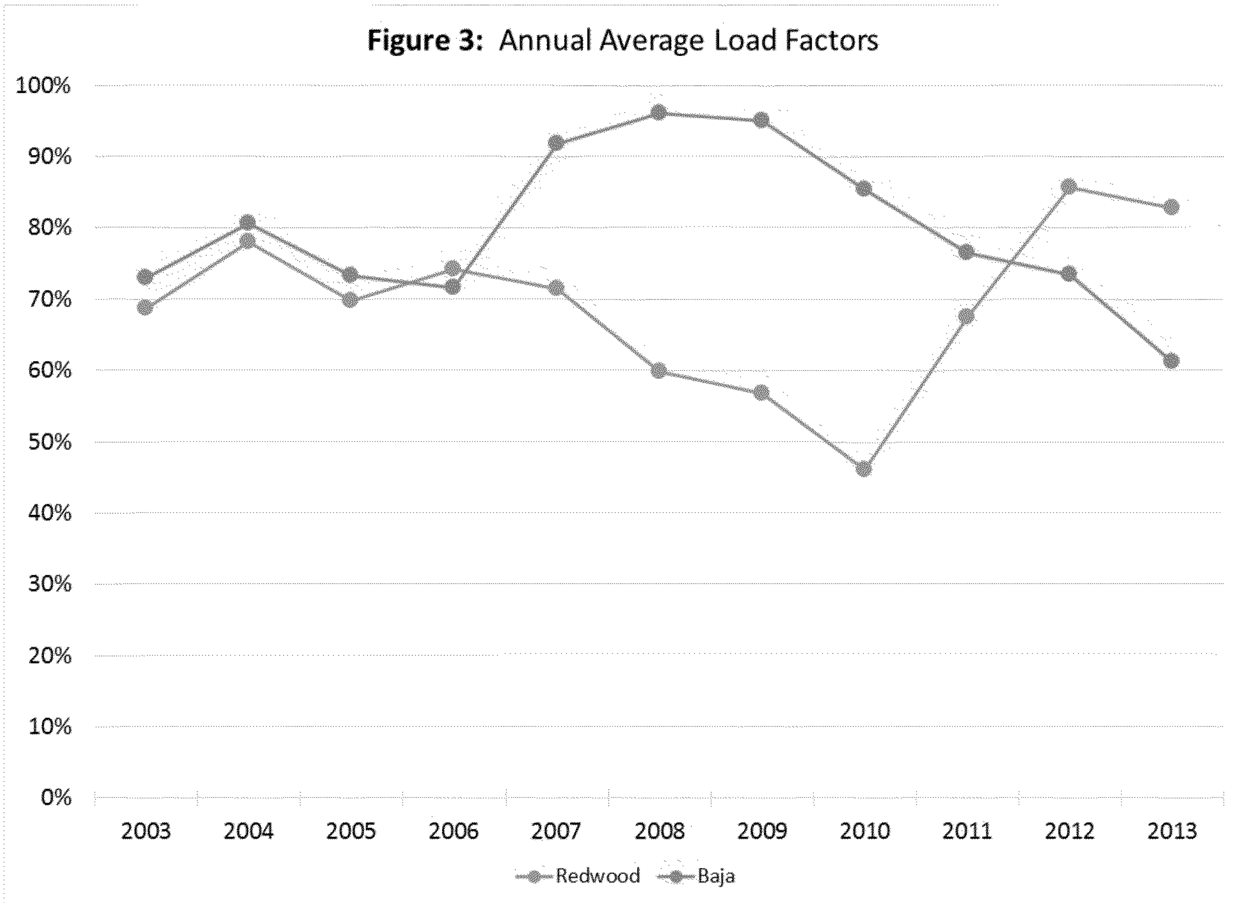
A: PG&E's changing arguments on this point illustrate the fundamental problem with this argument. Although reducing Baja rates and increasing Redwood rates might reduce PG&E City-gate prices today, this will not always be the result, and, at other times under different market conditions, the result will be to raise PG&E City-gate prices. When PG&E filed its last Gas Accord rate case in 2009, the Redwood path was the marginal source for the PG&E City-gate market, and raising Redwood rates would have increased PG&E City-gate prices. At that time, PG&E observed (correctly) that the marginal source of gas on its system has repeatedly flip-flopped between Malin to Topock in recent years.[16] We present this evidence in **Figure 2**, which shows the market value of Redwood and Baja capacity over the period 2002-2014, in terms of the benefits (positive) or costs (negative) for a shipper holding annual firm capacity on either path and selling gas at the PG&E City-gate. The path with the lower market value is the marginal source. The figure shows that the two paths were closely competitive (with a slight advantage to

[16] PG&E Testimony in A. 09-09-013, at 1-12.

Redwood) in 2002-2005, then Redwood became the marginal path from 2006-2009, with Baja returning to being more expensive since 2010. The relative attractiveness of the two paths also can be seen by comparing the annual average load factors on the two paths since 1999, as presented in **Figure 3**. Generally, the path with the higher value has been more heavily used, with higher load factors than on the lower-valued, marginal path. The data presented in these figures support the conclusion that the marginal path has changed a number of times over the last 15 years.

Figure 2: Path Value vs. PG&E City-gate





In the 2009 Gas Accord case, PG&E was unable to say that its proposal would reduce city-gate prices, so the utility made the more general argument that "equalizing PG&E's Redwood and Baja rates will ensure that the marginal backbone path is not priced higher than the alternative path, which will help enhance gas-on-gas competition."[17] PG&E presented no analysis or quantitative evidence that rate equalization would produce lower city-gate prices over time, and the utility has presented no such evidence in this case.

Robust competition does not require that backbone paths must be priced the same. Fundamentally, cost-based transportation rate differentials between supply sources should be part of the price signals seen by customers at the PG&E City-gate.

Competition at the PG&E City-gate is maximized when supplies competing at the City-gate pay accurate, cost-based rates for transportation to that market, not by rate designs that force the shippers on one path to subsidize the cost of transportation on another. In other words, competition in the gas markets in California does not and should not stop at the border, as it would if there were no rate differences downstream of the border, and transportation cost differences between paths to the PG&E City-gate should continue to be reflected in intrastate backbone rates.

Vigorous competition in the city-gate markets depends on the confidence of gas suppliers that this Commission's regulation of transportation rates within California will be fair and even-handed over the long-term. This confidence will be undermined if the Commission acts to shift costs from one supply source to another in an effort to manipulate prices at the city-gate. In 2007-2009, when supplies transported over the Redwood path were more expensive, shippers of U.S. Southwest supplies over the Baja path undoubtedly would have cried foul if Redwood rates had been reduced in order to increase the competitiveness of supplies from the north. Equalized rates also can give an additional, undue benefit to supplies that would be competitive even without the equalized rates. For example, for most of the initial decade of the Gas Accord market structure, Canadian supplies delivered by the Redwood path were less expensive at the PG&E City-gate, despite the higher rates on the Redwood path. In effect, the lower gas prices available on the higher-priced Redwood path provided gas-on-gas competitive benefits that more than paid for the cost of expanding that path through the addition of Line 401 and the matching upstream expansions all the way to Alberta. During this period, if Redwood and Baja rates had been equalized, the result would have been an unnecessary benefit for Redwood shippers, and suppliers on the Baja path undoubtedly would have complained mightily about being forced to subsidize the cost of expanding the pipeline capacity to access supplies from their competitors to the north.

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[17] *Ibid.*, PG&E Testimony, at 1-13.

3. The effects of a change in backbone rate design on new gas supplies

Q: In the 2009 Gas Accord case, PG&E claimed that equalized rates would reduce the barriers to new gas supplies, such as LNG supplies from Baja California, and that rolled-in rates will provide "an assurance that new supply opportunities will not be disadvantaged by a higher PG&E backbone rate for a particular path, if and when such supply is connected to the PG&E backbone system."[18] Do you agree with this point?

A: No, I do not. For example, in 2009 PG&E asserted that its planned large investments in the Baja path would raise Baja path rates significantly relative to the Redwood path, creating an incentive to use Canadian gas in preference to U.S. Southwest supplies unless rates were equalized. PG&E also argued that its proposal would ensure that a higher Baja rate would not disadvantage the liquefied natural gas (LNG) supplies which at that time had been proposed to be received in southern and Baja California and that might seek to be marketed in northern California.[19]

Rolled-in rates would force Redwood shippers to subsidize the entry of new Baja supplies into the PG&E market, and thus distort the true cost of delivering new supplies to the PG&E City-gate. Lowering Baja rates and raising Redwood rates obviously would have benefited LNG supplies from southern and Baja California. However, history now shows that the "LNG Boom" turned out to be a mirage, and new supplies actually entered the PG&E system from the north. Although the Costa Azul LNG terminal in Baja California, Mexico, was completed in 2008, very little LNG has flowed through that terminal to customers in either the U.S. or Mexico, because Pacific Rim LNG has not been economic in the California market as a result of the unexpected shale gas boom that

[18] *Ibid,* PG&E Testimony, at 1-14.

has dramatically increased North American supplies and reduced continental prices. The actual source of new gas supplies added to the PG&E system since 2009 is the Ruby pipeline from Opal, Wyoming to Malin. Ruby, which was placed into service in 2011, brings new supplies from the Rocky Mountains to Malin and the Redwood path. PG&E's proposal in 2009 to raise Redwood rates through rate equalization would have disadvantaged this new supply source, on which PG&E has contracted for long-term capacity to serve both its core customers and its power plants. Adopting PG&E's rate equalization proposal would have been exactly contrary to PG&E's own stated goal in 2009 of assuring that "new supply opportunities will not be disadvantaged by a higher PG&E backbone rate for a particular path."

In order to send the correct price signals to new supplies, PG&E backbone rates should be based on cost causation, and should reflect accurately the different costs of each of the two major "straws" to the City-gate, without judging where new supplies will enter the system or which straw will "win," i.e. transport more gas. The traditional Gas Accord backbone rate design accomplishes these goals, through its balanced use of path-specific costs in the numerator and a system load factor in the denominator.

It is also worth noting that the existing rate design charges a lower backbone rate (discounted by 50% compared to other backbone rates) to move California production to market on the Silverado path. This appropriately reflects the fact that California gas is produced within PG&E's service territory (mostly in the Central Valley and Sacramento / San Joaquin Delta regions), and thus requires fewer backbone facilities on average to reach PG&E's market. If the costs of all of all PG&E's backbone facilities were rolled into a single, postage-stamp backbone rate, which is the logical extension of PG&E's proposal, this would raise the Silverado rate substantially, and disadvantage indigenous gas production.

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[19] *Ibid.,* A. 09-09-013, at 14.

Finally, a fundamental change in rate design policy – from incremental to rolled-in rates – when the costs of Line 401 have dropped below the costs of competing paths would send precisely the wrong signal to the market about the consistency of the Commission's incremental rate policy. Indeed, it would tell a future shipper who might consider a long-term, incremental rate contract to support new gas infrastructure in California that the Commission cannot be relied upon to allow the shipper to keep the future benefits of such a contract, should the incremental rate fall below the market level. The same adverse message would be sent to companies seeking to produce natural gas within PG&E's service territory. This would be a poor signal to send to future investors in the state's energy infrastructure.

4. Preserving the benefits of incremental rates for core customers

Q: PG&E's testimony in this case does not discuss the impacts of its rate equalization proposal on core customers. In the 2009 Gas Accord case, PG&E claimed that its separate rate equalization for core and noncore backbone rates "preserves the benefits of the Core's vintage Line 400 capacity," such that "[c]ore customers are not disadvantaged by this backbone rate design."[20] Do you agree with this claim?

A: No, I do not, especially in the long-run. PG&E's equalization of Redwood and Baja rates would not result in significant additional costs for the core in 2015-2017 (an increase of about $1.1 million per year assuming that the core uses its Redwood capacity preferentially over its Baja capacity). However, equalizing the core's Redwood and Baja rates is inconsistent with maintaining vintage rates for the core over the long-term. The next logical step after rolling-in Redwood and Baja rates for noncore shippers would be to move to a fully rolled-in rate design for all shippers – such as the postage-stamp rate design the Commission has long used on the Southern California Gas (SoCalGas) system.

[20] A. 09-09-013, PG&E Testimony at 1-13.

Indeed, PG&E now cites the SoCalGas backbone rate design as a justification for its rate equalization proposal.[21] Moving to the SoCalGas model would result in a single rate for all backbone service on the PG&E system, including service to the core, and would end the incremental rate treatment that gives core customers preferential access to vintage Line 400 capacity. This would result in a significant increase in core costs, an increase of $12.6 million per year based on core throughput and capacity in 2015-2017.

5. Backbone rate design and the volatility of PG&E's backbone revenues

Q: In 2009, PG&E argued that its backbone revenues would be more volatile under path-specific backbone rates than under equalized rates, because it will lose more money if throughput shifts from a high-price path to a low-price route.[22] Please share your assessment of this argument.

A: Obviously, the reverse can occur as well – PG&E can make more money if load switches to a high-price path. PG&E's real concern in 2009 undoubtedly was that revenue volatility could result in the utility undercollecting its costs. PG&E has not renewed this argument in this case, possibly because the utility now is proposing full balancing account protection for its backbone revenue requirements, which would end its risk of revenue undercollections.

I will address this argument, as the Commission may not adopt PG&E's balancing account proposal. If PG&E's concern with revenue volatility was valid, then the utility should have experienced more difficulty recovering its backbone revenues in years when Redwood and Baja rates were very different, and less difficulty when they have been similar. Unfortunately, history does not support this thesis – the utility had three poor years recovering backbone revenues in 2005 - 2007, years when Redwood and Baja rates were very similar. It had strong years recovering backbone costs in 2001-2002, when

[21] PG&E Testimony, at 10-21.
[22] PG&E Testimony in A. 09-09-013, at 1-13.

Redwood rates were more than 50% higher than Baja rates.[23] The real answer to PG&E's concern is to address the utility's risk of revenue recovery directly through policies that address revenue recovery, and not indirectly through backbone rate design.

6. The partial integration of the PG&E backbone system

Q: PG&E asserts that the contractual and operational integration of its backbone facilities supports its rolled-in rate proposal.[24] How do you respond?

A: PG&E's position fails to consider that the PG&E system is only partially integrated. The traditional Gas Accord rate design takes into account the limited extent of this integration.

If the PG&E system was predominantly a fully-integrated, network-type system – for example, similar to the SoCalGas / SDG&E system – then a fully rolled-in, postage-stamp rate design might be appropriate. However, unlike the southern California system, the PG&E system has the two long, unidirectional "straws" from the completely distinct California border markets at Malin and Topock.[25] It is thus not a network system for which a postage-stamp rate would be appropriate. On the other hand, there is a limited amount of integration in the PG&E system, in the vicinity of the Bay Area load center. Gas from Line 300 can be moved to the northern Bay Area, and Line 400/401 volumes can be transported as far south as Panoche Junction.

Since 1998, the standard Gas Accord rate design has embodied a compromise that reflects the partial integration of the PG&E system. The standard rate design considers the integration of the PG&E system in the Bay Area by including an allocation of Bay

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[23] A. 09-09-013 PG&E Data Book, Tab 14 for 2003-2007 revenues.

[24] PG&E Testimony, at 10-21.

[25] The SoCalGas backbone lines to the California / Arizona border and to the PG&E and Kern River / Mojave pipelines in Kern County are much shorter, and all access the closely-linked southern California border markets at the receipt points into the SoCalGas system.

Area “common” backbone costs in the rates for all paths, and by using the single system-average load factor in the denominator of all backbone rates.

Finally, PG&E’s testimony refers to the “contractual integration” of its system – in other words, the fact that a customer served from Lines 400 / 401 in Redding can contract for gas at Topock, then pay for the delivery of that gas (via displacement) at the Baja rate, without paying the Redwood rate even though the customer is served from Redwood facilities.[26] The fact that there is contractual integration on the PG&E system does not support changing the traditional Gas Accord rate design, as contractual integration and the ability to deliver gas by displacement has been a central feature of the Gas Accord since 1998, and the Gas Accord’s backbone rate design with the system load factor in the denominator of all rates was developed with this contractual integration in mind.

Q: Do you believe that the traditional Gas Accord rate design, with path-specific costs and a single system load factor, is consistent with cost causation principles?

A: Yes. The use of path-specific costs in the numerator of the rate recognizes that a shipper moving gas on a particular path causes the utility to incur costs principally for that specific path. At the same time, the inclusion of Bay Area “common” backbone costs in the rates for all paths and the use of the single system load factor in the denominator of all backbone rates moderate the cost differences between the paths and accurately reflect cost causation for the portion of the PG&E system that is integrated. This compromise best incorporates PG&E’s costs to serve, for example, a Redwood path shipper who will receive gas at Malin and principally use the Redwood path, but who also may use the Bay Area common facilities and or even a portion of the Baja path to reach the end use customer.

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[26] PG&E Testimony, at 10-21.

B. A Backbone Rate Design Using Path-specific Load Factors

Q: Are there other possible approaches to backbone rate design, in addition to the standard Gas Accord method and PG&E's rolled-in approach?

A: Yes. In past Gas Accord cases, parties have proposed the use of path-specific load factors to design backbone rates. In essence, this would replace the single system-wide load factor in the traditional Gas Accord rate design with a forecasted load factor for each PG&E backbone path. This would treat each PG&E path as a stand-alone pipeline, and it can be argued that this would be the most accurate measure of the per-unit cost of transportation on each path, because the denominator of each rate would use expected path-specific flows.

Q: What are the issues associated with the use of path-specific load factors?

A: This approach raises several issues, compared to the traditional Gas Accord's use of a single system load factor.

Forecasting Future Gas Market Conditions. PG&E's 2009 testimony observed correctly that "the marginal gas supply source has switched frequently between Canadian supply sources and Southwest U.S. supply sources, including Rocky Mountain supplies." The CPUC has used a single system load factor in the denominator of path-specific backbone rates in recognition of the problems with forecasting path-specific load factors accurately. **Figure 3** above presents the historical data on path-specific load factors on Redwood and Baja. The record shows that path-specific load factors change based on market conditions in the producing basins that supply California and on trends in the larger North American gas market. Depending on market conditions, it could be a challenge for the Commission to forecast path-specific load factors accurately, although recent historical and forward market data can be used to project expected market conditions.

Equity for Shippers. In addition, as with PG&E's rolled-in proposal, it can be argued that it would be unfair to switch to path-specific load factors now, after many years of using a single system average load factor. However, history suggests that the load factor differences between the paths will even out over time. From 1998-2002, when Redwood load factors generally were much higher than those on Baja, Redwood rates were set using the system average load factor, and thus Redwood rates were significantly higher than if the Redwood-specific load factor had been used. The opposite was true in 2007-2011 when Baja load factors were higher.

Partial PG&E System Integration. The traditional Gas Accord structure has used the single system load factor, in part, to recognize the partial integration of the PG&E backbone system. However, this integration also is captured through the allocation of the costs of the Bay Area backbone network to the rates of both the Redwood and Baja paths.

Q: What do you conclude about the relative benefits of using a system average load factor?

A: The use of a single system load factor is neutral on changes in market conditions, and does not assume that either of the two PG&E "straws" will move proportionally more gas than the other. As noted above, the use of the system average load factor was an important element in the original Gas Accord's reforms approved by the CPUC to resolve PG&E's conflict of interest between its transportation paths and to recognize the cost causation consequences of the partial integration of the PG&E system.

PG&E's equalized-rate proposal is also neutral in this way, but its use of equalized costs in the numerator of backbone rates forces the lower-cost path to subsidize the higher-cost path, and thus departs from cost causation principles.

The use of a path-specific load factor could be the most accurate cost-based backbone rate design, assuming that market conditions allow path-specific throughput to be forecasted accurately.

C. The Precedent of D. 03-12-061, the One Fully-Litigated Gas Accord Case

Q: Has the Commission ever considered either equalized rates or the use of path-specific load factors as alternatives to the standard Gas Accord rate design?

A: Yes, it has. In the one fully litigated Gas Accord rate case, in 2003, the Commission considered and rejected both a fully-rolled-in, postage-stamp rate approach and the use of path-specific load factors. The Canadian Association of Petroleum Producers (CAPP) proposed the use of path-specific load factors as its primary proposal, with a postage-stamp rate design for all backbone paths as its secondary recommendation.[27] At that time, Redwood rates were higher than Baja rates, and Baja was the marginal path for gas supplies at the PG&E City-gate. TURN's witness Mr. Florio opposed CAPP's proposal on the grounds that path-specific load factors were hard to forecast and would lead to volatile and uncertain path-specific rates – again, identical to one of the concerns noted above.[28] PG&E summarized these arguments against the CAPP proposal in its brief in the case:

> CAPP witness Pinney's proposed path-specific load factor would likely increase costs to California end-use customers. The cost of the marginal supply to the Citygate will be the most expensive supply delivered to the Citygate, including the border price plus the on-system transportation costs. (Tr. 297:24-298:3 (Wilson, PG&E).) As previously noted, during the Gas Accord period, Topock was usually the marginal supply. Mr. Pinney's path-specific load factor proposal yields a Topock rate $.055/Dth higher than PG&E's proposed Topock rate. (Exh. 30, p. 14 (Pinney/CAPP).) Mr. Pinney's path-specific load factor proposal will raise costs to California consumers by increasing the transportation rate on the marginal path – namely, the Baja path. TURN also comments on Mr. Pinney's proposal, voicing concern about rate stability in light of uncertain

[27] D. 03-12-061 described CAPP's proposals at 288-292 and 300.
[28] Page 290 of D. 03-12-061 cites PG&E's and TURN's arguments against CAPP's proposals.

> path utilization and opposes this proposal. (Exh. 44, p. 5:5-19, Florio/TURN).) Mr. Pinney's proposal should be rejected.[29]

The Commission rejected CAPP's proposals on the grounds that they amounted to a roll-in of Line 401 costs with the rest of PG&E's backbone costs, a roll-in which the Commission rejected as contrary to the incremental rate treatment that the CPUC adopted when Line 401 was certificated in 1990, and as likely to raise costs for core customers.[30] The Commission also accepted the PG&E and TURN criticisms of CAPP's path-specific and postage-stamp proposals:

> Since we do not adopt the proposal of PG&E and the other parties to partially or fully roll-in the costs of Line 401 to the core, CAPP's proposal for a path-specific rate for the Redwood Path and other path-specific rates, is not adopted. In addition, since the [CAPP] postage stamp rate proposal depends on a single, average rate for all paths, which we do not adopt due to the non-roll-in of Line 401, the proposal for a postage stamp rate is not adopted. We also note the concern of PG&E and TURN that path-specific rates are likely to raise costs by increasing the transportation rate on the Baja path, and that path-specific rates are likely to hinder competition rather than promoting competition.[31]

D. 03-12-061 approved the continued use of the traditional Gas Accord backbone rate calculation, with path-specific costs in the numerator and a single system load factor in the denominator. This methodology has been the basis for all PG&E backbone rate designs since Gas Accord I was implemented in 1998.

[29] PG&E Opening Brief in A. 01-10-011, at 81.
[30] D. 03-12-061, at 284-285 and 302-303.
[31] *Ibid.*, at 303.

VI. RECOMMENDED BACKBONE RATE DESIGN

Q: What backbone rate design do you recommend?

A: The Commission should continue to use the standard Gas Accord backbone rate design that has been the basis for Gas Accord rates since 1998. In my opinion, the longstanding Gas Accord rate design

- reflects the different cost of service on the Redwood and Baja paths;
- is equitable for backbone shippers;
- promotes competition;
- sends correct and consistent signals to new gas supplies;
- best maintains the benefits of vintage rates for core customers;
- is a well-understood calculation; and
- accurately considers the partial integration of the PG&E gas system.

Q: Are there any elements of PG&E's calculation of the single system load factor with which you disagree?

A: Yes. In the calculation of the system load factor, PG&E proposes an adjustment based on "disproportionate path flows."[32] This adjustment is inconsistent with the assumption in the standard Gas Accord methodology of proportional flows on each path, and requires a forecast of path-specific flows for the future Gas Accord period. Eliminating this adjustment also will simplify the calculation of the system load factor. The traditional Gas Accord backbone rates shown in Table 2 above use system load factors that do not include this adjustment.[33]

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

A: Yes, it does.

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[32] PG&E Testimony, at Chapter 17A, pp. 17A-11 to 17A-12.

[33] The impact of the disproportionate path flow adjustment is very small. For example, without this adjustment, the traditional 2015 Redwood noncore backbone rate decreases from $0.437 per Dth to $0.434 per Dth.

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Attachment RTB-1

Curriculum Vitae 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 western U.S., Canada, and Mexico.

Since 1989, Mr. Beach has participated actively in most of the major energy policy debates in California, including renewable energy development, the restructuring of the state's gas and electric industries, the addition of new natural gas pipeline and storage capacity, and a wide range of issues concerning California's large independent power community. 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 PURPA.

AREAS OF EXPERTISE

- *Renewable Energy Issues:* extensive experience assisting clients with issues concerning California's Renewable Portfolio Standard program, including the calculation of the state's Market Price Referent for new renewable generation. He has also worked for the solar industry on the creation of the California Solar Initiative (the Million Solar Roofs), as well as on a wide range of solar issues in 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, electric transmission and interconnection issues, property tax matters, standby rates, QF efficiency standards, 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 CPUC

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 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 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 of R. Thomas Beach 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 of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)
    b. Prepared Supplemental Testimony of R. Thomas Beach 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 of R. Thomas Beach 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 of R. Thomas Beach 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 of R. Thomas Beach 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 of R. Thomas Beach 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 of R. Thomas Beach 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 of R. Thomas Beach 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 of R. Thomas Beach 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 of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 23, 2003)
    b. Prepared Supplemental Testimony of R. Thomas Beach 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 of R. Thomas Beach 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 of R. Thomas Beach on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 16, 2004)
    b. Prepared Rebuttal Testimony of R. Thomas Beach 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 of R. Thomas Beach 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 of R. Thomas Beach 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 of R. Thomas Beach 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 of R. Thomas Beach 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 of R. Thomas Beach 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 of R. Thomas Beach 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 of R. Thomas Beach 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 of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — August 31, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach 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 of R. Thomas Beach 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 of R. Thomas Beach 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 of R. Thomas Beach on behalf of the **California Producers** (R. 04-08-018 – January 30, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach 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 of R. Thomas Beach 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 of R. Thomas Beach 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 of R. Thomas Beach 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 of R. Thomas Beach 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 of R. Thomas Beach 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 of R. Thomas Beach on behalf of the **Solar Alliance** (A. 07-01-047 — August 10, 2007)
    b. Prepared Rebuttal Testimony of R. Thomas Beach 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 of R,. Thomas Beach on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — May 15, 2008)
    b. Prepared Rebuttal Testimony of R,. Thomas Beach 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 of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-015 — September 12, 2008)
    b. Prepared Rebuttal Testimony of R. Thomas Beach 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 of R. Thomas Beach 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 of R. Thomas Beach 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 of R. Thomas Beach 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 of R. Thomas Beach 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 of R. Thomas Beach on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 5, 2010)
    b. Prepared Rebuttal Testimony of R. Thomas Beach 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 of R. Thomas Beach 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 of R. Thomas Beach 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 of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 6, 2010)
    b. Supplemental Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 13, 2010)
    c. Supplemental Prepared Reply Testimony of R. Thomas Beach 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 of R. Thomas Beach on behalf of **The Vote Solar Initiative** (A. 10-11-015—June 1, 2011)

    - *Distributed generation policies; utility distribution planning.*

70. Prepared Reply Testimony of R. Thomas Beach 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 of R. Thomas Beach 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 of R. Thomas Beach on behalf of the **Northern California Indicated Producers** (R.11-02-019—January 31, 2012)
    b. Prepared Rebuttal Testimony of R. Thomas Beach 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 of R. Thomas Beach 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 of R. Thomas Beach 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 of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 12-03-014—June 25, 2012)
    b. Reply Testimony of R. Thomas Beach 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 of R. Thomas Beach 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 of R. Thomas Beach 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 of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 12-12-002—May 10, 2013)

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

EXPERT WITNESS TESTIMONY BEFORE THE COLORADO PUBLIC UTILITIES COMMISSION

1. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the Colorado Solar Energy Industries Association and the Solar Alliance, (Docket No. 09AL-299E – October 2, 2009).

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

2. Direct Testimony and Exhibits of R. Thomas Beach 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.*

EXPERT WITNESS TESTIMONY BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

1. Direct Testimony of R. Thomas Beach 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.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE 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)

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.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

1. Direct Testimony of R. Thomas Beach on Behalf of the **Interstate Renewable Energy Council** (Case No. 10-00086-UT—February 28, 2011)

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

2. Direct Testimony and Exhibits of R. Thomas Beach 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 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.*

EXPERT WITNESS TESTIMONY BEFORE THE VIRGINIA CORPORATION COMMISSION

1. Direct Testimony and Exhibits of R. Thomas Beach on Behalf of the Maryland – District of Columbia – Virginia Solar Energy Industries Association, (Case No. PUE-2011-00088, October 11, 2011)

   - *Standby rates for net-metered solar customers, and the cost-effectiveness of net energy metering.*

EXPERT WITNESS TESTIMONY BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

1. Direct and Rebuttal Testimony of R. Thomas Beach 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 NORTH CAROLINA UTILITIES COMMISSION

1. Direct, Response, and Rebuttal Testimony of R. Thomas Beach 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.*

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.