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Decision 91-11-056 November 20, 1991

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ORIGINAL

Application of Pacific Gas and Electric Company for authority to adjust its electric rates effective November 1, 1991; and adjust its gas rate effective January 1, 1992; and for Commission order finding that PG&E's gas and electric operations during the reasonableness review period from January 1, 1990 to December 31, 1990 were prudent. (U 39 M)	Application 91-04-003 (Filed April 1, 1991)

(Appearances are listed in Appendix F)

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OPINION

1. Summary of Decision

By this decision we approve for Pacific Gas and Electric Company (PG&E) an increase in its overall revenue requirement of $8,769,000, based on a 12-month forecast period beginning November 1, 1990. This increase is composed of the following elements:

Ratemaking Procedure:	Increase (Decrease) ($000)
Energy Cost Adjustment Clause (ECAC)	($167,670)
Annual Energy Rate (AER)	(11,052)
Electric Revenue Adjustment Mechanism (ERAM)	180,700
Low Income Rate Adjustment (LIRA)	6,791
Total	$ 8,769

We present the computation of total revenue requirement for each of these elements in Appendix A.

We are issuing a companion decision which separately addresses PG&E's ratemaking and policy proposals relative to its Customer Energy Efficiency (CEE) Programs, which were also included in Application (A.) 91-04-003.

In conjunction with our adoption of the revenue requirement adjustments noted above, this decision also adopts the forecast resource mix, energy prices, and payment factors for purchases from variably priced qualifying facilities (QFs) (i.e., only those QFs without fixed price contracts), presented in Appendices B and C. We discuss these adopted values in Section III of this decision.

1.1 AER

The AER is currently suspended for PG&E per our Order Instituting Investigation (I.) 90-08-006. This means that AER revenues and expenses are presently included 100% in the ECAC balancing account. We have calculated the AER revenue requirement adjustment noted above consistent with our adopted resource assumptions in the event we decide to reinstate the AER during the period covered by this ECAC forecast. The AER is equal to 9% of PG&E's total forecasted fuel and purchased power expense. Subject to AER reinstatement, PG&E is authorized to continue to include in the ECAC balancing account 100% of AER expenses and revenues as adopted herein.

1.2 ERAM and LIRA

The adopted revenue adjustments for ERAM and LIRA are based upon PG&E's estimated balancing account balances as of October 31, 1991. A more complete description of the basis for the ERAM and LIRA adjustments are presented in Section 6 of this decision.

1.3 Consolidation of Rate Changes

PG&E proposed to consolidate the rate changes adopted in this application with those in its 1992 Attrition and Cost of Capital proceedings to produce a single rate change effective January 1, 1992. PG&E made a similar request in its Petition for Modification of Decision (D.) 89-01-040, filed on January 23, 1991, for a permanent change in its authorized ECAC revision date from November 1 to January 1. Accordingly, we will authorize this rate increase to become effective January 1, 1992, concurrently with PG&E's attrition and cost of capital rate adjustments. The revenue allocation of this adopted increase among customer classes will be authorized in a separate decision scheduled to be issued on December 18, 1991.

1.4 Reasonableness of Record Period Costs

PG&E's application also asks for a finding on the reasonableness of recorded 1990 gas and electric costs. A decision on reasonableness will be issued in a separate phase of this proceeding.

2. Procedural Background

PG&E filed this application on April 1, 1991, initially requesting an increase of $264.8 million in its electric revenues on an annualized basis effective November 1, 1991. A prehearing conference was held on April 22, 1991 to establish a schedule for the proceeding and to address related matters.

By ruling dated May 29, 1991, the Administrative Law Judge (ALJ) adopted a procedural schedule based generally on the standard schedule adopted in D.89-01-040, referred to as the Rate Case Plan (RCP). Modifications in the RCP were required in this proceeding to accommodate parties' scheduling difficulties. The schedule was divided into two major phases, consistent with prior years' ECAC proceedings. Phase I covers three major issue areas:

Phase Ia: Forecast ECAC/AER/ERAM/LIRA Revenue Requirement, Related Resource Assumptions, and QF Price Factors

Phase Ib: CEE Issues

Phase Ic: Revenue Allocation Issues

Phase II covers reasonableness period issues. This decision addresses only Phase Ia issues.

A second prehearing conference was held on June 28, 1991 where the active parties requested an amended schedule to allow for discussions to occur prior to Phase Ia evidentiary hearings with the goal of resolving disputed issues. Parties engaged in such discussions on July 10 and 11, 1991. Only the Commission's Division of Ratepayer Advocates (DRA) and PG&E successfully reached resolution on all disputed Phase Ia issues. Toward Utility Rate Normalization (TURN) joined DRA and PG&E in a joint recommendation only on gas price issues. The three remaining active parties in this portion of the proceeding did not reach resolution of contested issues.

Evidentiary hearings on Phase Ia issues were held on July 12-19, 1991. Opening briefs were filed on August 2 with reply briefs on August 9, 1991. An ALJ ruling was issued on August 15 outlining the assumptions parties were to use in developing final model runs due on August 30, 1991. An informal workshop was held August 19 to further clarify the ruling. On August 30, PG&E provided an update exhibit which computed the revenue requirements consistent with assumptions designated in the August 15 ALJ ruling, as clarified at the August 19 workshop. All active parties stipulated to the accuracy of PG&E's updated computations, and did not provide separate exhibits.

Evidentiary hearings on Phase Ib Customer Energy Efficiency issues were held on August 5-9. A further discussion of the procedural background relative to Phase Ib is presented in a companion decision.

The proposed decision of the ALJ was mailed on October 18, 1991. Parties filed comments on November 7 and reply comments on November 12. We have reviewed all comments and have incorporated them into our final order where appropriate. The only substantive change we have made in resource assumptions relates to the treatment of cost elements included in the gas dispatch price, as discussed in Section 5.2.3 below.

3. ECAC Forecast Issues

3.1 Overview of Parties' Positions

PG&E's initial application included an ECAC/AER increase of $78.3 million. PG&E attributed the increase to below-normal hydroelectric generation, increased generation and prices associated with the Diablo Canyon nuclear plant, and higher QF purchases.

PG&E served updated testimony on July 1, 1991 to reflect significant changes in resource assumptions which had occurred since PG&E's April 1 filing. The July 1 update changed PG&E's request from a rate increase to a decrease of $40.6 million, reflecting a June hydro availability update and various other factors. The forecasted decrease was primarily due to lower thermal requirements resulting from additional hydro, QF and Diablo Canyon generation, lower Southwest gas prices, and a lower ECAC undercollection. Offsetting increases included reduced incremental sales revenues and higher QF expense, as well as certain gas cost adjustments.

The following parties sponsored testimony on Phase Ia issues: DRA, TURN, California Cogeneration Council (CCC), Geothermal Resource Associates/Independent Energy Producers Association (GRA/IEP), and Cogenerators of Southern California (CSC). TURN's testimony was limited to gas price issues. CSC sponsored testimony only on one issue related to the Energy Reliability Index.

3.2 Joint Recommendation

As noted previously, PG&E and DRA subsequently revised their proposals to reflect a resolution of all remaining disputes between them relative to resource assumptions, revenue requirements, and QF price factors. The resulting revenue requirement change proposed jointly by PG&E and DRA reflected a decrease of $172 million, as contained in the PG&E/DRA Joint Recommendation Exhibit (Exh. 39). In addition, TURN joined PG&E and DRA in jointly sponsoring a recommendation on gas prices. The other active parties did not join PG&E in sponsoring any joint recommendations.

The PG&E/DRA Joint Recommendation involved a compromise between the parties that each believes represents a "reasonable recommendation" (Exh. 39, p. 7). According to DRA witness Hicks, the Joint Recommendation satisfied four goals which DRA had in mind:

1. To achieve a revenue requirement and Incremental Energy Rate (IER) consistent with the resource mix.

2. To base each individual resource assumption upon a reasonable forecast.

3. Not to seek a settlement with the lowest possible IER.

4. To view the settlement as a whole, with compromises negotiated by both parties.

3.3 Parties' Positions on Revenue Requirement

Consistent with prior ECAC proceedings, parties were directed by the ALJ to prepare a comparison exhibit (Exh. 61) which set forth the positions of the parties on ECAC/AER revenue requirement and resource assumptions. CCC and GRA/IEP subsequently revised their revenue requirement estimates through late-filed Exhs. 59 and 60, respectively. Parties' proposals for changes in ECAC/AER revenue requirement (all representing decreases) and related IER values, as presented at various stages of this proceeding, are set forth below. (TURN and CSC did not sponsor total revenue requirement estimates.) The adopted ECAC/AER revenue requirement, shown in the last column for comparison, is discussed in Section 3.8 of this decision.

Parties' Position on ECAC/AER Revenue Requirement Changes
($ Millions) Increase (Decrease)

	PG&E	DRA	CCC	GRA/IEP	Adopted
Initial Estm.*	$78.3	$(215.1)	*	*	
July Updates	(41.2)	(194.0)	$(80.9)	$(155.8)	
Joint Recom.	(172.2)	(172.2)	n/a	n/a	
Rev. Update **	n/a	n/a	(240.8)	(248.9)	
Rev. Update ***	(134.5)	(134.5)	n/a	n/a	$(178.7)

* Initial intervenor testimony did not include revenue requirements estimates.

** Reflected intervenors' adoption of commodity prices proposed by the Joint Recommendation and correction of CCC's double-counting error (see Exhs. 59 and 60).

*** Reflected update of $40 million increase due to updating balancing account data through July 31, 1991 recorded balances, and offsetting reductions to reflect updated present revenues using rates effective May 1, 1991 as adopted in PG&E's Rate Design Window Proceeding (D.91-04-062).

3.4 QF Price Factors

As we have noted in prior ECAC decisions, there is a logical relationship between conventional ECAC issues and the bases for QF prices. The forecast of resource assumptions underlying ECAC revenue requirements also affect the determination of the utility's generating efficiency at the margin, as measured by the IER. Likewise, resource availability to meet demand is reflected in the Energy Reliability Index (ERI). Accordingly, in this decision, we adopt updated price factors for variably priced QFs.

Variable QF prices are the sum of payment components for capacity, avoided operating and maintenance (O&M) costs, other adders and energy. The ERI and IER are essential determinants of variable QF prices. The IER, which reflects the utility system's incremental efficiency in converting heat energy to electricity, is combined with avoided O&M costs to form an equivalent IER. This factor then is multiplied by the utility's incremental fuel cost to produce the price the utility pays for the variably priced QFs' energy. D.82-12-120 ordered that prices paid to QFs be time-differentiated to reflect the fact that the value of the power they provide varies with the time of day when it is supplied.

The IER is calculated using the "QFs-in/QFs-out" method. This method requires two separate production simulation model computer runs. The only difference in resource availability between the two runs is in the treatment of QFs. The QFs-out run represents system commitment and dispatch with all variably priced QFs removed. The QFs-in run adds back all variably priced QFs anticipated to be on-line during the forecast period. The difference in total system costs between the two runs equals the avoided costs of all variably priced QFs. The avoided costs are expressed in terms of cents/kWh and are then divided by the average utility electric generation (UEG) gas cost from the QFs-in run to develop the annual average IER.

The ERI is a factor which adjusts capacity payments to nonfirm QFs receiving as-delivered capacity under Standard Offer No. 1, or Option 1 of Standard Offer No. 4. It reflects the PG&E electric system capacity needs under a certain set of reserve margin and resource assumptions. The ERI is computed as an adjustment to the value of a generic combustion turbine, which we have assumed to be a proxy for PG&E's avoided capacity costs, consistent with past practice.

3.5.1 Adopted Incremental Energy Rate

Parties' estimates of the equivalent IER (including adders) is presented below, along with our adopted estimate. The parties' separate estimates are taken from the comparison Exh. 61, which reflected parties' July update estimates. The Joint Recommendation amended the estimates for PG&E and DRA. Our adopted IER is based upon the resource assumptions which we have concluded are reasonable for this proceeding, as discussed in Section 3.8 of this decision. The derivation of the adopted IER, DIER, and related price adders is presented in Appendix C.

Comparison of Equivalent IER Estimates
Parties' Positions vs. Adopted
(Btu/kWh)

PG&E	DRA	Joint Recom	CCC	IEP/GRA	Adopted
10,912	10,803	10,740	11,089	11,217	10,885

3.5.2 Adopted Diablo Canyon Incremental Energy Rate

D.88-12-083 ordered PG&E to develop a Diablo Canyon Incremental Energy Rate (DIER) to be filed in ECAC proceedings. The DIER is used to adjust the AER expense at the end of the forecast period to account for differences between forecasted and actual Diablo Canyon generation. PG&E has presented a detailed explanation of the derivation of the DIER (Exh. 1, pp. 3, 54-56). Our adopted DIER is presented in Appendix C, page 2.

3.6 Adopted Energy Reliability Index

3.6.1 Parties' Positions

Although PG&E assumed an ERI of 1.0 for its April 1 base case resource forecast, it also presented an alternative "PG&E preferred" ERI of 0.71. The alternative ERI was based on inclusion of purchases from Northwest utilities' spot capacity in its computation. DRA, CCC, GRA/IEP, and CSC all proposed ERIs of 1.0 and did not support PG&E's alternative. In developing their Joint Recommendation, DRA and PG&E agreed to an ERI of 1.0, and PG&E agreed not to pursue its lower ERI proposal.

CSC raised concerns over the underlying methodology and assumptions used to support the ERI. While CSC agrees that an ERI of 1.0 should be adopted in this proceeding, it asserts that the method used to determine the ERI is not clearly stated in the record. In its original testimony, PG&E advanced alternative ERI estimates based upon different assumptions over Northwest capacity availability. PG&E's witness Grief testified that these alternative assumptions were not intended to form a part of the joint recommendation. CSC is still concerned, however, that the Joint Recommendation does not specify the method used to derive the ERI.

3.6.2 Discussion

The Joint Recommendation represents a compromise, and the methodologies underlining the parties' positions are not being endorsed as part of the agreement. Accordingly, neither DRA nor PG&E cross-examined each other on this issue. CSC chose not to cross-examine PG&E on its ERI methodology.

Accordingly, we will adopt an ERI of 1.0, but we will not adopt specific language on methodology as proposed by CSC given the intent of the Joint Recommendation, and given that a complete record on methodology was not developed through cross-examination.

3.7 Computer Modeling Conventions

The ERI and IER values are derived from production cost model results which simulate the manner in which utility resources meet system loads. This simulation is driven by the resource and load assumptions that are inputs into the model. In this proceeding, a number of input assumptions were contested. The resolution of these contested issues form the bases for the ERI, IER, and ECAC revenue requirements we adopt herein. In some cases, resolution of IER issues may increase the revenue requirement. In other cases, it may lower it.

Our adopted IER values fall between the proposed IERs sponsored by the parties. They are higher than those proposed by the Joint Recommendation, but lower than those proposed by CCC or GRA/IEP.

The use of different computer models raises potential issues as to how the modeler and the model translate and simplify the complexities of the utility system into terms that the model can understand, and how the model manipulates this information. Over time, we have instituted and modified procedures designed to ensure the full exchange of information pertinent to understanding the computer models used in ECAC proceedings to develop the IER, ERI, and revenue requirements.

In D.89-01-040, we instituted a requirement for workshops to be held to facilitate the understanding of these models. The Commission Advisory and Compliance Division (CACD) convened such a workshop in this proceeding on April 25, 1991 to allow parties to investigate production cost modeling issues and to develop consensus on a base case resource plan and modeling conventions. Parties actively involved in the workshop were PG&E, DRA, GRA/IEP, and CCC.

CACD submitted a final Workshop Modeling Report on June 13, 1991. The report noted that all active modeling parties agreed to use the assumptions in PG&E's filing as the base case.

Accordingly, parties did not provide separate runs, but instead provided a qualitative description of the differences between the two models being used in the proceeding (PROMOD and PROSYM). PG&E, DRA, and CCC all used PROMOD III while GRA/IEP used PROSYM for modeling purposes. The revenue requirements adopted in this decision are based upon application of the PROMOD model. Our adopted revenue requirement also incorporates the uncontested modeling conventions which were listed in the comparison exhibit and are reproduced as Appendix D of this decision.

In the Joint Recommendation in this proceeding, PG&E agreed to make available its QF relational database model by January 1992 on a good faith basis. We will adopt this provision as reasonable.

3.8 Adopted Revenue Requirements and Resource Assumptions

Our adopted ECAC/AER revenue requirements for the 12-month forecast period beginning November 1, 1991 results in a revenue decrease of $178,722,000 comprised of:

ECAC ($167,670,000)
AER ($11,052,000)

The complete computation of our adopted revenue requirements is presented in Appendix A. The adopted revenue requirements are based upon the resource assumptions we have concluded are reasonable, as set forth in Appendix B. We have consistently applied the same resource assumptions in developing the QF price factors adopted in this decision. The ECAC portion of the revenue requirement is composed of both the forecast period costs and amortization of the undercollection in the ECAC balancing account based upon its estimated balance at October 31, 1991 (reflecting the actual July 31, 1991 recorded balance).

3.9 General Framework for Consideration of Resource Assumptions

In adjudicating the resource proposals in this proceeding, we have divided the proposed assumptions into three categories: (1) Uncontested Assumptions; (2) Initially Contested Assumptions Ultimately Agreed Upon; and (3) Contested Assumptions. We discuss each of these categories and our treatment of them below.

The PG&E/DRA Joint Recommendation contained numerous resource assumptions and modeling conventions on which all active parties agreed. Both PG&E and DRA propose that the Commission adopt these uncontested assumptions for this proceeding. No party opposes this recommendation.

We accept as reasonable all of the resource assumptions which were never contested by any active party, or were agreed to prior to the DRA/PG&E Joint Recommendation. Since PG&E's uncontested assumptions were subjected to scrutiny by a number of parties and found to be reasonable, we hereby adopt those assumptions. These uncontested resource assumptions are listed in Appendix E of this decision, as extracted from the comparison exhibit.

We also find reasonable those assumptions which were initially contested among PG&E, DRA, and TURN, but agreed to through the Joint Recommendation and ultimately accepted by all other active parties. We base our conclusion on both an overall evaluation of revenue requirements separately estimated by the parties and the estimates reached in the Joint Recommendation. We discuss these considerations below in terms of the specific assumptions involved.

The Joint Recommendation states that the principles, assumptions, or methodologies underlying the specific items addressed therein are not to be construed as parties' acceptance or endorsement of such principles, assumptions, or methodologies. Neither are they to be deemed by the Commission or any other entity as precedent in any other proceeding or litigation beyond this proceeding. We accept these terms insofar as they pertain to our adoption of assumptions in the Joint Recommendation which were previously in dispute among the cosponsors of that exhibit.

There were a number of assumptions embodied in the Joint Recommendation that were contested by other active parties. For some of these contested issues, we have not adopted the Joint Recommendation's assumptions. Our adopted assumptions are based upon the merits of the evidence presented by each contesting party, and reach a resolution consistent with our findings of fact and conclusions of law. Although we have not adopted the Joint Recommendation in total, but have deviated on certain points, this does not nullify the remaining portions of the Joint Recommendation. Our conclusion is consistent with the intent of the exhibit's cosponsors (Tr. 325).

3.10 Discussion of Adopted Resource Assumptions

Based on this general framework, we will now consider the individual resource assumptions. First, we will cover the initially disputed assumptions which were ultimately stipulated to unanimously. Then we will resolve the contested assumptions which were never unanimously agreed upon.

4. Initially Contested Assumptions Finally Agreed to Unanimously

4.1 Geothermal Resources

4.1.1 Parties' Positions

PG&E and DRA initially disputed the estimate for steam curtailments at PG&E's Geysers plant. DRA forecasted somewhat lower curtailments of 36.7% of total capacity versus PG&E's 39.7% estimate. The QF intervenors accepted PG&E's estimate.

PG&E based its curtailment estimate on an update from its forecast in its 1990 ECAC proceeding. The 1990 forecast was based upon studies from PG&E's steam suppliers and reservoir consultant, in response to a 1989 ECAC decision ordering PG&E to prepare a verifiable method of forecasting steam curtailments. PG&E asserts that no party disputed the forecast in the 1990 ECAC. DRA's forecast was based upon a more simplified linear regression of four years of recorded data. Given the uncertainty in forecasting steam curtailments, DRA believed its linear regression provided a comparable level of accuracy to PG&E's more complicated model.

The PG&E/DRA Joint Recommendation resolved this dispute by adopting the PG&E estimate of 39.7%. Upon cross-examination, DRA's witness noted that the difference between the parties on this estimate was small, and was a beneficial resolution in context to the overall Joint Recommendation.

4.1.2 Discussion

We will adopt the Joint Recommendation's steam curtailment estimate of 39.7%, for a total geothermal generation of 6,411 gigawatt-hours (gWh). Based upon the initial evidence submitted, the adoption of PG&E's original estimate by the Joint Recommendation is a reasonable resolution of the parties' dispute, and is unanimously supported.

4.2 Gas Curtailments for OF-In Purposes

4.2.1 Parties' Positions

PG&E and DRA forecasted different levels of gas curtailments in their initial testimony. Gas curtailments increase ECAC revenue requirements since curtailed gas must be replaced with more expensive fuel oil. PG&E initially forecasted a fuel oil burn of 4.1 million barrels or $94.6 million due to gas curtailment, assuming normal temperatures. DRA forecasted a fuel oil burn of only 2.0 million barrels or $46.1 million. The difference of $48.5 million is attributable largely to different estimates of supplies from El Paso Natural Gas Company and storage gas supplies. These supply estimates differ by roughly 9 billion cubic feet (Bcf) and 12 Bcf respectively.

In the Joint Recommendation, PG&E and DRA amended their positions to recommend oil test burns of 42,000 barrels per month and gas curtailment requiring fuel oil burn of 3,077,000 barrels for the forecast year. This represents approximately the midpoint between the original positions of the parties. No other parties disputed the Joint Recommendation on gas curtailments for QF-in purposes. The dispute over gas curtailments for QF-in/QF-out purposes is discussed separately.

PG&E used the GASDOS model to generate its gas curtailment forecast. The unbundling of gas procurement for noncore customers creates more uncertainty as to the risk of curtailment than in prior years' ECACs.

In rebuttal, PG&E explained the differences in assumptions between DRA and PG&E gas curtailment estimates. Since DRA and PG&E subsequently reached agreement on an estimate of gas curtailments in the Joint Recommendation, neither party cross-examined the other on methodological differences. While the Joint Recommendation sponsors a gas curtailment estimate, it does not advocate adoption of either DRA's or PG&E's original forecasting methodologies.

4.2.2 Discussion

Since the Joint Recommendation estimate falls within the range of original estimates of PG&E and DRA and was not contested by any other party, we find the estimate to be reasonable. Accordingly, we will adopt the Joint Recommendation estimate of gas curtailments for purposes of this proceeding.

As a condition of accepting the compromise on a gas curtailment estimate, PG&E agreed to convert the mainframe GASDOS model to a desktop model, and to perform certain modeling conversions related to GASDOS as specified in Item C.5. of the Joint Recommendation. We will require PG&E to satisfy these modeling conditions.

4.3 Commodity Gas Prices

4.3.1 Parties' Positions

All active parties ultimately agreed on commodity gas price assumptions. Initially, PG&E, DRA, and TURN all presented different estimates of commodity gas prices for ECAC purposes. In preparing their revised IER calculations, both GRA/IEP and CCC agreed to the use of the gas commodity price assumptions in the Joint Recommendation while continuing to contest the assumptions for dispatch cost and incremental UEG cost. (Exhs. 59 & 60).

Subsequently, PG&E, DRA, and TURN prepared a Gas Price Joint Recommendation (Exh. 14) which resolved all the disputed differences among those three parties with respect to gas price forecasts for the ECAC revenue requirement. For gas commodity costs, the Gas Price Joint Recommendation adopted the midpoint between the commodity costs from the original testimony of DRA and TURN.

According to the Gas Price Joint Recommendation testimony, the basis for the proposed prices was that they represented a compromise on behalf of all sponsoring parties. The principles, assumptions and methodologies underlying specific issues addressed in this joint exhibit were not to be deemed as precedent-setting in any proceeding.

A comparison of the initial and final recommendations on commodity gas prices of the parties to the Gas Price Joint Recommendation are summarized herewith:

Comparison of Parties' Positions
on Gas Price Assumptions
($/MMBTU)

Supply Source	DRA (Exh. 20)	TURN (Exh. 13)	PG&E (Exh.17)	Gas Price Joint Recommendation (Exh.14)
S.W. -Spot	2.04	1.82	2.30	1.95
-L.T.	2.04	1.86	2.26	1.93
Calif.	1.90	1.90	2.01	1.90
PGT	1.81	1.64	2.04	1.72

The bases for parties' assumptions on commodity prices prior to the joint recommendation are as follows:

PG&E based its price assumptions on the gas prices expected to be adopted in PG&E's 1991 Annual Cost Allocation Proceeding (ACAP) (A.90-08-029), and made no further adjustments.

DRA did not use ACAP price assumptions. For California suppliers, DRA used PG&E's most recent price offer, reflecting an 11% reduction from current prices. For Canadian suppliers, DRA assumed on an interim basis the same 11% reduction pending new negotiated prices. For Southwest gas, DRA computed a time series projection of actual Southwest gas prices using the most recent 51 months of recorded California border prices. DRA then lowered the computed price by $0.1834/decatherm (Dth) to reflect an expected reduction in the El Paso volumetric rate as testified to by PG&E in the Capacity Brokering case (Rulemaking (R.) 88-08-018). DRA asserted that Southwest prices have dropped dramatically since the most recent ACAP, and PG&E's reliance on ACAP prices for Southwest gas assumptions had no foundation.

TURN's initial testimony raised three basic objections to PG&E's gas price forecasts: First, PG&E ignored an expected 23 cents/Dth reduction in El Paso volumetric charges. Second, PG&E failed to reflect its own formal proposal for a 50 cents/Dth reduction in Pacific Gas Transmission (PGT) gas. Third, PG&E improperly assumed the recent gas price drop will not continue beyond spring 1992.

<u>4.3.2 Discussion</u>

The commodity prices in the Gas Price Joint Recommendation fall within the range proposed by DRA and TURN, provide an outcome which is beneficial to the ratepayer, and result in lower expenses than either DRA's or PG&E's earlier forecasts. The proposed commodity prices were finally accepted by all active parties, and thus we will adopt them for computation of the gas components of the revenue requirement.

4.4 Spinning Reserve Assumptions

4.4.1 Parties' Positions

PG&E differed with DRA and QF intervenors in their initial testimony on spinning reserve assumptions. PG&E assumed a 7% spinning reserve constraint in its PROMOD modeling for weekday periods only, while assuming 9% during weekend subperiods in October through April and 11.5% for weekend subperiods in May through September. PG&E bases its estimate on the simple average of the spinning reserve margins at the time of monthly peak recorded from 1988 thorough 1990.

DRA, CCC, and GRA/IEP all assumed a 7% spinning reserve constraint for all periods of the year. Parties objected to the use of PG&E's recorded data because PG&E did not adjust its historical data to account for other constraints which would impact spinning reserve. These parties argued that in practice, PG&E plans and commits to meet only a 7% spinning reserve. The California Power Pool Agreement requires each member maintain spinning reserves of at least 7%.

Without resolving the merits of the underlying methodology differences of the parties, PG&E and DRA agreed upon a 7% spinning reserve assumption for all subperiods in the Joint Recommendation.

4.4.2 Discussion

Since the Joint Recommendation resolved this dispute in favor of those parties opposing PG&E, it resulted in unanimous support for a 7% spinning reserve assumption. Based on the underlying evidence and the resolution by parties, the Joint Recommendation of 7% spinning reserve is reasonable, and shall be adopted.

4.5 Fuel Oil Inventory

4.5.1 Parties' Positions

PG&E and DRA initially disputed the estimates for residual fuel oil inventory and related carrying costs. PG&E first forecasted an average residual fuel oil inventory of 8.3 million barrels and an inventory carrying cost of $12.3 million. In its June update testimony, PG&E revised its estimates to 8.5 million barrels of residual fuel oil.

DRA forecasted 7.2 million barrels of residual fuel oil inventory. Two factors account for the difference: (1) differing gas curtailment estimates; and (2) DRA's estimated 60-day inventory resupply time versus PG&E's 90-day estimate. No other party sponsored independent estimates on this issue.

In the Joint Recommendation, DRA and PG&E resolved their dispute by proposing an average residual fuel oil inventory of 8.3 million barrels, without making any explicit assumptions as to the exact number of inventory resupply days underlying the estimate.

4.5.2 Discussion

Since no other party disputed this estimate, and it falls within the range of DRA's and PG&E's earlier estimates, we will adopt it for use in this proceeding. This resolution eliminates the need to make findings on the resupply dispute for purposes of this proceeding, and is consistent with the gas curtailment estimate we have adopted.

We will likewise adopt the Joint Recommendation's estimates for an average distillate inventory of 131,000 barrels. This results in a total average inventory of 8,435,000 barrels, and a residual oil peak inventory of 8,987,000 barrels.

We will also adopt the Joint Recommendation's assumption on inventory carrying costs, based upon a 6.24% commercial paper interest rate which reflects DRA's original assumption and is consistent with a downward interest rate trend since PG&E's initial filing (Tr. 339).

4.6 Irrigation District Expenses

4.6.1 Parties' Positions

DRA initially proposed a reduction of $47,782,900 in the ECAC/AER revenue requirement to remove certain purchased power costs it believed were improperly included. (Exh. 10.) DRA claimed

PG&E was erroneously recording the fixed bond payments and fixed and variable O&M payments related to energy and firm capacity purchases from irrigation districts in Federal Energy Regulatory Commission (FERC) Account 555 (Purchased Power). DRA concluded these costs were improperly included in the ECAC proceeding, citing D.850731, which indicated that "fixed charges" were to be excluded from ECAC recovery. Likewise, DRA proposed excluding irrigation district expense allocated to purchased water for power from ECAC/AER recovery. DRA concluded, however, that "PG&E is not precluded from applying to recover these expenses in its next General Rate Case."

PG&E opposed DRA's proposal (Exh. 15), stating that the charges have been included by the Commission as part of ECAC for several years, that the costs are legitimate capacity charges warranting ratepayer recovery, and that DRA proposed no transition mechanism to provide recovery of the charges until PG&E's 1993 test year general rate case (GRC).

In the Joint Recommendation, PG&E and DRA reached a mutually agreeable resolution of this dispute. PG&E withdrew its opposition to the proposed removal of the charges from ECAC, provided that the Commission agrees that the removal would not take effect until January 1, 1993, at which time these costs would begin to be recovered as part of PG&E's Base Rate Revenue Amount in ERAM. In the interim, the costs would continue to be recovered in ECAC rates.

<u>4.6.2 Discussion</u>

There is no dispute over the reasonableness of the irrigation district costs. The Joint Recommendation reaches a reasonable resolution of the dispute over the proper recovery vehicle for the costs and provides a transition period to allow PG&E continued recovery of the charges through ECAC until the next GRC test year.

The adoption of the Joint Recommendation on this issue eliminates the need to adjudicate the underlying merits of the arguments of PG&E or DRA. We need simply note that the recovery of the costs through ECAC in this proceeding with transfer to base rate recovery beginning January 1, 1993 will not disadvantage either ratepayers or shareholders.

Accordingly, we adopt the Joint Recommendation's proposal that effective January 1, 1993, the O&M expenses not related to the purchased volumes of water and power plus the fixed costs associated with the irrigation district contracts will be recovered as part of PG&E's Base Rate Revenue Amount in ERAM. PG&E will include forecasts of these expenses in the Notice of Intent for its test year 1993 GRC. As requested by the joint parties, we will adopt an estimate of $54,055,300 for irrigation district expenses for this proceeding, which includes the costs DRA had proposed to disallow. PG&E will be permitted to seek recovery of the expenses associated with irrigation district contracts for November and December 1993 in its 1992 ECAC proceeding.

4.7 NCPA Sales

The Northern California Power Administration (NCPA) is a resale customer of PG&E. DRA's Forecast Report (Exh. 9, Ch. 12, pp. 12-13) stated that sales to NCPA are FERC-jurisdictional and that no revenues from NCPA are in PG&E's filing. On rebuttal, PG&E noted that while the text of DRA's report does not recognize them, the DRA Forecast Report, Part I, Table 16-2 did include the total $92 million of revenue from Designated Sales Transactions forecast by PG&E. PG&E also provided DRA with a cost/benefit study of the NCPA off-peak energy sale as agreed upon in PG&E's 1990 ECAC proceeding. Accordingly, DRA and PG&E jointly recommend that the Commission find that it is reasonable to treat the NCPA off-peak energy sale as a Designated Sales Transaction in this proceeding.

supplies. Based upon PG&E's assumption of 100% Southwest spot gas for incremental noncore demand, CCC and GRA/IEP initially advocated using the same 100% assumption for the dispatch cost. The QFs subsequently revised their position to reflect a 75/25 mix of Southwest/PGT gas for both dispatch and incremental noncore purposes. Although they still argued for consistent assumptions, they were persuaded by PG&E's arguments that less than 100% of Southwest gas would be used for dispatching.

PG&E denied any inconsistency in its treatment, explaining that the gas source used in daily dispatch decisions serves an entirely different purpose than the gas used to determine monthly UEG usage above core subscription volumes. The latter source is based on the overall volume of gas purchased over the course of the entire year. It is not merely the sum of gas taken daily on an incremental basis.

According to PG&E, the 65% limit on core subscription gas is only a seasonal and monthly limitation while PG&E expects to have significant flexibility on a daily basis. Core subscription can be on the margin on a daily basis (Tr. 140). PG&E also noted its anticipation of purchasing gas from various sources in addition to core and Southwest gas. For these reasons, PG&E argues that intervenors' assumption that dispatch gas comes 100% from Southwest spot purchases is unfounded.

5.1.3 Discussion

We first address the dispute over the dispatch price. PG&E actually presents two separate arguments to rebut intervenors' assumption about the source of dispatch gas. First, it cites the supply availability of sources other than Southwest spot gas for dispatching. Second, it cites its flexibility to dispatch core supplies as the marginal fuel on certain days. Based on the evidence as discussed under "Incremental Noncore Gas Supply" below, we agree with PG&E that it is reasonable to assume dispatch supplies will not come exclusively from the Southwest spot market.

There was no opposition to the PG&E and DRA joint request, and we will accordingly grant it, as reflected in our adopted resource assumptions.

5. Contested Assumptions

In this section, we discuss those assumptions which were not unanimously agreed to as a result of the DRA and PG&E Joint Recommendation, and present our adopted resolution.

5.1 Assumptions for Gas Dispatch and Incremental Gas

There was considerable controversy over the proper assumptions for the gas dispatch price for electric generation. On one side of the dispute were PG&E, DRA, and TURN, the parties to the Gas Price Joint Recommendation. On the other side were QF intervenors, CCC and GRA/IEP.

The QFs disputed both the sources of dispatch gas and the cost elements to be included therein. The QFs also claimed there should be a linkage between the sources of dispatch gas and the sources for incremental noncore gas.

5.1.1 Sources of Gas for Dispatch and for Incremental Noncore Supply

5.1.2 Parties' Positions

The Gas Price Joint Recommendation assumed a 50/50 mix of Pacific Gas Transmission (PGT) and Southwest spot gas for dispatching purposes. It also assumed that incremental noncore gas supplies for utility electric generation will be derived 100% from Southwest spot gas. PG&E is limited to taking a maximum of 65% of its ACAP forecast electric generation requirements from the core portfolio per D.90-09-089. Thus, if UEG requirements differ from those forecast, only Southwest gas will make up the difference, based on PG&E's assumptions.

Both CCC and GRA/IEP argued it is inconsistent to make different assumptions about the source of incremental noncore gas versus marginal gas used for electric dispatch. They propose that the dispatch cost reflect the same assumption as for noncore gas

We conclude, however, that these additional supplies are available from the noncore UEG market, and that it is not necessarily appropriate to assume that core supplies are used for marginal dispatching.

Although scheduling flexibility could theoretically allow some core volumes to be on the margin, PG&E failed to demonstrate how such flexibility justifies its assumption that fully 50% of the time, cheaper Canadian gas will be available on the margin and dispatchable. (Tr. 160.)

PG&E admitted that its 50/50 assumption reflected the lack of certainty as to the true mix of gas sources for dispatch purposes. As PG&E's witness Smith stated: "We believe 50-50 is probably a better estimate. 75-25 may be reasonable. But right now we just don't know exactly where we stand, except as I said, we certainly do not expect it to be Southwest gas 100% of the time." (Tr. 161.) PG&E's witness was unable to provide an assessment that a 50/50 mix was any more plausible than a 75/25 mix for dispatch purposes. (Tr. 161.)

The uncertainty expressed by PG&E's own witness as to how actual dispatching would proceed raised further questions as to the reasonableness of assuming core gas as a dispatch source. PG&E demonstrated no empirical quantification linking the amount of time that core gas would be on the dispatch margin with its 50/50 Southwest/PGT mix assumption. In any event, even if some core gas were assumed in the dispatch rate, PG&E's claimed 50% availability of PGT gas for dispatching appears overstated, given the relative scarcity of such cheaper gas.

PG&E warns of the scarcity of PGT Canadian gas relative to Southwest gas in Exh. 1: "If Canadian supplies are less expensive than those from the Southwest, then customers with higher transportation priorities will use all available interruptible capacity from Canada and the only interruptible capacity available for PG&E's electric generation will be from the Southwest." We see no reason why PGT supply scarcity applicable to noncore volumes will not also reduce the availability of PGT gas at least to some degree for dispatch purposes. According to TURN, core volumes (including PGT Canadian gas) are assumed to be the first through the pipeline (Tr. 142), further suggesting a less-than-even chance of PGT gas being on the margin during the year.

If we were to accept PG&E's argument that the core volumes will be on the dispatch margin, we should also consider the resulting costs associated with lost flexibility. For core gas to be on the margin, PG&E would have to exceed its average limit of 65% of demand on certain days. The excess daily core takes beyond 65% would require PG&E to take less than 65% of demand from core gas on a subsequent day in order to stay within the seasonal and annual 65% core limits. Thus, by dispatching core gas on a given day in excess of its average 65% limit, PG&E would be reducing its future flexibility to dispatch cheaper core gas at a later date. There is no indication PG&E factored in the effects of this lost flexibility in assuming core volumes are on the dispatch margin.

On this basis, although it may be theoretically possible for PG&E to take daily core volumes as its marginal fuel, it is not evident that it would necessarily be cost-effective to do so, considering the lost opportunity to take future core gas. CCC's brief warned of an example where dispatching core gas as a marginal fuel may not reflect true economic opportunity cost, and could cause nonoptimal dispatching over time: "For example, if PG&E chose to forego a non-gas option, early in the month, that is more expensive than the use of core gas supplies but less expensive than use of the noncore gas supplies, PG&E could miss the opportunity to reduce its total monthly costs by using both the less expensive core supplies and the less expensive non-gas alternative, which may not be available once PG&E reaches its 65% core limitation."

Thus, even if core quantities are dispatched on the margin on a given day, using the core price for dispatch purposes ignores the costs of lost flexibility to take future core supplies. PG&E's flexibility in daily dispatching of core volumes doesn't change the fact that core volumes are in reality fixed over the forecast year. Increased flexibility on some days must be offset by reduced flexibility later on other days.

Given the above considerations, we cannot reasonably assume that PGT gas will be on the dispatch margin 50% of the time, nor can we assume core gas should be included for computing the dispatch cost of gas. While we agree that it is reasonable to assume at least some non Southwest gas will be available for dispatch, we conclude that such additional supply flexibility should be drawn first from noncore supplies, not the core portfolio. This will help to avoid depleting the finite supplies of cheaper core gas prematurely. We conclude that the most defensible assumption is that dispatch fuel will come from noncore incremental sources. We will adopt this assumption for dispatch purposes.

To determine the dispatch mix, we must then resolve the related dispute over the appropriate source(s) of incremental noncore gas. We take up this topic next.

5.1.4 Incremental Noncore Gas Supply

Although PG&E, DRA, and TURN assume that 100% of noncore incremental gas comes from Southwest spot sources, these parties' testimony leads to a conclusion that at least some noncore UEG demand will be met from sources other than the Southwest. As stated in TURN's opening brief, "PG&E will have the option of purchasing Canadian gas from shippers on PGT's interruptible queue as part of its noncore procurement." Also, PG&E in Exh. 15 states, "In addition to ...core gas and gas from the Southwest, the electric department anticipates participating in" various additional gas sources. PG&E further admits "the details of the purchases from the Southwest and other supply sources (generally referred to as the UEG portfolio) have not been finalized."

DRA's witness Hallman likewise conceded that not all incremental noncore gas is necessarily from the Southwest: ("When it comes to the revenue requirements...I could go half and half, or some percentage of PGT being on the margin...." (Tr. 185.)

5.1.5 Discussion

These facts are inconsistent with PG&E's assumption that 100% of incremental noncore UEG gas comes from the Southwest. Thus, even apart from intervenors' arguments as to the need for consistency between dispatch and noncore gas, the evidence shows that PG&E's 100% Southwest gas assumption for incremental noncore gas is unrealistic.

Although PG&E's 100% Southwest spot price assumption for noncore gas is unrealistically high, it does suggest that at least more than half of noncore incremental supplies will come from the Southwest, given core customers' priority claim on cheaper PGT gas.

The lack of certainty over both dispatch and incremental gas sources in light of gas industry restructuring makes it difficult to develop estimates for either variable. Although the evidence indicates it is unrealistic to assume 100% Southwest gas for either incremental noncore or dispatch purposes, we are also convinced that PGT gas will be less available than Southwest gas for either of these two purposes. We will therefore adopt a mix of 75% Southwest gas and 25% PGT gas both for determining the incremental noncore UEG supply and for computing the dispatch gas price. In this respect, we agree with PG&E that sources other than the Southwest will be available for dispatching, but conclude they will come from noncore sources, and will be less available than Southwest gas.

The adopted mix represents the midpoint between assumptions of either no PGT gas versus equality of PGT and Southwest gas, and reflects the uncertainty of supply sources in light of gas industry restructuring. It further balances the influences of (1) PG&E's flexibility to take gas sources other than

Southwest spot gas both for dispatching and noncore procurement against (2) the relative supply scarcity of cheaper gas.

5.2 Cost Elements to Include in Dispatch Price

5.2.1 Parties' Positions

The other major controversy over gas dispatch assumptions involved the treatment of cost elements to include in the dispatch price. The dispute centered on whether to include PG&E's UEG Tier II transport rate (a Utility Electric Generation interdepartmental tariff rate component) and on the appropriate factor for gas shrinkage. Parties to the Gas Price Joint Recommendation exclude PG&E's UEG Tier II rate from the dispatch price and estimate gas shrinkage at 4%. CCC and GRA/IEP instead advocate the Tier II rate be included in the dispatch cost and also estimate shrinkage at 3.5%. In addition, GRA/IEP included brokerage fees and franchise and uncollectibles factors in its dispatch calculation. We will discuss each of these factors, in turn.

5.2.2 Tier II Rate Treatment

The UEG Tier II rate is based on gas system cost estimates adopted in PG&E's general rate case and attrition rate adjustments, and allocated among gas customer classes in ACAPs. The Tier II rate paid by the electric department is a variable transportation charge based on the total volume of gas it purchases.

CCC and GRA/IEP argue that the Tier II rate belongs in the dispatch price since it is an avoidable cost to the electric department that varies with the amount of gas taken each moment. PG&E argues that the Tier II rate is merely an artificial transfer price between the electric and gas departments, and includes a portion of the "fixed" costs of owning, operating and maintaining PG&E's gas system. According to PG&E and TURN, from the perspective of combined gas and electric departments, Tier II, related costs are not avoidable, and thus, should not enter into gas dispatch costs.

PG&E and TURN argue that the Commission's "one-company" policy requires that dispatch prices be established based upon one-company system costs rather than electric department costs. The goal of the one-company policy is to minimize overall costs considering both gas and electric customers. As such, the interdepartmental Tier II transfer price would not be treated as a component of the dispatch cost, since it is not an avoidable cost, viewed from the perspective of the combined gas and electric system costs. PG&E and TURN further argue that including the Tier II rate in the dispatch price merely increases the IER and revenue requirement without providing any real benefit to ratepayers.

CCC and GRA/IEP respond that the one-company approach should be abandoned in reference to electric dispatching assumptions, because it creates an artificial price signal upon which PG&E bases dispatch decisions. They also argue that the one-company approach is inconsistent with the Commission's procompetitive goals, particularly with respect to the current restructuring of the gas industry. According to these intervenors, an understatement in the dispatch price may lead to use of less economical generation sources, would subsidize the gas department in a anticompetitive manner, and would conflict with state and federal law by paying QFs less than PG&E's full avoided costs.

<u>5.2.3 Discussion</u>

The purpose of the dispatch, as opposed to the commodity, cost of gas is to measure the avoidable or incremental costs at stake relative to dispatch choices among alternative resources. Accordingly, fixed commodity charges are not properly included in the dispatch cost since they do not change as a result of dispatching alternatives. The proper dispatch price is essential to determine the proper sequence in which resources should be dispatched to provide most efficient generation costs charged to customers. The correct dispatch price is also needed to forecast the proper prices for power sources from QFs and other purchased power suppliers whose payments are based upon PG&E's system avoided costs. We have evaluated parties' arguments regarding the treatment of the Tier II rate with these considerations in mind. We have also considered parties' opening and reply comments to the proposed decision of the ALJ relative to this issue.

CCC and GRA/IEP have not provided compelling reasons to justify inclusion of the Tier II rate. PG&E, TURN, and DRA have shown that inclusion of the Tier II rate would actually increase ratepayer costs. We conclude that, on balance, it is not appropriate to include the Tier II rate in the dispatch cost of gas.

We will consider each of the arguments presented by parties relating to Tier II treatment, in turn. As to the argument that exclusion of the Tier II rate creates an artificial price signal, we disagree. It is true that the Tier II rate, itself, is volumetric and is billed to the electric department based on actual units of gas transported. However, the underlying transportation costs incurred by PG&E to deliver gas for electric generation are fixed, not variable. The exclusion of the Tier II rate from the dispatch cost realistically recognizes that the actual transport costs associated electric department gas purchases are not avoidable relative to the company as a whole. Only if we assume the electric department is a separate entity from the gas department can the argument be made that exclusion of Tier II creates an artificial dispatch price signal.

In order to treat gas transport charges as an avoidable cost, we would have to ignore the fact that the electric department's transport costs are ultimately part of the total fixed corporate costs of PG&E. We would have to abandon our long standing policy of minimizing ratepayer charges by setting revenue requirements based upon costs incurred by the company as a whole.

This least-cost policy has been traditionally described as the "one-company" approach. CCC and GRA/IEP do not dispute that under the one-company perspective, the gas transport costs incurred by PG&E are fixed. Rather, they argue that we should not apply the one-company policy in this instance. They advocate that we abandon the "one-company" approach on the basis that it is inconsistent with our procompetitive goals, particularly in the context of gas industry restructuring.

We find no basis in our gas restructuring rules to abandon our longstanding one-company policy with respect to intercompany transfer payments for gas transport. Our gas restructuring rules adopted in D.90-09-089 provide a framework for the electric department to procure its gas competitively as a separate entity from the gas department. As PG&E states: "after August 1, 1991, PG&E will dispatch its electric plants based on the incremental cost of gas faced by the electric department rather than by the corporation as a whole. This is a consequence of gas industry restructuring." (Exh. 15, p. BTS-1.) PG&E's reference, however, is to the fact that the electric department must now limit its purchases of core subscription gas to 65% of its requirements. The remaining 35% is to come from noncore sources. Thus, the dispatch cost of gas faced by the electric department necessarily will differ from the core portfolio costs faced by the company as a whole.

The same distinction does not apply relative to gas transport, which the Tier II rate covers. Unlike procurement, the transport of gas is not subject to competition. PG&E's gas department is currently the only source for transporting all electric deparment gas purchases. GRA/IEP and CCC have not demonstrated how minimizing costs to ratepayers through exclusion of Tier II transport charges in the dispatch price conflicts with our procompetitive goals.

Thus, there is no basis to treat the electric department as separate from the gas department with respect to transport of gas in the context of our procompetitive goals. The fact that the second tier of the electric department transport rate is volumetric is merely an artifact of our ratemaking. It was not our intent in designing Tier II as a volumetric rate that it be used to penalize ratepayers with higher rates. The Tier II rate does not create competition with respect to gas transport. It does not change the fact that PG&E as a whole incurs zero incremental transport costs as a result of dispatching a marginal unit of gas. Accordingly, we reject the argument that we should abandon our one-company policy in the treatment of the Tier II rate because of any perceived conflict with our gas restructuring goals. On a broader basis, a change in our longstanding one-company policy could raise generic concerns affecting other utilities or other contexts where the one-company rule would apply. We hesitate to repudiate such a fundamental ratemaking principle absent a more comprehensive record on the generic implications of changing our one-company policy and its relationship to other Commission goals among all California utilities.

We are also unpersuaded by the argument of CCC and GRA/IEP that exclusion of the Tier II rate may lead to use of less economical generation resources. PG&E and TURN have shown to the contrary that the inclusion of the Tier II rate actually leads to less economical generation costs for ratepayers. Since the price of Northwest purchased power is indexed to PG&E's system incremental cost (Exh. 1, pp. 3-45), an increase in the dispatch price for the Tier II rate results in a corresponding increase in the price of purchased power, rather than any significant change in quantity dispatched.

This price-quantity sensitivity effect is illustrated in the CCC's late filed exhibit (Exh. 60) which corrected an overstatement error in the dispatch price (see PG&E Reply Brief,

p. 13). In correcting the error, CCC changed the price of Northwest power by about 3.1%, but changed the quantity by only 0.6%. (Compare July 23 versus August 2 revisions in Exh. 60, Line 13, Columns (a) and (b) of the Calculation of Change in Revenue Requirement). Thus, any minimal change in volumes is more than offset by automatic increases in purchased power prices. Ratepayers would likewise pay higher costs for QF purchases to the extent that Tier II inclusion increases the avoided costs used to compute QF payments.

Likewise, CCC and GRA/IEP presented no evidence to support a finding that exclusion of Tier II from the dispatch price somehow unfairly subsidizes the gas department in an anticompetitive manner. The discussion above illustrates that the primary effect of Tier II inclusion is to increase prices paid to purchased power suppliers, rather to change quantities sold. GRA/IEP and CCC have not shown that PG&E shareholders are enriched as a result of exclusion of Tier II from the discount rate. Rather, ratepayers are relieved of the burden of paying higher prices for purchased power. Accordingly, we find no basis to conclude that third party power producers are unfairly disadvantaged in their ability to compete as a result of Tier II exclusion from the dispatch price.

We are also unpersuaded by the argument of CCC and GRA/IEP that failure to include Tier II in the dispatch price would conflict with state and federal laws by resulting in QF payments less than PG&E's full avoided costs. Since we have determined above that the proper measure of PG&E's full avoided costs should reference PG&E's total company transport costs, our Tier II exclusion results in payments to intervenors based upon PG&E's full avoided costs in conformance with state and federal laws.

TURN also raises the concern that if we were to include the Tier II rate in dispatching for forecast modeling purposes, this would be in conflict with PG&E's actual dispatch operations.

This inconsistency would create an inherent mismatch between adopted resource assumptions and real-world operations. In the absence of a complete record as to the impacts and advisability of requiring PG&E to change its recorded operations relative to generation dispatching, we hesitate to order such a change in operations. Accordingly, our adopted modeling assumptions should be consistent with actual operations.

In summary, none of the reasons presented by CCC and GRA/IEP compel us to include the Tier II rate in the dispatch price. PG&E and TURN, however, show that ratepayers are disadvantaged by including the Tier II rate. Accordingly, we exclude the Tier II rate from our adopted dispatch assumptions. Consistent with this treatment, we likewise reject GRA/IEP's proposal to include associated brokerage fees and franchise and uncollectibles in the dispatch rate, since these are not avoidable costs.

<u>5.2.4 Intrastate Shrinkage Rate</u>

The Gas Price Joint Recommendation includes a 4% intrastate shrinkage factor to account for "lost and unaccounted for gas" and compressor fuel used to move gas in intrastate pipelines (Tr. 135). Sponsors of the Gas Price Joint Recommendation advocate use of the 4% figure on the basis that "it reflects PG&E's actual dispatch price assumptions."

The QF intervenors, on the other hand, use a 3.5% shrinkage factor. This is based upon the intrastate shrinkage component charged under the UEG tariff.

Consistent with our treatment of the Tier II rate, we adopt an interstate shrinkage factor of 4% to account for intrastate shrinkage as proposed in the Gas Price Joint Recommendation. This factor represents "lost and unaccounted for gas" and compressor fuel used to move gas in intrastate pipelines (Tr. 135). The 4% intrastate shrinkage rate assumption is consistent with the manner in which PG&E actually dispatches its system. It is also consistent with our treatment of the Tier II rate by basing dispatch costs on actual company operations rather than interdepartmental tariff rates.

5.3 Gas Curtailments in QF-Out Case

5.3.1 Parties' Positions

Although intervenors took no position on the absolute level of gas curtailments, both GRA/IEP and CCC contended that the IER should be increased to reflect greater gas curtailments based upon a QF in/out computation. GRA/IEP proposes that the added curtailments be computed by first measuring fuel oil consumption as a percentage of total thermal requirements in the QF-in case, and then applying this same percentage of fuel oil consumption to total thermal requirements in the QF-out case. GRA/IEP believes it is unreasonable to expect curtailment-driven fuel oil burns not to increase absent QF generation, since PG&E would rely more heavily on its oil and gas system. Although the effects of gas curtailment from removal of QFs cannot be known with exact precision, GRA/IEP believes that its assumption is more reasonable than PG&E's assumption that no change in curtailments would occur.

PG&E opposed GRA/IEP's proposal, arguing that no adjustment should be made to the IER for gas curtailments. PG&E opposed any adjustment to the IER because of the significant uncertainties over how curtailments might be impacted by removal of QFs. PG&E's expert concluded that "we have no information as to what the gas availability might look like in a QF-out case" (Tr. 4:247). According to PG&E, because gas curtailments in the QF-in case were based on gas volumes determined in PG&E's ACAP decision, the only way to determine gas availability in a QFs-out case would be to repeat the ACAP proceeding with new QF-out assumptions. Absent running a new ACAP model incorporating the new assumptions, the level of gas available to UEG and, hence, the level of curtailments cannot be known. (PG&E, Grief, Tr. 246-247.)

PG&E's witness Grief listed variables that could affect gas availability in unknown ways based on a QF-out assumption. These include different PG&E actions as to pipeline access, gas storage, or placement of other resources. Demand charges would also change. Since gas-fired cogenerators make up 80% of variable-priced QFs, the elimination of these QFs' gas consumption would actually increase gas available to PG&E, even after allowing for gas supplies that these QFs would retain for themselves.

5.3.2 Discussion

We conclude that it is not appropriate to assume an increase in gas curtailments for QF-out purposes. GRA/IEP's assumption that gas curtailments would increase because of heavier reliance on PG&E's fossil-fueled generators absent QFs fails to take into account adequately all the potential effects on gas availability absent QFs, as explained in PG&E's testimony.

To support its gas curtailment adjustment, GRA/IEP cited Exh. 50, sponsored by CCC witness Younger. Exhibit 50 included excerpts from a recent quarterly posting of PG&E's QF prices which showed an oil allowance as the marginal fuel part of the time. GRA/IEP argued that PG&E's quarterly QF price postings supported its proposal to recognize increased curtailment-driven oil burns in the IER.

Exhibit 50 fails to justify GRA/IEP's proposed IER adjustment. The avoided cost posting is intended to reflect the then-current status of fuel prices and fuel mix of the utility, as noted in the data response appended to Exh. 50. The timing, purposes, and measurement requirements of the avoided cost postings differ from those of the IER. Because of these differences, the analogy GRA/IEP draws between quarterly QF avoided cost postings and the annual IER relative to the treatment of gas curtailments is not sustainable.

Unlike the quarterly postings, the IER is based on a longer term forecast using the utilities' production simulation models in a QFs-in/out analysis. To compute the percent of time that oil is the marginal fuel for purposes of the quarterly avoided cost postings, PG&E merely forecasts each quarter the fraction of its total fossil fuel mix represented by oil as noted in PG&E's data response included in Exhibit 50. This derivation is not based on any QF-in/out analysis as is required to compute the IER. The simplified method used to compute oil allowances in the quarterly postings provides no basis to determine what changes in oil usage would result from the absence of QFs, which is the variable GRA/IEP seeks to reflect in the IER. As noted above, the evidence does not inform us as to how gas curtailments would change absent QFs. Consequently, the payment procedures used in quarterly avoided cost postings do not support GRA/IEP's gas curtailment adjustment to the IER methodology.

Given all the uncertainties of measurement as noted by PG&E, we have insufficient basis to conclude that GRA/IEP's assumption of a proportionate increase in gas curtailments in the QF-out case is reasonable. On the other hand, the assumption of no change in gas curtailments in the QF-out case is generally consistent with our past policy of not changing resource assumptions in the QF-out case (D.88-11-052, 29 CPUC 2d 566, 600, 601). Accordingly, we will not adopt GRA/IEP's gas curtailment adjustment in computing the IER.

5.4 Diablo Canyon Generation

5.4.1 Parties' Positions

There was considerable controversy surrounding the appropriate estimate for Diablo Canyon nuclear generation expense. The controversy centered on the proper assumption for the duration of Diablo Canyon's refueling outages during the forecast period. Prior to submitting the Joint Recommendation, PG&E forecasted a 10-week outage while DRA forecasted a 12-week outage. DRA based its original 12-week outage estimate on a review of industry data for 13 U.S. nuclear plants similar to the Diablo Canyon units. DRA also cites D.88-11-052 and D.89-12-015 as evidence that 12-week refueling outages have been adopted in the past for the Diablo Canyon units as the optimal refueling time to cover all contingencies that might arise. The forecasts adopted in those decisions were based upon all of the plant's completed cycles, not just the two most recent ones.

PG&E and DRA resolved their dispute by agreeing on a 10-week outage in the Joint Recommendation. On cross-examination, DRA's witness on this issue stated he was persuaded by reviewing PG&E's rebuttal evidence on this issue. (Tr. 1:69/Gibson/DRA).

CCC and GRA/IEP each sponsored testimony proposing a 12-week outage. TURN expressed support for the 12-week outage assumption in its brief.

Revenue requirement increases as the length of the assumed Diablo outage decreases, because the costs of generation displaced by Diablo are cheaper than the performance-based prices PG&E receives for Diablo Canyon generation. The IER, however, decreases as the assumed Diablo outage decreases.

PG&E's forecast of Diablo Canyon refueling outages of 10 weeks and a 90.7% operating capacity factor yield a generation of 15,808.7 gWh. PG&E's forecast is based on the average duration of only the two most recent refueling outages for each unit. Both CCC and GRA/IEP assert that a 12-week duration should be adopted to conform with past Commission decisions, as cited above. GRA/IEP contends that PG&E is attempting to change the methodology adopted by the Commission by basing its forecast only on the last two outages for each unit. GRA/IEP also recommends that in applying the 12-week assumption, the Commission use Diablo Canyon's historic recorded cycle capacity factor of 73.7% as a forecast assumption. Consistent with these assumptions, GRA/IEP further recommends adoption of an 11.95% forced outage rate which equals an 88.5%

operating capacity factor. CCC computes the operating capacity factor as 87.1%.

In its brief, CCC reminds us of our concerns expressed in D.89-12-015 regarding the estimate of Diablo outages, stating:

> "We do not know if or when it will become possible to detect a meaningful trend in the length of these refueling outages. In any event, two data points for each plant certainly are not enough."

TURN, in its brief, voiced support for the previously adopted Diablo forecasting methodology advocated by GRA/IEP and CCC. TURN warned that "PG&E's proposed method overemphasizes recent performance because it assumes that Diablo's performance in the last two fuel cycles will accurately predict its performance in the upcoming fuel cycle. With only two data points, the effect of a single extraordinary fuel cycle, be it good or bad, will dominate the forecast."

PG&E responds that recent Diablo performance data showed that "a fairly stable operational history that deviates quite significantly from...(the) first three refueling outages" (PG&E, Woehl, Tr. 23). PG&E cites a reduction in the number of design modifications from the initial refueling outages at the plant (PG&E Exh. 4, p. RDW-4), and a reduction by half in the number of activities undertaken relative to earlier, longer outages (Tr. 34-35).

PG&E asserts that the outage length has declined due to lessons learned from earlier outages. PG&E has added an outage management team and a 24-hour per day outage control center, as well as the use of contractors during the outage period. Because of such changes to shorten outage lengths, PG&E asserts that the more recent data is much more indicative of the outage length likely to take place during the forecast period. Finally, PG&E argues that recent data is more appropriate for developing a short-term forecast such as in the ECAC.

PG&E further notes that the 1990 forecast outage, which was based on the same methodology PG&E has proposed in this proceeding, came closest to predicting the plant output, compared to the forecast of Diablo generation adopted in the last three ECAC proceedings versus recorded generation (Exh. 21, Table 1). While acknowledging the 1990 forecast methodology resulted from a joint recommendation that was not intended to set precedent for the future, PG&E still asserts the accuracy of the method should be noted in evaluating the merits of parties' arguments.

5.4.2 Discussion

We conclude that the arguments on both sides of this controversy have some merit, but that neither approach provides an ideal solution to the measurement uncertainties related to Diablo outages. A broader range of historical data provides a more complete profile of expected outage durations, and takes into account a greater variety of potential outcomes. It also tends to provide more contingency for unexpected variance in actual outage durations. On the other hand, PG&E has presented evidence to indicate that more recent outage data is more representative of expected outage durations than is older data. Yet PG&E's evidence was largely anecdotal in nature, and PG&E failed to quantify the specific effect of the improved measures it has implemented on reducing outage durations.

All parties' outage forecasts were based upon a similar methodology of using an average of past cycles. Parties' different forecasts resulted from the application of different weights to different periods of historical outage cycles. PG&E applied zero weight to all but its two most recent cycles for each unit; it applied an equal average weighting to these more recent cycles. CCC and GRA/IEP applied equal weight to all past outages whether recent or not.

We conclude that the more recent outage cycles provide better predictive value of forecasted outages than do older cycles, given the recent measures PG&E has undertaken to reduce the risk of extended outages. We are not convinced, however, that we should totally ignore the value of longer term experience as having no predictive relevance at all, based upon the concerns we have raised in past decisions and the forecasting uncertainties noted by intervenors. We believe a reasonable resolution of these differences is to consider all historic Diablo refueling cycles, but to apply greater weight to more recent outages and lesser weight to earlier outages in developing an average estimate of outage duration.

Following this approach, we will adopt an 11-week refueling outage for each unit as a basis to forecast Diablo Canyon generation in this proceeding. We base the 11 weeks upon consideration of all past refueling cycles while assigning greater relative weight to more recent cycles. We base our weighting on a sum-of-the-years'-digits approach to yield a uniform incremental increase in weighted value for each progressive cycle. The development of the weighting factors and resulting outage lengths is presented below:

Diablo Unit 1	Weighted % Factor	Diablo Unit 2	
Cycle 1	10%	Cycle 1	16.7%
Cycle 2	20%	Cycle 2	33.3%
Cycle 3	30%	Cycle 3	50%
Cycle 4	40%		

By applying these weighted percentage factors to the historical outage durations for each cycle, we derive an average forecasted outage duration of 11 weeks each for Diablo units 1 and 2. We consistently apply the same weighting of historical cycles to derive values for the operating capacity factor of 89.2%. This approach recognizes the value of PG&E's measures to shorten the outage relative to earlier experience while still incorporating to a lesser extent the experience from the earlier outages, and the uncertainty related to reliance on limited historical data.

5.5 Hydro Modeling

5.5.1 Parties' Positions

There was considerable controversy between PG&E and GRA/IEP over the proper modeling for PG&E's hydro resources. PG&E specifies a minimum operating capacity, a maximum operating capacity, and a monthly amount of energy available for various hydro resources. Its production simulation model then schedules these resources against system load so as to maximize capacity benefits from the resource. GRA/IEP agrees this hydro modeling approach is reasonable as long as resources are operated in such a way as to be optimized against overall system load. GRA/IEP contended that such is not the case for at least two hydro resources modeled by PG&E, namely those of the Sacramento Municipal Utilities District (SMUD) and the United States Bureau of Reclamation's Western Area Power Administration (WAPA).

GRA/IEP disagreed with PG&E's modeling assumptions as to minimum operating capacity for these two hydro resources. GRA/IEP claims PG&E's modeling assumes more capacity is available for peaking than is actually true. GRA/IEP revised the modeling of SMUD and WAPA hydro by assuming minimum generation capacities higher than modeled by PG&E. GRA/IEP set the minimum capacity for SMUD at the 25th percentile of 1990 recorded production and assigned a ramp rate of 50 MW per unit. For WAPA, GRA/IEP assigned a ramp rate of 100 MW. The ramp rate determines how quickly a unit can move from one capacity level to another. GRA/IEP's imposed ramp rates limit the ability of the hydro units to reach maximum capacity. (Tr. 4:278, Greif.)

GRA/IEP's modeling assumptions result in more hydro energy being taken during off-peak hours and less hydro being available during peak hours relative to PG&E's modeling. More expensive replacement power during peak hours results in a higher

IER. In addition to an adjustment to the IER to reflect its hydro modeling, GRA/IEP also proposed that PG&E be directed to revise its own hydro modeling consistent with GRA/IEP's findings, and that PG&E thoroughly investigate the operation of all hydro resources modeled and improve its modeling conventions for hydro in next year's ECAC proceeding.

PG&E opposed GRA/IEP's modeling proposals. PG&E contends GRA/IEP's recommendations mischaracterize the scheduling and operation of these resources, improperly mix modeling conventions from a chronological model (PROSYM) and a load duration model (PROMOD), inappropriately shift hydro energy from on-peak and partial-peak hours into off-peak hours, and misstate PG&E's representation of these resources in PROMOD. PG&E challenged both the validity of GRA/IEP's empirical comparisons of data as well as GRA/IEP's assumptions regarding the operating constraints on SMUD and WAPA hydro capacity.

GRA/IEP based its conclusions on an analysis of recorded hourly operating data for these hydro facilities for July 1990, compared against the expected results using PG&E's typical peak-shaving production modeling mode. GRA/IEP chose July 1990 as a sample since recorded and forecast data were virtually identical for that month. GRA/IEP contended that the comparison showed that the GRA/IEP simulation more closely reflected recorded experience than the PG&E simulation.

In addition to the comparison of recorded versus modeled results, GRA/IEP further based its assumptions on its understanding of actual system operating constraints imposed on the hydro systems. GRA/IEP reasoned that the SMUD hydro could not be available for peaking at levels assumed by PG&E because more off-peak capacity was needed for constant around-the-clock resource flexibility to service hydro regulation needs. According to GRA/IEP, PG&E overstated the amount of hydro available for peaking from SMUD by ignoring the constant around-the-clock operating requirements of SMUD's hydro unit. GRA/IEP revised the modeling of SMUD hydro by establishing much higher minimum generating capacities than did PG&E.

GRA/IEP criticized PG&E's assertion that a near-zero minimum capacity is sufficient for instantaneous regulation on the belief that load regulation requires a resource which can both pick up and reduce load rapidly. If the regulating resource is operating at levels barely above zero (as PG&E assumed) it has no ability to reduce generation when load drops.

For WAPA, GRA/IEP contends that similar limitations restrict USBR's ability to load its available generation into which PG&E did not consider the peak. GRA/IEP assumed a ramp rate of 100 MW for the WAPA hydro.

PG&E disagrees with GRA/IEP's conclusion that PG&E's assumed minimum capacity is inadequate to provide resource flexibility to meet load regulation needs. PG&E states that regulation is typically only 3% of spinning reserves (Exh. 33, p. CG-1), and the relatively small minimum capacities used by PG&E are more than adequate to respond to instantaneous changes in load. For the month of July 1992, PG&E assumed a minimum capacity of 8 MW. (Tr. 251.)

PG&E further states that the operational constraint described by GRA/IEP is really that of load following, not regulation. PG&E contends that SMUD has no need to increase its resource's off-peak capacity, as GRA/IEP assumes, since SMUD has 360 MW of firm capacity and associated energy at load factor from WAPA, as well as purchases from PG&E and the Southwest, all of which provide load following. Further, the PG&E/SMUD agreement allows SMUD up to four changes per day for load following.

PG&E also disagreed with GRA/IEP's imposition of ramp rates for SMUD and USBR on the grounds that such ramp rates arbitrarily limit the units' flexibility to 50 MWh and 100 MWh, respectively. PG&E provided a number of examples where actual operation of the units varied on an hourly basis by more than the constraints assumed by the ramp rates (Exh. 33).

Another source of parties' disagreement involved the results of PROMOD versus PROSYM to model hydro assumptions. GRA/IEP performed its simulations using PROSYM. GRA/IEP re-sorted the chronological load data from PROSYM into load duration curves, without reference to the actual chronological modeling that occurred in PROSYM. According to GRA/IEP, this was done to allow a reasonable comparison with PROMOD, which presents results in load duration rather than chronological format. Yet PG&E contended that GRA/IEP mischaracterized PG&E's hydro modeling by using PROSYM to interpret PG&E's modeling in PROMOD, but without truly replicating the actual PROMOD algorithm. Since PROSYM is a chronological model which schedules hydro every hour, PG&E asserted its data is best plotted chronologically.

In response to PG&E's criticism, GRA/IEP recast its original load data in chronological form, arguing that either load duration or chronological formats showed GRA/IEP's simulation matched recorded data more closely than did PG&E's simulation.

While GRA/IEP's comparison of recorded versus modeled data focused on one week of July 1990, PG&E's rebuttal showed that for other weeks of July 1990, GRA/IEP's modeling resulted in an overstatement of minimum hydro capacity during practically all night hours. Extension of GRA/IEP's calculations to additional weeks in July raises further doubts about the validity of applying the model's results to the rest of the forecast period. GRA/IEP's comparison was made in a month where recorded SMUD hydro levels are similar to forecasted levels. PG&E notes that GRA/IEP has not analyzed other months where the 1990 recorded hydro differs from the forecast.

PG&E also noted an inconsistency in GRA/IEP's use of recorded 1990 data for deriving capacity minimum without regard to the amount of energy available in any given forecast month from

November 1991 through October 1992. GRA/IEP's method results in a mismatch whereby minimum capacities are derived from recorded 1990 data while energy and maximum capacities are derived from PG&E's forecast data.

5.5.2 Discussion

No simulation can be expected to perfectly model actual performance, but the simulation should reasonably reflect operations over the full duration of a forecast period. PG&E's criticisms of GRA/IEP's assumptions and modeling techniques as described are persuasive. GRA/IEP failed to demonstrate that its assumed minimum capacities and ramp rates depict more realistic hydro assumptions than those of PG&E. PG&E demonstrated that its minimum hydro capacities are adequate to accommodate the resource flexibility needs of SMUD and WAPA.

Accordingly, we will not adopt GRA/IEP's hydro modeling assumptions. Instead, we will adopt the hydro modeling assumptions underlying the PG&E/DRA Joint Recommendation on this issue. Likewise, since we have found PG&E's modeling assumptions to be reasonable, we have no basis to require PG&E to perform any special studies of hydro modeling in the next ECAC proceeding, as proposed by GRA/IEP.

5.6 Transmission Line Loss Adjustment

5.6.1 Parties' Positions

GRA/IEP challenged PG&E's assumptions as to transmission line losses in computing the IER. PG&E's IER computation assumed no net change in line losses between its QFs-in and QFs-out cases. GRA/IEP recommended that costs related to incremental purchases over the intertie in the QFs-out case be increased by energy loss adjustment factors of 6.1% for AC intertie purchases and 7.5% for DC intertie purchases.

PG&E cited D.88-11-052 as authority for the Commission's previous rejection of the inclusion of transmission losses in the QF-out case. GRA/IEP's witness Branchcomb testified that one of the reasons for the Commission's rejection of a line loss adjustment in the IER was that losses were already accounted for in the planning load in the calculation of lost and unaccounted for (LUAF) power. (Tr. 5:375-6.) GRA/IEP further argues that because PG&E changed its method of determining line losses, "the basis for the Commission's earlier rejection of this approach (in D.88-11-052) has been modified substantially." (Exh. 43, p. 11/Branchcomb/GRA/IEP.)

The change in methodology referred to by GRA/IEP involves a broadening of the definition of near-thermal generation (NTG), which is one of the independent variables in a single regression equation used to forecast line losses. This variable is intended to capture, in a very broad way, the effect of resource proximity to load centers on losses. PG&E's witness Bennett cautions, however, that it would be inappropriate to use PG&E's line loss model to infer impacts on system losses for the QFs-out case. PG&E's model is a "reduced form" model rather than a "structural model." As such, it may not give reasonable results when used to answer "what-if" questions of how losses would change absent QFs. (Exh. 26/Bennett/PG&E.)

5.6.2 Discussion

GRA/IEP's argument fails to establish that the change in PG&E's method of accounting for losses eliminated the Commission's basis for exclusion of line loss adjustments in calculating the IER in D.88-11-052. PG&E's refined method of accounting for line losses merely corrected an inconsistency in its regression equation to include non-remote QF generation as a component of Near Thermal Generation. PG&E's modification does not change the fact that line losses are still being accounted for in the planning load; it merely improves the precision of the line loss estimate.

GRA/IEP states that it does not propose to rely on PG&E's econometric model to forecast losses. This statement appears to conflict with GRA/IEP's testimony in Exh. 43 (p. 11) that "the basis for the Commission's earlier rejection of (line loss recognition) has been modified substantially by PG&E, and justifies inclusion of incremental line losses in the IER determination." Here, GRA/IEP cites PG&E's model change as a basis for the line loss adjustment. If we cannot rely on PG&E's model, as GRA/IEP argues, then it is unclear how our earlier basis for rejection of line losses in D.88-11-052 can been nullified based upon PG&E's modification of that same model.

The basis for our position in D.88-11-052 was that the record in that case lacked sufficient information as to permit an assumption of increased line losses in the QFs-out case. As we stated in that decision: "Without better information on the effect on losses from the removal of QFs in the QFs-out case, we decline to make this assumption." For example, there was no confirmation as to the number of QFs located far from load centers or whose power was transmitted over lines less efficient than the Pacific Intertie.

PG&E's change in methodology in this proceeding to quantify the number of QFs located far from load centers represents an improvement in available data relative to what was available when we made our determination in D.88-11-052. There are still, however, a number of uncertainties which have not been resolved as to the effects on line losses in the QFs-out case, as noted in PG&E's Rebuttal Exh. 26.

GRA/IEP argued that its proposal provides merely a fuller accounting of costs avoided by QFs. A problem with GRA/IEP's argument is that it fails to account consistently for other anticipated changes which may reduce line losses in the QFs-out case. For example, GRA/IEP fails to factor in the effects of DC line purchases which flow from South to North to PG&E's Midway connection, which would act to reduce Northwest losses on a QF-out basis. (Exh. 29, p. 3/Kerler/PG&E.)

While we agree with GRA/IEP that there is likely some impact on line losses as a result of the QFs-out case, the complexities of computing that impact are beyond the scope of the record developed in this case. While PG&E's assumption of zero line loss impacts in the QFs-out case appears unrealistic, at least it recognizes that there are offsetting effects on line losses, both positively and negatively. PG&E's proposal also avoids the need to perform a full recast of the resource plan to measure replacement resources for the QFs, which we have previously declined to do in an ECAC case.

GRA/IEP's analogy of transmission line losses to incremental heat rates is unconvincing. The recognition of incremental heat rates is merely a reflection of running the same resources at a higher utilization level. No change in loads or resources are assumed. Yet to factor in line losses as GRA/IEP proposes, we must assume a new load (reduced by line losses) and a new set of resources to reflect the new load.

GRA/IEP's calculation of line losses fails to consider the multiple effects on line losses resulting from the QFs-out case. We are led to a similar conclusion we expressed in D.88-11-052: "Although PG&E's approach may understate the losses resulting in the QFs-out case, we conclude that it is more likely to represent the losses in this hypothetical situation accurately."

Accordingly, we will not adopt GRA/IEP's line loss adjustments to the IER. Instead, we will adopt the PG&E/DRA assumption of no line loss adjustments in the IER calculation.

5.7 SMUD Sales

5.7.1 Parties' Positions

GRA/IEP contested PG&E's forecast of its sales to SMUD. PG&E revised its initial estimate of sales to SMUD from SCE and PG&E from a 75%/25% split to a 50%/50% split in its July 1 update testimony. GRA/IEP took exception to PG&E's recommendation in its update testimony. PG&E's revised split was based on 1991 recorded sales for January through April 1991 (Exh. 23, p. 129, Kerler/PG&E.) PG&E subsequently added data for June 1991 in additional rebuttal testimony to show continuation of this pattern of SMUD sales. (Exh. 29, pp. 2-3/Kerler/PG&E.) GRA/IEP proposed adoption of an assumption based upon SCE's separate estimate from the SCE's ECAC application. GRA/IEP concludes that "SCE is in a much better position to estimate how much energy it expects to sell to SMUD than is PG&E, since SCE is the originator of the sales." GRA/IEP's assumption reflects a 94%/6% split between PG&E and SCE in SMUD sales (Exh. 61.)

In the alternate, GRA/IEP proposes the adoption of PG&E's original estimate of 75%/25% based upon 1990 recorded data. GRA/IEP argues the original estimate is superior to PG&E's revised July 1 update assumption for the following reasons:

It is not reasonable to forecast annual sales for a future 12-month period based on only four months of recorded data. PG&E responds that it provided supplemental sales data for June 1991. PG&E argues that this confirms that the trend of increased SMUD Southwest purchases will continue into the summer months.

Contract renegotiations between SMUD and PG&E now underway will increase SMUD's ability to purchase PG&E power relative to recent recorded sales. PG&E's witness countered that the renegotiation will likely lead to increased flexibility rather than increased purchases.

GRA/IEP also contend that PG&E incorrectly modeled all SCE sales as firm although they include non-SCE sources which are nonfirm.

PG&E responds that the recorded 1991 data demonstrates that PG&E initially underforecasted SMUD sales outside the PG&E area. Given the nature of the SMUD/PG&E energy account, it is reasonable to assume that these purchases will continue, since SMUD is using any energy it purchases in excess of SMUD's own load to pay back energy owed to PG&E under the account. PG&E's update also recognized an increase of an additional 100 MW of transmission capacity permitting SMUD to take 33% more capacity from the south.

5.7.2 Discussion

We will not adopt the SCE estimate of PG&E/SCE SMUD sales as represented by GRA/IEP. There is no basis in this record to test the validity of the SCE estimate since no witness from SCE was produced to testify to its estimate.

We agree with PG&E that the recorded sales provided through June 1991 indicate a pattern of increasing SMUD sales from the Southwest relative to PG&E's original 75/25 assumption. PG&E's updated estimate, however, would require us to accept a significant increase over a relatively short time, effectively doubling the share of sales coming from the Southwest from 25% to 50%. Although PG&E has noted anecdotal factors that could help to continue an increased level of 1991 SMUD sales relative to 1990, it did not specifically quantify the precise effects on sales expected from these factors. Rather, PG&E simply annualized the available months of recorded data from 1991. There is still uncertainty as to what the sales level for the second six months of 1991 will be. PG&E's original estimate had the appeal of providing 12 months of recorded data which is consistent with the number of months in the forecast period.

We will adopt an assumed split of 62.5%/37.5% based upon an equal weighting of PG&E's original 1990 ratio of 75/25 and its updated 1991 ratio of 50/50. This resolution recognizes that there has been some upward trend in sales since the end of 1990, but stops short of simply extrapolating the limited recorded 1991 data for the full 12 months of the forecast period. We will temper our uncertainty inherent in only a half-year's worth of recorded 1991 data by weighting in the recorded PG&E/SCE mix for one-half of 1990. We also observe our adopted split almost exactly equals the recorded split for April 1991 (i.e., 62.4/37.6) which is the last month of recorded data used by PG&E in computing its proposed 50/50 split (Exh. 23, p. 129/Kerler/PG&E).

5.8 Distillate Dispatch Price

5.8.1 Parties' Positions

GRA/IEP proposed the use of monthly distillate fuel purchase price as set forth in PG&E's workpapers to measure the cost of operating combustion turbines in setting the ECAC revenue requirement and IER. PG&E witness Grief (Tr. 4:239) testified that PG&E does not account for fuel oil as an expense in the month of purchase but rather uses the LIFO (last in first out) method of accounting. The distillate oil expense is priced at the LIFO annual average price.

5.8.2 Discussion

We conclude that PG&E's method of treating distillate oil expense best minimizes overall costs. Because the costs of distillate oil are higher in winter months than spring and summer months, PG&E endeavors to purchase the distillate in the months in which the cost is lower. (Tr. 240.) The difference in delivery dates and burn dates for distillate oil reflects PG&E's least cost purchasing strategy. The use of the LIFO annual average cost better reflects the reality of PG&E's least cost purchasing strategy and the actual costs incurred as compared with GRA/IEP's alternative. We will accordingly adopt PG&E's distillate pricing assumptions.

6. ERAM and LIRA Revenue Requirements

PG&E's application included a request to increase rates to recover increased revenue requirements for ERAM and LIRA.

The ERAM balancing account was established by the Commission to eliminate fluctuations in base revenue recovery due to variations in sales. The balancing account accumulates the difference between the actual billed base rate revenue versus the authorized base revenue amount. Revenue adjustments to amortize the under- or overcollection in the ERAM balancing account are customarily adopted in ECAC proceedings.

The LIRA was adopted by D.89-07-062 and D.89-09-044. The LIRA provides for a 15% discount on residential rates for customers who qualify under a low-income criterion. PG&E is reimbursed for its costs of the LIRA program through a rate surcharge. The LIRA balancing account accumulates the difference between LIRA surcharge revenues collected and related program costs. D.89-09-044 ordered that LIRA-related rate revision be reviewed and adopted through the ECAC proceeding.

PG&E's initial ERAM/LIRA request was based upon the recorded balance in the accounts at February 28, 1991. PG&E's July update revised its requested increase to reflect the May 31 recorded balancing account balances, instead of the earlier February balances.

DRA was the only other party to sponsor any testimony on ERAM/LIRA revenue requirements. The DRA/PG&E Joint Recommendation resolved all outstanding issues between DRA and PG&E as to ERAM and LIRA.

PG&E's August 30, 1991 update testimony further revised ERAM/LIRA revenue requirements to reflect July 31, 1991 recorded balances. This is consistent with the Joint Recommendation's proposal to update recorded balances for computing revenue requirements. The revenue increase was also recomputed to reflect rates effective May 1, 1991. As a result, the ERAM balance at October 31 is forecasted to be undercollected rather than overcollected, as was assumed in the Joint Recommendation.

The LIRA revenue requirement was similarly updated, resulting in a slightly higher overcollection. Since the LIRA revenue shortfall is dependent on the adopted residential rate design for 1992, the LIRA rate change will be subject to revision in the revenue allocation phase of this ECAC proceeding.

The proposed ERAM/LIRA revenue requirement increases were unopposed by any active party. PG&E's updated ERAM revenue requirement in its August 30 update, however, included one accounting error. As discussed in Section 6.3 below, PG&E agreed to credit its ERAM account for $590,327. Instead, PG&E inadvertently debited ERAM for that amount. Accordingly, we have corrected this accounting error in deriving our adopted ERAM/LIRA revenue requirement of $187,492,000.

Appendix A presents the derivation our adopted ERAM and LIRA revenue requirements. The summary below compares our adopted results to PG&E's initial and updated estimates.

($ 000's)

	April 1 Initial	July 1 Update	Joint Recommendation	Aug. 30 Update	Adopted
ERAM	$142,991	$147,966	$148,559	$181,885	$180,701
LIRA	10,771	10,112	10,112	6,791	6,791
Total	$153,762	$159,078	$159,671	$188,676	$187,492

DRA raised certain issues in connection with its review of the ERAM/LIRA revenue requirements which were resolved through the Joint Recommendation. We adopt the Joint Recommendation's resolution of these issues as reasonable. These issues are discussed below.

6.1 SMUD Revenues

DRA initially proposed a $2.6 million reduction in ERAM to reflect, in part, a 1991 rate change for capacity purchased from SMUD. On rebuttal, PG&E noted that the additional revenue from the SMUD rate increase had already been deducted from PG&E's base revenue amount in PG&E's 1991 attrition adjustment (D.89-12-057, Apdx. C, p. 11). PG&E and DRA both acknowledged this in the Joint Recommendation. Accordingly, we adopt the Joint Recommendation on this issue, and make no additional adjustment for SMUD revenues as originally proposed by DRA.

6.2 Helms Adjustment Account

In connection with its review, DRA proposed various wording changes to Part F of PG&E's Electric Tariff concerning the Helms Adjustment Account (HAA) to reflect changed circumstances since the HAA was established in 1984. PG&E expressed concern that any changes to the Helms tariff not prejudge PG&E's ability to request recovery of the balance in the HAA. We will adopt the language as proposed in the Joint Recommendation Item C.3 as the appropriate resolution of this matter, and order that PG&E's electric preliminary statement be amended accordingly. This language change has no revenue requirement impacts on the adopted forecast in this proceeding.

6.3 Conservation Financing Adjustment

PG&E conducts conservation financing programs through its Conservation Financing Adjustment (CFA).

DRA concluded during its field audit work that the balance in the CFA Allowance for Doubtful Accounts was too high. DRA proposed to reduce the balance for the electric portion of this account by $590,327. The PG&E/DRA Joint Recommendation acknowledged this adjustment by proposing a credit of the $590,327 to the ERAM balancing account with an equal debit to the electric CFA Allowance for Doubtful Accounts. No party opposed this proposal, and we will accordingly adopt it.

Findings of Fact

1. PG&E filed this application on April 1, 1991, requesting an annualized increase of $264.8 million in its electric rates relative to its ECAC/AER/ERAM/LIRA/CEE rate procedures, effective November 1, 1991.

2. PG&E also proposed to update the equivalent IER used to determine payments to variably priced QFs, consistent with its resource assumptions, and to update its ERI used to adjust capacity payments to certain as-delivered QFs.

3. PG&E and DRA sponsored a Joint Recommendation which resolved all disputes between them related to Phase Ia issues in this proceeding and which resulted in a final proposed ECAC/AER revenue requirement decrease of $134.5 million.

4. Parties to the Joint Recommendation concluded that each resource assumption included therein was based on a reasonable forecast which was was consistent with its proposed revenue requirement and QF price factors.

5. PG&E, DRA, and TURN sponsored a separate joint recommendation which resolved all disputes between those three parties related to gas price issues in Phase Ia of this proceeding.

6. All active parties were in agreement on a number of uncontested resource and modeling assumptions which are attached as Appendices D and E.

7. Several resource assumptions remained in dispute among active parties other than the sponsors of the Joint Recommendations referred to above.

8. The resource assumptions which have been adopted in this decision result in an ECAC/AER revenue requirement reduction of $169,532,000 and result in price factors for variably priced QFs as set forth in Appendix C.

9. There is uncertainty about the actual mix of gas sources from which dispatchable gas will be procured during the forecast period, and this uncertainty precluded a precise determination of the exact mix in adopting resource assumptions in this proceeding.

10. A forecasted mix of 75% Southwest spot gas and 25% PGT gas reflects the relative scarcity of cheaper PGT gas while acknowledging that Southwest spot gas is not the sole source for dispatch purposes.

11. Under its interdepartmental tariff, PG&E's electric department pays a volumetric transport rate known as the Tier II transport rate which can be avoided by the electric department by dispatching a resource other than gas.

12. Including Tier II in the price for dispatching the electric system of a combined utility minimizes costs to all ratepayers.

13. The one-company approach to dispatching the electric system of a combined utility minimizes costs to all ratepayers.

14. The use of the 4% shrinkage factor for dispatch purposes is consistent with the one-company approach.

15. Gas curtailments could be affected in various and unknown ways based upon a production cost estimate absent variably priced QFs which would require a new ACAP simulation to determine.

16. The avoided cost postings for quarterly QF prices do not incorporate an analysis of gas curtailments on a QF-in/out basis.

17. Past Commission policy has been to consider all past refueling outages in forecasting Diablo Canyon generation for ECAC/AER purposes.

18. The use of longer term experience avoids the risk that the effects of very good or bad short-term performance will dominate the forecast.

19. PG&E based its Diablo Canyon refueling outage estimates of 10 weeks on only the two most recent cycles for each of the units, based upon measures taken to shorten outage lengths, and based upon comparisons that show that its method has more closely approximated recent years' recorded experience than does an average of all historical outages.

20. All parties based their Diablo generation forecast on averages of past outages, differing merely in the choice of periods covered.

21. An 11-week forecast results from adjusting the weighting factors applied to historical outages to reflect a uniform increase in relative weight over time.

22. GRA/IEP's hydro modeling conventions imposed higher minimum capacities than did those of PG&E on the assumption that

more off-peak capacity was needed for constant resource flexibility to service hydro load regulation needs.

23. PG&E's near-zero minimum capacity hydro modeling assumptions are adequate to respond to instantaneous changes in load.

24. PG&E provided various examples where actual operation of its hydro units varied by more than the ramp rate constraints imposed by GRA/IEP.

25. GRA/IEP's hydro modeling results inconsistently used recorded 1990 data to derive minimum capacities without regard to energy availability assumed during the forecast period.

26. The complexities of computing the impact of transmission line losses on the IER make it uncertain as to what the net change would be on a QFs-in/out basis.

27. GRA/IEP's proposed method of accounting for line losses fails to account consistently for factors which may reduce as well as increase line losses.

28. PG&E revised its forecast of the percentage of SMUD's sales it would provide during the forecast period from 75% down to 25% based upon certain months of 1991 recorded data.

29. GRA/IEP proposed using SCE's estimate of SMUD sales to determine the percentage of sales supplied by PG&E, or in the alternative to rely on PG&E's original estimate based on 12 months of recorded data.

30. An estimated 62.5% of SMUD sales provided by PG&E results from applying equal weight to PG&E's recorded data from 1990 and its updated 1991 data.

31. PG&E's method of accounting for distillate oil expense on a last-in first-out basis minimizes overall costs.

32. The ERAM and LIRA revenue requirements as cosponsored by PG&E and DRA in the Joint Recommendation were uncontested by any other party.

33. D.89-12-057 reduced PG&E's ERAM base revenue amount by $2.4 million to account for the forecast effect of additional revenue due to a rate increase for the Designated Sales Transaction to SMUD.

34. Parties to the Joint Recommendation agreed to include in the forecast the revenue from SMUD in the amount of $427,533 to properly reflect capacity sales to SMUD for November and December 1991.

<u>Conclusions of Law</u>

1. The resource assumptions which were not contested by any party as set forth in the joint recommendation and presented in Appendix E should be adopted, as adjusted for recorded balancing account data through July 31, 1991.

2. The uncontested resource assumptions which we adopt from the joint recommendation shall not be used as precedent in any other proceeding or litigation beyond this proceeding.

3. PG&E should adjust its adopted revenue requirements for ECAC/AER/ERAM/LIRA as set forth in Appendix A based upon a forecast period November 1, 1991 to October 31, 1992, and should incorporate these adopted adjustments into its total consolidated rate changes to become effective January 1, 1992.

4. The price factors for variable-priced QFs which should be adopted for the November 1, 1991 to October 31, 1992 forecast period for PG&E are set forth in Appendix C for the IER, the time-differentiated IERs, the O&M adders. The DIER for this forecast period is also contained in Appendix C. An ERI of 1.0 should also be adopted.

5. These QF price factors should go into effect consistent with Commission decisions on avoided cost quarterly price postings.

6. The gas industry restructuring rules do not require the abandonment of the one-company approach for dispatching the electric department of combined utilities.

7. The dispatch cost of gas for electric generation should exclude the G-UEG Tier II transport rate, and should include a 4% gas shrinkage rate.

8. The IER should not be increased to reflect greater gas curtailments due to the lack of certainty as to how gas availability would change absent QFs.

9. While more recent outage cycles for Diablo Canyon provide better predictive value of forecasted outage durations than do older cycles, longer term experience should not be totally ignored given the uncertainties of forecasting.

10. A forecasted outage duration of 11 weeks fairly incorporates the superior predictive value of recent outages while still giving some weight to longer term historical outage experience.

11. PG&E's hydro modeling assumptions for SMUD and WAPA provide reasonable forecasts and properly incorporate minimum hydro capacities adequate to accommodate resource flexibility requirements.

12. The IER should not be increased to reflect a changes in line losses since no party has presented a convincing measure of how net line losses would change absent QFs, and the complexities of determining such a measure is beyond the scope of this proceeding.

13. SMUD sales should be assumed to comprise 62.5% from PG&E and 37.5% from other sources, based upon an equal weighting of available recorded data from 1990 and 1991.

14. PG&E's method of accounting for distillate oil inventory on a LIFO basis should be adopted for developing the IER.

15. The estimated revenue requirements for ERAM and LIRA for the 12-month period beginning November 1, 1991, as set forth in the Appendix A, updated to reflect July 31 recorded balances, are reasonable and should be adopted.

O R D E R

IT IS ORDERED that:

1. Effective November 1, 1991, Pacific Gas and Electric Company (PG&E) is authorized and directed to record amounts in its respective balancing accounts covered by this order consistent with the following adjustments in adopted revenue requirements: A decrease in Energy Cost Adjustment Clause (ECAC) of $159,300,000; a decrease in the Annual Energy Rate (AER) of $10,232,000; an increase in Electric Revenue Adjustment Mechanism (ERAM) of $180,701,000; an increase in Low Income Rate Adjustment (LIRA) of $6,791,000.

2. The rate adjustments related to the revenue requirements changes adopted in Ordering Paragraph 1 shall be included in the revenue allocation phase of this proceeding, and deferred from November 1, 1991 to January 1, 1992, to be consolidated with PG&E's 1991 Cost of Capital Proceeding, its 1991 Attrition Rate Adjustment filing, and other pending proceedings with an effective rate change date of January 1, 1992.

3. The QF price factor shall go into effect consistent with Commission decisions on avoided cost quarterly price posting.

4. Effective January 1, 1993, O&M expenses for PG&E's irrigation district contracts not related to purchased volumes of water and power plus fixed costs shall be subtracted from the adopted ECAC/AER revenue requirement and recovered as part of PG&E's Base Revenue Amount in ERAM. PG&E is directed to include forecasts of these expenses in its 1993 General Rate Case Application for the 1993 test year. The adopted ECAC/AER forecast in this proceeding includes irrigation district expenses of $54,055,300. PG&E will be permitted to recover the above-mentioned irrigation district expenses for November and December 1992 in its 1992 ECAC proceeding.

5. Effective November 1, 1991, PG&E shall add the following language as section 4(c) to PG&E's electric Preliminary Statement Part F:

> c. Pursuant to D.85-08-012, Part F.4(b) is in effect and the entries described in 3(a) through 3(d) above were discontinued effective September 1, 1985. The balance in the Helms Adjustment Account, accrued pursuant to D.84-07-070 when the Helms units were out of service from September 30, 1984 through April 30, 1985, shall remain in place pending a Commission decision on an application for recovery by PG&E.

6. PG&E shall make its best efforts to complete a conversion of the mainframe GASDOS model to a desktop model. In this new version, (1) simulation will not be restricted to calendar years, and the entire winter season (September through March) will be included, (2) gas supply and demand balancing will be fully integrated to eliminate the need for separate spreadsheets, (3) simulation results will be made with minimal manual intervention, and (4) modifications to service categories will be simplified and less difficult to make.

7. PG&E shall make a good faith effort to have its QF relational database model available by January 1992.

8. PG&E shall credit to the ERAM balancing account the amount of $590,327 and debit a similar amount to the electric Conservation Financing Adjustment Accumulated Provision for Doubtful Accounts.

This order is effective today.

Dated November 20, 1991, at San Francisco, California.

PATRICIA M. ECKERT
President
DANIEL Wm. FESSLER
NORMAN D. SHUMWAY
Commissioners

Commissioner John B. Ohanian, being necessarily absent, did not participate.

I CERTIFY THAT THIS DECISION WAS APPROVED BY THE ABOVE COMMISSIONERS TODAY

Neal J. Shulman

NEAL J. SHULMAN, Executive Director

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APPENDIX A
TABLE 1

PACIFIC GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
Summary of Revenue Changes
Effective January 1, 1991

REVENUE ELEMENT	PRESENT RATE REVENUE 1/ ($000's)	REVENUE CHANGE ($000's)	ADOPTED REVENUE REQUIREMENT ($000's)	ADOPTED AVERAGE RATE 2/ (cents/Kwh)
Energy Cost Adjustment Clause (ECAC)				
1 Adopted ECAC Costs	$3,877,596	($415,799)	$3,461,797	
2 Estimated ECAC account balance as of 10/31/91		217,393	217,393	
3 DC Safety Committee Fee	663	0	663	
4 Designated Sales Transactions to Resale Customers	(63,834)	0	(63,834)	
5 Subtotal	3,814,425	(198,406)	3,616,019	
6 Franchise Fees & Uncollectible Accounts Expense @ 0.85%	0	30,736	30,736	
7 Total ECAC Retail Revenues	$3,814,425	($167,670)	$3,646,756	4.600
Annual Energy Rate (AER)				
8 Adopted AER Costs	$221,610	($12,780)	$208,830	
9 Designated Sales Transactions to Resale Customers	(6,313)	0	(6,313)	
10 Subtotal	215,297	(12,780)	202,517	
11 Franchise Fees & Uncollectible Accounts Expense @ 0.85%	0	1,728	1,728	
12 Total AER Retail Revenues	$215,297	($11,052)	$204,245	0.258
Base Energy Revenues (ERAM)				
13 Authorized Base Revenue Amount for 1991	3,352,842	168,471	3,521,313	
14 Estimated ERAM account balance as of 10/31/91		12,230	12,230	
15 LIRA Shortfall	(26,678)	0	(26,678)	
16 Designated Sales Transaction to Resale Customers	(53,142)	0	(53,142)	
17 Total ERAM Retail Revenues	3,273,022	180,700	3,453,723	4.356
Low Income Rate Assistance (LIRA)				
18 LIRA Shortfall	9,174	17,504	26,678	
19 Estimated LIRA account balance as of 10/31/91	0	(10,713)	(10,713)	
20 Administrative Costs	2,437	0	2,437	
21 Total LIRA Revenues	11,611	6,791	18,402	0.023
22 Conservation Financing Adjustment (CFA)	$1,428	$0	$1,428	
23 California Public Utilities Commission Fees	$8,571	$0	$8,571	
24 Other Revenues	$46,536	$0	$46,536	
TOTAL RETAIL REVENUES	$7,370,891	$8,769	$7,379,660	9.309
PERCENTAGE INCREASE		0.12%		

1/ Based on rates effective 5/1/91.
2/ Average Rates based on the forecasted retail sales of 79,277.9432 Gwh.

(END OF APPENDIX A)

APPENDIX B
TABLE 1

PACIFIC GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
ADOPTED ENERGY COSTS
ECAC Forecast period: November 1, 1991 through October 31, 1992

TYPE OF ENERGY	PURCHASES/ GENERATION (Gwh)	%	AVERAGE COSTS (cents/Kwh)	TOTAL COSTS ($000's)	TOTAL CPUC Costs 1/ ($000's)	ECAC COSTS 2/ ($000's)	AER COSTS 3/ ($000's)
Fossil Fuel							
Gas - PC	170,062	66.07%	1.96161	$331,896	$330,336	$300,606	$29,730
Gas - UEG'				134,100	$133,470	121,457	12,012
Oil - Residual	22,386	8.70	3.05981	68,497	$68,175	62,039	6,136
Oil - Distillate	404	0.16	5.12871	2,072	$2,062	1,877	186
Subtotal Fossil Fuel	192,852	74.93	2.78226	536,565	534,044	$485,980	$48,064
Geothermal Steam	6,413	2.49	1.66501	106,776	$106,275	96,710	9,565
Purchased Power							
Irrigation Districts	4,492	1.75	1.12099	50,355	$50,118	45,608	4,511
CVP	(3,563)	(1.38)	1.16087	(41,366)	($41,172)	(37,467)	(3,705)
Variably Priced QF Energy	9,896	3.84	3.01831	298,704	$297,300	270,543	26,757
Other QF (Including Capacity Payments)	11,033	4.29	11.23116	1,239,089	$1,233,265	1,122,271	110,994
Northwest	8,186	3.18	1.55895	127,620	$127,020	115,588	11,432
Southwest (Including Sales)	(43)	(0.02)	3.13937	(1,350)	($1,344)	(1,223)	(121)
CDWR	0			0			
Other	6	0.00	11.76667	706	$703	639	63
Subtotal Purchased Power	30,007	11.66	5.57791	1,673,757	1,665,890	1,515,960	149,930
Water for Power	12,775	4.96	0.03541	4,524	$4,503	4,097	405
Oil Inventory Carrying Cost				9,395	$9,351	8,509	842
Variable Wheeling				271	$270	245	24
Losses(Gaines) on Fuel Oil Sales				0			
Subtotal Engergy Expenses	242,047	0.94	0.96315	2,331,289	2,320,332	2,111,502	208,830
DC Settlement Revenues	15,338	5.96	8.85561 /4	1,556,241	$1,548,927	1,548,927	0
Excess Oil Inventory Carrying Cost				(1)	(1)	(1)	0
DC Basic Revenue Requirement				(198,630)	(198,630)	(198,630)	0
TOTALS	257,385	100.00%	1.43322	$3,688,899	$3,670,627	$3,461,797	$208,830

1/ Jurisdictionalized at 99.53%.
2/ ECAC costs are 91% of CPUC total costs, unless otherwise specified.
3/ AER costs are 9% of CPUC total costs, unless otherwise specified.
4/ The average cost for Diablo Canyon Settlement Revenues is adjusted for the Diablo Canyon Basic Revenue Requirement of $198,630 and the Safety Committee Fee of $663.

(END OF APPENDIX B)

APPENDIX C

PACIFIC GAS & ELECTRIC COMPANY

TOTAL EQUIVALENT QFIER CALCULATION

Average Conv Thermal Cost- $/MMbtu	2.7479
Total QF-In Cost- Thousand $	1,499,916
Total QF-Out Cost -Thousand $	1,761,529
Change in Total Cost - Thousand $	261,613
Variable QF's - Gwh	9,896.4
Marginal Energy Cost - mills/kwh (excl. O&M adder)	26.44
QFIER - Btu/kwh	9,620
Variable O&M adder - mills/kwh	2.80
Geothermal adder - mills/kwh	0.5732
Cash Working Capital - mills/kwh	0.1012
Total Marginal Energy Cost - mills/kwh	29.91
Equivalent QFIER - Btu/kwh	10,885

Notes:
(1) Variable O&M Adder from joint recommendation in A.90-04-003
(1) Geothermal Adder from Advice Filing No. 1336-E dated Feb. 1, 1991
(1) Cash Working Capital as adopted in D.89-12-057

APPENDIX C

PACIFIC GAS & ELECTRIC COMPANY
Derivation of Time-Differentiated QF Incremental Energy Rates
(QFIERs)

	Marginal Energy Csts ($/mwh)	MEC FCTR	Annual Avg. QFIER (Btu/kwh)	QFIER By Timer Period (Btu/kwh)	Hours Per Period
Summer					
Peak	18.33	1.026		9871	789
Partial-Peak	17.35	0.971		9344	920
Off-Peak	16.21	0.907		8730	1971
Super Off-Peak	15.15	0.848		8159	736
Seasonal Avg.	16.65	0.932		8967	
Seasonal Tot.					4416
Winter					
Partial-Peak	20.06	1.123		10803	1690
Off-Peak	18.63	1.043		10033	1950
Super Off-Peak	18.07	1.012		9731	728
Seasonal Avg.	19.09	1.069		10281	
Seasonal Tot.					4368
Annual Avg.	17.86	1.000	9620	9620	
Annual Tot.					8784

Notes:
(a) Summer includes May through October 1992
Winter includes November, December 1991 and January through April 1992
(b) QFIER based on overall average conventional thermal rate of $2.7479/MMBtu
Rate calculations include commodity charge, demand charge and volumetric transportation charges
(c)The marginal energy costs by time period are based on the PROMOD simulation run that includes QFs in the resource plan. Steam generation valued at gas dispatch price.
(d)The marginal energy cost factor is the marginal energy cost for that time period divided by the annual average marginal energy cost.
(e)The QFIER for a time period is equal to the marginal energy cost factor for that timer period multiplied by the annual average QFIER.
(f)The number of hours in the various time periods will differ slightly from those approved in CPUC Decision 86-12-091 because PROMOD does not reflect weekdays holidays, and the load forecast assumes that the calendar year always begins on a Sunday.

(END OF APPENDIX C)

PACIFIC GAS AND ELECTRIC COMPANY
1991 ECAC/AER/ERAM/LIRA/CEE FILING

SUMMARY OF UNCONTESTED MODELING CONVENTIONS

1. Dispatchers Risk Aversion feature (PROMOD)

   100 percent of weekends with a MW adjustment, zero week nights and weekdays.

2. Minimum Thermal Generation

   In PROMOD, the minimum fuel burn feature is used to assure at least 565 GWh/month generation from the conventional thermal generating plants. In PROSYM, units are combined into stations, with a station minimum specified in order to produce the minimum generation each hour.

3. Must Run Units

   Combination of designating units as must run or use of PROMOD's area protection feature. At least seven units are maintained on line, with additional units during the summer peak period.

4. Minimum Load Conditions

   Backdown order according to economic and contractual rules as shown on pages 3-28 and 3-29 of PG&E's Forecast Report. In PROMOD, FRPL records are used to obtain the order.

5. Minimum Downtime of Conventional Thermal Units

   72 hours for 750 MW and 330 MW class units. 48 hours for all other classes of units.

(END OF APPENDIX D)

APPENDIX E

PACIFIC GAS AND ELECTRIC COMPANY
1991 ECAC/AER/ERAM/LIRA/CEE FILING

SUMMARY OF UNCONTESTED RESOURCE ASSUMPTIONS BASED ON PARTIES JUNE UPDATE FILINGS

1. Area Load Forecast-June update

   ECAC Test Year Nov. 1991-Oct. 1992 103,616.8 GWh

2. Hydroelectric Generation amounts-June update

a.	PG&E owned Hydro w/o Helms	12,684.6 GWh
b.	Irrigation Districts	4,494.0 GWh
c.	USBR (WAPA) Hydro	3,335.7 GWh
d.	NCPA	500.1 GWH
e.	SMUD	1,653.6 GWh
f.	CCSF	1,734.9 GWh
g.	MID/TID	511.0 GWh

3. Helms Pumped Storage

   Three units with a combined generating capacity of 1212 MW and pumping capacity of 966 MW, and inflows and water management represented in both PROMOD and PROSYM.

4. Northwest firm purchases by PG&E from PP&L - 250.3 GWh

   Firm peaking purchase from PP&L based on contract, 80 MW/100 MW capacity seasonal.

5. Northwest purchases by CSC - 97.9 GWh

   On-peak firm takes over CSC's 25 MW share of DC line capacity.

6. Southwest Miscellaneous purchases by PG&E - 96.0 GWh, priced at 17.5 mills/kWh

   Fixed off-peak purchases based on historical quantities.

7. California Power Pool Sales - 156.0 GWh

   Fixed around the clock energy sale transaction based on historical quantities.

8. California Power Pool Purchases

   Economic energy purchases assumed at an incremental heat rate of 11,000 Btu/kWh.

APPENDIX E

PACIFIC GAS AND ELECTRIC COMPANY
1991 ECAC/AER/ERAM/LIRA/CEE FILING

SUMMARY OF UNCONTESTED RESOURCE ASSUMPTIONS
(Continued)

9. Sierra Pacific Purchases - 3.6 GWh at a cost of $326,000

   Around the clock deliveries to serve PG&E customers in the Echo Summit Area

10. Miscellaneous purchases for others - 35.1 GWh

    Around the clock purchases of 4 MW by others in the area, based on historical quantities.

11. NCPA Resources

    a. NCPA Geothermal - 1338.0 GWh
       Unit with cycling operations - 238 MW on-peak and 90 MW off-peak.
    b. NCPA COG - 36.3 GWh
       Fixed firm around the clock transaction based on historical quantities.
    c. NCPA CT - 15.9 GWh
       Fixed non-firm peaking transaction based on historical quantities.

12. SMUD Resources

    a. NW for SMUD - 1735.6 GWh
       Assumes full utilization of 200 MW AC line entitlement. AC loop flow causes line limitations from April through June.
    b. SMUD PV, SMUD CT - 5.3 GWh
    c. SMUD Geothermal - 630.6 GWh
       Unit availability based on two year average historical outage statistics.
    d. SCE and PG&E sales to SMUD -
       SMUD elected 300 MW and 550 MW of contract capacity from SCE and PG&E respectively. Takes are based on availability of other resources and SMUD's loads. SMUD's deficit energy supplies by split between PG&E and SCE (see contested assumption No. 7). SCE modeled as a hydro unit.

13. CCPA Geothermal - 457.5 GWh

    One 62 MW unit available based on actual operations. Energy split 50 percent to SMUD, 40 percent to MID/TID, and 10 percent to CSC based on ownership.

PACIFIC GAS AND ELECTRIC COMPANY
1991 ECAC/AER/ERAM/LIRA/CEE FILING

SUMMARY OF UNCONTESTED RESOURCE ASSUMPTIONS
(Continued)

14. QF Generation - 20,929.3 GWh, including hydro QF's, includes 9,896.4 GWh of variably priced QF generation[b].

   a. Firm capacity contracts modeled at their firm capacity ratings. Remaining QF's reflect average megawatts.
   b. Gilroy Foods operates as a S04.
   c. BAF is shut down in April, curtailed 6 hours per day January through March and May through September, curtailed 10 hours per day Monday through Saturday and all day Sunday October through December. 20 percent fixed priced and 80 percent variable priced.
   d. Curtailments for minimum load conditions (600 hour or S04 curtailment option B) are not forecasted to occur. However, non-standard curtailment provisions are forecasted (not tied to minimum load conditions).
   e. Hydro capacity factor for 1991 is adjusted to reflect June hydro conditions.

15. Sales to Southern Cities - 71.1 GWh

Firm 39 MW peak sale at 62.5 percent capacity factor through July 1991, 34 MW peak sale through November 1991, 14 MW peak sale at 78 percent capacity factor December 1991 through June 1992.

16. MID/TID Resources

   a. MID/TID CT - 10.5 GWh
      Fixed non-firm peaking transaction based on historical quantities.
   b. MID/TID Other Imports - 1,135.3 GWh
      Takes based on MID and TID loads, availability of own resources and purchases from PG&E.

17. Northwest for WAPA - 3,428.2 GWh

Forecast based on WAPA's estimate of their firm imports from the Northwest. Resource may be backed down during minimum loads. AC loop flow causes line limitations from April through June.

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[b] Reflects removal of 3 QF's agreed to by all parties.

(END OF APPENDIX E)

APPENDIX F
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List of Appearances

Applicant: Michelle L. Wilson and Robert Mc Lennan, Attorneys at Law, for Pacific Gas and Pacific Company.

Interested Parties: C. Hayden Ames, Attorney at Law, for Chickering & Gregory; Barkovich and Yap, by Barbara Barkovich, for Barkovich and Yap; Patrick J. Bittner and Caryn Hough, Attorneys at Law, for California Energy Commission; Morrison & Foerster, by Jerry Bloom and Lynn Haug, Attorneys at Law, and Morse, Richard, Weisenmiller & Associates, by Mark Younger, for California Cogeneration Council; Jackson, Tufts, Cole & Black, by William H. Booth and Joseph S. Faber, Attorneys at Law, for California Large Energy Consumers Association; Henwood Energy Services, by David Branchcomb, for Independent Energy Producers Association; Maurice Brubaker, for Drazen Brubaker & Associates; Mc Craken, Byers & Martin, by David J. Byers, Attorney at Law, for Peninsula Street Light Authority and City of Fresno; Ralph Cavanagh, Attorney at Law, for Natural Resources Defense Council; Brobeck, Phleger & Harrison, by Gordon E. Davis, Attorney at Law, for California Manufacturers Association; Sam De Frawi, for Naval Facilities Engineering Comman; Phil Di Virgilio, for Destec Energy, Inc.; Karen Edson, for KKE & Associates; Norman Furuta, Attorney at Law, for Federal Executive Agencies; Steven A. Geringer, Attorney at Law, for California Farm Bureau Federation; Grueneich, Ellison & Schneider, by Dian M. Grueneich, Attorney at Law, for California Department of General Services; Steve Harris, for Transwestern Pipeline Company; Fulbright & Jaworsky, by Pat Keeley, Attorney at Law, and Recon Research Corporation, by Dr. Andrew Safir, for Canadian Petroleum Association; Roberts & Kerner, by Douglas K. Kerner, Attorney at Law, for Geothermal Resources Association; Joseph G. Meyer, for Joseph Meyer Associates; Melissa Metzler, for Barakat & Chamberlin; Steven Moss, for Spectrum Economics, Inc.; Anderson, Donovan & Poole, by Edward G. Poole, Attorney at Law, for various clients; John D. Quinley, for Cogeneration Service Bureau; Bruce A. Reed, Janet K. Lohmann, and David R. Hinman, Attorneys at Law; for Southern California Edison Company; C. B. Rooney and David J. Gilmore, Attorneys at Law, for Southern California Gas Company; Donald Salow, for Association of California Water Agencies; Bartle Wells Associates, by Reed V. Schmidt, for California City-County Street Light Association; Michel P. Florio and Joel R. Singer, Attorneys at Law, for Toward Utility Rate Normalization; Downey, Brand, Seymour & Rohwer, by Phil Stohr and Ron Liebert,

APPENDIX F
Page 2

Attorneys at Law, for Industrial Users; Randolph L. Wu and Phillip D. Endom, Attorneys at Law, for El Paso Natural Gas Company; Larry Golberg, for Sequoia Technical Services; Carolyn Kehrein, for Procter & Gamble Manufacturing Company; Sara Steck Myers, Attorney at Law, for Coalition for Energy Efficiency and Renewable Technologies; Thomas A. Tribble, P.E, J.D., for Regents - University of California; Messrs. Ater, Wynne, Hewitt, Dodson & Skerritt, by Mark Trinchero, Attorney at Law for Cogenerators of Southern California; and William B. Marcus, for JBS Energy, Inc.

State Service: Messrs. Greve, Clifford, Diepenbrock & Paras, by Matthew V. Brady, for California Department of General Services.

Commission Advisory and Compliance Division: Martha J. Sullivan.

Division of Ratepayer Advocates: James E. Scarff and Robert Cagen, Attorneys at Law, and Jeff Meloche.

Division of Strategic Planning: Jeffrey Dasovich.

(END OF APPENDIX F)