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Decision 97-09-048 September 3, 1997

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation.	Rulemaking 94-04-031 (Filed April 20, 1994)
Order Instituting Investigation on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation.	ORIGINAL Investigation 94-04-032 (Filed April 20, 1994)

INTERIM OPINION: CAPITAL ADDITIONS

Today's decision establishes the approach we will take to review past and future expenditures for non-nuclear capital additions put into service by Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company (PG&E, SCE, and SDG&E, respectively; referred to as "the utilities" collectively).[1] We will review capital additions put into service by the utilities in 1996 and 1997 on an after-the-fact (*ex post facto*) basis. For 1996 capital additions, the utilities should file applications requesting recovery in the competition transition charge (CTC) based upon 1996 *recorded* expenditures within thirty days from the effective date of this order. After recorded data is available for 1997, the utilities should follow this same process. We will consider the following criteria, among others, in determining the reasonableness of 1996 and 1997 recorded expenditures on a case-by-case basis:

(1) Consistency with recent capital budgets and expenditures for the respective power plants,

(2) The need for compliance with other regulatory requirements,

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[1] The ratemaking treatment for the costs of capital additions to nuclear facilities is addressed in Decision (D.) 96-01-011, D.96-04-059 (San Onofre); D.96-12-083 (Palo Verde) and D.97-05-088 (Diablo Canyon). Today's decision addresses non-nuclear capital additions only.

(3) Cost-effectiveness, and

(4) The impact of the capital addition on the unit's heat rate.

In their applications, the utilities should specifically demonstrate how their requests meet the above criteria. Utilities and other parties may propose additional evaluation criteria for Commission consideration. This *ex post facto* review will apply to all types of non-nuclear generating capital additions, including must-run and nonmust-run plants, whether they are gas-fired, geothermal, hydroelectric or solar.

For non-nuclear capital additions made in 1998 and beyond, we adopt the market control approach proposed by the Office of Ratepayer Advocates (ORA) and others, with certain modifications. Additions occurring after January 1, 1998 to must-run plants would be recovered from payments under the Independent System Operator's (ISO) reliability contracts or Power Exchange (PX) prices. As explained in this decision, the ISO is responsible for maintaining system reliability after January 1, 1998, and will designate units as must-run for that purpose. Given the responsibilities of the ISO, we believe that the ISO's determination of what facilities are required to maintain system reliability is a reasonable standard for the purpose of implementing Public Utilities (PU) Code § 367. 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 SCE as we explore the performance-based ratemaking (PBR) proposals pending in Application (A.) 96-07-009 and A.96-07-018.

We further find that the contract options currently proposed by the ISO afford utilities the opportunity to recover the costs of capital additions necessary to maintain system reliability. However, since these options are still in the proposal stage, we provide the opportunity for utilities to seek an *ex post facto* reasonableness review of capital addition expenditures for collection via the CTC, under limited circumstances. These circumstances are that the following four conditions must be met: (1) the capital additions were made to ISO designated must-run units and were necessary to continue operating the must-run unit during the transition (through December 31, 2001), 2) the capital additions were cost-effective compared to other options for maintaining plant operations through the transition *and* compared to other resources available to the ISO for system reliability, 3) the final ISO contracting options approved by the Federal Energy Regulatory Commission (FERC) did not include provisions that would allow utilities to negotiate recovery of these costs and 4) the costs of capital additions could not be recovered in market prices (e.g., through the sale of energy, voltage support, spinning reserves or other services).

We do not adopt ORA's supplemental proposal regarding market valuation of capital additions at this time. The issue of how market valuation of capital additions will occur is beyond the scope of this phase of the proceeding. This issue should be raised and addressed in the proceedings that will address utilities' applications for divestiture of specific plants, or in Phase 3 of the CTC proceeding, A.96-08-001 et al., which will address market valuation and appraisal issues.

PG&E and SCE both have proposed to divest themselves of significant portions of their fossil-fueled power plants. This divestiture is expected to occur in the near future. We will allow PG&E and SCE to utilize *ex post facto* review for capital additions occurring prior to divestiture of these plants, but only if this divestiture is completed prior to March 31, 1998. Recovery of capital additions for these plants under this mechanism will cease at the earlier of (1) when the plant is sold or (2) March 31, 1998 and should only apply to capital additions not otherwise recovered through the marketplace.

Background

By Joint Assigned Commissioners' Ruling (ACR) dated February 4, 1997, the Energy Division was directed to convene workshops to address standards for review of utility capital additions. The ACR set forth the following questions for comment:

(1) PU Code § 367 requires that the capital additions incurred after December 20, 1995, that are granted transition cost treatment must be reasonable and must be incurred to maintain the generating facilities through December 31, 2001. The Commission may wish to consider establishing as a standard that the utilities shall not be allowed to use additional capital investments to overhaul their generation assets so as to improve significantly their performance or heat rate. Is this a reasonable and effective standard to implement? If so, how should significant improvement be defined? What showing should be

required of the utilities to establish that such additions were necessary to maintain the facilities through 2001?

(2) Should the Commission use a different set of standards for review of capital additions made in 1996 and 1997 and capital additions performed during the transition period, 1998-2001.

(3) For capital additions performed during the transition period, should utilities be allowed some form of preapproval? If so, should the utilities seek preapproval on a case-by-case basis or should the Commission establish guidelines for preapproval?

(4) Should the Commission require that the utilities must demonstrate that the statistical relationship established over the last decade between each fossil plant's heat rate and forced outage rate, on the one hand, and the same plant's incremental investment on the other, did not change during the years of incremental investment. Is there a methodology or measure which can be easily calculated and readily verifiable that will reasonably approximate appropriate expenditures under PU Code § 367? If so, should this standard of review apply to 1996 and 1997 capital additions? Should it be required to be demonstrated on a prospective basis for capital additions made during the transition period?

(5) Should environmental requirements and joint service agreements be critical considerations in assessing the review requirement? How should these requirements be considered in an ex post review?

(6) The Commission has previously authorized revenue requirements for capital expenditures during the test year cycle in PG&E's and Edison's recent general rate cases. What are reasonable standards for ensuring that these amounts are spent appropriately and whether any capital expenditures have been deferred? Other considerations that might be addressed in future reasonableness reviews of capital additions are whether out-year investments have been accelerated into the transition period and whether the utility has spent more than previously budgeted on incremental capital investments during this period. Are these considerations appropriate standards for review? Should the Commission consider additional standards on potential anticompetitive impacts of additional capital investments?

(7) How do such criteria fit in with the approach that has been applied in traditional ratemaking? Given that SDG&E has a generation PBR mechanism, should any different criteria be applied to SDG&E?

PG&E, SCE, SDG&E, ORA, Independent Energy Producers (IEP), and California Industrial Users (CIU) filed comments on the ACR questions prior to the workshop. The Energy Division held a capital additions workshop on February 24 and 25, 1997. The following organizations were represented at the workshop: PG&E, SCE, SDG&E, ORA, IEP, Center for Energy Efficiency and Renewable Technology, JBS Energy Inc. for The Utility Reform Network (TURN), RMI, the California Energy Commission (CEC), California Large Energy Consumers Association, the California Manufacturers Association, El Paso Energy, and California Energy Markets. The Energy Division's Workshop Report was filed and served on March 19, 1997.

Comments on the Workshop Report were filed by PG&E, SCE, SDG&E, ORA, IEP, and jointly by CIU, Energy Producers and Users Coalition, and the Cogeneration Association of California (hereinafter "Joint Parties"). In its comments, ORA presented a supplemental proposal regarding the treatment of capital additions at the time of sale or market valuation. SCE, PG&E, SDG&E, and IEP filed replies to ORA's proposal. (See Administrative Law Judge's ruling dated May 29, 1997.)

Parties believe that the Workshop Report thoroughly and accurately described the discussions at the February 24-25 workshops, with very few exceptions. We commend Wade McCartney and Donna Wagoner of our Energy Division for their contributions to a well organized and informative report.

Positions of the Parties

During the course of the workshop, participating parties reached consensus on several issues related to 1996 and 1997 capital additions. However, parties could not agree on the approach to take for capital additions undertaken in 1998 and beyond. Below, we briefly summarize the areas of agreement and disagreement. Attachment 1 presents a side-by-side comparison of positions in response to the ACR questions.

1996 and 1997 Capital Additions

For capital additions put into service by the utilities in 1996 and 1997, the workshop participants agree that it is appropriate for the Commission to review these expenditures on an *ex post facto* basis. This approach would apply to all types of non-nuclear generating capital additions, including must-run and nonmust-run plants, whether they are gas-fired, geothermal, hydroelectric or solar.[2] Workshop participants also agree that the utilities would file applications requesting recovery for 1996 capital additions based on 1996 recorded expenditures, not on any forecasts . Workshop participants propose the following procedural schedule: Consistent with the direction given in the ACR, the utilities would file their applications 30 days after today's decision. After recorded data is available for 1997 (expected to be early 1998), the utilities would follow this same process. Workshop participants will continue discovery on 1996 additions, but agree to suspend discovery on 1997 capital additions until after applications are filed.

Workshop participants recommend that the Commission evaluate 1996 and 1997 projects on a case-by-case basis, with possibly some grouping of the costs of smaller cost projects as appropriate. However, workshop participants could not agree on a definition of reasonableness or on the specific review guidelines for 1996 and 1997 capital additions. In particular, they could not agree on whether environmental requirements and Joint Service Agreements should be critical considerations in assessing the review requirement. They also could not agree on whether or how to determine if capital expenditures authorized in previous general rate cases are deferred for recovery through the CTC.

Workshop participants recommend that the Commission not adopt review guidelines at this time other than "reasonable costs on a project by project basis." They also believe that trying to correlate the effects of incremental plant investment on plant heat and forced outage rates, as suggested in the ACR, would not be a useful expenditure of resources.

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[2] The costs of capital additions to nuclear facilities are the responsibility of utility shareholders, pursuant to the ratemaking mechanisms adopted in D.96-01-011, D.96-04-059 (San Onofre), D.96-12-083 (Palo Verde) and D.97-05-088 (Diablo Canyon).

Capital Additions In 1998 and Beyond

Consensus was not reached on standards of review for capital additions in 1998 and beyond. The utilities would prefer some presumptive cost categories and pre-approval for certain large projects with some *ex post facto* review. Joint Parties oppose any approach that designates cost categories as presumptively eligible for recovery in the CTC. They prefer that all costs undergo review on an *ex post facto* basis. ORA, TURN/JBS Energy Inc., and IEP would prefer to let the market decide—i.e., the ISO or the PX price—what is a reasonable capital addition and what is not. In a workshop statement, the CEC put forth a framework for assessing the eligibility of future capital additions in terms of market value verses book value. We discuss these approaches below.

Market Control Approach

Several of the intervenors (ORA, IEP, and TURN) support market control of capital additions that occur after January 1, 1998. Additions occurring after January 1, 1998 to a must-run plant would be recovered from payments under the ISO call contracts[3] or through the PX and the costs of additions occurring after January 1, 1998 to a nonmust-run plant would be entirely recovered from PX prices.

The intervenors who support the market control proposal believe that the cost of a capital addition that is reasonable will be fully recovered from either an ISO call contract or the PX price. They propose that if a utility is unable to recover the cost of an addition through the market, then the utility has the option of not making the addition and shutting the plant down. They argue that this approach best defines the reasonableness of capital additions in an increasingly competitive environment.

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[3] ISO Call (or Must-Run) Contracts refer to the eventual reliability contracts between the ISO and the utilities. Generally, these contracts will (1) give the ISO the right to dispatch the utilities' generating units and units under their control, (2) specify conditions of payment, (3) define the obligations of the utilities, (4) state dispute-resolution provisions, and (5) contain other terms and conditions. The boilerplate language in these contracts must be approved by FERC prior to actual use.

In its March 28, 1997 comments, ORA supplemented its market control proposal. ORA expects that many of the utilities' plants will be sold or market valued before the utilities will have an opportunity to fully recover the costs associated with capital additions. To address this discrete issue for nonmust-run plants, ORA recommends that the Commission separate out capital additions expenditures, allow utilities to recover depreciation and return through the ISO contract and PX prices, and provide the utilities with the opportunity to recover the lesser of the net book value or the incremental value of the capital addition when the plant is sold or market valued.

Under ORA's proposal, the incremental market value of the capital addition would be deducted from the sales price or market valuation before crediting the sales revenues or market valuation to the CTC balancing account. This approach is different from the utilities' proposed accounting method, which would add the full undepreciated portion of the capital addition to net book value before subtracting the market valuation or sales price.[4]

ORA argues that its recommended approach would increase market discipline on the utility's current costs by forcing utilities to recover their current costs of operating the plant through ISO and PX revenues. ORA also argues that this approach puts appropriate market pressure on utilities to limit capital additions to only those items which maintain or enhance the value of the plant by at least the cost of the addition. ORA believes that the utilities would be effectively shielded from the market discipline under their proposed CTC accounting approach.

SCE and PG&E object to ORA's supplemental proposal on both procedural and substantive grounds. PG&E argues that the issue of market valuation of

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[4] A numerical example is useful: Assume that the net book value of the plant without the capital addition is $90 million and its market valuation is $75 million. Assume further that the undepreciated portion of the capital addition at the time of sale/market valuation is $9 million. Under the utilities' CTC accounting approach, the calculation of revenues collected via CTC would be: $99 million (net book value of plant plus addition) less $75 million (market price) = $24 million. ORA would first establish a market valuation for the capital addition (assume it is

Footnote continued on next page

utility assets is beyond the scope of the capital additions proceeding. SCE objects to the introduction of this proposal after the capital additions workshop was held. Both PG&E and SCE argue that ORA's market valuation proposal is unworkable because it would require a market valuation both with and without a capital addition. In their view, it is difficult, if not impossible, to separate a plant from its various capital additions in market valuation.

IEP supports ORA's valuation proposal. While IEP believes it would impose some administrative burden, IEP argues that it is less burdensome than utility proposals, which call for annual administrative reviews and reasonableness determinations at an early date.

Preapproval Approach

The utilities believe that the market control approach is not consistent with the intent of PU Code § 367. They argue that PU Code § 367 provides for recovery of reasonable additions that might not be recoverable from the ISO call contracts or PX prices, and that the market approach precludes this option. The utilities prefer a flexible, non-mandatory, preapproval process. PG&E proposes a set of six cost categories that should be presumptively eligible for recovery in the CTC: (1) expenditures that ensure worker safety, (2) mandated regulatory or legal expenditures, (3) projects already underway which, if delayed or canceled, would significantly increase costs, (4) projects essential to maintaining the infrastructure of the facility, (5) projects necessary to maintain, restore or avoid a deterioration in performance in heat rate using industry-accepted practices and standards, and (6) projects necessary to maintain reliable and cost-effective plant operations through 2001.

SCE proposes a set of three cost categories that would be eligible for recovery as a transition cost: (1) asbestos removal, (2) projects undertaken to satisfy environmental regulations, and (3) maintenance projects costing less than $1,000,000.

$7 million), and establish the CTC costs as follows: $90 million (net book value of plant without the addition) less $68 million (the market value of the plant without the addition) = $22 million.

SDG&E proposed a $200,000 preapproval threshold. Projects over this amount would require prior Commission approval. Projects less than this amount would be made at the discretion of the utility. Applications for preapproval of major 1998 additions could accompany the applications for recovery of 1996 and 1997 capital additions, at the utility's discretion.

Market vs. Book Valuation Approach

At the workshop, the CEC proposed a framework that would classify capital additions into three types: Type 1 capital additions are those that add at least as much to market value as to book value. Type 2 capital additions are those that do not increase market value at least as much as book value, but preserve market value. The CEC maintains that Type 2 situations involve the type of capital improvements that Assembly Bill (AB) 1890 contemplates, i.e., those reasonable and necessary to maintain the plant through December 31, 2001. Type 3 capital additions are those that neither increase nor preserve market value. Type 3 situations would include plants that have no value as going concerns, i.e., these are not must-run and will not be otherwise competitive, and it will not be economic to make them competitive.

The CEC's proposed guidelines would require some proxy for market valuation prior to actual market valuation in order to allow utility decision-makers to gauge the cost-effectiveness of a proposed capital addition. SCE and others argue that this approach is impractical to implement.

Ex Post Facto Reasonableness Review

CIU argues that the same set of standards should apply to all capital additions made after December 20, 1995, irrespective of when those investments are made. CIU believes that PU Code § 367 intended for an *ex post facto* review of all such costs, and does not allow for preapprovals or presumptions of reasonableness. CIU would review capital additions in 1998 and beyond similar to the process for 1996 and 1997 described above. CIU argues that the standards articulated in the statute should be used for this review, i.e., such capital additions must be appropriate, reasonable, and necessary to maintain the plants through the end of 2001.

Limited Preapproval With Ex Post Facto Review

If the Commission rejects the market control approach described above, ORA, TURN, and IEP would support a limited preapproval process and an *ex post facto* review, where the utility could: 1) seek preapproval of large capital projects (which would be subject to a limited reasonableness review of construction management after costs are recorded), or 2) seek review of 1998 and beyond capital additions on an *ex post facto*, recorded basis only, similar to the process for 1996-1997. IEP makes it clear in its written comments that this type of limited recovery should be available only to must-run units.

In the event of a preapproval process, ORA proposed the following threshold dollar amounts at the workshop: PG&E—$1 million; SDG&E—$200,000; SCE—$500,000. TURN holds that preapproval should be reserved for very large expenditures in the $5 million range and beyond.

Discussion

PU Code § 367 was added by AB 1890 and states, 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, including but not limited to, restructurings, renegotiations or terminations thereof approved by the commission, 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, in that these costs may not be recoverable in market prices in a competitive market, *and appropriate costs incurred after December 20, 1995, for capital additions to generating facilities existing as of December 20, 1995, that the commission determines are reasonable and should be recovered, provided that these additions are necessary to maintain the facilities through December 31, 2001*. These uneconomic costs shall be recovered from all customers on a nonbypassable basis and shall:
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> "c) Be limited in the case of utility-owned fossil generation to the uneconomic portion of the net book value of the fossil capital investment existing as of January 1, 1998, *and appropriate costs incurred after December 20, 1995 for capital additions to generating facilities existing as of December 20, 1995, that the commission determines are reasonable and should be recovered,*

provided that the additions are necessary to maintain such facilities through December 31, 2001." (Emphasis added.)

The utilities argue that PU Code § 367 precludes this Commission from considering the market control approach for capital additions in 1998 and beyond. We do not agree. Nothing in the statute precludes us from determining that the appropriate and reasonable level of costs necessary to maintain utility facilities after 1998 is that level determined via ISO and PX contracting and pricing arrangements. The utilities' assertions that the statute affords them an opportunity to recover costs in excess of that level is not supported by the plain language of the statute. While the statute specifically refers to costs that are not recoverable "in market prices in a competitive environment" with respect to costs currently in rates, it does not similarly define what should be recovered in CTC for capital addition costs incurred after December 20, 1995.

Instead, the language refers to these capital addition costs in terms of them being "appropriate" and "reasonable," provided that they are "necessary to maintain the facilities through December 31, 2001." The statute does not define the terms "appropriate costs," "reasonable" or "necessary to maintain," but leaves it to the Commission to make this determination. Hence, the plain reading of the statute gives us discretion to establish what constitutes appropriate costs and reasonableness in implementing PU Code § 367. Consistent with statutory construction principles, we rely on the plain reading of the statute in determining the Legislature's intent.[5]

For similar reasons, we reject CIU's arguments that the statute precludes any approach other than an *ex post facto* review. While CIU might prefer that the Commission determines reasonableness after conducting evidentiary hearings in an after-the-fact reasonableness review, nothing in the statute precludes this Commission from determining reasonableness in an alternative manner, e.g., by considering applications for preapprovals or by applying market control standards.

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[5] For a discussion of statutory construction principles, see D.97-02-014, mimeo., pp. 41-46.

In sum, we believe that the Legislature has given us latitude to adopt one or a combination of approaches for determining the reasonableness of transition cost recovery for capital additions. In doing so, we keep foremost in our minds the objective of creating a level playing field for all market participants during the transition to a fully competitive electric services industry. How we handle the issue of capital additions is a critical aspect of creating this level playing field. We do not wish to establish standards of reasonableness that afford utilities an unfair advantage in the market, particularly at ratepayers' expense. At the same time, we wish to encourage utilities to make cost-effective investments that will maintain the reliability of the electric system. As intended by PU Code § 367, utilities should have the opportunity to recover the costs of those investments during the transition period.

In considering options for achieving the objectives stated above, we must first define what utility facilities are necessary to maintain the reliability of the electric system. We note that the ISO assumes responsibility for operating the state's transmission system in the restructured industry environment. Among other things, the ISO is responsible for scheduling the dispatch of power from all sources, balancing load on a real-time basis, managing transmission congestion and maintaining system reliability. Plants that the ISO determines are necessary to maintain the reliability of the system are deemed by the ISO as must-run. Given the responsibilities of the ISO, we believe that the ISO's determination of what facilities are required to maintain system reliability is a reasonable standard for the purpose of implementing PU Code § 367. Accordingly, only those of the utility plants designated as must-run by the ISO will be eligible for recovery of capital additions after January 1, 1998.

Having established the standard for determining which facilities are eligible for capital additions under PU Code § 367, we turn now to our standard of reasonableness for the costs of capital additions made to these facilities. As noted above, the ISO is uniquely responsible for evaluating the relative costs and reliability benefits of all must-run units, and for negotiating appropriate reliability contracts with the owners of those facilities. On March 31, 1997, the ISO forwarded to FERC its proposal for reliability contracts that affords utilities, as well as nonutility providers, the opportunity to recover the costs of capital additions to must-run plants. In fulfilling our obligation under PU Code § 367, we believe that it is entirely appropriate to take market developments, such as the ISO's offering of reliability contracts, into account.

To summarize, the ISO proposes three types of reliability contracts, identified as Agreements A, B, and C. Agreement A assumes that the plant is economic and the ISO simply purchases needed resources at market prices. The owner can sell additional resources over and above the needs of the ISO (e.g., spinning reserves, voltage support, energy) into the PX. Agreement B provides for negotiated terms whereby the owner may have the right to collect revenues above what it might otherwise get above a market-based rate. In particular, Agreement B provides for a fixed cost payment and operating cost payment up to 100% of the cost of providing the needed must-run services to the ISO. Agreement B allows the plant to operate during hours when not needed by the ISO, but credits most of the profits from such operations to the fixed cost component. Agreement C is a cost-of-service contract for uneconomic units that must run for reliability reasons and are not likely to run during other hours. The units under this agreement are prohibited from supplying power during hours when the ISO does not need them.

The ISO may terminate these contracts upon 90 days' notice; however, should the ISO exercise this option, it is required under Agreements B and C to pay back the owner for "undepreciated and unrecovered costs previously agreed to be paid by the ISO for capital improvements made to the facility." Moreover, if the plant owner closes the facility because it becomes uneconomic or otherwise impractical to run, the ISO is similarly obligated to pay back the owner for the unrecovered costs of capital additions. The agreements set forth procedures by which the owner may request the ISO to preapprove of capital additions, and the grounds under which the ISO may object to such requests. The agreements contain dispute resolution procedures should there be any dispute between the ISO and plant owner over the need for capital additions or the need to shut down the facility. (See Phase II Filing of the California Independent System Operator Corporation before FERC; Docket Nos. EC96-19-001 and ER96-1663-001. ISO

Tariff Sheet No. 477-479, 491-498; 554-556, 566-573.) This contract language is appended as Attachment 2.

In its response to ORA's supplemental proposal, PG&E makes the following assertions concerning the ISO contract options:

> "ORA's comments are based on the assumption that 1) current depreciation and return for necessary capital additions will be recovered through the ISO contract; and 2) when the contract is terminated, the ISO will pay the generator any undepreciated balance for necessary capital additions. In reality, the must-run contract, as submitted to FERC consists of three agreements, identified as A, B, and C. All must-run plants must begin operation under Agreement A. They must remain under Agreement A for at least 90 days, and it is not clear exactly how difficult it will be for the plant operator to get permission to move from Agreement A after the 90 days. Agreement A does <u>not</u> assure recovery of necessary capital additions....
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> "If a generating plant is able to move to Agreement B or C, it would be able to recover the current depreciation and return for capital additions while the contract is in force, but ORA's second point would still not be accurate. If the contract was terminated, the generation owner would be able to recover the undepreciated portion of capital additions *only* if the generating plant was permanently retired from generation service."

We do not concur with PG&E's characterization of the contracts. Even if every unit were signed up under Agreement A, the utility may request a transfer to B or C in 90 days after contract signing. Our reading of the Agreement indicates that switching from Agreement A to B or C would be quite perfunctory, provided that the ISO needs the plant for reliability purposes. The ISO is required to respond to the utility's request within 30 days. If the plant is needed for reliability purposes, the ISO will simply make the switch from Agreement A to Agreement B or C.[6] If the ISO does not need the plant for reliability purposes, it will deny the request and the must-run obligations of that unit will correspondingly cease. It does not follow that the capital recovery provisions

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[6] If the utility has also proposed modifications to Agreement B, the ISO may respond with proposed amendments and a short (90 day) negotiation process would begin.

of the ISO contracts are insufficient just because the ISO may not be receptive to paying above-market prices for all generating units.

We also do not agree with PG&E's characterization of the provisions under Agreements B and C for recovery of capital addition costs. As discussed above, these agreements require that the ISO pay the owner for all unrecovered capital addition costs if 1) the ISO terminates the agreement or 2) the plant becomes uneconomic or impractical to run. Under the latter condition, the owner is required to reimburse the ISO for any such payments *if* the owner brings the unit back to market within three years. (See Attachment 2.) This provision is clearly intended to prevent gaming situations where the plant owner shuts down the facility and recovers the undepreciated costs of capital additions from the ISO, only to bring the plant back into the market shortly thereafter. There are no reimbursement provisions under the first condition.

In sum, recovery of capital addition costs is provided for under Agreements B and C under the following situations: 1) when the plant continues to operate under the agreement, 2) when it is permanently retired, or 3) when it is reopened as a generating facility at least three years after it has been found uneconomic and shut down. PG&E's assertion that a plant owner must permanently retire the unit in order to get recovery for capital additions is simply not supported by the contract language.

We believe that the contracting options offered by the ISO afford utilities the opportunity to recover the costs of capital additions needed to maintain system reliability. It would be entirely inappropriate, in our view, to establish a duplicate procedure whereby utilities could recover the costs of capital additions in a separate forum before this Commission. To do so would not only be inefficient from a regulatory perspective, but could give utilities an unfair competitive advantage over other providers of must-run units and skew the real economic options facing the ISO. No persuasive argument has been advanced for providing greater assurance for recovery of such costs than will be provided by the ISO, which is responsible for assuring reliable operation of the system while encouraging development of a competitive market.

Establishing a process whereby the ISO's determination of need and cost-effectiveness is the standard of reasonableness has clear advantages over the other approaches proposed by parties. First, this market control approach best achieves our objective of creating a level playing field by placing utility must-run units, nonutility must-run units and transmission projects all on the same footing. In contrast, all of the other recommended approaches (i.e., case-by-case preapprovals, *ex post facto* reasonableness reviews, market v. book valuations) would create a review process for utility-owned units in isolation from other resource options. Further, by requiring that the utilities deal with the ISO on equal footing with other service providers, the market control approach also creates a powerful incentive for the utility owner to consider only those additions that are cost-effective from the perspective of total system reliability. Moreover, it places the responsibility for evaluating the relative benefits and costs associated with capital additions squarely on the entity responsible for system reliability.

In addition, as ORA points out, the cost of upgrades under the market control approach would be recovered from all users of the transmission system, not merely the customers of the local utility which owns the unit. It would also conserve Commission, utility and intervenor resources that would otherwise be required to process applications for preapprovals or *ex post facto* reasonableness reviews.

We adopt the proposed market control approach with some refinements, however, in view of the fact that the ISO contracts described above are currently in the proposal stage, and subject to FERC approval. These contracts could be significantly modified during the FERC review process and, depending on the nature of the modifications, we may no longer be satisfied that the ISO contracting options provide utilities a reasonable opportunity to recover the costs of additions to must-run plants.

Therefore, we will afford utilities the opportunity to propose CTC recovery of the costs of additions to non-nuclear must-run plants in the limited circumstances where cost-effective capital additions to utility must-run plants cannot be recovered via the ISO contracting process because negotiating options or cost recovery provisions are excluded from the final ISO contracts. We will review such requests in *ex post facto* reasonableness reviews.

In its application for a finding of reasonableness under those limited circumstances, the utility would need to demonstrate the following four conditions: 1) the capital additions were made to ISO designated must-run units with ISO approval and were necessary to continue operating the must-run unit during the transition (through December 31, 2001), 2) the capital additions were cost-effective compared to other options for maintaining plant operations through the transition *and* compared to other resources available to the ISO for system reliability, 3) the ISO contracting options approved by FERC did not include provisions that would allow utilities to negotiate recovery of these costs and 4) the costs of capital additions could not be recovered in market prices (e.g., through the sale of energy, voltage support, spinning reserves or other services).

We also do not adopt ORA's supplemental proposal regarding market valuation at this time. We agree with PG&E that the issue of how market valuation of capital additions will occur is beyond the scope of this phase of the proceeding. This issue should be raised and addressed in the proceedings that will address utilities' applications for divestiture of specific plants, or in Phase 3 of the CTC proceeding, A.96-08-001 et al., which will address market valuation and appraisal issues.

While we believe that the market control approach, as modified above, best meets our policy goals and the Legislative intent in enacting PU Code § 367, we recognize that it is impractical to apply this approach to capital additions undertaken in 1996 and 1997. For one thing, all of these additions will be completed or under construction before the ISO and PX are operating. In fact, almost all of 1996 capital additions were completed or under construction at the time PU Code § 367 was enacted. We agree with the utilities and others that a different approach needs to be taken for capital additions made in 1996 and 1997, from those made in 1998 and beyond. An *ex post facto* review of these expenditures, as recommended by workshop participants, is a reasonable approach given the circumstances.

For 1996 capital additions to non-nuclear generating plant, the utilities should file applications requesting recovery via the CTC based upon 1996 recorded expenditures. These applications should be filed and served on the service list in this proceeding within thirty days from the effective date of this order. After recorded data is available for 1997, the utilities should follow this same process. We will consider the following criteria, *among others*, in determining the reasonableness of 1996 and 1997 recorded expenditures on a case-by-case basis:[7]

(1) Consistency with recent capital budgets and expenditures for respective power plants,

(2) The need for compliance with other regulatory requirements,

(3) Cost-effectiveness, and

(4) The impact of the capital addition on the unit's heat rate and output.

In their applications, the utilities should specifically demonstrate how their requests meet the above criteria. Utilities and other parties may propose additional evaluation criteria for Commission consideration. As recommended by the workshop participants, we will not require that utilities demonstrate any statistical relationship between a fossil plant's heat and forced outage rates on the one hand, and a plant's incremental investment on the other. We agree with workshop participants that demonstrating this type of statistical relationship is difficult because there are other relevant factors that influence plant operation. In addressing criterion (4) above, the utilities and other interested parties may describe the impact of the capital addition on the unit's heat rate and output in an alternative manner.

We will allow PG&E and SCE to utilize the same criteria above for capital additions occurring in 1988 for those fossil-fueled plants that will be divested prior to March 31, 1998. It does not make sense to conduct a market valuation approach for these plants for a period of less than three months. It makes administrative sense

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[7] Some grouping of costs of smaller cost projects may be appropriate for this case-by-case review.

instead to conduct our review of these plants as part of our review of 1996 and 1997 capital additions for these plants and to use the same review criteria. For those plants that the utility has not divested by March 31, 1998, all capital additions occurring in 1998 must be recovered through market mechanisms.

The workshop report raised the issue of how to treat capital additions for hydroelectric and geothermal units in 1998 and beyond, since these units may be subject to PBR mechanisms. If they are, ORA suggests that the Commission consider reviewing the reasonableness of capital additions to these plants in the process of establishing the PBR base-year revenue requirement. In the alternative, ORA recommends that the upcoming PG&E general rate case might be an appropriate forum for reviewing capital additions made to PG&E's hydroelectric and geothermal units. (ORA Comments, page 10.)

As ORA points out, the procedural status of the generation PBR proceedings for SCE and PG&E is currently uncertain.[8] By Joint Ruling dated June 25, 1997, the assigned Commissioner and Administrative Law Judge determined that the various proposals for generation PBR should not go forward at this time. Even if these proceedings are not deferred indefinitely, it is unclear that capital additions to geothermal and hydroelectric units in 1998 and beyond should be subject to PBR, rather than the modified market control approach we adopt today. Until further notice, capital additions to these plants in 1998 and beyond will be subject to the modified market control approach discussed above for other non-nuclear plants. As discussed above, recorded expenditures for 1996 and 1997 additions to geothermal and hydoelectric units should be included in the utilities' applications for *ex post facto* review.

[8] The Commission has granted SDG&E's request to withdraw its PBR application, so the only applications pending are for SCE (A.96-07-009) and PG&E (A.96-07-018).

Findings of Fact

1. The treatment of cost recovery for utility capital additions is a critical aspect of creating a level playing field for all market participants during the transition to a fully competitive electric services industry.

2. It is appropriate and reasonable to take market developments into account in fulfilling our obligations under PU Code § 367.

3. Utilities should have the opportunity to recover the costs of cost-effective capital additions that will maintain the reliability of the electric system without obtaining an unfair advantage in the market, particularly at ratepayers' expense.

4. As of January 1, 1998, the ISO assumes responsibility for operating the state's transmission system in the restructured industry environment. Among other things, the ISO is responsible for scheduling the dispatch of power from all sources, balancing load on a real-time basis, managing transmission congestion and maintaining system reliability.

5. Plants that the ISO determines are necessary to maintain the reliability of the system are deemed by the ISO as must-run.

6. As of January 1, 1998, the ISO will be responsible for evaluating the relative costs and reliability benefits of all must-run units and for negotiating appropriate reliability contracts with the owners of those facilities.

7. The ISO's proposed reliability contracts, as submitted to the FERC on March 31, 1997, afford utilities the opportunity to recover the costs of capital additions that are necessary to maintain system reliability.

8. Establishing a duplicate procedure, whereby utilities could recover the costs of capital additions in a separate forum before this Commission, would be inefficient from a regulatory perspective, could give utilities an unfair competitive advantage over other providers of must-run units, and could skew the real economic options facing the ISO.

9. The market control approach best achieves our objective of creating a level playing field by placing utility must-run units, nonutility must-run units and transmission projects all on the same footing.

10. All of the other recommended approaches (i.e., case-by-case preapprovals, *ex post facto* reasonableness reviews, market v. book valuations) would create a review process for utility-owned units in isolation from other resource options.

11. By requiring that the utilities deal with the ISO on equal footing with other service providers, the market control approach also creates a powerful incentive for the utility owner to consider only those additions that are cost-effective from the perspective of total system reliability.

12. The market control approach is the only proposal that places the responsibility for evaluating the relative benefits and costs associated with capital additions squarely on the entity responsible for system reliability.

13. Under the market control approach, the cost of upgrades would be recovered from all users of the transmission system, not merely the customers of the local utility that owns the unit.

14. The market control approach would conserve Commission, utility and intervenor resources that would otherwise be required to process applications for preapprovals or *ex post facto* reasonableness reviews.

15. The ISO's proposed reliability contracts could be significantly modified during the FERC review process and, depending on the nature of the modifications, we may no longer be satisfied that these contracting options provide utilities a reasonable opportunity to recover the costs of additions necessary to maintain system reliability.

16. ORA's supplemental proposal on market valuation of capital additions is beyond the scope of this phase of the proceeding.

17. Workshop participants agree that it is impractical to apply the market control approach to capital additions undertaken in 1996 and 1997. They recommend that the Commission undertake an *ex post facto* reasonableness of 1996 and 1997 recorded expenditures on capital additions. This review would apply to all non-nuclear facilities, including hydroelectric and geothermal, must-run and nonmust-run units.

18. Because there are many relevant factors that influence plant operations, it is very difficult to demonstrate a statistical relationship between a fossil plant's heat and forced outage on the one hand and a plant's incremental investment on the other.

19. The procedural status of PG&E's and SCE's PBR applications is currently uncertain.

20. Subject to certain limitations, it is reasonable to allow PG&E and SCE to utilize *ex post facto* reasonableness review for capital additions occurring in 1998 prior to divestiture for those fossil-fueled plants that will be divested prior to March 31, 1998.

Conclusions of Law

1. The plain language of PU Code § 367 gives the Commission discretion to establish what constitutes appropriate costs and reasonableness in implementing the statute.

2. PU Code § 367 does not preclude this Commission from determining that the appropriate and reasonable level of costs necessary to maintain utility facilities after 1998 is that level determined via ISO and PX contracting and pricing arrangements.

3. The language of PU Code § 367 does not specify what approach the Commission should take in determining the reasonableness of capital additions, and therefore does not preclude any particular approach presented by parties to this proceeding.

4. Given the responsibilities of the ISO, the ISO's determination of what facilities are required to maintain system reliability is a reasonable standard for the purpose of implementing PU Code § 367.

5. Only utility plants designated as must-run by the ISO should be eligible for recovery of capital additions after January 1, 1998 and those plants that a utility will have divested by March 31, 1998.

6. Given the responsibilities of the ISO, it would be inappropriate to establish a duplicate procedure whereby utilities could recover the costs of capital additions in a separate forum before this Commission.

7. The market control approach for capital additions in 1998 and beyond is reasonable subject to the following refinements:

a. Utilities should have the opportunity to propose CTC recovery of the costs of post-1997 capital additions to must-run plants under the following circumstances: 1) the capital additions were made to ISO designated must-run units and were necessary to continue operating the must-run unit during the transition (through December 31, 2001), 2) the capital additions were cost-effective compared to other options for maintaining plant operations through the transition *and* compared to other resources available to the ISO for system reliability, 3) the ISO contracting options approved by FERC did not include provisions that would allow utilities to negotiate recovery of these costs and 4) the costs of capital additions could not be recovered in market prices (e.g., through the sale of energy, voltage support, spinning reserves or other services). Any utility proposals for recovery of the costs of post-1997 capital additions should be reviewed by the Commission on an *ex post facto* basis.

b. ORA's supplemental proposal for market valuation of capital additions should not be adopted at this time. The issue of how market valuation of capital additions will occur and be accounted for in the CTC should be addressed in the proceedings that will examine utilities' applications for divestiture of specific plants, or in Phase 3 of the CTC proceeding (A.96-08-001 et al.)

8. Since all of the capital additions for 1996 and 1997 will be completed or under construction before the ISO and PX is operating, it is reasonable to adopt the *ex post facto* approach agreed to by workshop participants.

9. In evaluating the costs of capital additions for 1996 and 1997, it is reasonable to consider the following criteria, among others: (1) consistency with recent capital budgets and expenditures for respective power plants; (2) the need for compliance with other regulatory requirements, (3) cost-effectiveness and (4) the impact of the capital addition on the unit's heat rate and output. In their applications, the utilities should specifically demonstrate how their requests for cost recovery meet the above criteria. Utilities and other parties should have the opportunity to propose additional evaluation criteria for Commission consideration.

10. Utilities should not be required to demonstrate any statistical relationship between a fossil plant's heat and forced outage rates on the one hand, and a plant's incremental investment on the other. In addressing criterion (4) above, utilities and interested parties may describe the impact of the capital addition on the unit's hear rate and output in an alternative manner.

11. In order to proceed expeditiously with the review of 1996 capital additions, this order should be effective today.

12. Utilities should be allowed to utilize *ex post facto* reasonableness review for capital additions occurring prior to divestiture but only for those plants that will have been divested by March 31, 1998.

INTERIM ORDER

IT IS ORDERED that:

1. Within thirty (30) days from the effective date of this decision, Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) shall file applications for competition transition charge (CTC) recovery of 1996 capital additions to non-nuclear generating plant based on an after-the-fact (*ex post facto*) review of recorded expenditures.

2. After recorded data is available, PG&E, SDG&E, and SCE shall file applications for CTC recovery of 1997 capital additions to non-nuclear generating plant and 1998 capital additions to fossil-fueled power plants that have been divested by March 31, 1998 based on an *ex post facto* review of recorded expenditures. Recovery of capital additions incurred in 1998 for divested fossil-fueled plants must have occurred prior to divestiture of the plant, must not have been otherwise recovered through ISO contracts or Power Exchange revenues, and the divestiture must have been completed by March 31, 1998. Capital additions incurred in 1998 will not be eligible for *ex post facto* review for any plant that has not been divested by March 31, 1998.

3. In their applications, PG&E, SDG&E, and SCE shall demonstrate how their requests for recovery of capital addition costs meet the following criteria, among others: (1) consistency with recent capital budgets and expenditures for respective power plants, (2) the need for compliance with other regulatory requirements, (3) cost-effectiveness and (4) the impact of the capital addition on the unit's heat rate. PG&E, SDG&E, SCE, and other interested parties may propose additional evaluation criteria for Commission consideration.

4. For non-nuclear capital additions made in 1998 and beyond and not otherwise addressed in Ordering Paragraph 2, PG&E, SDG&E, and SCE shall file applications for

CTC recovery of costs on an *ex post facto* basis only under the limited circumstances where cost-effective capital additions to utility must-run plants cannot be recovered via the Independent System Operator's (ISO) contracting process because negotiating options or cost recovery provisions are excluded from the final ISO contracts. In their applications under these limited circumstances, PG&E, SDG&E, and SCE shall demonstrate that the following four conditions are met:

a. The capital additions were made to ISO designated must-run units with ISO approval and were necessary to continue operating the must-run unit through December 31, 2001; and

b. The capital additions were cost-effective compared to other options for maintaining plant operations through the transition *and* compared to other resources available to the ISO for system reliability; and

c. The ISO contracting options approved by the Federal Energy Regulatory Commission did not include provisions that would allow utilities to negotiate recovery of these costs; and

d. The costs of capital additions could not be recovered in market prices (e.g., through the sale of energy, voltage support, spinning reserves or other services).

This order is effective today.

Dated September 3, 1997, at San Francisco, California.

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

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COMPARISON OF POSITIONS IN RESPONSE TO FEBRUARY 4, 1997, ACR QUESTIONS

1a. Section 367 requires that the capital additions incurred after December 20, 1995 that are granted transition cost treatment must be reasonable and must be incurred to maintain the generating facilities through December 31, 2001:

The Commission may wish to consider establishing as a standard that the utilities shall not be allowed to use additional capital investments to overhaul their generation assets so as to improve significantly their performance or heat rate. Is this a reasonable and effective standard to implement?

From Comments Filed February 18, 1997, and March 28, 1997					
PG&E	Edison	SDG&E	ORA	IEP	Joint Parties (CIU et al.)
No.	No.	No.	Yes, possibly.	No.	Yes, but unsure how.

In their filed comments, all parties agreed that the establishment of such a standard would be difficult, and all agreed that routine maintenance can result in incidental increases in plant performance; and that such unintended increases in plant performance should be allowed.

Alternatively, PG&E, in its filed comments, proposed six capital improvement categories which would be preemptively eligible for recovery in the CTC. Edison, in its filed comments, proposed three cost categories (which are stated under its response to question 3). SDG&E, on the other hand, in its filed comments, proposed a case-by-case review of each activity either in advance or after the fact as a means of determining the reasonableness of each activity.

During the workshop, the group discussed the anticipated future relevance or benefit of such cost categories, whether preapproved, or *ex post facto*. ORA, IEP, and Joint Parties do not agree with the utilities that any specific type of improvements should be presumptive. The utilities concluded that whether in a preapproval application or *ex post facto* review application, they believe that there would be some benefit from grouping of costs. In other words, cost categories would generally form around the details of a specific filing. However, parties agreed that no cost categories should be developed at this time as a standard for determining reasonableness.

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1b. If so, how should significant improvement be defined?

Parties appear to agree that significant improvement would be defined as anything beyond incidental increases in heat rate and output, and beyond the realm of cost effectiveness just for maintenance purposes. However, several of the utilities pointed out that a cost-effective standard would be difficult to implement. For example, a utility member said that a hydroelectric license may not be considered as cost-effective in the traditional sense, but is necessary.

1c. What showing should be required of the utilities to establish that such additions were necessary to maintain the facilities through 2001?

From Comments Filed February 18, 1997, and March 28, 1997					
PG&E	Edison	SDG&E	ORA	IEP	Joint Parties (CIU et al.)
Six proposed categories.	Three proposed categories.	Case-by-case basis.	ISO and/or the PX will make the determination.	ISO recovery first, then case-by-case.	

For 1996 and 1997, the parties agreed during the workshop that a reasonableness review should be based on the actual recorded capital additions, not on any forecasts. For 1998 and beyond, parties suggest that it might be two-staged with a preapproval step and a later *ex post facto* review, if capital additions are not expected to be recovered entirely from call contracts with the ISO or PX prices during this period.

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2. Should the Commission use a different set of standards for review of capital additions made in 1996 and 1997 and capital additions performed during the transition period, 1998 - 2001?

From Comments Filed February 18, 1997, and March 28, 1997					
PG&E	Edison	SDG&E	ORA	IEP	Joint Parties (CIU et al.)
Yes.	Yes.	Yes.	Yes.	Yes.	No.

There was clear agreement by the workshop participants that review of 1996 and 1997 capital additions should be on an *ex post facto* basis. For the transition period, 1998-2001,

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parties agreed that in the absence of market control, the standard of reasonableness would be based upon a combination of preapproval and *ex post facto* review. IEP's position is that if the Commission does not adopt a market-based approach for capital additions in 1998 and beyond, the Commission should apply similar standards to evaluate capital additions in 1996 and 1997 as for those made in 1998 and beyond. Specifically, the Commission should allow recovery only for capital additions necessary to maintain the facilities through December 31, 2001.

3a. For capital additions performed during the transition period, should utilities be allowed some form of preapproval?

3b. If so, should the utilities seek preapproval on a case-by-case basis or should the Commission establish guidelines for preapproval?

From Comments Filed February 18, 1997, and March 28, 1997					
PG&E	Edison	SDG&E	ORA	IEP	Joint Parties (CIU et al.)
• Preapproval should be available but not mandatory. • Reasonableness determined later.	Guidelines for three categories of capital expenditures to be presumed reasonable. (Asbestos removal; environmental regulations; and maintenance.)	Request flexibility to seek preapproval for projects costing $200,000 or more. Will have reasonableness review for those projects which have not been pre-approved.	(ISO could pre-approve for Must-Run.) Guidelines can be established for ex post reasonableness reviews of non-Must Run units. (Examples might include: Not anti-competitive; not possible to defer environmental retrofit; consistent with normal pattern of expenditures.)	Preapproval on a case-by-case basis, for system reliability only.	No. Post-Hoc Review only.

ORA, IEP and TURN's proposal of market control would negate the need for any preapproval of capital additions from this Commission. However, in the event that the Commission does not adopt market control, the parties' consensus on preapproval options can be summarized as follows. The utilities could:

(1) Seek preapproval of large capital projects (which would be subject to a limited

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reasonableness review of construction management after costs are recorded), or

(2) Seek review of post-1998 capital additions on an *ex post facto*, recorded basis only, similar to the process for 1996-1997.

In the event of a preapproval process, ORA proposed the following threshold dollar amounts for preapproval of specific projects: PG&E—$1 million; SDG&E—$200,000; Edison—$500,000. Parties were amenable to these amounts; however, TURN holds that preapproval should be reserved for very large expenditures in the $5 million range and beyond. ORA stated that they would also like the total estimated dollar amount of all proposed additions be included in the utilities applications for preapproval of specific projects.

4a. Should the Commission require that the utilities must demonstrate that the statistical relationship established over the last decade between each fossil plant's heat rate and forced outage rate, on the one hand, and the same plant's incremental investment in the other, did not change during the years of incremental investment?

From Comments Filed February 18, 1997, and March 28, 1997					
PG&E	Edison	SDG&E	ORA	IEP	Joint Parties (CIU et al.)
No.	No.	No.	No.	No.	No.

The participants agreed that there are other relevant factors that influence plant operation. In addition, the parties agreed that the Commission should not devote valuable resources of its own and other parties to demonstrate such a statistical relationship.

4b. Is there a methodology or measure which can be easily calculated and readily verifiable that will reasonably approximate appropriate expenditures under § 367?

From Comments Filed February 18, 1997, and March 28, 1997					
PG&E	Edison	SDG&E	ORA	IEP	Joint Parties (CIU et al.)
No.	No.	No.	No.	No.	No.

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All the utilities commented that they are not aware of any statistically valid measure or methodology which would correlate the effects of incremental plant investment on plant heat rate and Forced Outage Rate (FOR).

4c. If so, should this standard of review apply to 1996 and 1997 capital additions?

4d. Should it be required to be demonstrated on a prospective basis for capital additions made during the transition period?

From Comments Filed February 18, 1997, and March 28, 1997					
PG&E	Edison	SDG&E	ORA	IEP	Joint Parties (CIU et al.)
n.a.	n.a.	n.a.	n.a.	n.a.	n.a.

Questions 4c and 4d are moot given the parties' responses above.

5a. Should environmental requirements and joint service agreements be critical considerations in assessing the review requirement?

5b. How should these requirements be considered in an ex post review?

From Comments Filed February 18, 1997, and March 28, 1997					
PG&E	Edison	SDG&E	ORA	IEP	Joint Parties (CIU et al.)
Should presumptively qualify for transition cost recovery.	Should be determined reasonable.	Should be determined reasonable.	No. Recovery should be negotiated outside of CTC.	No. Maybe elsewhere but not through the CTC.	No different than other adds.

In addition to Joint Service Agreements (JSAs), which apply to generation provided to more than one service area, several of the utilities have contractual obligations incidental to generation. One such example would be hydroelectric facility in which a utility may be under a contract to provide water as well as generation. In such an instance, if a water flue broke, the utility would be required to fix it and per the utility, it should be able to recover this cost. Intervenors feel that the entire amount of recovery

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of any environmental requirements, JSA, or other contractual obligation should be recovered through the ISO call contract or the PX price.

6a. The Commission has previously authorized revenue requirements for capital expenditures during the test year cycle in PG&E's and Edison's recent general rate cases. What are reasonable standards for ensuring that these amounts are spent appropriately and whether any capital expenditures have been deferred?

From Comments Filed February 18, 1997, and March 28, 1997					
PG&E	Edison	SDG&E	ORA	IEP	Joint Parties (CIU et al.)
CPUC authorizes overall level of revenue, not specific capital expenditures. It is the utility's responsibility to manage day-to-day operations. Utilities have disincentive to spend money on unneeded projects.	It's not necessary because the Commission did not authorize capital additions beyond 1995, and those balances are being reviewed as part of the transition cost audit in this proceeding.	The Commission's customary prudence standards along with the requirements contained in PU Code § 367 provide the necessary direction.	Test to determine if expenditures deviate from prior patterns.	Focus on recorded data not forecasted additions. Review of previously authorized additions should focus on recorded actual expenditures with any deferred expenditures reviewed on the same basis as other additions made in post-1997 time periods.	Determination of whether an addition could have been made earlier is a question of fact. "The Commission must be vigilant in preventing utilities from using [§ 367(c)] to 'tune up' fossil generation facilities for the new market."

Utilities are concerned about development of such a standard because forecasts of plant additions are constantly being updated, often due to changes the utilities do not have any control over. Such an instance would be the 1997 floods, which caused a realignment of resources and completion dates for previously estimated additions.

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6b. Other considerations that might be addressed in future reasonableness reviews of capital additions are whether out-year investments have been accelerated into the transition period and whether the utility has spent more than previously budgeted on incremental capital investments during this period. Are these considerations appropriate standards for review?

From Comments Filed February 18, 1997, and March 28, 1997					
PG&E	Edison	SDG&E	ORA	IEP	Joint Parties (CIU et al.)
No.	No.	No.	Possibly, but would be difficult to show on a per-unit basis.	Yes.	Yes.

6c. Should the Commission consider additional standards on potential anti-competitive impacts of additional capital investments?

From Comments Filed February 18, 1997, and March 28, 1997					
PG&E	Edison	SDG&E	ORA	IEP	Joint Parties (CIU et al.)
Probably not, events would be difficult to prove.	No.	No.	Possibly, but difficult to do.	Yes.	Yes.

7a. How do such criteria fit in with the approach that has been applied in traditional ratemaking?

From Comments Filed February 18, 1997, and March 28, 1997					
PG&E	Edison	SDG&E	ORA	IEP	Joint Parties (CIU et al.)
Consistent	Projects have been reviewed prospectively and not *ex post facto*.	Consistent.	Consistent.	No.	Same standard for all years.

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7b. Given that SDG&E has a generation performance-based ratemaking (PBR) mechanism, should any different criteria be applicable to SDG&E?

From Comments Filed February 18, 1997, and March 28, 1997					
PG&E	Edison	SDG&E	ORA	IEP	Joint Parties (CIU et al.)
No Opinion.	No Opinion.	No.	No.	No.	No.

(END OF ATTACHMENT 1)

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EXCERPTS FROM ISO PROPOSED CONTRACT OPINIONS

AGREEMENT A
(ISO Tariff Original Sheets No. 377-378)

ARTICLE 3

RELATIONSHIP BETWEEN CONDITIONS OF MUST-RUN AGREEMENTS

3.1 Transfer by ISO

(a) ISO may at any time give 90 days' notice to Owner to terminate the Conditions of Must-Run Agreement "A" with respect to specific Units, stating that it wishes to transfer the Units concerned to the Conditions of Must-Run Agreement "B" with such modifications as ISO may propose.

(b) Owner may, within thirty (30) days of receipt of the notice:

(i) accept ISO's proposal, in which case the Conditions of Must-Run Agreement "A" shall terminate in regard to the Units concerned upon expiry of ISO's 90-day notice and shall thereupon be replaced by the Conditions of Must-Run Agreement proposed by ISO in regard to the Units concerned; or

(ii) give notice to ISO that it wishes to amend the modifications to the Conditions of Must-Run Agreement "B" proposed by ISO or any other provisions of the Conditions of Must-Run Agreement "B," in which case the Parties shall negotiate in good faith the detailed terms of the proposed agreement. Such negotiations shall include the extent, if any, to which ISO should be responsible for payment of more than the proportion of the Annual Fixed Costs for which ISO is responsible under Conditions of Must-Run Agreement "A." If the Parties are not able to reach agreement by the time of expiry of the 90-day notice period, the Conditions of Must-Run Agreement "A" shall terminate and the Conditions of Must-Run Agreement "B" shall apply and take effect from such date in regard to the Units concerned.

If Owner does not give notice to ISO, Owner shall be deemed to have accepted the proposals contained in ISO's notice.

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AGREEMENTS B AND C
(ISO Tariff Original Sheets No. 550-557, 566-573)*

ARTICLE 2

TERM

2.1 Term

(a) These Conditions of Must-Run Agreement shall become effective on the date determined under Article 3 of the Master Must-Run Agreement and, subject to Section 2.1(b), shall expire at 00.01 hours on the Expire Date.

(b) ISO may, upon giving Owner at least ninety (90) days' written notice prior to the Expire Date, extent the term of these Conditions of Must-Run Agreement for a further 12 calendar months from the Expire Date. Such extension shall not limit or affect in any way the rights of either Party to terminate this Agreement in accordance with Section 2.2.

2.2 Termination

(a) This Agreement may be terminated at any time:

(i) by ISO for any reason upon 90 days' notice;

(ii) by ISO pursuant to Section 2.2(b);

(iii) by Owner pursuant to Section 5.1(h);

(iv) by Owner by written notice in the event ISO fails, for any reason other than a billing dispute, to make payment to Owner on or before the Due Date, and such failure of payment is not corrected within thirty (30) days after Owner notifies ISO in writing to cure such failure;

(v) by Owner, if it sells Units to a purchaser who, if ISO requires the Facility to continue to be available, executes a contract with ISO, to

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*These excerpts are taken from Agreement C. With only minor exceptions, the provisions under Agreement B are identical. (See ISO Tariff Original Sheets No. 472-480, 491-498.)

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provide ISO the right to purchase Energy and Ancillary Services from the Units under substantially the same terms as the Master Must-Run Agreement and Conditions of Must-Run Agreement "A" (as defined in the Master Must-Run Agreement) (including terms specifying cost-based or deemed cost-based rates, subject to the provisions of Section 5.7 of the Master Must-Run Agreement). Such termination may not take effect prior to the receipt of all necessary regulatory approvals, including acceptance of the contract between ISO and the purchaser; or

(vi) by Owner, if with the prior written consent of ISO, Owner transfers ownership of the Facility to a subsidiary that executes a contract with ISO identical to the terms of the Master Must-Run Agreement and Conditions of Must-Run Agreement "A" (as defined in the Master Must-Run Agreement). Such termination may not take effect prior to the receipt of all necessary regulatory approvals, including acceptance of the contract between ISO and the subsidiary.

(b) If at any time during the term hereof, Owner shuts down or states an intention that it will shut down, a Unit or Owner otherwise defaults in the due performance or observance of any material term or condition of this Agreement, ISO shall have the right to issue a notice ("Default Notice") setting out the circumstances constituting the default. If Owner disputes the Default Notice, Owner shall notify ISO within fourteen (14) days of receipt of the Default Notice setting out the grounds upon which it disputes the Default Notice and referring the matter to the dispute resolution procedures set out in Section 7.1. If Owner fails within thirty (30) days after receiving the Default Notice to remedy the default or, if the Default Notice was referred to the dispute resolution procedure, within thirty (30) days of any decision that a default has occurred, and any such default is continuing, ISO shall be entitled by a further written notice to terminate this Agreement. If ISO terminates this Agreement pursuant to this Section 2.2(b), Owner shall reimburse to ISO the total of all payments made and all costs incurred by ISO resulting directly from the termination and which ISO would not have paid or incurred but for such termination. In addition, Owner shall reimburse to ISO that proportion of the amount of all payments made by ISO to Owner in respect of replacements or repairs or Capital Improvements pursuant to Section 5.1(f) which have been expensed by Owner but have not been amortized as at the date of termination of this Agreement.

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(c) This Agreement shall terminate automatically if Owner's license to operate the Facility under Section 1 of the Act expires without being renewed by FERC provided that Owner shall be under an obligation to use its best efforts to renew and keep in effect its license.

(d) Termination of this Agreement shall be subject to the approval of [FERC] [the appropriate regulatory authority].*

(e) Termination of this Agreement or of these Conditions of Must-Run Agreement shall not affect the accrued rights and obligations of either Party, including either Party's obligations to pay all charges payable to the other Party pursuant to this Agreement or these Conditions of Must-Run Agreement for the period when it was, or they were, in effect.

(f) If, within six (6) months after expiration of this Agreement or the termination of this Agreement pursuant to Sections 2.2(a)(i), (iii), or (iv), Owner considers that it is uneconomical or otherwise impracticable to continue operating and maintaining the Facility and wishes to recover the amounts from ISO pursuant to this Section 2.2(f), Owner may give ISO notice in writing to that effect stating the grounds upon which it considers that it is uneconomical or otherwise impracticable to continue operating and maintaining the Facility, the date upon which it is intended to permanently close the Facility, such date to be not more than six (6) months from ISO's receipt of Owner's notice hereunder, and the amounts which Owner considers to be payable to it pursuant to this Section 2.2(f) in consequence of closing the Facility. If ISO wishes to dispute the validity of Owner's notice, including whether it is uneconomical or otherwise impracticable to continue operating and maintaining the Facility and/or the amount which Owner claims will become payable to it under this Section 2.2(f), it shall within twenty-one (21) days of receipt of Owner's notice give notice in writing to Owner setting out the grounds upon which it disputes Owner's notice. If the Parties are unable to resolve the dispute, either Party may refer the matter to the disputes resolution procedure set out in Section 7.1. If ISO does not dispute Owner's notice or if it is determined pursuant to the disputes resolution procedures that Owner is entitled to close the Facility, subject to any necessary prior [FERC] [appropriate regulatory authority] approval, Owner shall then close the

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* Delete whichever is not applicable.

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Facility for operation as an electrical generating facility and, provided the amount payable by ISO under this Section 2.2(f) has been agreed by ISO or determined pursuant to the disputes resolution procedures, Owner may within fourteen (14) days thereafter deliver an invoice to ISO in respect of any undepreciated and unrecovered costs previously agreed to be paid by ISO for Capital Improvements made to the Facility since the Effective Date. The amount of the invoice submitted shall be expressed as a lump sum, adjusted for savings in interest where appropriate, in accordance with the formula set out in Schedule B. ISO shall pay Owner the amount of such invoice within thirty (30) days of its receipt, following which period interest at the Interest Rate shall accrue on such sum. If within three (3) calendar years after ISO has made payment to Owner under this Section, the Facility is opened either by Owner or any third party either in whole or in part as an Energy-generating facility, Owner shall reimburse ISO the amount paid hereunder as a lump sum for those specific assets returned to service together with interest thereon calculated at the Interest Rate from the date Owner received payment from ISO under this Section 2.2(f). As a condition to receiving payment from ISO under this Section, Owner shall procure a parent company guarantee from Parent or a bond from a reputable bank or insurance company, in a form acceptable to ISO acting reasonably, guaranteeing or securing the obligations of Owner under this Section 2.2(f) in the event of the Facility being reopened.

(g) ISO may exercise its rights under Section 2.2(a)(i) in relation to a specified Unit or Units, in which case this Agreement shall, on expiration of ISO's notice, terminate in relation only to the Unit or Units concerned and the provisions of this Agreement relating to termination shall be read and construed accordingly. In such event, Owner shall notify ISO as to whether any modification to Schedule B is required. ISO shall accept such modifications or propose alternative modifications, and in such event, the Parties shall negotiate in good faith. If the parties are unable to reach agreement, then the provisions of Section 5.7 of the Master Must-Run Agreement shall apply.

ARTICLE 5

OWNER'S PERFORMANCE OBLIGATIONS

5.1 Operation and Maintenance of the Units: Modifications: Planned Outages

(a) Owner shall fuel, operate, and maintain the Units, or cause the Units to be fueled, operated, and maintained, in accordance with all Laws and Good Industry Practice so that Owner is able to perform its obligations under this Agreement. Owner shall keep ISO advised of the Availability of the Units by issuing Owner's Availability Notices. Subject to Section 5.7(c), an Owner's Availability Notice or ISO's Availability Notice shall continue in effect until it is superseded by a subsequent Owner's Availability Notice or by an ISO's Availability Notice.

(b) In the event of any loss or damage to the Facility that impairs the capability of the Facility to Deliver Energy or Ancillary Services, Owner shall at its own expense make the necessary repairs or replacements, subject to the provisions of Section 5.1(c).

(c) If Owner's estimated cost to make the necessary repairs or replacements referred to in Section 5.1(b), or to make a Capital Improvement required by any Law, exceeds either the per incident or the annual aggregate Maximum Cost Requirement, or if Owner wishes to make any other Capital Improvement the estimated cost of which is not already included in the Availability Payment and which exceeds the per incident or annual aggregate Maximum Cost Requirement, then Owner shall provide a notice thereof ("Action Notice") to ISO setting out in detail:

(i) the cause and nature of the loss or damage involved, and a description of the repairs or replacements or a description of the Capital Improvement required or requested, the relevant Law, and the manner in which the proposed Capital Improvement will secure compliance with it;

(ii) the estimated cost of the repairs or replacements, or of the Capital Improvement and, if relevant, in respect of each affected Unit the duration of any Forced Outage necessary to perform the repair, replacement, or Capital Improvement, together with such information as ISO may reasonably require in order to verify such estimate; and

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(iii) Owner's proposals with respect to carrying out such repairs or replacements, or Capital Improvement, and payment of cost thereof, including the amortization of such cost over a period of time.

(d) Within thirty (30) days of receipt of an Action Notice, ISO may object in writing to Owner's proposals on the grounds that:

(i) the loss or damage was caused by Owner's failure to comply with Good Industry Practice or by a deliberate act or omission or wrongdoing by Owner or any of its employees, agents, suppliers, or subcontractors;

(ii) the repairs or replacements are not required or are more extensive than required in order to make good the loss or damage concerned;

(iii) the Capital Improvement is not required in order to comply with the Law or is more extensive than is required to comply with the Law;

(iv) the cost of the repairs or replacements or the Capital Improvement will not exceed the per incident or annual aggregate Maximum Cost Requirement;

(v) the estimated cost of repairs or replacements or the Capital Improvement exceeds that which is reasonably necessary to effect such repairs, replacements, or Capital Improvement;

(vi) if the Capital Improvement is not one required by Law, the implementation of the Capital Improvement will not result in any savings to ISO; or

(vii) the proposals for the carrying out of the repairs, replacement, or Capital Improvement, or the payment of the cost thereof, including the amortization of such cost, are unreasonable.

(e) If ISO objects under any of bases (i) to (v) or (vii) of Section 5.1(d) to an Action Notice and the Parties cannot reach agreement on any adjustments to Owner's proposals, the matter shall be referred to the disputes resolution procedures set out in Section 7.1.

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(f) If it is agreed or determined pursuant to Section 5.1(c) to (e) that the repairs or replacements are necessary or that the Capital Improvements are required by Law or if, in the case of Capital Improvements not required by Law, ISO wishes to have them carried out, and, in each case, it is agreed or determined pursuant to Section 5.1(c) to (a) that the estimated cost of the repairs or replacements or Capital Improvements exceeds either the per incident or aggregated Maximum Cost Requirement, and if ISO agrees in writing to pay the amount by which such estimated cost exceeds either the per incident or aggregated Maximum Cost Requirement, whichever is the greater ("ISO Share"), in accordance with the proposals for payment of the ISO Share agreed or determined pursuant to Section 5.1(c) to (e), Owner shall promptly proceed with the necessary repairs or replacements, or Capital Improvement. Owner shall keep full and detailed records of the cost of effecting the repairs or replacements or the Capital improvement and shall make them available to ISO for inspection upon reasonable request. ISO shall pay Owner the amounts by which the actual cost of the repairs or replacements or Capital Improvement exceeds the per incident or aggregated Maximum Cost Requirement, whichever is the greater, up to a maximum of the ISO Share. Such payment shall be made by adjustment of the Availability Payment pursuant to the proposals agreed or determined pursuant to Section 5.1(c) to (e). In the event of any dispute arising as to the amount of the payment or the adjustment to the Availability Payment, it shall be referred to the dispute resolution procedures under Section 7.1.

(g) In relation to a repair or replacement, if ISO notifies Owner that ISO is unwilling to pay the ISO Share, or if ISO fails to respond to an Action Notice within thirty (30) days (or such longer period as Owner may agree (such agreement not to be unreasonably withheld or delayed)) after receipt of the Action Notice, then, unless the repair or replacement was necessitated by Owner's failure to comply with Good Industry Practice or by any deliberate act or omission or wrongdoing by Owner or any of its employees, agents, suppliers, or subcontractors, Owner shall not be obligated to make such repair, or replacement, and an appropriate downward adjustment shall be made to the capacity of the affected Unit as shown in Schedule A so as to reflect the changed capabilities of the Facility.

(h) If Owner considers it would be uneconomical or otherwise impracticable or illegal to continue operating and maintaining the Facility without making the aforesaid repairs, replacements, or Capital Improvement,

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Owner shall be entitled, at the time that it submits its Action Notice under Section 5.1(c), to give written notice to ISO to that effect setting out the grounds for its Notice. Within thirty (30) days of receipt of such notice, ISO shall notify Owner in writing whether or not ISO accepts that the notice is correct. If ISO notifies Owner that ISO does not accept the notice, the dispute shall be referred to the dispute resolution procedures pursuant to Section 7.1. If ISO fails to respond to the Action Notice within thirty (30) days, or it is determined pursuant to the dispute resolution procedures that ISO should have accepted the notice as being correct, or if ISO accepts the notice, Owner may, subject to obtaining the authorization of [FERC] [the appropriate regulatory authority]* (where required by Law) terminate this Agreement without cost or liability therefore.

(i) If Owner makes a repair, replacement, or Capital Improvement notwithstanding ISO's refusal to pay for such expenditure, Owner shall not be entitled to recover the costs of such expenditure whether as part of the Availability Payment or as a termination fee pursuant to Section 2.2(g) or in any other manner from ISO. Notwithstanding any other provision of this Agreement, in no event shall a Unit's Availability Payment be decreased for any of the period of time during which Owner is waiting for ISO's response to an Action Notice or during which a dispute concerning an Action Notice is pending.

(j) Owner shall be entitled to take each Unit out of operation in order to perform routine and overhaul maintenance, and shall perform such maintenance in accordance with Good Industry Practice. The dates and times when Owner may take the Units out of operation for such purposes and any amendments to those dates and times shall be determined in accordance with the ISO Tariff.

(k) Owner may of its own volition and at its own cost, upgrade any Unit, and may replace any Unit with another comparable electrical generating unit at the same Facility, provided that no such upgrade or replacement shall release Owner from or modify or affect the Owner's performance obligations under this Agreement.

(END OF ATTACHMENT 2)

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* Delete whichever is not applicable.