ALJ/MSW/tcg

Mailed

DEC 1 8 1997

Decision 97-12-096 December 16, 1997

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of Southern California Edison Company (U-338-E) To Adopt The Performance Based Ratemaking and Incentive Based Ratemaking Mechanisms Specified in D.95-12-063, as Modified by D.96-01-009, and Related Changes.	Application 96-07-009 (Filed July 15, 996)
Application of Pacific Gas and Electric Company To Adopt Performance-Based Ratemaking (PBR) For Generation And To Change Electric Revenue Requirement Subject To PBR, Effective January 1, 1998. (Electric) (U 39 E)	ORIGINAL Application 96-07-018 (Filed July 15, 1996)

(See Appendix A for List of Appearances.)

OPINION ON PACIFIC GAS AND ELECTRIC COMPANY'S HYDROELECTRIC AND GEOTHERMAL REVENUE REQUIREMENT

1. Summary

As an alternative to performance-based ratemaking (PBR), the Commission adopts a mechanism for determining Pacific Gas and Electric Company's (PG&E) hydroelectric and geothermal generation revenue requirements for 1998. The mechanism applies to PG&E's conventional hydroelectric, Helms Pumped Storage (Helms), and geothermal facilities.

2. Background

This consolidated proceeding was initiated by Southern California Edison Company (Edison) and PG&E in response to the Commission's directive in Decision (D.) 95-12-063, as modified by D.96-01-009 (the Preferred Policy Decision) to file applications for PBR for generation. The early background and procedural history of this proceeding is described in D.97-07-042, which addressed the respective roles of the

Commission, the Federal Energy Regulatory Commission (FERC), and the Independent System Operator (ISO) with respect to transmission system reliability and related market power issues.

A prehearing conference was held on June 23, 1997 at which the Assigned Commissioner and Administrative Law Judge (ALJ) heard oral argument on the question of deferring or terminating the proceeding as a non-critical path electric industry restructuring activity. PG&E stated its position as follows:

> "We continue to understand the constraints faced by the parties to this proceeding. We're feeling similar constraints on our limited resources. However, ... the existence of constraints does not create the rationale for providing inadequate or inaccurate revenue requirement for the utility to go forth and continue to operate its hydro and geothermal facilities.
>
> "We agree with the parties that the issue is what should be the revenue requirement, and we also agree with the parties that the [generation] PBR is not necessary to come up with that revenue requirement, but ... a firm commitment to come up with an alternative approach in a timely basis so that we can have the necessary assurance of revenue requirement as of 1-1-98 is necessary." (Tr. PHC-3, p. 128.)

A *Joint Ruling of Assigned Commissioner and Administrative Law Judge* issued on June 25, 1997 determined that the various proposals of PG&E and Edison for development of PBR/incentive mechanisms for generation were not on a critical path for implementation in 1998, and would not be considered for the time being. The ruling adopted PG&E's procedural recommendation for consideration of an alternative proposal for developing a hydroelectric/geothermal revenue requirement for 1998. Pursuant to the ruling, PG&E filed and served the conceptual framework of its proposal on July 1, 1997; filed and served a detailed proposal on July 11, 1997; provided notice of and convened a workshop on July 17, 1997; and filed and served a workshop report including further procedural recommendations on July 24, 1997.

On August 22, 1997 the ALJ convened a prehearing conference to consider proposals for establishing PG&E's hydroelectric and geothermal revenue requirement. The ALJ assigned to the transition cost proceeding (Application (A.) 96-08-001, et al.)

participated to facilitate coordination of this proceeding with the transition cost proceeding. The ALJ emphasized that this sub-phase of the proceeding would not consider PBR and incentive ratemaking mechanisms. (Tr. PHC-4, pp. 146-47.)

Four days of hearing were concluded on September 23, 1997. The matter was submitted on October 10, 1997 with the filing of concurrent reply briefs. PG&E, the Office of Ratepayer Advocates (ORA), James Weil, Raymond Czahar and Ronald L. Knecht, and the El Dorado Irrigation District (EID) presented testimony and filed opening and reply briefs.[1] In addition, Enron filed a reply brief.

The proposed decision of the ALJ was issued on November 14, 1997 in accordance with the provisions of Section 311(d) and Article 19 of the Commission's Rules of Practice and Procedure.[2] Comments and reply comments were filed by PG&E, ORA, Weil, and Knetch/Czahar. Our order makes certain revisions to the proposed decision in response to the comments and to reflect recent Commission orders that were issued after the proposed decision.

3. Revenue Requirement Mechanism

3.1 Proposed Architecture

Establishing a hydroelectric/geothermal revenue requirement is necessary to determine the level of transition cost recovery by PG&E that will be reflected in the Transition Cost Balancing Account (TCBA). PG&E and ORA have agreed upon a proposed "architecture" for determining this revenue requirement and most of the components thereof. PG&E intends that the mechanism will provide it with the same opportunities for generation cost recovery that was contemplated by the Preferred Policy Decision and Assembly Bill (AB) 1890 (Stats. 1996, Ch. 854).

---

[1] Weil, Czahar, and Knecht are PG&E customers. Czahar and Knecht participated jointly.

[2] All such section references are to the Public Utilities Code.

Under this proposal, the revenue requirement for conventional hydroelectric, Helms, and geothermal generation facilities would be calculated as the sum of the capital-related revenue requirement, the expense revenue requirement, and actual fuel expense. The expense revenue requirement would be based on PG&E's 1996 general rate case (GRC). Fuel and capital costs would be determined on a recorded basis. Applying its proposed architecture, PG&E calculated illustrative 1998 revenue requirements for conventional hydroelectric, Helms, and geothermal facilities as $325,871,000, $109,775,000, and $219,807,000 respectively.

Weil agrees that assembling ratemaking elements from various proceedings as proposed is a reasonable alternative to full-scale litigation of all relevant revenue requirements. However, Weil finds aspects of the mechanism to be unreasonable, particularly recorded cost ratemaking. Weil believes that, taken as a whole, the proposal does not fairly balance ratepayer and shareholder risk and rewards. Knecht and Czahar likewise support the overall architecture proposed by PG&E, and share Weil's reservations concerning the use of recorded cost ratemaking. In addition, they take issue with the proposal's failure to account for net-of-inflation productivity improvements.

Discussion

In its general form, the proposed revenue requirement architecture is uncontested. As PG&E and ORA have pointed out, it draws upon existing proceedings as data sources, including GRCs, capital additions proceedings, and the ratesetting/unbundling proceeding. Using this approach as an alternative to either PBR or a fully litigated revenue requirement construction should save time and resources of parties and the Commission. We are persuaded that it should be adopted for purposes of determining PG&E's hydroelectric/geothermal revenue requirement for 1998. We address the concerns of Weil and Knecht/Czahar regarding the architecture in Sections 3.2 and 3.3. In Section 3.4 we consider proposals to extend the architecture to the entire electric restructuring transition period (i.e., through 2001) or until the facilities undergo market valuation.

3.2 Capital-Related Costs

Under the PG&E-proposed architecture, the capital-related revenue requirement consists of return on rate base, depreciation, decommissioning costs, taxes, and franchise fees and uncollectibles. All the components would be based on actual recorded monthly costs, including recorded rate base which reflects capital additions in service at the time and accumulated depreciation. Capital additions would be subject to after-the-fact reasonableness review. The previously determined rate of return of 90% of the cost of debt would apply to the uneconomic facilities eligible for transition cost recovery as determined in Phase 2 of the transition cost proceeding. The rate of return for other facilities would be determined in PG&E's cost of capital proceeding for 1998 (A.97-05-016).

Weil contends that compared to GRC ratemaking, cost variations under recorded cost ratemaking cause variability or uncertainty in customer obligations, while utility returns are stable. In essence, Weil claims, moving to recorded cost ratemaking shifts risks associated with the variability or uncertainty of outcomes from the utility to its customers. Weil finds that there is little evidentiary support in this proceeding for the use of recorded cost ratemaking, and notes that the PG&E/ORA approach fails to offer any reduction in financial rewards commensurate with the shift in risk to customers. He then argues that this shifting of risk is a step backward from the Commission's PBR goals of creating incentives to reduce costs and improve productivity.

Weil recognizes, however, that at this stage of the proceeding there is little choice but to proceed with recorded cost ratemaking for capital costs for 1998. Thus, he recommends that the Commission approve the use of recorded rate base, and offset the reduced utility risk by ordering reduced utility rewards. Weil asserts that the most logical method of accomplishing this is in the setting of PG&E's authorized return on equity, but he believes that there are other opportunities to create a fair balance of risks and rewards. These include denying PG&E's proposals regarding TCBA debits, expense levels, capital additions, reasonableness review, and Catastrophic Events Memorandum Account (CEMA) tariff provisions.

Weil takes issue with the PG&E/ORA rate of return recommendations because they are founded upon non-coordinated reviews of risks and rewards in disconnected proceedings. He notes, for example, that the issue of reduced risk associated with recorded cost ratemaking is not being addressed in A.96-08-001 or in A.97-05-016. Weil suggests that given the absence of a record in those proceedings as well as in this one, the Commission could rely upon its judgment in setting a reduced return on equity. In any event, Weil opposes the use of a company-wide return on equity for hydroelectric and geothermal facilities.

As noted above, Knecht and Czahar share Weil's criticisms of recorded cost ratemaking. However, they do not favor Weil's proposed risk readjustments. Instead, they suggest that the Commission simply reject recorded cost ratemaking and adopt a forecast of capital-related costs. They recommend that if recorded costs must be used, they be used for 1998 only. Knecht and Czahar propose using the rate of return adopted in A.97-05-016 for 1998.

Discussion

We seek to avoid the use of ratemaking and cost recovery methods that put customers at undue risk, or that unduly reward customers, for utility management actions. Even traditional cost-of-service ratemaking, despite its faults, has the advantage of placing utility management at risk for its performance relative to the forecast test year revenue requirement. In recent years we have sought through PBR to provide a more equitable balancing of risks, and a more rational set of incentives to encourage utility management actions that benefit ratepayers as well as shareholders. We find that compared to traditional cost-of-service ratemaking or PBR, recorded cost ratemaking generally reduces utility risk and tends to make management less concerned with controlling capital-related costs.

Accordingly, we generally do not favor recorded cost ratemaking as proposed by PG&E and ORA. As the customer intervenors have pointed out, it represents a step back from our PBR goals. On the other hand, we recognize that under the AB 1890 rate freeze/transition cost recovery mechanism that overlays this proceeding, utilities remain at risk for recovery of uneconomic generation costs by the end of the transition period. This should provide PG&E with some incentive for efficient operations, even if it is not as well-defined and targeted as we believe PBR incentives can be. Further, as ORA notes, D.97-09-048 places utilities at risk for the costs of capital additions. In any event, it is necessary to adopt the PG&E /ORA approach to setting a capital-related revenue requirement, since there is no record that would support other approaches. Knecht and Czahar suggest that we simply order PG&E to use a forecast approach, but they present no practical or record-based means of doing so for 1998.

We therefore adopt the use of recorded capital-related costs for 1998 as recommended by PG&E and ORA, with provisions for post-1997 capital additions as discussed in Section 4.3. As we do so, we agree that it is reasonable and appropriate, at least in principal, to make compensating adjustments to the assignment of risks and rewards to PG&E and its customers. A logical way to do this would be to adopt an authorized return on equity which corresponds to the risks associated with recorded cost ratemaking. Again, there are no specific proposals to support this, and we decline to make a judgment on the appropriate return on equity in the absence of record evidence. Nevertheless, we are satisfied that the program we adopt today for establishing PG&E's hydroelectric and geothermal revenue requirement represents a fair balancing of risk and rewards overall.

In D.97-06-060, we established guidelines regarding the TCBA and accelerated cost recovery. Among other things, we provided that as assets which are currently in rate base are amortized, rate base should be reduced correspondingly on a dollar-for-dollar basis, including the impact of associated taxes. (D.97-06-060, pp. 5, 84.) PG&E should observe this guideline in its accounting of recorded capital costs.

We adopt PG&E's and ORA's rate of return proposal (which Knecht and Czahar join) for PG&E's hydroelectric and geothermal revenue requirement. Weil has identified a legitimate concern regarding the disconnection of proceedings affecting the rate of return, but this is only a part of a larger issue regarding the disaggregation of utility ratemaking generally, one that is not appropriately addressed here. The transition cost proceeding is the forum for implementing the reduced rate of return on assets which are eligible for uneconomic cost recovery. We have already provided in D.97-08-056 that unbundling of the rate of return is not an urgent matter, and that it will be considered in cost of capital proceedings to be filed next year. We have no basis for modifying the results of these other proceedings due to an asserted need to coordinate issues in this proceeding.

3.3 Expenses

Following the briefing outline used by the parties, we address the proposal for a productivity adjustment in this section. Additional issues related to the expense revenue requirement are addressed in Section 4 of this decision.

The proposed architecture provides that the expense revenue requirement will consist of operation and maintenance (O&M) expense, administrative and general (A&G) expense, payroll and other taxes, franchise fees and uncollectibles, and working cash. Except for working cash, the amounts would be fixed by using adopted figures from PG&E's test-year 1996 GRC, without adjustments for data trends, inflation, or productivity. Weil takes no position on the use of test-year 1996 GRC expense data. Knecht and Czahar generally agree with the proposal, with one significant exception. They argue that we should adopt a net-of-inflation productivity adjustment of 1% per year for 1997 and 1998, and apply the adjustment by reducing the O&M and A&G expenses by 2% for 1998.

Discussion

The use of test year 1996 GRC data for setting a 1998 expense revenue requirement is uncontested with the exception of the proposed productivity adjustment. We first address the argument that the proposed adjustment may not be considered because it assertedly represents a PBR or incentive-based mechanism, which would be outside of the scope of this phase of the proceeding. Knecht and Czahar are not proposing a performance measure or a PBR standard. Instead, they are proposing the adjustment as a means of accurately forecasting the 1998 expense revenue requirement.

Knecht and Czahar argue that the proposed adjustment is similar to the total-factor productivity (TFP) adjustments that the Commission has made to utility expenses in the past. However, they acknowledge that a TFP adjustment was not made in the test year 1996 GRC. PG&E argues that we should reject the proposed adjustment because, among other things, there is no underlying cost study to support it.

We accept witness Knecht's qualifications to testify in this area, but we still find insufficient justification or record support for his proposed productivity adjustment for 1998. We adopt the PG&E/ORA proposal for establishing the expense revenue requirement without modification. However, we do not preclude any party from taking up this issue in PG&E's 1999 GRC.

3.4 Extension of the Term of the Mechanism

PG&E and ORA have agreed and recommend that their proposed architecture be used to establish and adjust PG&E's hydroelectric and geothermal revenue requirement through 2001, i.e. for the entire transition cost recovery period designated (with certain exceptions) in AB 1890, or until market valuation, whichever occurs first. PG&E points out that, at the most, the architecture would be in effect for only three more years after 1998. PG&E notes that parties have expressed a desire to minimize the level of resources that would be necessary for a full-blown PBR proceeding. Also, PG&E has announced its intention to sell its geothermal facilities. If it does, approximately one-third of the revenue requirement that would be subject to a PBR would disappear. In addition, PG&E claims its is quite possible that the valuation of its Helms and conventional hydroelectric facilities could occur before the end of the transition period. Finally, PG&E notes, O&M and A&G expenses will be updated in the test year 1999 GRC proceeding, and capital and fuel costs will be based on recorded costs subject to some form of reasonableness review. PG&E concludes that the rationale for a PBR proceeding for generation is diminishing with the passage of time and the onset of competition in the generation market.

ORA believes that the AB 1890 rate freeze/transition cost recovery mechanism provides adequate incentives to reduce costs. It also provides a rate cap. ORA believes that these provisions obviate the need for a PBR mechanism. ORA also believes that the "no debit" proposal for hydroelectric and geothermal revenues which it supported in the Transition Cost proceeding will impose another cost control incentive.

Weil, Knecht, and Czahar oppose extending the term of the mechanism beyond 1998. Instead, they propose that PG&E's hydroelectric and geothermal generation be subjected to PBR for the duration of the transition period. (Weil also supports conventional GRC treatment as an alternative to PBR.) In response to PG&E's argument that a PBR would only be in effect for three years at the most, Weil observes that as much as $2 billion in revenue requirement is at issue over the three-year period. He contends that the magnitude of revenue requirements justifies either adoption of a PBR mechanism or litigation of the hydroelectric and geothermal revenue requirement in PG&E's pending 1999 GRC. Weil, Knecht, and Czahar do not believe that the rate freeze and the related limitations on transition cost recovery provide adequate incentives to constitute a substitute for PBR.

Discussion

Extending the revenue requirement architecture beyond 1998 instead of pursuing PBR has the advantage of avoiding litigation of potentially controversial PBR proposals. On the other hand, the 1997 resource constraints that were largely responsible for transforming this generation PBR proceeding into a relatively narrow forum for consideration of PG&E's hydroelectric and geothermal revenue requirement may not be as severe in 1998.[3]

Resource constraints are not the primary consideration, however. To the extent that PG&E's hydroelectric and geothermal revenue requirement represents a significant ratepayer impact, we want reasonable assurance that PG&E's management faces appropriate incentives to operate its facilities efficiently. The architecture we approve

---

[3] A proposal by Edison for determining its hydroelectric revenue requirement is currently before the Commission in another phase of this consolidated proceeding.

today provides some incentives through a combination of reasonableness review for recorded costs and the use of forecast expenses. The rate freeze/transition cost recovery mechanism also provides some incentive to control costs. We recognize, however, that legitimate disputes about the effectiveness of these provisions are not fully resolved in this proceeding.

Thus, it may be appropriate to institute PBR to provide more effective incentives for the remainder of the transition period after 1998. Yet, it is premature to determine that PBR should be pursued. Clearly, the need for a PBR mechanism will diminish to the extent that hydroelectric and geothermal facilities are market-valued and removed from revenue requirements. In the coming months we expect learn more about the schedule for and status of market valuation for PG&E's hydroelectric and geothermal facilities. This should permit a better assessment of whether pursuit of a maximum three-year PBR program is worthwhile. As industry restructuring takes place, and as the records in PG&E's 1999 GRC and other proceedings develop, we may also learn more about the prospects for early recovery of transition costs, which should also help in determining whether to pursue PBR.

We find that the best approach is to provide that the architecture adopted today may continue in effect through 2001, while leaving the door open for possible consideration of PBR for PG&E's hydroelectric and geothermal generation next year. Accordingly, the revenue requirement architecture adopted herein should be continued in effect through 2001, subject to further order of the Commission. We direct PG&E to report on May 1, 1998 on its plans for, and the status of, market valuation and divestiture for its hydroelectric and geothermal facilities, the status of must-run designations, and any other factors affecting the need for and appropriateness of a proceeding to consider PBR. We do not intend to keep this proceeding open for this purpose. Instead, PG&E's status report should be submitted to the Director of the Energy Division, who will make recommendations to the Commission on whether to initiate a new proceeding, whether to direct PG&E to file a new PBR application, or any other appropriate response. The Energy Division Director may provide for comments or convene workshops as he deems appropriate (perhaps as part of PG&E's 1999 GRC or its Distribution PBR proceeding) before making these recommendations.

As discussed earlier, we are adopting a recorded cost approach to capital-related costs in the absence of a record that would support a forecast of these costs for 1998. Based upon our concerns with recorded cost ratemaking, we believe that the revenue requirement architecture should possibly be modified to use a forecast of capital-related costs for the post-1998 period. PG&E's 1999 GRC proceeding is the appropriate forum for exploring the use of forecast capital-related costs for 1999 in lieu of the recorded cost approach adopted today for 1998. PG&E should supplement its 1999 GRC testimony by including a forecast of capital-related costs.

4. Related Issues

4.1 Revenue Requirements for Must-Run Units

This section addresses competing proposals of PG&E and ORA for the treatment of the revenue requirement for hydroelectric and geothermal units operating pursuant to must-run agreements with the ISO.[4]

4.1.1 Recommendations and Positions of the Parties

PG&E proposes to include the combined revenue requirement of all of its hydroelectric and geothermal facilities, including those subject to must-run contracts, in the total revenue requirements that are debited monthly to the TCBA. PG&E would

---

[4] D.97-09-048 describes (at p. 14) three forms of reliability contracts that were then pending FERC approval. FERC has since approved such contract forms. (*Pacific Gas and Electric Company, San Diego Gas and Electric Company, and Southern California Edison Company* Docket Nos. EC 96-19-001 et al. (1997) 81 FERC ¶61,122.) Agreement A provides for market pricing and allows the owner to sell services beyond the needs of the ISO. Agreement B provides for utility collection of revenues above a market rate through a "credit-back," a fixed cost payment, and operating cost payments of up to 100% of the cost of providing must-run services. Proposed Agreement C is a full cost-of-service contract for uneconomic units. For purposes of the following discussion, ORA considers Agreement A to be an example of a competitive form of contract and Agreement B and Agreement C to be examples of full cost recovery contracts. It is expected that all must-run units will be on Agreement A for the first 90 days of the transition period.

also enter a monthly credit to the TCBA to recognize revenues that all hydroelectric and geothermal facilities earn from the Power Exchange (PX), the ISO, and other sources. In effect, gains and losses relative to the revenue requirement which PG&E incurs from the operation of must-run units would be reflected in the TCBA.

ORA believes that including the revenue requirement of must-run units which rely upon the ISO for full cost recovery would misallocate risk between ratepayers and shareholders, and would inhibit competition for must-run services. In addition, ORA finds that it is inconsistent with the Preferred Policy Decision's premise that low-cost hydroelectric and geothermal resources should be used to pay down transition costs.

ORA's central recommendation is to assign responsibility for the results of must-run hydroelectric and geothermal contracts with full cost recovery provisions to PG&E, by prohibiting access to the ratemaking mechanism of the TCBA. ORA proposes that as of January 1, 1998, and for the first 90 days of the transition period during which it is expected that all must-run units would be operating under Agreement A, the revenue requirement for such units would be included in the revenue requirement used to determine the TCBA balance. In effect, gains and losses associated with these plants would be recorded in the TCBA. Thereafter, the revenue requirement for any individual must-run unit that moves from a competitive ISO agreement to one with full cost recovery (for example, from Agreement A to either Agreement B or C) would be removed from the total hydroelectric/geothermal revenue requirement debited to the TCBA. Gains and losses relative to the revenue requirement would generally remain with the utility. However, for any credit-back type of must-run agreement, profits from the unit that exceed the equivalent of the revenue requirement would be credited to the TCBA. ORA recommends this provision to create parity between Agreement B and Agreement A.

While the focus of ORA's proposals is the treatment of revenue requirement for units on full cost recovery contracts, ORA believes that PG&E may have an incentive to keep some money-losing units on competitive ISO contracts rather than pursuing full cost recovery. ORA recommends that if that occurs, parties be given an opportunity to prospectively seek a Commission order for the exclusion of the revenue requirement of that unit from the TCBA. As a criterion for such consideration, ORA proposes that the unit must have suffered a loss of at least 2% of the revenue requirement over a calendar year.

ORA recommends a default ratemaking rule providing that if a unit moves from a competitive form of contract to a full cost recovery contract, the revenue requirement should be excluded indefinitely. If such a unit will be returned to a competitive contract, the utility should file a notice with the Commission. In addition, if the utility seeks to change the default provision and instead debit the revenue requirement of the unit in the TCBA, that request should be included in the required notice.

ORA's overall proposal includes three sub-accounts to track conventional hydroelectric, Helms, and geothermal separately. The purpose is to minimize the potential for cross-subsidy among these types of generation. The sub-accounts would be trued up annually, and over-collections would be credited to the TCBA. Losses in one sub-account would not be offset by profits in another.

Weil takes no position on the merits of PG&E's and ORA's recommendations. Nevertheless, he suggests that ORA's recommendations be adopted as a means of adjusting the risks created by the use of recorded cost ratemaking. Weil agrees with two principles underlying ORA's position: PG&E should be given an incentive to negotiate adequate cost recovery with the ISO; and PG&E should not in effect be given two opportunities to recover the costs of must-run units. Knecht and Czahar raise issues regarding the ratemaking treatment of capital additions in connection with must-run units. Capital additions issues are addressed in Section 4.3.

4.1.2 PG&E's Negotiating Position

ORA contends that under PG&E's proposal, PG&E will not have a sufficient incentive to negotiate adequate cost recovery with the ISO. ORA believes that its proposal guards against the possibility of the utility's failure to negotiate adequate cost recovery with the ISO. ORA's primary concern is with full cost recovery contracts negotiated with the ISO, i.e., Agreement B and Agreement C.

PG&E argues it has the incentive of the rate freeze/transition cost recovery mechanism to negotiate adequate cost recovery terms with the ISO. PG&E also argues that its ability to control the contract development process is limited. PG&E asserts there is uncertainty regarding the final outcome on what compensation provisions the ISO contracts will contain. PG&E notes that this depends on FERC decisions and on negotiations with the ISO.

If PG&E were not able to negotiate adequate cost recovery with the ISO, it would be inappropriate to place it at risk for negotiating adequate contract terms and for operating in a manner that meets or surpasses the negotiated terms. We do not find PG&E's negotiating position to be so limited. Even though the form of the ISO contracts is subject to FERC jurisdiction, contract cost recovery terms will be negotiated bilaterally between PG&E and the ISO. We find unpersuasive PG&E's argument that political pressures will result in contracts that fail to provide a reasonable opportunity full cost recovery, or that PG&E's hands will be tied at the bargaining table such that it will simply be forced into providing must-run services at a loss.

PG&E asserts that development of policies based on must-run agreements which have not yet been approved by FERC is premature. However, we have already dealt with the proposed ISO contracts in D.97-09-048 and in the transition cost proceeding. As noted in footnote 4, *supra*, FERC has recently approved the reliability must-run contracts.

Earlier in this decision we stated our recognition that the effectiveness of the rate freeze/transition cost recovery mechanism as an incentive for PG&E to reduce costs is uncertain. We concur with ORA's assessment that we should not rely upon this incentive alone to provide assurance that PG&E will negotiate reasonable cost recovery terms with the ISO.

4.1.3 Section 367(b)

PG&E contends that ORA's proposal violates AB 1890's required netting of positive and negative values for certain generation-related costs. Section 367 provides in relevant part:

> "The commission shall identify and determine those costs and categories of costs for generation-related assets and obligations, consisting of generation facilities, generation-related regulatory assets, nuclear settlements, and power purchase contracts, ... that were being collected in commission-approved rates on December 20, 1995, and that may become uneconomic as a result of a competitive generation market, ..."
>
> ***
>
> "These uneconomic costs...shall be recovered from all customers...on a nonbypassable basis and shall:
>
> ***
>
> "(b) Be based on a calculation mechanism that nets the negative value of all above market utility-owned generation-related assets against the positive value of all below market utility-owned generation related assets."

PG&E contends that the revenue requirement treatment for must-run hydroelectric and geothermal units must meet the "netting" test of Section 367(b). According to PG&E,

> "... ORA has proposed a CTC [competition transition cost] calculation mechanism that does <u>not</u> net the negative value of above-market utility-owned generation assets against the positive value of below-market utility-owned assets. Therefore, ORA's recommended treatment of must-run facilities is in clear violation of Section 367(b) and must be rejected." (PG&E Opening Brief, p. 14.)

The required netting applies to the negative value and the positive value of various utility-owned generation-related assets, not to costs reflected in revenue requirements. Section 367(b) does not proscribe ORA's proposal for the treatment of revenue requirements. PG&E's argument is without merit.

4.1.4 Cost Recovery Opportunity

PG&E's proposal for TCBA treatment of must-run gains and losses for full cost recovery ISO contracts has the virtue of simplicity. Moreover, PG&E is correct when it argues that its proposed TCBA treatment "ensures that PG&E just recovers its costs of providing must-run services." (PG&E Opening Brief, p. 11.) The problem is that this guarantee of cost recovery would exist in addition to the opportunity for cost recovery that PG&E enjoys through full cost recovery ISO contracts. PG&E would be able to effectively classify must-run losses as transition costs.

The cost recovery assurance requested by PG&E provides ratepayers and competitors with too little assurance that PG&E will undertake all reasonable means to negotiate adequate cost recovery for the services that it provides to the ISO. With a second opportunity for cost recovery through the TCBA mechanism, and the reduced incentive to negotiate adequate cost recovery from the ISO in the first place, there is too much potential for a competitive advantage and other distortion in the market for must-run services.[5] We find PG&E's proposal to be deficient in this regard, and the advantage of relative simplicity does not justify its adoption.

By contrast, ORA's proposal offers a reasonable balance of risk and rewards such that its relative complexity is justified. It offers an incentive to negotiate reasonable cost recovery terms that is lacking in PG&E's proposal. ORA's recommendations provide that PG&E will retain profits or incur the losses associated with the difference between actual expenditures and authorized levels. In effect, they provide the equivalent of traditional cost-of-service treatment with respect to retention of profits. We are persuaded that ORA's approach provides reasonable cost recovery opportunity as long as PG&E negotiates and operates to the best of its ability. It is reasonable to assign the risk of cost recovery under full cost must-run contracts to the utility.

4.1.5 Related Must-Run Issues

While PG&E opposes ORA's overall approach to the treatment of must-run revenue requirements, it has also proposed certain modifications to ORA's specific recommendations. For example, PG&E proposes that a simple notice would be sufficient when a unit switches from a full cost recovery contract to a competitive one. ORA counters that neither FERC nor the ISO would review the impact of such a change

---

[5] The beneficiaries of below-cost must-run services would be the recipients of those services. As ORA noted (in Exhibit 7, p. 9), to the extent these recipients are not the same as PG&E customers, cost-shifting occurs.

on transition cost recovery, so the more comprehensive notice and review that it recommends is appropriate. ORA's proposal will provide an opportunity for the Commission to consider the impact of the change of contract and take appropriate action. We adopt ORA's proposed notice requirement.

PG&E prefers a multi-year assessment of debits and credits over the calendar year approach favored by ORA. PG&E contends that since ISO contracts are expected to be for one-year terms, it will not be able to negotiate terms providing for offsetting prior-year revenues to offset future losses. PG&E gives the example of using such revenues to offset losses due to a dry hydro year. ORA asserts that the annual approach has the merits of conforming to the period of ISO contracts and reducing of ratemaking complexity. We believe that annual reconciliation as proposed by ORA is reasonable. We do not believe that the risk of a dry hydro year should be transferred to ratepayers in the manner proposed by PG&E.

PG&E prefers aggregating all must-run units into a single category rather than using unit-by-unit determinations. ORA points out that this would create an incentive to have competitive units on full cost recovery agreements. This would allow PG&E to inappropriately shield losses associated with individual units.

Knecht and Czahar have suggested allowing PG&E to retain a percentage of must-run profits to induce PG&E to enter into credit-back forms of contracts. We deny this proposal, as the merits of inducing PG&E to enter into Agreement B have not been demonstrated.

4.1.6 Conclusion

In its comments on the proposed decision, PG&E contends that the proposed treatment of must-run hydroelectric and geothermal revenue requirements is inconsistent with the Commission's treatment of hyroelectric and geothermal assets as set forth at pages 135-137 of D.97-11-074. However, pursuant to the September 9, 1997 *Administrative Law Judge's Ruling Clarifying Scope of Proceeding on Pacific Gas and Electric Company's (PG&E) Hyroelectric/Geothermal Revenue Requirement*, ORA's proposals for the revenue treatment of must-run hyroelectric and geothermal units were litigated in this proceeding. This is confirmed by Finding of Fact 82 of D.97-11-074, which states that "[c]ertain issues associated with must-run hyroelectric plants...will be considered in A.96-07-009 et al." The adopted treatment of hydroelectric and geothermal facilities in D.97-11-074 did not supersede the litigation of issues which that decision acknowledged was being addressed in this proceeding.

Based on the foregoing, we adopt the ORA recommendations, as set forth in Exhibit 7 and as summarized below, for the treatment of the revenue requirement and related procedural requirements for must-run hydroelectric and geothermal units:

- For units which come to be on a negotiated ISO agreement for full cost recovery, the associated revenue requirement would not be included in computing the TCBA balance.

- For each unit that operates under an ISO agreement that provides both for full cost recovery and a credit-back of revenue from the ISO to the utility (for example, proposed Agreement B), revenues credited to the utility would be retained by the utility, except that revenues in excess of the units' revenue requirement would be a general credit to the TCBA.

- Once a unit has switched from a competitive to a full cost recovery form of ISO contract, default ratemaking should provide that the revenue requirement is excluded from the TCBA indefinitely.

- Parties should be permitted to prospectively seek, by petition for modification in this docket, exclusion of a competitive unit's TCBA revenue requirement if that unit's revenue requirement exceeded revenues, such that the unit lost two percent or more over a calendar year. The Commission should determine whether such a unit should be excluded from revenue requirement.

- If a unit has switched from a full cost to a competitive contract form, the utility should be required to file a notice with the Commission. The utility should be required to include in that notice any request to include the revenue requirement of that unit in the TCBA revenue requirement.

4.2 Catastrophic Events Memorandum Account (CEMA)

D.97-08-056 dated August 1, 1997, issued in A.96-12-009 et al. (the unbundling proceeding), ordered PG&E, Edison, and San Diego Gas & Electric Company (SDG&E) not to enter into their respective CEMAs any costs related to generation after January 1, 1998. The Commission found that permitting utilities to recover generation costs in CEMA would provide a competitive advantage to utilities in generation markets. (D.97-08-056, Finding of Fact 14, p. 57.) In its August 19 prehearing conference statement, PG&E stated that notwithstanding D.97-08-056, it sought CEMA or similar cost recovery treatment for catastrophic events that occur after December 31, 1997. At the August 22, 1997 prehearing conference, the ALJ ruled that in light of procedural uncertainty, PG&E would be permitted to offer testimony on its CEMA proposal. PG&E's September 8, 1997 prepared testimony included a proposal for CEMA treatment, which other parties addressed in rebuttal testimony served on September 15, 1997.

By letter dated September 16, 1997, PG&E advised the ALJ and the parties that on September 8, 1997 it filed a petition for modification of D.97-08-056, requesting continuation of the CEMA. PG&E further advised that it had recently become aware of the applicability of Section 454.9.[4] PG&E noted that Section 454.9 was not discussed in the testimony or briefs leading to the issuance of D.97-08-056 or in the decision itself. Based on its discovery of Section 454.9, PG&E took the position that the dispute over its CEMA proposal was moot.

PG&E did not raise the argument that Section 454.9 renders the dispute moot until after the service of prepared testimony and prepared rebuttal testimony. At the

---

[4] Section 454.9(a) provides that the Commission shall authorize utilities to establish catastrophic event memorandum accounts to record the costs of service restoration; repairing, replacing, or restoring damaged facilities; and complying with government agency orders in connection with disaster declared by competent state or federal authorities. Section 454.9(b) provides that the costs, including capital costs, recorded in the CEMAs shall be recoverable in rates subject to request of the utility, a Commission finding of reasonableness, and Commission approval.

outset of hearings on September 18, 1997, the ALJ ruled that the testimony on CEMA proposals would be heard notwithstanding a risk of duplication of consideration of the issue in multiple forums. On September 25, 1997, two days after the completion of hearings, PG&E, Edison, and SDG&E filed a petition for modification of D.97-08-056, requesting that utilities be allowed to establish CEMAs pursuant to Section 454.9.

D.97-08-056 has already addressed the applicability of CEMA treatment for generation, and by virtue of the September 25, 1997 petition for modification of D.97-08-056, the CEMA-related issues affecting generation facilities of Edison and SDG&E as well as PG&E are being resolved in the unbundling proceeding.[7] ORA argues that this proceeding should not be used to carve out an exception for hydroelectric and geothermal facilities for one utility. We concur. We are not persuaded to adopt a separate resolution of CEMA-related issues that would apply to PG&E's hydroelectric and geothermal facilities only. As ORA points out, the risk of duplication of issues in multiple forums has been realized. Although it may have been appropriate under the circumstances of September 18, 1997 to receive testimony on the CEMA issues, we find the issues belong in the unbundling proceeding. We note that both the issue of recording of CEMA expenses under Section 454.9(a) and the issue of reasonable cost recovery under Section 454.9(b) are before the Commission by virtue of the petition and the responses in the unbundling proceeding. We therefore do not consider the post-1997 event CEMA issues further in this limited-scope proceeding.

There is general agreement that PG&E should be allowed to continue CEMA procedures for pre-1998 events. Knecht and Czahar propose one exception. They contend that the use of a gross return which includes an allowance for income taxes should be prohibited. Again, we find no reason why this proposal should be applied to hydroelectric and geothermal generation facilities but not to other areas where PG&E might enter amounts in CEMA. We conclude that this is not the appropriate

---

[7] D.97-11-073 disposed of PG&E's September 8 petition for modification and deferred resolution of CEMA isuses to a later decision in the unbundling proceeding.

proceeding for this issue. However, when PG&E seeks recovery of costs related to pre-1998 events, we will closely examine all costs asserted to be eligible for recovery.

4.3 Post-1997 Capital Additions

D.97-09-048 provides that the reasonableness of non-nuclear capital additions put into service in 1996 and 1997 will be reviewed on an after-the-fact basis, and that post-1997 capital additions will be subject to a "market control" approach. The market control approach provides for recovery of capital additions costs through market revenues. Notwithstanding this decision, PG&E requests inclusion of the cost of post-1997 capital additions for hydroelectric and geothermal facilities in the approved revenue requirement. PG&E recommends reconsideration of the market control approach as it applies to its hydroelectric and geothermal revenue requirement. PG&E notes that D.97-09-048 provides that:

> "Until further notice, we will include hydroelectric and geothermal facilities under this approach. We may reconsider the inclusion of these facilities for PG&E and [Edison] as we explore the performance-based ratemaking (PBR) proposals pending in application (A.) 96-07-009 and A.96-07-018.)"

As recommended by ORA, we decline to make any findings on capital additions. We defer to the market control approach that we recently adopted in D.97-09-048. Although D.97-09-048 left the door open for reconsideration in the event we consider PBR, PBR proposals have been explicitly excluded from this sub-phase of the proceeding. We note that PG&E has filed an application for rehearing of D.97-09-048. There is no basis for reconsidering application of the market control approach for hydroelectric or geothermal units in this docket.

In its comments on the proposed decision, PG&E asserts that the Commission will need to address the issue of how post-1997 capital additions will be reflected in market valuation. As PG&E has suggested, it can address this issue in the market valuation application to be filed pursuant to D.97-11-074, Ordering Pararaph 17.

4.4 Reasonableness Review

In lieu of a general provision for traditional reasonableness reviews of its hydroelectric and geothermal operations, PG&E proposes reliance upon a combination of market forces, ISO and FERC supervision for reliability and market power, monthly and annual reporting of fuel and energy costs, traditional reasonableness review for water purchases and administration of steam contracts, and Commission investigations when deemed necessary.

ORA proposes that we make provision for reasonableness reviews pertaining to the hydroelectric and geothermal revenue requirement until market valuation is completed. Specifically, PG&E would be required to file testimony showing the reasonableness of expenses for geothermal operations, purchased water for power production, and Helms operations. ORA would exclude from reasonableness review units which are under must-run contracts and excluded from the hydroelectric and geothermal revenue requirement that is accorded balancing account treatment. Weil, Knecht, and Czahar support ORA's position on reasonableness reviews. Weil also proposes that reasonableness reviews cover capital-related costs.

In D.96-12-088 (the updated Roadmap decision), the Commission provided that as long as fuel procurement practices are undertaken in a regulated regime, reasonableness reviews would be the *quid pro quo* of balancing account treatment. (D.96-12-088, p. 23.) The Commission went on to state that it was hopeful that once the PX is functioning, market incentives would begin to take the place of reasonableness reviews. (*Id.*) The Commission also noted that some new form of review and verification would be necessary to verify the accuracy and fairness of recovery of PX costs. (*Id.*) ORA relies on the former holding to support its position. To support its position, PG&E emphasizes the Commission's hope of moving away from reasonableness reviews and its provision for a new form of review.

PG&E notes that, by law, the PX must begin operations at the beginning of 1998. PG&E believes that the new form of review anticipated by the Commission as a replacement for traditional reasonableness review should be implemented. PG&E contends that its proposal is consistent with this new form of review.

What PG&E fails to point out is that when the Commission issued D.96-12-088 and stated its hope to move away from traditional reasonableness reviews, it also anticipated adoption of PBR for generation. However, we are now using a cost-of-service approach for establishing PG&E's hydroelectric and geothermal revenue requirement that includes balancing account treatment of certain expenses through the TCBA. Also, while the Commission was hopeful that it could *begin* to move away from the traditional approach to reasonableness review once market incentives are in place, it did not simply provide for the elimination of reasonableness reviews on the date that the PX begins functioning.

The revenue requirement architecture that we approve today, including its provision for recorded cost ratemaking for capital costs, does not represent the approach we envisioned when we stated our hope to move away from this regulatory tool. Under the adopted proposal, ratepayers will effectively pay for PG&E's actual fuel costs. We continue to believe that reasonableness reviews are the *quid pro quo* of balancing account treatment, even if the balancing account in question has a new name or serves a somewhat different function. This principle applies to other forms of recorded cost ratemaking as well. Proposals that require the initiation of Commission investigations and assignment of the burden of proof to the Commission staff, as opposed to proposals which require the utility to demonstrate the reasonableness of its actions, do not represent a sufficient counter-balance to the overall risks associated with the adopted mechanism.

We adopt the proposals for comprehensive reasonableness reviews, including recorded capital-related costs other than post-1997 capital additions. However, we do not require PG&E to report separate data for each unit as initially proposed by ORA. We recognize that multiple units may be hydraulically linked, and that separate consideration of units with shared O&M expenses may require the resolution of complex allocation issues. Consistent with our provision for reasonableness reviews in

Ordering Paragraph 13 of D.97-10-057, such reviews will take place in PG&E's annual transition cost or revenue adjustment proceedings pursuant to Commission orders or rulings.

4.5 The El Dorado Project

PG&E's El Dorado hydroelectric plant was closed for several years in the early 1990's. It was reopened in 1996 after EID and PG&E signed an Asset Sale Agreement and an Operation and Maintenance Agreement, and EID, the prospective purchaser, had spent over $5 million on capital modifications to the plant to make it operational. The plant was severely damaged in the January 1997 storms, and it has not been producing power since then. On June 5, 1997 PG&E terminated the Asset Sale Agreement. On August 27, 1997 PG&E filed with the FERC a proposed schedule for a license surrender application for the El Dorado project. PG&E has notified parties that it does not intend to operate the project as a power facility in the future. In PG&E's 1996 GRC, the Commission approved $1.1 million in O&M expenses for the El Dorado project.

EID takes the position that under applicable regulatory principles and statutes, PG&E cannot recover costs for the El Dorado project since it is not used and useful and it has not been operating for more than nine months. EID recommends removal of the O&M expenses and related expenses from the 1998 revenue requirement. EID also recommends that an investigation be instituted to examine the effects of the El Dorado outage and resolve all related reasonableness issues in that proceeding.

PG&E recommends that expenses related to the El Dorado project be included in rates. PG&E contends that the project is operational from the FERC perspective because the license surrender application has not been acted upon. PG&E believes it is required to incur between $850,000 and $1.1 million in O&M expenses in 1998. PG&E also contends that under the three-year cycle of forecast test year ratemaking, the next opportunity for parties to address this expense is PG&E's 1999 GRC. PG&E argues that focusing on particular cost declines while not recognizing other cost increases is contrary to the very concept of test year ratemaking. Finally, PG&E argues that since the FERC has not accepted surrender of the license, regulatory costs that are driven by the FERC license are appropriately recoverable from ratepayers.

With certain exceptions, the general rule for test-year ratemaking cited by PG&E is correct. As we have stated,

> "We do not expect a utility to come running to the Commission for a rate adjustment each time its expenses may be more than anticipated in a given rate setting case. A utility is granted only the opportunity to make its anticipated rate of return, it is not guaranteed that return. Conversely, if a utility accomplishes a reduction in an anticipated expense that was found reasonable by the Commission for the purpose of setting rates, the Commission should not step in and order a refund unless such a reduction was anticipated. To do so would soon discourage utilities from searching for ways to cut costs and be contrary to the intent of Section 456." (*Re Pacific Power and Light Company* (1980) 4 CPUC 2d 544, 572.)

Among the exceptions to this rule are those established by the Legislature in Section 454.9 (CEMA) and Section 455.5. The latter statute provides that in the event of an outage of a major generation or production facility for nine or more consecutive months, the Commission may eliminate consideration of the value of the facility and may disallow any related expense. On November 19, 1997, we instituted an investigation (I.97-11-026) pursuant to Section 455.5 into the out-of-service status of the El Dorado project. Among other things, we ordered that all rates associated with the El Dorado project are subject to refund, and we directed PG&E to establish a memorandum account to track all associated costs. No further consideration of this issue is necessary in this proceeding.

4.6 Geothermal Decommissioning Expense

In PG&E's 1996 GRC the Commission approved geothermal decommissioning costs of $1.939 million. PG&E recommends that these costs be recovered through the TCBA for ease and efficiency of administration.

ORA takes the position that this is the proceeding designated by the Commission to determine hydroelectric and geothermal revenue requirements, and recommends that the geothermal decommissioning costs be included in the revenue requirement determined in this proceeding. ORA contends it is easier to include the amount in this proceeding rather than the transition cost proceeding. Enron, Weil, Knecht, and Czahar support ORA's recommendations.

As Weil explains, the nature of decommissioning costs favors ORA's position. We adopt ORA's recommendation.

4.7 Fossil Plant Memorandum Account

D.97-04-042 and D.97-07-037 have addressed a request by PG&E to establish an earnings allowance whereby it would retain earnings up to 150 basis points above its authorized rate of return for its merchant fossil plants. PG&E acknowledges that this sub-phase of the proceeding is limited to hydroelectric and geothermal generation issues, but it nevertheless recommends adoption of a memorandum account to track the 150 basis points amount for non-must-run fossil plant operations starting January 1, 1998, to ensure the possibility of recovery once the Commission determines the underlying issue. ORA and Weil oppose the proposed memorandum account.

As we noted in D.97-07-037, consideration of PBR/incentive mechanisms has been deferred indefinitely. (D.97-07-037, Footnote 2, p. 3.) The possibility of future consideration of such a mechanism for PG&E's non-must-run fossil generation does not warrant adoption of memorandum account treatment at this time. PG&E's request for a memorandum account is denied.

Findings of Fact

1. Establishing a hydroelectric/geothermal revenue requirement is necessary to determine the level of transition cost recovery by PG&E that will be reflected in the TCBA.

2. PG&E and ORA propose that the 1998 revenue requirement for conventional hydroelectric, Helms, and geothermal generation facilities be calculated as the sum of the capital-related revenue requirement using recorded capital costs, the expense revenue requirement using PG&E's 1996 GRC data, and actual fuel expense.

3. Assembling ratemaking elements from various proceedings is a reasonable alternative to full-scale litigation of all relevant revenue requirements which should save time and resources of parties and the Commission.

4. Compared to traditional cost-of-service ratemaking or PBR, recorded cost ratemaking reduces utility risk and tends to make management less concerned with controlling capital-related costs, and it is generally not consistent with PBR goals. However, under the mechanism adopted herein PG&E remains at risk for recovery of uneconomic generation costs by the end of the transition period, which should provide some incentive for efficient operations.

5. Overall, the revenue requirement mechanism adopted herein fairly balances ratepayer and shareholder risk and rewards.

6. The proposed net-of-inflation productivity adjustment to O&M and A&G expenses is intended as a means of accurately forecasting the 1998 expense revenue requirement.

7. There is insufficient justification or record support for a productivity adjustment to O&M and A&G expenses for 1998.

8. While it is premature to determine that PBR for PG&E's hydroelectric and geothermal generation should be pursued for the remainder of the transition period after 1998, we expect to obtain more information in the coming months that will allow a decision on whether to do so.

9. PG&E's 1999 GRC proceeding is the appropriate forum for exploring the use of forecast capital-related costs for 1999 in lieu of the recorded cost approach adopted today for 1998.

10. Including the revenue requirement of must-run units which rely upon the ISO for full cost recovery in the total revenue requirements that are debited monthly to the TCBA would misallocate risk between ratepayers and shareholders, and could inhibit competition for must-run services and cause unwarranted cost-shifting.

11. It has not been shown that PG&E will be unable to negotiate adequate cost recovery with the ISO for must-run services.

12. The rate freeze/transition cost recovery mechanism provides some incentive for PG&E to negotiate adequate cost recovery with the ISO for must-run services provided by hydroelectric and geothermal facilities, but its effectiveness is uncertain, and if PG&E is entitled to additional cost recovery through the TCBA mechanism, we cannot be assured that it will have sufficient incentive to negotiate adequate cost recovery terms with the ISO.

13. The required netting of the negative value and the positive value of various utility-owned generation-related assets under Section 367(b) does not proscribe ORA's proposals for the treatment of revenue requirements for must-run units.

14. ORA's proposals for the revenue requirement treatment of must-run units provide reasonable cost recovery opportunity as long as PG&E negotiates and operates to the best of its ability.

15. ORA's proposals for the revenue requirement treatment of must-run units provide an incentive to negotiate reasonable cost recovery terms that is lacking in PG&E's proposal, and provide a reasonable balance of risk and rewards.

16. Requiring notice when a unit switches from a full cost recovery contract to a competitive one will provide an opportunity for the Commission to consider the impact of the change of contract and take appropriate action.

17. Transferring the risk of a dry hydro year to ratepayers through a multi-year reconciliation of debits and credits, thereby offsetting losses in one year with gains in another year, is not necessary to provide an overall reasonable balancing of risks for must-run contracts.

18. Aggregating all must-run units into a single category rather than unit-by-unit determinations could allow PG&E to inappropriately shield losses associated with individual units.

19. While D.91-11-074 addressed the treatment of revenue requirement generally, the treatment of must-run hydroelectric and geothermal facilities is under consideration in this proceeding pursuant to the September 9, 1997 ALJ ruling on the scope of this proceeding.

20. Post-1997 event CEMA issues related to the generation facilities of Edison and SDG&E as well as PG&E remain at issue in the unbundling proceeding.

21. Establishing a separate set of catastrophic event cost recovery criteria that would only apply to PG&E's hydroelectric and geothermal generation facilities has not been justified.

22. PBR proposals have been explicitly excluded from this sub-phase of the proceeding, and there is no basis for reconsidering application of the market control approach for hydroelectric or geothermal units in this docket.

23. Our policy is that as long as fuel procurement practices are undertaken in a regulated regime, traditional reasonableness reviews are the *quid pro quo* of balancing account treatment, and it is reasonable to apply this policy to other recorded costs as well.

24. The revenue requirement architecture adopted herein does not represent the approach we envisioned when we stated our hope to move away from traditional reasonableness reviews.

25. Proposals that require the initiation of Commission investigations and assignment of the burden of proof to the Commission staff, as opposed to proposals which require the utility to demonstrate the reasonableness of its actions, do not represent a sufficient counter-balance to the overall risks associated with the adopted mechanism.

26. Multiple generating units may be hydraulically linked, and separate consideration of units with shared O&M expenses may require the resolution of complex allocation issues.

27. PG&E's El Dorado hydroelectric plant was severely damaged in the January 1997 storms, and it has not been producing power since then.

28. In PG&E's 1996 GRC, the Commission approved $1.1 million in O&M expenses for the El Dorado project.

29. With certain exceptions, under the three-year cycle of forecast test year ratemaking, the next opportunity for parties to address the ratemaking impact of the

El Dorado outage is PG&E's 1999 GRC. One of the exceptions is set forth in Section 455.5, which provides that in the event of an outage of a major generation or production facility for nine or more consecutive months, the Commission may eliminate consideration of the value of the facility and may disallow any related expense.

30. The Commission instituted an investigation of the El Dorado outage pursuant to Section 455.5 on November 19, 1997.

31. The geothermal decommissioning accrual of $1.939 million which was approved in PG&E's 1996 GRC is properly classified as part of the geothermal revenue requirement.

32. Consideration of PBR/incentive mechanisms has been deferred indefinitely, and the possibility of future consideration of such a mechanism for PG&E's non-must-run fossil generation does not warrant adoption of memorandum account to track earnings up to 150 basis points above its authorized rate of return for its merchant fossil plants.

Conclusions of Law

1. The proposed architecture for determining PG&E's hydroelectric/geothermal revenue requirement for 1998 as set forth in Exhibit 1 should be adopted.

2. The use of recorded capital-related costs as well as the rate of return proposal recommended by PG&E and ORA should be adopted for PG&E's 1998 hydroelectric and geothermal revenue requirement.

3. The PG&E/ORA proposal for establishing the expense revenue requirement should be adopted without a productivity adjustment for 1998.

4. The revenue requirement architecture adopted herein should be continued in effect through 2001, subject to further order of the Commission.

5. Upon review in PG&E's 1999 GRC, the revenue requirement architecture may be modified to use a forecast of capital-related costs for the post-1998 period unless the architecture will be replaced by PBR.

6. PG&E should submit a forecast of capital-related costs for hydroelectric and geothermal generation in its 1999 GRC.

7. ORA's proposal to exclude the revenue requirement associated with must-run units under full cost recovery contracts from the hydroelectric/geothermal revenue requirement considered in the TCBA and related proposals as set forth in Exhibit 7 should be adopted.

8. Post-1997 catastrophic event cost recovery issues should be considered generically in the unbundling proceeding.

9. The market control approach for capital additions adopted in D.97-09-048 should apply for PG&E's hydroelectric and geothermal facilities.

10. ORA's proposal for reasonableness reviews, amended to include review of recorded capital-related costs other than capital additions which are subject to the market control approach, should be adopted as part of the revenue requirement architecture adopted in this decision.

11. As the Commission has instituted an investigation of the El Dorado outage pursuant to Section 455.5 on November 19, 1997, this decision should not address issues related to the El Dorado outage.

12. Geothermal decommissioning costs should be included in the revenue requirement determined in this proceeding.

13. PG&E's request for a memorandum account track earnings up to 150 basis points above its authorized rate of return for its merchant fossil plants should be denied.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company's (PG&E) proposed mechanism for determining the 1998 revenue requirement for its hydroelectric (including Helms Pumped Storage) and geothermal generation facilities, as set forth in Exhibit 1, with the modifications discussed in the opinion and set forth in the foregoing findings and conclusions, is adopted. The mechanism will continue in effect until December 31, 2001

or until market valuation, whichever occurs first, unless it is discontinued, modified, or replaced before then by further order of the Commission.

2. PG&E shall modify its tariffs to implement the foregoing ordering paragraph by filing an advice letter within five days of the effective date of this order. The tariffs shall become effective no earlier than January 1, 1998 after they have been reviewed for compliance with this order by the Energy Division.

3. On May 1, 1998 PG&E shall submit a report to the Director of the Energy Division on its plans for, and the status of market valuation and divestiture of its hydroelectric and geothermal facilities, the status of must-run designations, and any other factors affecting the need for and appropriateness of a proceeding to consider PBR. PG&E shall serve copies of the report on parties to this prodeeding.

4. PG&E shall submit a forecast of the capital-related revenue requirement for its hydroelectric and geothermal generation facilities in its Test Year 1999 general rate case. PG&E shall submit the forecast according to the schedule established by the Assigned Commissioner and Administrative Law Judge in the general rate case.

5. Following receipt of PG&E's status report, the Director of the Energy Division will make recommendations to the Commission on whether to initiate a new proceeding, whether to direct PG&E to file a new PBR application, or other appropriate response. The Energy Division Director may provide for comments or convene workshops as he deems appropriate before making these recommendations.

This order is effective today.

Dated December 16, 1997, at San Francisco, California.

P. GREGORY CONLON
President
JESSIE J. KNIGHT, JR.
HENRY M. DUQUE
JOSIAH L. NEEPER
RICHARD A. BILAS
Commissioners

APPENDIX A

Page 1

List of Appearances

Applicants: William H. Edwards, Attorney at Law, for Pacific Gas and Electric Company; Munger, Tolles & Olson, by John D. Spiegel, Attorney at Law, and Carol B. Henningson and Manuel A. Abascal, Attorneys at Law, for Southern California Edison Company; Keith Melville and Joseph Vaccaro, Attorneys at Law, for San Diego Gas & Electric Company.

Interested Parties: Marron, Reid & Sheehy, by Emilio E. Varanini, III, Attorney at Law, for AES Pacific, Inc.; Ater, Wynne, Hewitt, Dodson & Skerritt, by Michael Alcantar, Attorney at Law, for Cogeneration Association of California; Edson & Modisette, by Carolyn A. Baker, Attorney at Law, for Chevron, U.S.A., and Various Interested Clients; Barbara R. Barkovich, for Barkovich & Yap, Inc.; Jackson, Tufts, Cole & Black, by William H. Booth, Attorney at Law, for California Large Energy Consumers Association; David Branchcomb, for Independent Energy Producers Association; Charles A. Braun, for Sacramento Municipal Utility District; Brady & Berliner, by Jonathan A. Bromson, Attorney at Law, for Watson Cogeneration Company; Maurice Brubaker, for Brubaker & Associates, Inc.; Ray Czahar, for Consumers for the Public Interest; Wright & Talisman, by Mike Day, Margaret Rostker, and Jim McTarnaghan, Attorneys at Law, for Enron Capital & Trade Resources; Sam De Frawi, for the Department of the Navy; Ater, Wynne, Hewitt, Dodson & Skerritt, by Evelyn Elsesser, Attorney at Law, for Energy Producers and Users Coalition; Goodin, MacBride, Squeri, Schlotz & Ritchie, by Diane Fellman and James D. Squeri, Attorneys at Law, for San Luis Obispo County and for Calpine Corporation; Robert Finkelstein, Attorney at Law, for Toward Utility Rate Normalization (TURN); Norman Furuta, Attorney at Law, for Department of Defense; Sutherland, Asbill & Brennan, by Catherine George, and Keith R. McCrea, Attorneys at Law, for California Manufacturers Association (CMA); Grueneich Resource Advocates, by Dian Grueneich, Attorney at Law, for Department of General Services and City and County of San Francisco; Ellison & Schneider, by Lynn Haug and Doug Kerner, Attorneys at Law, for Independent Energy Producers Association; Aldyn Hoekstra, for Cambridge Energy Research Associates; Adams & Broadwell, by Marc Joseph, Attorney at Law, and David Marcus, for Coalition of California Utility Employees; Carolyn Kehrein, for Energy Management Services; Ron Knecht, for Consumers for the Public Interest; Ronald Liebert, for California Farm Bureau Federation; William Marcus, for JBS Energy, Inc.; Melisssa Metzler, for Bakarat & Chamberlin; Sara Steck Myers, Attorney at Law, for Center for Energy Efficiency and Renewable Technologies and El Dorado Irrigation District; Noble Sprunger, Attorney at Law, for El Dorado Irrigation District; Judy Pau, for El Paso Energy Marketing Company; Paul M. Premo, for Foster Associates, Inc.; Reed V. Schmidt, for California City-County Street Light Association; Michael Shames, Attorney at Law, for Utility Consumer

APPENDIX A
Page 2

Action Network (UCAN); Goodin, MacBride, Squeri, Schlotz & Ritchie, by James Squeri, Attorney at Law, for California Retailers Association, and Diane Fellman, Attorney at Law, for Calpine Corporation; Downey, Brand, Seymour & Rohwer, by Philip A. Stohr and Dan L. Carroll, Attorneys at Law, for California Industrial Users; Robert Wallace, for Watson Cogeneration Company; Brady & Berliner, Tom Beach, for Watson Cogeneration Company; Wright and Talisman, by Michael Day and Catherine George, for Enron Capital & Trade Resources; William Petmecky, for Southern California Edison Company; and James Weil and Ronald L. Knecht, for themselves.

Intervenors: Morrison & Foerster, by Jerry Bloom, Attorney at Law, for California Cogeneration Council; Sheryl Carter, for Natural Resources Defense Council (NRDC); Caryn Hough, Attorney at Law, for California Energy Commission; Steven Patrick, Attorney at Law, for Southern California Gas Company; Sutherland, Asbill & Brennan, by Keith McCrea, Attorney at Law, for California Manufacturers Association; and Wright & Talisman, by Margaret A. Rostker, Attorney at Law, for Enron.

Division of Ratepayer Advocates: Irene K. Moosen, Jonathan A. Bromson, Attorneys at Law, and Scott Cauchois, Steve Linsey, Farzad Ghazzagh, Tom Thompson, and Maurice Monson.

(END OF APPENDIX A)