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Decision 89 12 015 DEC 6 1989

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of PACIFIC GAS AND ELECTRIC COMPANY for Authority to Adjust its Electric Rates Effective November 1, 1989; and for Commission Order Finding that PG&E's Gas and Electric Operations during the Reasonableness Review Period from February 1, 1988, to December 31, 1988, were Prudent. (U 39 M)	Application 89-04-001 (Filed April 3, 1989)

(See Appendix B for appearances.)

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OPINION

Summary

In this decision, we approve for Pacific Gas and Electric Company (PG&E) an increase in its overall revenue requirement of $272,048,000 to reflect the following changes:

1. An increase of $613.9 million under PG&E's Energy Cost Adjustment Clause (ECAC),
2. An increase of $26.5 million under PG&E's Annual Energy Rate (AER), and
3. A decrease of $368.3 million under PG&E's Electric Revenue Adjustment Mechanism (ERAM).

This amount will be consolidated with the revenue requirement changes approved in PG&E's current general rate case (Application (A.) 88-12-005) for determination of overall revenue allocation and rate design.

I. Background

A. Procedural History

PG&E filed this application on April 3, 1989, requesting an increase of $378.3 million in its electric revenues on an annualized basis effective November 1, 1989. This requested increase was based on the following revenue requirements changes:

1. An increase of $815.2 million under PG&E's ECAC,
2. An increase of $32.7 million under PG&E's AER, and
3. A decrease of $469.9 million under PG&E's ERAM.

Although PG&E never formally changed its rate request, the company did change many of its forecast assumptions during the course of its hearings and expressed the opinion that the revenue requirements should be less than that indicated in the application. On June 28, 1989, John E. Kerler, testifying for PG&E, offered a revised revenue requirement increase estimate of $146.22 million with the following elements (See Ex. 9; Tr. 123):

1. An ECAC increase of $597.1 million,
2. An AER increase of $22.6 million, and
3. An ERAM decrease of $473.5 million.

This ECAC filing is PG&E's first since we issued Decision (D.) 89-01-040, which modified the rate case plan and the schedule for processing energy cost offset proceedings. Prior to that decision, PG&E's rates reflecting ECAC, AER, and ERAM revenue requirements were adjusted on an annual basis effective August 1st.

In order to spread the Commission's workload more evenly across the year and to facilitate coordination with PG&E's general rate case, we changed PG&E's revision date to November 1st. As a result, during this transitional year, PG&E's balancing accounts have registered over- and undercollections for 15 months without revision. In addition, since the last AER revision only forecasted costs through the end of July 1989, we suspended PG&E's AER as of August 1st, allowing 100% of the fuel costs incurred since that date to be tracked in the ECAC balancing account.[1] The AER remains in suspension in anticipation of this decision.[2] Normally, an ECAC application will include a request for approval of the reasonableness of gas and electric operations during a

1 See D.89-01-040, mimeo. p. 23.

2 Ibid. p. 26.

preceeding 12-month period. As directed in D.89-01-040, however, the pending application covers a shorter period, from February 1, 1988 to December 31, 1988.[3]

Because there was also a pending PG&E general rate case this year, the Commission faced the potential of end-of-the-year decisions that would have developed two different revenue requirements calculations and allowed for two separate considerations of revenue allocation and rate design issues. Soon after filing this application, PG&E filed a Motion to Consolidate Revenue Allocation and Rate Design Issues in the general rate case Proceeding. Appropriately, this motion was granted in a joint administrative law judge (ALJ) ruling issued April 24, 1989. The revenue requirement derived from this proceeding has been merged with the revenue requirement determination in the general rate case. All revenue allocation and rate design issues have been heard on a consolidated basis in A.88-12-005, the general rate case.

The determination of sales forecasts provides another area of substantial overlap between the two proceedings. In the general rate case, forecasted sales were needed for all of 1990. In this proceeding, sales projections were needed for the forecast period, November 1, 1989 through October 31, 1990. PG&E moved that the sales forecast developed in this proceeding be used in the general rate case for purposes of consolidated consideration of revenue allocation and rate design issues. In a ruling dated May 24, 1989, ALJ Cragg granted that motion.

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3 In future ECAC filings, PG&E's reasonableness review period will return to the normal 12-month span, ending 60-75 days prior to the ECAC (see D.89-01-040, mimeo. p. 26). The next reasonableness review period may need to be slightly longer than 12 months, in order bring the process up to date.

We have recently issued two orders that affect calculations to be made in this proceeding.

In D.89-06-048 (in A.82-04-44 et al., "OIR 2"), we adopted a floor/ceiling methodology to calculate the short-term Energy Reliability Index (ERI) affecting capacity payments to variably priced qualifying facilities (QFs).[4] In addition, we directed PG&E to submit late-filed exhibits in this proceeding to conform its showings on marginal costs, revenue requirements, and others where appropriate to the adopted methodology (see Ordering Paragraph 2).

In D.89-09-093, as part of this year's PG&E general rate case, we adopted a method for calculating the operations and maintenance (O&M) costs that PG&E avoids because of its purchases from variably priced QFs. The proposed order that was to become D.89-09-093 was issued after the commencement of this proceeding. Parties to this proceeding were instructed to calculate the O&M component of payments to variable QFs (O&M adder) according to the method in the proposed order. Subsequently, in D.89-09-093 we affirmed the reasonableness of that method.

Hearings in the current proceeding were divided into three phases. The first phase encompassed those issues relating to the forecasts of fuel costs, resource mix, and variable payments to QFs. The second phase relates to the reasonableness of prices in special contracts entered into between PG&E and certain large electricity customers. We added this subject to the ECAC menu in D.89-05-067 (in I.86-10-001). The third phase will address the

4 QFs are certain cogeneration and small power production facilities that qualify for specified benefits under the federal Public Utility Regulatory Policies Act of 1978 (PURPA). PURPA establishes that the prices a utilitiy pays for power generated by QFs are to be based on the costs the utility avoids by purchasing the QFs' power rather than generating the electricity from the utility's own plants. The costs avoided by such purchases include energy, capacity, and operation and maintenance costs.

reasonableness ofPG&E's operation during the period discussed above. This opinion decides only the first phase issues.

Eight days of hearings in the forecast phase of this proceeding were held between June 26 and September 6, 1989, in San Francisco, California. Concurrent opening and closing briefs were filed July 21, 1989 on the issue of sales forecasts. Concurrent opening briefs on resource assumptions and modeling issues were filed July 28, 1989. Concurrent reply briefs were filed August 4, 1989. A ruling by the ALJ, dated August 15, 1989, listed the resource plan input assumptions for parties to use in preparing their final calculations of revenue requirements and other relevant factors. Additional hearings were held on September 1 and September 6, 1989, to discuss the implications of these final calculations; and concurrent opening and closing briefs were filed on September 25, 1989.

The parties filing briefs in this proceeding included PG&E, the Commission's Division of Ratepayer Advocates (DRA), the California Cogeneration Council (CCC), the Geothermal Resources Council, the Independent Energy Producers Association (IEP), the Independent Power Corporation (IPC), the Association of California Water Agencies (ACWA) and the California Farm Bureau Federation (CFBF).

The ALJ's Proposed Decision was mailed on November 6, 1989. Comments were filed on November 27, 1989 by PG&E, DRA, CCC, IEP, and CFBF. Responsive comments were filed on December 4, 1989. We have reviewed and carefully considered the comments. We have incorporated appropriate changes in this decision.

B. The Framing of the Issues

Consistent with last year's PG&E ECAC proceeding, this application combines consideration of ECAC issues with an updating of key components of the calculation of prices paid for power sold to the utility by QFs. The ECAC process enables a utility's rates to reflect changes in its fuel and purchase power expenses on an annual basis outside of the three-year general rate case cycle. The QF calculation issues relate to the prices to be paid to QFs that do not have contracts specifying fixed prices.

Variable QF prices are the sum of three basic components: a payment for capacity, a payment for avoided O&M, and a variable payment for energy. Critical to the determination of these payments are the utility's ERI and Incremental Energy Rate (IER).

The ERI is used to adjust the value of a generic combustion turbine, which we have used as a proxy for a utility's avoided capacity costs and which therefore forms the basis for capacity payments to QFs. In another proceeding, while this matter was pending, we approved a method for calculating PG&E's ERI. All active parties used this method to calculate the ERI and differences arose as to how the adopted method should be implemented.

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 which is multiplied by the utility's incremental fuel cost to produce the price the utility pays for the variably priced QFs' energy.

There is a logical relationship between conventional ECAC issues and the bases for QF prices. The forecast used to develop a utility's ECAC revenue requirement is derived from the estimated production and expense levels related to hydroelectric, nuclear, purchased power, alternative and renewable power, and oil- and gas-fired resources. The forecasts of energy production and availability affect the determination of the utility's generating efficiency at the margin as measured by the IER. Similarly, the expected availability of resources to meet forecasted demand is reflected in the ERI.

ERI and IER values are generally derived from the results produced by production cost models. These models are designed to 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. However, these inputs are not mere abstractions. In many cases, the inputs to the models are the resolutions of conventional ECAC issues that constitute the heart of the ECAC proceeding.

The use of computer models introduces another set of issues concerning how the modeler and the model translate and simplify the complexities of the utility system into terms that the model can understand, and what manipulations the model makes of this information. This category of issues is referred to as the modeling conventions.

As we have faced more ECAC applications that include IER and ERI considerations, we have instituted and modified procedures designed to ensure the full exchange of information pertinent to an understanding of the computer models used and a full exchange of data used to develop the IER and ERI. At an earlier time, we required that all parties to ECAC and general rate case proceedings of the major electric utilities use the ELFIN production cost model in developing a "base case" run. (D.87-12-066, at p. 203.) The Commission reasoned that use of the same model "to present a base case will aid the Commission, as a starting point, in determining whether model, assumption, or methodological differences are causing the different results." Each party, however, was also given the opportunity to present additional testimony using its model of choice.

Additionally, the Commission directed that "a workshop be held no later than one week following [the] ECAC filing to determine the data sets, resource plans, load shape, heat rate input, unit commitment and dispatch, minimum load conditions, resource assumptions, marginal fuel assumptions, and all other pertinent data that [the utility] used to calculate its IER." (D.87-12-066, at p. 205.) The workshop was also to serve as a forum for the parties to agree, to the extent possible, on the assumptions to be used and the appropriate source of those assumptions. The Director of the Commission Advisory and Compliance Division (CACD) was to appoint an arbiter for the workshop to resolve any issues related to the development of a common data set upon which agreement could not be reached. This workshop procedure was employed in PG&E's last ECAC proceeding.

This year brought at least one major change to the workshop process. In D.88-11-052, which followed the first phase of PG&E's 1988 ECAC proceeding, we concluded that the base case run that had resulted from having all modelers use the ELFIN model had not been useful. We determined that a more useful comparison would have been among the models. Therefore, we directed those parties to the 1989 ECAC who intended to sponsor a model run to present a base case run that was the result of using inputs from a common data set applied to its favored model. The workshops became the forum for developing the common data set and identifying and resolving, if possible, the differences among the parties.[5]

The modeling workshop was made a requirement for future ECAC proceedings in D.89-01-040. The workshops were held on April 19 and May 18, 1989, with Linda Gustafson of the CACD serving as arbiter to develop common data set assumptions for computer model runs to be used in this proceeding.

Another change introduced in this ECAC proceeding is that the active parties were asked to develop a consensus document allowing for a comparison of the positions taken by various parties on each of the contested issues. The resulting Comparison Exhibit (Exhibit 1) listed contested and uncontested resource assumptions

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5 See D.88-11-052, mimeo. p. 68.

as well as the modeling conventions used by all parties. The parties are to be congratulated for their work in developing the Comparison Exhibit, which appears to have helped the parties to limit the areas of contention and shorten the hearing time needed for this proceeding.

The issues litigated in the forecast phase of this proceeding thus included not only PG&E's revenue requirement for the ECAC forecast period, but also the development of the IER and the calculation of the ERI and O&M adder used in determining variable QF payments.

In reviewing these issues, we will first examine the issues that must be resolved before the production cost models may be run: the load forecast, resource assumptions, and modeling conventions. Next, we will discuss the calculation of the IER, ERI, and O&M adder. Then we will consider the differences between the three production cost models that were used in this proceeding.

II. Load Forecast

With only one exception, the active parties agreed with PG&E's sales projections. PG&E's initial forecast was set forth in Exhibit 2, Table 2-1. The table was revised in Exhibit 3 by adding information concerning area load during the forecast period and comparative figures for the 1990 test year covered by the general rate case. PG&E later revised its sales forecast (Exhibit 25) to reflect the announcement that the Rancho Seco Nuclear Power Plant (Rancho Seco) would be closed.

A. The Effect on Sales of Closing Rancho Seco

Rancho Seco is owned and was operated by the Sacramento Municipal Utility District (SMUD). Without the benefit of power generated at Rancho Seco, SMUD will have to purchase more electricity from other entities. For various reasons, it is not yet possible to know with certainty how SMUD will meet its needs.

However, it is reasonable to assume that SMUD will make use of its existing contracts with PG&E, Southern California Edison Company (SCE), and utilities in the Pacific Northwest. PG&E has divided the additional purchases among those three sources in a manner found acceptable by all parties.

B. Agricultural Customer and Sales Forecasts

The one source of controversy in this area involved the appropriate forecasts for the total number of agricultural customers and the projected level of agricultural sales. The CFBF presented evidence contesting the number of agricultural customers predicted by PG&E. The ACWA presented evidence conflicting with PG&E's forecast of agricultural sales.

The agricultural customer class is intended to include only those customers who use electricity predominantly to serve agricultural end-uses. Agricultural end-uses include growing crops, raising livestock, pumping water for irrigation, and other uses that involve production for sale and that do not change the form of the agricultural product.

In last year's ECAC proceeding, PG&E proposed that the agricultural schedules be reserved for those customers who meet the condition that 70% or more of their energy usage is dedicated to agricultural end-uses. PG&E also recommended that the new definition of the agricultural class be implemented in the 1989 ECAC decision. The intervening year would give PG&E time to identify affected customers and inform them of their options in their new rate classes. We adopted PG&E's proposed redefinition and ordered that it would become applicable on the effective date of the decision adopting specific rates in the 1989 ECAC proceeding.[6]

6 See D.88-12-031, Ordering Paragraph 10.

In the intervening year, PG&E did not reach its goal of identifying affected customers. This undermined the company's ability to produce, in this proceeding, an accurate estimate of the number of customers in the agricultural class.

The number of active agricultural accounts does not equal the number of customers with agricultural end-uses. For instance, each time a new pump is connected to the utility lines, a new account is opened. Despite overall reductions in farmed acreage during the last few years, many new accounts have been opened. This is largely because of the increased need for pumps to deliver water to irrigated fields in drought years such as those recently experienced in California. In addition, many accounts are opened or closed simply because farm property changes hands and the electric billing is transferred to a new name. The interaction of these forces adds to the challenge of accurately predicting the number of agricultural accounts in any future year.

Michael Robinson, testifying for PG&E, explained that the company used an econometric model to develop its forecast of agricultural customers. Such a model attempts to forecast and explain changes in the number of customers over time. PG&E's model suggests that the number of agricultural customers will continue to grow.

CFBF challenges that assessment. Using its econometric model, PG&E predicts an average of 101,858 agricultural customers during the ECAC period. In order to test the assumptions underlying this number, CFBF sent data requests to PG&E asking for a comparison of the numbers of all of its agricultural customers on a year-to-year basis. The request sought a tally of accounts actually opened and closed during a given year. CFBF argues that relating this account activity to the number of accounts in existence in the prior year provides the most accurate assessment of the number of agricultural customers for each year. Starting with a base of 99,599 customers in 1985, PG&E had forecasted

100,951 customers for 1988, reflecting a net increase of 1,352 customers. CFBF showed that an actual tally of accounts opened and closed during those years yields a net reduction of 804 accounts, leading to 98,795 customers in 1988. This is 2,156 customers below PG&E's estimate.

PG&E disputed the usefulness of the information provided to CFBF in response to its data request (Exhibit 5). Robinson said he did not know where the data came from, but assumed that it was accumulated for some other purpose and cannot be used for CFBF's purposes. Despite repeated opportunities, PG&E did not provide any evidence to support its effort to refute its own numbers.

CFMB's analysis has brought into question PG&E's forecast of agricultural customers. The most compelling factor is that the growth in the number of accounts projected by the model does not coincide with recorded openings and closings in the years for which data was provided. PG&E argues that its econometric projection is conservative, predicting that the survey necessary to find out who is an agricultural customer within the newly adopted customer class definition will ultimately increase the number of customers in the class. DRA seems to agree. However, CFBF argues that the new definition will result in fewer customers in the class because of the 70% usage requirement. The parties debated as to whether or not Standard Industrial Code classifications could be used to predict the ultimate size of the agricultural class. The record on this issue is inconclusive. All that is clear is that the study has not been done yet and no one knows for sure what it will show.

We are not persuaded by PG&E's claim that the data offered to show actual openings and closings should be disregarded because PG&E's witness is not sure where these numbers came from. These numbers were provided by PG&E in response to a clearly worded data request from CFBF. In order to support its position, PG&E is trying to undermine the credibility of its own data. This argument is disingenuous. PG&E did not take the opportunity of providing evidence to support its position.

CFBF has offered 96,000 customers as a proxy for PG&E's forecast for both the ECAC forecast period and the general rate case calendar year of 1990. However, CFBF has also stated that it calculates the number of agricultural customers in 1988 to be 98,765. CFBF's testimony does not adequately explain why it would expect the number of customers to decrease by 2,765 in two years. Due to the apparent unreliability of PG&E's calculation and the uncertain effects of the new class definition, we will adopt the 98,765 figure for the purposes of this forecast.

Despite the disagreements as to the size of the agricultural class, the various estimates of agricultural sales are very close. In fact, ACWA endorses DRA's numbers because there is little difference between the two and DRA endorses PG&E's numbers for the same reason. We see no compelling reasons that PG&E's projections should not be adopted. Changes in the number of customers may reflect little more than the number of new pumps installed or old pumps disconnected. Sales is more a reflection of the overall irrigation needs. PG&E has lowered its forecast in response to improved hydro conditions. As the parties are all quite close in their current projections, we will adopt PG&E's forecast: PG&E sales of 69,300 gigawatt hours (GWh) and a total area load of 94,343 GWh for the ECAC forecast year; PG&E sales of 69,668 GWh and a total area load of 94,612 for the general rate case calendar year 1990.

C. Sales Forecasts for All Other Classes

For all other purposes, the parties agreed with PG&E's sales forecasts. We will adopt that forecast as reflected in Exhibit 25.

TABLE 1

Sales Forecast Assumptions

Class of Service		ECAC[7] Amount in Gigawatt-hours	GRC[8] Amount in Gigawatt-hours
Residential		23,479	23,557
Small Light & Power		7,268	7,274
Medium Light & Power		16,732	16,756
Large Light & Power:		15,523	15,558
CCSF	702		
Other	14,821		
Agriculture		3,099	3,091
Street Lighting		363	365
BART		256	256
Public Authority		512	526
SMUD		982	1,191
Other non-CPUC		931	939
Interdepartmental		155	155
Total PG&E Sales		69,300	69,668
SMUD		7,638	7,471
LUAF		7,956	7,964
Electric Department Usage		26	26
Other Area Load		9,422	9,483
Total Area Load		94,343	94,612
Deliveries out of Area		503	569
Total Planning Load		94,845	95,181

7 November 1, 1989 to October 31, 1990.

8 January 1, 1990 to December 31, 1990.

III. Resources

A. Purchases of Economy Energy from the Pacific Northwest

As was the case in the ECAC proceeding last year, this was a highly contested issue. The predominant source of power imported from the Pacific Northwest is hydroelectric. The Northwest has experienced two exceptionally dry years. While all parties assume that rainfall will now return to normal, there are disagreements as to the lingering impact of drought conditions on price and the amount of energy that Northwest suppliers are likely to make available. In addition, this issue has raised two other questions for our consideration: Should PG&E be required to rely on quantitative analysis in making its short-term forecasts? Should apparently illogical computer outputs persuade us to abandon an otherwise reasonable price forecast? All parties agreed that the Pacific Northwest forecast should be considered in two stages: November 1989 through February 1990 and March through October 1990.

1. Stage 1: November 1989 through February 1990

a. Installed Capacity

PG&E's ability to import energy from the Pacific Northwest is limited by the amount of carrying capacity to which it has access over existing transmission lines. PG&E calculated its entitlement on the installed capacity of AC and DC lines, plus any layoffs from unused Western Area Power Administration (WAPA) entitlements, minus any periods of time when a line is down for maintenance. All parties agree with PG&E's forecast of installed transmission capacity. We will adopt PG&E's figures.

b. Availability

PG&E and the QFs (CCC and IEP) agree that the drought in the Northwest will limit the availability of economy energy purchases from the Northwest through next February. PG&E predicts that the reservoirs will not be filled to 100% level during this period and that the experience of the last two years will cause suppliers to be cautious in dispensing the energy that is available. DRA disagrees. A key factor influencing the availability of energy is the nature of flows on the Columbia River, which generates electricity supplied to California utilities by the Bonneville Power Administration (BPA).

There is little dispute as to the expected size of Columbia River flows, just disagreement as to what it means. PG&E predicts 90% of normal flow and characterizes this as "below normal." DRA says 90-94% of flow is "normal" for forecasting purposes. BPA says there is a 99% chance that reservoir levels will be at 100%. PG&E's witness Jack Kerler says this is optimistic, but offers no empirical support for his position.

Even if current river flows and reservoir levels are at or near normal, the reality of two prior dry years is likely to restrain deliveries to California. Kerler argues persuasively that Northwest suppliers will be cautious. This perspective is supported by the fact that BPA, the largest supplier in the region, curtailed all deliveries to the south on the intertie as of July 5, 1989. It appears that BPA is sensitive to monthly changes in precipitation and will carefully husband its supplies if current rainfall levels suggest the possibility that the accumulations this season may be less than normal.

While all parties agree that some energy will be made available to PG&E during the first stage, no two parties agree as to how much. DRA's estimate is unacceptable because it assumes that normal rainfall year quantities apply. IEP acknowledges that there is very little difference between its estimate and those of PG&E and CCC. We will adopt PG&E's forecast, which is the most consistently moderate across the period.

PG&E also assumed that its forecasted energy availability would be sufficient to fill all of its entitlement on the transmission interties during peak periods and 50% of its entitlement during off peak hours. We will adopt this assumption as well.

c. Price

PG&E predicts that the average price for purchases from the Pacific Northwest during the first stage of the ECAC period will be 25 mills. CCC and IEP agree with PG&E. DRA, which is more optimistic about hydro conditions in the Northwest, predicts that the price on average will be equal to 90% of PG&E's incremental fossil fuel cost. PG&E agrees that if supplies were normal this would be the correct price.

To support its 25 mill price prediction, PG&E referred to the less-than-normal energy expectation during the first stage, the 1988 fixed price of 22 mills, a contract for 1988 deliveries from BPA to SCE at a price of 25 mills, and a recent BPA offer to provide energy in October 1989 at a price of 23 mills. We are not convinced that these factors support a 25 mill price.

In 1988, reservoir levels in the Northwest were dramatically lower than they are in 1989. That fact certainly does not suggest that the price this year would be even higher. The fact that SCE signed a 25 mill contract in 1988 says little about what PG&E may need to pay this year. The only thing it clearly shows is that in 1988 PG&E was able to purchase power from the Northwest at a lower price than was SCE. Finally, while the evidence indicates that BPA made a 23 mill offer this fall, there is no reason to expect that the two parties would have settled on a 23 mill price. Nor do we know whether or not the agreed-upon price would apply in any or all of the November 1989 through February 1990 period.

In his August 15th ruling, the ALJ directed the modelers to assume that energy would be available from the Northwest at the levels advocated by PG&E at a 22 mill price during the first stage. Modelers for PG&E, CCC, and IEP found that these assumptions produced an unexpected result. Normally, one would expect that the cost of an additional increment of energy and the IER would be higher during peak periods than during off peak. However, under the assumptions adopted in the ALJ's ruling, the IER for winter partial peak was lower than the IER for winter off peak. PG&E and the QFs blamed their unexpected modeling results on the 22 mill price assumption. IEP went so far as to suggest that the price assumption must be changed to eliminate this effect.

Applying the same assumptions, the DRA's ELFIN run did not produce this result. According to DRA's calculations, the partial peak IER was larger than the off-peak IER. DRA argues that there is nothing unreasonable with the 22 mill assumption and the record does not suggest that changing the assumption would have a significant effect on either the revenue requirement or the IER. In fact, IEP tested the affect of changing the assumption to 25 mills and concurred with DRA's assertion.

However, even if we were to determine that the unexpected results were a matter of concern, there is no logical basis for concluding that the 22 mill is incorrect. While the QFs place the blame for the "counter intuitive" results on the 22 mill price assumption and advocate a return to the 25 mill level, DRA points out that there are other equally likely causes for this result. For instance, higher availability assumptions would be likely to bring the results within traditional expectations. Further, even if it was determined that the price has to change in order to have the model results fit within expectations, there is nothing to suggest that the price should be changed to 25 mills. No party has offered a sensitivity analysis to demonstrate where the cross-over point would be on a price continuum between 22 and 25 mills.

In its concurrent brief dated September 25, 1989, DRA raises a significant policy question stemming from the suggestion that the 22 mill price should be changed. Starting at page 3, DRA states:

> "Implicit in HESI's suggestion to abandon the 22 mills price and adopt 25 mills is the assumption that the Commission should tailor its decisions to satisfy the production cost models. This may be the first time such a recommendation has been made and it raises a broad and important policy question which will sooner or later demand resolution.
>
> "When models are unable to reach intuitively expected results based on apparently reasonable assumptions, we must ask what role the models should play in our proceedings. DRA believes that in an instance such as this one, an assumption which appears to be reasonable, should not be rejected strictly because it may create one counter-intuitive result. The Commission should be the ultimate decision maker. Whether one model or all models produce unexpected results, the Commission must decide whether a given assumption, is reasonable.
>
> "In this instance, because one of the models is not producing the unexpected IERs, the Commission is not forced to resolve the underlying policy question. If the Commission wishes to maintain the 22 mills price adopted in the ALJ's ruling, it appears that ELFIN will produce intuitively correct results."
> (Ex. 54.)

We agree that 22 mills is an appropriate price assumption to apply to the first stage of purchases from the Pacific Northwest. While PG&E and the QFs have offered little more than a best guess to support the 25 mills prediction, actual practice confirms PG&E's ability to obtain energy at 22 mills under less favorable conditions. Further, we will not change a reasonable assumption just to make the modeling results look better. Even if we were otherwise inclined, there would be no compelling reason to do so in this situation, where the change would have virtually no effect on the IER or on the overall revenue requirement.

2. Stage 2: March through October 1990

a. Installed Capacity

During this stage as well, all parties are in agreement with PG&E's forecast of installed transmission capacity, whether or not loop flow is a factor. We will adopt PG&E's figures.

b. Availability

One goal of an ECAC proceeding is to apply the most current information to derive a short-term forecast of resource availability, load requirements, and related costs. However, since we are not able to make reliable forecasts of seasonal precipitation, we conventionally assume normal precipitation during the forecast period. All parties have applied such an assumption in predicting Pacific Northwest energy availability. While PG&E argued that past drought conditions would stifle sales during the first four months of the period, it is not predicting any unusual limits to the availability of energy during the remaining eight months.

PG&E and DRA predict the same energy availability during this stage. The QFs, on the other hand, rely on PG&E's long-term forecast as submitted in this year's general rate case, which predicts significantly lower energy availability in 7 of the 8 months.

The QFs argue that PG&E should not be allowed to be inconsistent in its forecasts in two proceedings that are heard concurrently. They assert that there are unexplained inconsistencies between the two forecasts. Perhaps most significantly, they fault PG&E for developing its ECAC forecast in a way that lacks sufficient analytical rigor.

For the general rate case, PG&E produced a forecast based on what the QFs refer to as a quantitative model. The key characteristic of such a model is its relative verifiability. Assumptions as to what may affect energy supplies are clearly defined and subject to critique for conceptual soundness. Once the conceptual framework is understood, results can be checked and replicated by others willing to undertake the same analysis.

For the ECAC forecast, PG&E undertook a largely empirical study. PG&E's forecasters talked to people in relevant decision-making positions, considered recent events, reflected on the methods available to the Northwest utilities to control energy releases and relied on their collective experience to produce an informed judgment. Robert Weisenmiller, testifying for CCC, characterized this as the crystal ball approach.

The QFs assert that PG&E should be required to rely on a quantitative approach, arguing that PG&E's analysis is difficult, if not impossible to verify because it relies on the subjective experience and judgments of power control personnel rather than on an analytical model. Because PG&E's forecast in the general rate case relied on an analytical model, the QFs argue that it is preferable to the forecast offered in this case.

PG&E responds by pointing out that the goal of the general rate case analysis was to prepare a long-term forecast. The utility further points out that the use of the long-term analysis is to calculate the cost-effectiveness of long-term demand-side management programs, not to determine the revenue requirement. PG&E argues that the use of such analysis in an ECAC proceeding would negate the benefit of using more recently available information to develop a short-term forecast.

There are two separate issues raised by this debate. One goes to the merits of applying the results of a long-term forecast to the short-term issues of IERs and ECAC revenue requirements for the next 12 months. Using PG&E's long-term analysis for such a purpose is inappropriate and that is why we will not adopt the availability forecasts put forth by the QFs. When the purpose of analysis is to determine the life cycle cost-effectiveness of a program, one can be much more forgiving of potential year-to-year variations. Because the projections extend into periods for which forecasts cannot be dependable, the use of averages and hypothetical assumptions may be more acceptable. We can and must expect more in an ECAC forecast. The reliance is on short-range vision and the factors that are recognizable from where we stand today.

That aside, we are still left with one important issue. Should PG&E be required to develop and rely on a quantitative analytical framework for preparing its ECAC forecasts of availability of energy from the Pacific Northwest?

We do not pretend to be at a point where we can say that properly executed quantitative analysis will always provide a more reliable forecast than empirical judgment. In most of our proceedings, we are offered the opinion of experts who are relying to a large extent on their professional judgment based on a perspective harvested from years of experience. Without a doubt, such expert testimony should always be put to the test. Experts must be prepared to demonstrate to the Commission how their experiences were brought to bear on their judgments. Experts must always be able to show that their judgments flow logically from an assessment of facts and that the full range of essential facts have been considered. Nonetheless, we cannot negate the merits of such testimony out of hand.

In this instance, PG&E's expert was available for scrutiny. Where there were apparent inconsistencies, the QFs or other parties were free to test his judgment through discovery and cross-examination. He could have (and most likely should have) been asked to set out the full array of factors he considered and had his judgments challenged with apparently contrary facts. However, this was largely not done. Instead, QFs raised many questions in the relative vacuum of post-hearing briefs where they could not result in an enhancement of the factual record.

It is undeniable that a well developed quantitative analysis would carry great evidentiary weight. We would encourage PG&E, DRA, or any other party to develop such an approach to forecasting short-term Pacific Northwest energy availability. To be certain, the expertise applied to empirical judgment could be equally as valuable if a more analytically rigorous approach were applied. However, we are not prepared to require such analysis in this situation.

c. Price

For this stage, PG&E applied the same pricing assumption that we adopted in last year's ECAC.[9] The price of Northwest purchases would be assumed to equal 90% of PG&E's average incremental fossil-fired steam generation costs. All other parties support PG&E's assumption and we will adopt it.

B. Purchases from the California Department of Water and Power

All parties agreed that the determination of price for these purchases is linked to the assumption of energy available from the Northwest. It was agreed that if Northwest supplies were considered limited during the first stage of the ECAC period, the price should be assumed to be 20 mills. All parties agreed that the price for the remainder of the ECAC period should be assumed to be the same as the price for Northwest purchases during the second stage. Since we are assuming limitations to availability during the first stage, we adopt the prices as just described.

C. Geysers Generation

1. Availability

In 1987, the Geysers field began to experience frequent steam curtailments, when there was insufficient steam to run all of the units although the units were available for service. PG&E expects these curtailments to continue and increase during the

9 See D.88-11-052, discussion on p. 36.

forecast period. In addition, Unit 15 is now out of service for an indefinite period and is assumed to be unavailable during the forecast period, due to insufficient steam. PG&E's estimates reflect these expectations.

These curtailments were at issue during the last ECAC, by which time they had been a factor for about a year. At the time, PG&E argued that the year's curtailments represented a trend that was likely to continue. DRA had argued that the basis of the curtailments was unknown and there was no reason to expect them to continue. We felt that a year's experience did not provide a basis for projecting a trend of increased curtailments, but expressed skepticism concerning DRA's assumption that the problem would disappear. Instead, we projected curtailments for the next year based on the five most recent months of curtailment data.

The problem did not disappear. In fact, curtailments have continued to grow. This year, PG&E was able to shed little new light on the reasons for these developments, or provide a convincing basis for predicting curtailments during the forecast period. PG&E has once again proposed that a trend of increasing curtailments be assumed. CCC and IEP agree. DRA argues that two years' worth of data is insufficient to predict such a trend, a problem that is aggravated by our continuing lack of understanding as to why the curtailments are occurring and proposes that an average of historical curtailments be used to forecast performance during the test year.

Because of the continuing uncertainty about the status of Unit 15, which is currently down, and the fact that we are no more enlightened than we were a year ago about the causes of the curtailments, we are not persuaded that a predictable pattern of curtailments has been set. The staff's recommended approach of averaging the last two years' curtailments for use in the forecast period may be too conservative of an approach to take. As PG&E has pointed out, actual curtailments in 1989 already exceed DRA's predictions for the forecast period.

We have chosen to assume, for the purposes of setting rates and IERs, that curtailments during the forecast period will be the same as those during the last 12 months for which data was available prior to the final IER calculation. That data indicates that curtailments are still increasing.

At the same time, we are concerned about PG&E's failure to gain a more sophisticated understanding of the nature and magnitude of the problem during the last year. During the hearings, anecdotal information was provided of studies conducted by other users of steam from the Geysers concerning curtailments in other fields. We will expect PG&E to present information during with its next ECAC filing that will reflect specific study of the problems affecting PG&E's Geysers plants including a verifiable method for determining the likely yield from the Geysers during the next forecast period.

2. <u>Price</u>

PG&E proposes that the assumed price be based on its contractual formula involving recorded and forecasted fossil costs and recorded and forecasted nuclear fuel costs, as in past years. DRA has proposed that the nuclear fuel cost component be decreased to reflect what it asserts to have been unreasonable delays in the completion of the Diablo Canyon Nuclear Plant (Diablo Canyon). In its report for the reasonableness review portion of this application, DRA has proposed a disallowance, couched on a related theory. We feel that the consideration of these DRA proposals should be consolidated for hearing in the reasonableness phase. Thus, we are adopting PG&E's geothermal price assumptions without prejudice to later consideration of the DRA position.

D. Diablo Canyon Generation

In the last ECAC proceeding, the appropriate method of characterizing the forecast performance of Diablo Canyon was heavily debated. We determined that it was inappropriate to ignore the effect that refueling outages may have on the performance of the plant.

The necessity of shutting down a generating unit and removing the reactor head during the refueling process makes the refueling outage an ideal time to perform necessary maintenance on various parts of the plant. Although those activities are carefully planned, they may take longer to perform than was originally anticipated. In addition, the maintenance and refueling process may enable the engineers to uncover damaged parts and unexpected maintenance tasks that could extend the length of the outage. These are usually problems that could not be detected before the plant was shut down and various components were dismantled. Because of the unpredictability and the variable length of these outages, it would not be meaningful to simply consider the plant's performance while in operation without considering the amount of time it is down for refueling.

For that reason, we chose to rely on the full cycle capacity factor. This is a measure that includes consideration of the length of a refueling outage. It is measured from the time a unit begins generating electricity after a refueling outage to the comparable time--the start of generation--in the following cycle, approximately an 18-month period. We found that it is a measure that seems particularly well suited for the Diablo Canyon units; to the extent that Diablo Canyon's very high operating capacity factor is the result of maintenance performed during its longer than average refueling outages, the full cycle capacity factor balances these influences. Unfortunately, predicting generation from a full cycle capacity factor is difficult, because the percentage factor depends not only on the length of the refueling outage, but also on the actual length of the full cycle. Therefore we converted the full cycle capacity factor to an expected operating capacity factor (OCF) by assuming that the full cycle performance occurred over a typical fuel cycle of 18 months and a typical refueling outage of 12 weeks.[10]

CCC and IEP have recommended that the same formula be used this year, yielding an OCF of 80.5%. On the basis of one additional fuel cycle for each unit, PG&E has now recommended that the formula be changed. PG&E still is assuming a 12-week refueling outage. However, instead of applying that assumption to the historical full cycle performance, the company would apply it to the historical operating capacity factor. The result is a recommended OCF of 85.4%. DRA supports the PG&E proposal. PG&E argues that Diablo Canyon is now a mature plant, with predictable refueling outages.

There have now been two refueling outages each for Units 1 and 2. The last outage was for Unit 2 and it was completed in 2 days less than 12 weeks. PG&E argues that this fact demonstrates that refueling outages should be expected never to exceed 12 weeks. However, this outage was preceded by a Unit 1 refueling outage of more than 18 weeks. PG&E's witness explained that the company was able to learn enough during that lengthy Unit 1 outage to allow them to anticipate and plan for the repairs to be completed during

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10 The implications of the OCF chosen for the the ECAC period have changed with the approval of the settlement of the Diablo Canyon Reasonableness Review in D.88-12-083. PG&E now receives a specified payment for each kilowatt hour of net generation from Diablo Canyon. The AER will be adjusted to become indifferent to the performance of the plant. The generation forecast adopted in this proceeding will allow us to establish a Diablo Canyon component of the ECAC revenue requirement in anticipation of expected performance. In additon, forecasted Diablo Canyon performance is still a factor in planning for other fuel needs and in calculating the IER.

the Unit 2 outage. That is because the two units are mirror images of each other.

CCC and IEP argue that a plant that had previously experienced only one fuel cycle per unit does not suddenly become mature after the second fuel cycle. We agree. It makes no more sense to assume that the last Unit 2 outage is typical of future outages than to assume the same of the last Unit 1 outage. 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. As CCC points out, if the two data points available for Unit 1 could constitute a trend, they would suggest that the outages will become longer and longer. As further defense of its proposed change, PG&E asserts that the industry averages show that refueling outages become shorter with time. CCC appropriately reminds us that the methodology that we adopted in the last ECAC proceeding relies on Diablo Canyon's performance, not on the industry average. We prefer to adhere to our earlier approach because the performance of the each unit is more appropriately reflected by its performance across the fuel cycle. We will adopt the 80.5 % figure offered by CCC and HESI.

E. Minimum Downtime and Startup Fuel Requirements for Fossil Plants

In order to simulate the dispatching decisions that will be made in practice, computer modelers must establish certain modeling conventions. These function as rules or constraints that help shape the hypothetical dispatcher's resource choices. One such modeling convention is the concept of minimum downtimes for fossil plants. Another is an assumption as to the amount of fuel needed to start up a unit that has been down.

As PG&E explains, for modeling purposes, it imposes a minimum 72-hour downtime for its larger steam units and a 48-hour minimum downtime for its smaller units. The practical effect is that the smaller units will not be shut down overnight, for economic reasons, if they are perceived as being needed the next day and the larger units will not be shut down for less than three days. Startup costs are also used in production simulation models to allow for a comparison of the cost of shutting units down for fuel economy with the cost of keeping units on-line at minimum load in anticipation of the next time a particular unit is needed to serve load. PG&E argues that to ensure that the decision to startup a unit is correct, the full cost of startup must be considered. Those costs include fuel, distilled water, labor, and auxiliary power required to start up a unit. For modeling purposes, PROMOD reflects all of these costs as if they were related to fuel.

IEP argues that these assumed minimum downtimes and startup costs are excessive. The modeling implication is that the fossil plants are less likely to ever be decommitted either because they could not comfortably be brought back on-line without violating the minimum downtime constraint, or because the assumed startup costs are too high to make a temporary shut down appear economically justified. IEP asserts that if these constraints are excessive, the value of variably priced QFs may be understated.

IEP presents two types of evidence to support its claim that PG&E's assumed minimum downtimes are excessive. IEP refers to PG&E's submissions before the California Energy Commission (CEC) in its Biennial Update Proceeding (CFM7) concerning startup time requirements. These ranged from three to ten hours for "hot" startups and six to 18 hours for "cold" startups. PG&E responds that startup time requirement is a concept independent of the minimum downtime requirement. As PG&E explains it, startup time is the number of hours required to bring a unit from shut down to the point where it can begin to serve load, while minimum downtime is the number of hours from the time when a unit is taken off-line until it can begin to be started up again. PG&E goes on to explain that the minimum downtime requirement is used to minimize unit on- and off-line cycling, which causes thermal and mechanical stresses and vibrations that in turn result in increased wear and tear on mechanical components. PG&E says that, as a result, its dispatchers will not shut down and restart units for less than the minimum downtimes except in the case of emergencies.

IEP responds by saying that although this concept might make theoretical sense, it does not reflect reality. IEP reports that it reviewed PG&E's hour by hour oil and gas steam plant production data as provided in the ECAC reasonableness review last year. According to IEP, combined with the hourly production data provided by PG&E was an explanation of each outage incurred by a power plant. David Branchcomb, testifying for IEP, stated that this data indicated that in a number of instances, PG&E took some of its oil and gas steam plants off-line on a reserve status for as little as three hours. Branchcomb argues that this shows that the minimum downtime concept is not meaningful.

PG&E responds by saying that most of the reserve shutdowns of less than 48 to 72 hours appear in the records as short term because they were immediately preceded or followed by scheduled maintenance or a forced outage. The implication is that the plants were usually shut down for longer than the data examined by IEP might suggest. IEP responds by pointing out that in several instances, very short downtimes were recorded and were neither adjacent to a longer outage nor associated with some emergency. PG&E counters by saying that IEP is only discussing nine starts out of a total of about 200 cold starts over the course of a year. IEP says that PG&E's data from its CFM8 submissions should be adopted, instead of the numbers offered by PG&E in this proceeding.

As was the case with the question of Pacific Northwest availability, IEP is asking us to reject PG&E's showing in this case largely because PG&E has said something elsewhere that appears to be contradictory. Although truly contradictory showings in two proceedings would seriously undermine the credibility of the presentations in either case, the existence of a contradiction does not lend instant reliability to the "other" showing. In this instance, we are not convinced either that a true contradiction exists or that the CFM7 numbers are more reliable.

PG&E has testified that the downtimes are not as short as they appear and that there are technical reasons to keep the plants down longer. IEP has not offered engineering support for its claims that shorter downtimes can be assumed. The IEP showing has, nonetheless, placed a spotlight on a subject that merits greater scrutiny. In its next ECAC filing, we will expect PG&E to demonstrate, based on historical data from 1986 and 1989, the actual amount of time each plant was down in each instance and provide the reason for the duration of the outage. PG&E should offer minimum downtime assumptions that do not simply reflect the optimal operating conditions, but take into account the downtimes that are actually experienced.

IEP also raised the possibility that PG&E's technique of including all startup costs as a fuel cost equivalent may lead to double counting. The nonfuel costs such as labor and distilled water would normally be considered in a general rate case, not in a fuel cost offset proceeding. The ALJ directed PG&E to provide evidence showing which costs are already accounted for in the general rate case and the revenue requirement associated with those costs. PG&E reported that for the IER and revenue requirements calculations, the costs of the auxiliary power, distilled water, and labor were removed because these costs are recovered elsewhere (the nonfuel costs in the general rate case and the auxiliary power costs in the general steam rate). These costs represent $585,000 out of the $3,948,000 startup cost assumed for dispatching purposes.

For dispatching purposes, it is realistic to consider the full cost of start-up. It is not, however, reasonable to double count dollars. The additional information provided by PG&E assures us that the company is not asking for the same dollars in two separate proceedings. Thus, we will adopt PG&E's assumptions for minimum downtimes and startup fuel costs for steam plants using fossil fuel.

F. <u>Restart of Standby Oil and Gas Units for QF-Out Simulation</u>

PG&E has certain oil and gas generating units that are kept on standby. PG&E says that these units are not likely to be needed in 1990. Placing the units in standby, according to PG&E, saves costs associated with keeping the units in as-available status. Nonetheless, these units are capable of being put into service relatively quickly. PG&E argues that, in modeling the utility's dispatch decisions in the absence of variably priced QFs, it is inappropriate to treat these units as if they were available for use.

IEP points out that PG&E has made this argument before. In fact, PG&E made the same argument in its ECAC proceeding last year. In D.88-11-052 (at p. 64) we said:

> "We believe that it is appropriate to model standby units that can be restarted in a short time as being available for the entire forecast period. Presumably, these plants were put on standby because they were less efficient than other plants. Since the model dispatches generation on an economic basis, except for certain constraints, these plants would not be employed by the models unless and until they were cheaper than alternatives."

In that decision, we required all modelers to model standby units that can be restarted in short time as being available for the entire forecast period. Nothing has changed that should cause us to alter our position this year. As proposed by IEP, we will ask all modelers to assume that all six units in question will remain available for the entire forecast period.

G. Uncontested Assumptions

The parties were able to reach agreement as to many of the resource and modeling assumptions to apply to IER and revenue requirements calculations. Appendix A to this decision contains the portion of Exhibit 1 that lists the uncontested resource assumptions and modeling conventions. We adopt all of those assumptions as listed, with the exception of the sales forecast (which has been adjusted as described in an earlier section) and hydro generation (which has been changed to reflect June snow survey information).

IV. Calculation of the ERI

There are three computational factors set in the ECAC proceeding that govern the payments to be made by PG&E to variably priced QFs. The IER, which reflects the utility system's incremental efficiency in converting heat energy to electricity, is multiplied by the utility's incremental fuel cost to produce the energy price to be paid to variably priced QFs. The ERI is a way of expressing whether the value of additional capacity on an electric utility system in a given year is the same as, or greater or less than the utility's marginal capacity investment, assumed to be a combustion turbine. It is a fraction that is multiplied by the cost of a combustion turbine to produce the capacity price to be paid to variably priced QFs. The O&M adder reflects the operation and maintenance costs that are avoided when variably priced QFs are available. It is added to the energy and capacity prices to form the total price paid to variably priced QFs. The modeling parties were directed to present their IER, ERI, and O&M adder calculations in the hearings which followed the ALJ's resource assumption ruling.

The first ERI was adopted in PG&E's test year 1984 general rate case D.83-12-068. Since then, this Commission has considered aspects of the ERI in a number of other decisions.[11] The ERI capacity value adjustment is calculated using either short-term or long-term forecasts of utility loads and resources, depending on the type of standard offer.[12] Short-term ERIs are updated annually in the Energy Cost Adjustment Clause (ECAC) proceedings. Long-term ERIs are updated as part of the Biennial Resource Plan Update (BRPU) in A.82-04-44 et al.[13]

Prior to June 22, 1989, we had adopted methods for calculating the long-term ERIs for PG&E, SCE, and San Diego Gas & Electric Company (SDG&E).[14] We had also adopted methods for calculating short-term ERIs for SCE and SDG&E. However, in D.88-03-079, we deferred final adoption of a short-term method for PG&E. Instead, we continued the use of PG&E's 1987 capacity price for 1988, and requested comments on a "floor/ceiling" proposal.[15]

In D.89-06-048, we adopted a floor/ceiling methodology, modified in response to comments on an earlier proposal, to calculate the short-term ERI for PG&E.

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11 See D.86-07-004, pp. 27-30 and 81; D.86-11-071, pp. 1-17; D.88-03-079, pp. 3-18; and D.89-06-048 in its entirety.

12 Capacity payments under our as-available offers (SO1 and SO3) are based on ERI calculations using <u>short-term</u> forecasts of loads and resources. Capacity payments under SO2 and our "long-run" final Standard Offer 4 are based on ERI calculations using <u>long-term</u> forecasts.

13 See D.88-03-026, Table A and D.88-03-079, pp. 6-8.

14 In D.88-03-079, we directed SDG&E and SCE to adjust the capacity cost of a CT using an ERI based on expected unserved energy. We directed PG&E to use a CEC-based Target Reserve Margin method. See D.88-03-079, pp. 6-8, 18.

15 D.88-03-079, pp. 16-18.

Until further action by this Commission, PG&E's short-term ERI will have a ceiling of 1.0 and a floor of 0.4. The ceiling ERI will be used to calculate capacity payments whenever PG&E's projected reserve margin for the forecast year is equal to or less than the target reserve margin established in the most recent Electricity Report of the CEC. The ERI will decline exponentially as the projected reserve margin increases above the target, until the projected reserve margin is six percentage points over the target. At or beyond that point, the ERI will be the floor value of 0.4.

Our adopted floor/ceiling approach is to be used consistently for all applications involving short-term capacity valuation on PG&E's system, including pricing for as-available QFs, forecasts of energy-related revenue requirements, revenue allocation, and rate design.

Since this ECAC proceeding and the general rate case were already in progress when the floor/ceiling approach was adopted, we directed PG&E to make late filings in both cases to assure that its ERI calculations conformed to the new approach. The timing of the ERI decision allowed for PG&E and other parties to present responsive ERI calculations along with their final IER runs. When asked to prepare its calculation, PG&E sought guidance as to how the calculation should be made. There were two lengthy off-the-record discussions dedicated to answering PG&E's questions. One of those discussions was preceeded by the issuance of a letter from the ALJ (dated July 12, 1989) setting forth for discussion a format for calculating the ERI. Since the company continued to request more explicit guidance, the ALJ included the following instructions in his August 15, 1989 ruling on resource input assumptions, which reiterated the format discussed in his earlier letter:

1. Calculate projected reserve margin based on QF-in run.

2. Calculate projected reserve margin based on QF-out run.[16]

3. Calculate the average of these two values.

4. Calculate ERI, based on the average projected reserve margin, using the CEC's adopted target reserve margin of 17.5%[17] and the floor/ceiling methodology adopted in D.89-06-048.

5. Incorporate the ERI in the revenue requirements calculation.

Ultimately, PG&E calculated the ERI as .40, while DRA and the QFs all calculated the ERI as 1.0. There were four major areas of disagreement between PG&E and the other parties as to how the calculation should be made.

A. Dry Year Hydro Assumption

When placing a value on contribution of new capacity to the reliability of the utility system, it is important to take into account any conditions which could reasonably apply in the period under consideration. We have consistently required that this analysis include an assumption that in any given year the utility may face dry hydro conditions. In this proceeding PG&E has argued that dry year hydro conditions should not apply to the ERI forecast, because it is only a one-year forecast. PG&E suggests that there is sufficient predictability in the short-term hydro forecast process to make this planning exception.

16 QF-in/QF-out should be defined in a manner consistent with the IER runs. Consistent with the Commission's determination in D.86-11-071 (see Finding of Fact 7 and p. 10), "dry hydro" conditions should be assumed for the ERI calculation.

17 Derived from the CEC's Electricity Supply Planning Assumptions Report, Docket 87-ER-7, p. A-50.

In this regard, we agree with the comments of DRA witness Robert Kinosian that we have always used adverse hydro conditions when doing reliability planning because it is impossible to forecast what the actual hydro conditions will be in a following year. In D.86-11-071, this Commission responded to an earlier request by PG&E to reconsider that requirement. The Commission said (at p. 11), "...we reaffirm that adverse hydro conditions are to be the basis of capacity planning in California....[S]ince we are using the perspective of system operability, we think the reliability target must ensure smooth operation in dry years."

In its testimony and brief, PG&E has put much effort into explaining to us what we meant in earlier rulings on this point. We will not attempt to explain further what the Commission may have had in mind in earlier decisions. One need do little more than examine the nature of PG&E's system. Because of its heavy reliance on hydro power, PG&E's system is particularly sensitive to changes in hydro availability. This makes its system relatively less reliable in dry years. This increases the value of other sources of capacity and must be considered, even in short-term forecasts.

We are aware that, in some years, the use of dry hydro assumptions will create the potential for higher-than-needed capacity payments to variably priced QFs. That is why we adopted a ceiling for PG&E's ERI. However, in many dry years, the ERI could exceed the ceiling of 1.0. As a matter of equity, we have also adopted a floor level of .4, which will assure QFs of some revenue consistency. As we stated in D.88-03-079, ceiling and floor provisions for PG&E's short-term ERI provide a reasonable balance of interests on a system where hydro plays such an important part. One of the factors being balanced is the use of dry hydro assumptions for the planning process.

Finally, it should be noted that this ECAC did not provide a forum for reconsidering the assumptions which apply to a short-term ERI calculation. In fact, we have no factual basis for reconsidering the use of the dry hydro assumption in this record. If PG&E wishes to pursue this issue further, it should do so in the biennial resource planning update proceeding. We agree with DRA and the QFs that dry year hydro assumptions should apply to this short-term ERI calculation.

B. Northwest Capacity Assumption

PG&E's witness (Kerler) testifies that the company could, if necessary, "firm up" more capacity in the Pacific Northwest than is indicated in its IER forecast and that it should be allowed to do so for the purpose of its ERI calculation. The company argues that it is being unrealistically constrained by being told to factor in a high reserve margin while not being able to assume greater capacity purchases from the Northwest. PG&E argues that, operating under such constraints, the inevitable result will be an ERI of 1.0.

CCC asserts that any potential extra capacity in the Northwest should not be counted because it is not "committed". Mark Younger, testifying for CCC, states that the CEC already took into account the possibility that PG&E could firm up extra Northwest capacity when it established the reserve margin which is being used for the ERI calculation. He argues that to allow PG&E to assume greater Northwest capacity to meet that reserve margin would constitute double counting, understating the value of added capacity.

CCC points out that there are other inconsistencies in PG&E's capacity assumptions between the ERI and IER calculations. In the ERI calculation, PG&E has added 100 MW to the assumed firm capacity purchases from the Northwest by SMUD. In addition, PG&E has added the assumption that all WAPA purchases are firm. CCC argues that, instead, firm capacity should be consistently defined throughout the proceeding.[18]

We agree. Perhaps the main benefit in merging the processes for calculating the IER and ERI in one proceeding is to ensure the integrity of the forecasting process. For the purposes of all short-term forecasting, PG&E should present a unified picture of its expected purchases and resource plans during the forecast period. It must be remembered that the goal of the ERI calculation is not to reinvent PG&E's resource plant, but to place a value on the added reliability stemming from the presence of a variably priced QF. The capacity assumptions applied in the IER calculation shall apply to the ERI as well.

C. QF Capacity

For purposes of calculating the IER, PG&E and all other parties used the expected average capacity of QFs offering firm capacity. DRA, CCC, and IEP have used the same figure in calculating their ERIs. In its ERI calculation, PG&E has relied, instead, on the full contractual capacity of the QF facilities. The result understates the value of the added reliability introduced by variably priced QFs. Again, inconsistency is part of the problem. The same assumptions should apply when calculating the IER and the ERI. We agree with the DRA and QFs and will adopt their position.[19]

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18 DRA and IEP comments are consistent with those of CCC.

19 On October 3, 1989, DRA moved to strike a portion of PG&E's brief that concerned the ERI calculation. DRA is concerned that PG&E was using its brief to propose a change in the short-term ERI methodology in this proceeding. DRA is correct in stating that this ECAC proceeding is not the appropriate forum for questioning the methodology. In its October 13, 1989 response, PG&E stated that it is not proposing a new methodology, but advocating a

(Footnote continues on next page)

D. Standby Units

PG&E argues that if we were to adopt a dry year hydro assumption, this would constitute the use of long-term planning assumptions. As such, PG&E asserts that we should also allow long-term stand-by units (those which normally require more than 12 months to restart) to be included in the calculation. As stated earlier, we do not accept the underlying premise. For reliability purposes, dry hydro conditions comprise the appropriate short-term assumption. It is inappropriate to include long-term stand-by units in a short-term ERI calculation.

As we have stated previously, the ERI calculation method can be reviewed in the Biennial Resource Update Proceeding. Nonetheless, we are satisfied that the method set forth in D.89-06-048 and guided by the ALJ ruling in this proceeding is reasonable and shall apply in this case.

V. Calculation of the O&M Adder

Prior to decisions stemming from last year's PG&E ECAC proceeding, PG&E included avoided O&M costs in its IER calculation. Based on the arguments offered by CCC and the IPC, we concluded that the avoided O&M payment should be removed from the calculation of the IER and added as a separate payment to the base energy price

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(Footnote continued from previous page)

specific way to implement the methodology which we recently approved. We will accept PG&E's statement that it is not proposing that the floor/ceiling provisions or the target capacity factor be changed. The crucial question is whether or not in calculating the short-term ERI the various parties have implemented the methodology in a manner consistent with D.89-06-048. We will review the comments in PG&E's brief in that light. DRA's motion is denied.

paid to QFs.[20] We also determined that these payments should be expressed in mills/kWh and allowed to vary with the amount generated in the swing units, rather than with changes in the price of the marginal fuel.

In last year's ECAC proceeding, we found that the lack of information on variable O&M costs presented a formidable obstacle to the resolution of this issue. We directed PG&E to present a study of the O&M costs avoided by QFs' generation in its test year 1990 general rate case. PG&E was told that, at a minimum, the study should examine the reductions in costs--including materials, labor, and any other appropriate costs--that occur when generation is reduced at its existing conventional fossil plants. In addition, PG&E was to:

1. Calculate the savings in O&M expenses that have resulted from the retiring or removal to standby status of conventional fossil plants in the last five years,

2. Attempt to identify and quantify the O&M costs that vary in one-, three-, and five-year time frames, and

3. Present any other relevant information available to it.

We issued D.89-09-093 in response PG&E's O&M study as presented in the pending general rate case application. As stated earlier, the proposed order that was to become D.89-09-093 was issued after the commencement of this proceeding. Parties to this proceeding were instructed to calculate the O&M component of payments to variable QFs (O&M adder) according to the method in the proposed order. Subsequently, in D.89-09-093 we affirmed the reasonableness of that method.

20 D.88-11-052, starting at p. 61.

We determined that, in this ECAC proceeding, the calculation of the adder would begin with the QFs-in/QFs-out runs that are used to determine the IER. For purposes of calculating the adder, standby reserve units should be modeled as being available for dispatch in the QFs-out run. We concluded that the avoided O&M costs should be calculated separately for three types of generating units: operating units, cold standby units, and retired plants. Operating units form a residual category that includes regularly operating units and reserve units that have not yet been placed in cold standby status. The change in generation between the QFs-in and QFs-out runs for each operating unit should be multiplied by the appropriate variable O&M figure from PG&E's filings in CFM6 and CFM7 to develop a total avoided O&M cost for that unit. The avoided costs for all operating units should then be added together to arrive at the total O&M savings from operating units.[21]

There are two areas of contention between the parties as to how the O&M adder should be calculated this year.

First, just as it did for its ERI calculation, PG&E would deviate from its IER assumptions concerning firm capacity arrangements in the Pacific Northwest for itself, SMUD, and WAPA. PG&E asserts that the same arguments support the use of different assumptions for O&M calculation as support deviating from the IER assumptions for the ERI calculation. As we stated in D.89-09-093, the same QFs-in and QFs-out runs used for the IER calculation should form the basis of the O&M adder calculation. Consistent with our earlier consideration of the ERI calculation, we reject PG&E's effort to modify our recently adopted O&M formula.

21 See D.89-09-093, pp. 33-34.

Second, parties disagree as to the proper consideration of Moss Landing Units 4 and 5. As PG&E argues, these units are neither operational nor in cold standby. Instead, they occupy the relatively unique status of near-term standby units. According to PG&E, these generating units are maintained in such a way as to remain available to come on-line in 2-3 days. PG&E claims that this status results in virtually the same O&M expenditures for the two units whether or not they are placed into operation. Therefore, PG&E would change its QFs-in calculation to include Moss Landing Units 4 and 5. The effect would be to eliminate any assumed O&M savings for those units resulting from the contributions of variably priced QFs.

It is DRA's position that Moss Landing Units 4 and 5 should be considered operational in the QFs-out run, but not the QFs-in run. This is consistent with the IER assumptions and with D.89-09-093, which says that the IER runs should be used for this purpose. We agree with DRA that, when calculating the O&M adder, it is more appropriate to use the same assumptions for Moss Landing Units 4 and 5 as were applied in the IER calculation. After all, these units are not expected to generate power during the forecast period. If these units were included in the QFs-in run, the overall generation mix would be changed in a way that no party predicts would actually occur.

This assumption, alone, merely affects the amount of additional generation for each of the two units predicted to occur if the variably priced QFs were not available. Additional generation leads to avoided O&M costs only after the change in generation for each unit is multiplied by a variable which reflects incremental O&M savings. No party contests PG&E's claim that its O&M costs for these units are virtually the same whether or not the plants are operated. Therefore, in the proposed decision, the ALJ found that the appropriate factor by which the predicted change in generation should be multiplied is zero. The result is that no avoided O&M costs for these units would be assumed.

In their comments, DRA and the QFs pointed out that this assumption is not precisely correct, since certain consumable commodities such as distilled water and oil can be saved when the units are not placed in operation. We agree that it would be most appropriate for future O&M adder calculations to place a value on these avoided consumables. However, we feel that, on balance, the O&M adder adopted in this proceeding is fair.

Finally, we also agree with DRA that Moss Landing Units 4 and 5 should be considered firm capacity for the purposes of calculating the avoided cold standby capacity related O&M costs. This will appropriately reflect the fact that these units are not in cold standby status.

VI. Calculating the DIER

A. Use of the Full UEG Rate

In D.88-12-083, we adopted a settlement in the Diablo Canyon Reasonableness Review. Among many other things, the settlement requires that Diablo Canyon revenues be excluded from PG&E's AER. In particular, PG&E expenses for replacement or displacement fuel due to operation of Diablo Canyon will be removed from AER recovery, through an annual adjustment at the end of each AER forecast period. For example, if Diablo Canyon production over a given period is greater than was forecast in a given ECAC proceeding, then PG&E expenses for other fuels would be lower than expected and PG&E would be in a position to increase its earnings through the AER. The annual AER adjustment will reduce customer costs by crediting the ECAC balancing account with the AER fraction of the displacement fuel expenses foregone by PG&E. If Diablo

Canyon production is less than forecast, an opposite adjustment will be made to prevent PG&E losses through the AER.

The settlement proponents proposed a formula for making this annual adjustment utilizing the system average heat rate. We determined, however, that it would be better to use a production cost model to calculate incremental costs, than to use the system average heat rate found in the proposed tariff formula. Therefore we changed the formula to substitute an appropriate IER for the proposed system average heat rate.

We found in D.88-12-083 that the IER used to calculate QF payments is the wrong IER for the annual AER adjustment. We ordered PG&E to calculate an appropriate IER, to be called the Diablo Incremental Energy Rate (DIER) to distinguish it from the QF IER, as follows.

> "In each ECAC case the QF IER is developed by calculating the difference in operating costs between two scenarios, QFs-in and QFs-out, then dividing that difference by the energy purchased from the QFs and by the Utility Electric Generation (UEG) gas rate. The total costs for each scenario are computed using production cost models. The DIER should be developed in much the same way, by calculating operating costs for two scenarios, both of which should assume QFs-in, for which Diablo Canyon output is 10% above and 10% below the capacity factor or availability factor assumed in the calculation of the QF IER. The DIER is then the difference in costs between the two scenarios, divided by the difference in Diablo Canyon generation and by the same UEG gas rate used in the QF calculation. This calculation should not be difficult because all model assumptions have been made in the process of determining the QF IER. If the specified 10% deviations are so small as to yield erratic DIER values, PG&E should revise the deviations appropriately and justify its revisions.
>
> "PG&E should make the calculations using the model conventions and resource assumptions adopted in A.88-04-057, its current ECAC proceeding, and report the resulting DIER with

> its first annual Diablo Canyon compliance filing. Future DIERs should be litigated in ECAC proceedings, not simply provided by PG&E."[22]

In the same decision, we stated that the formula described above may be modified in ECAC proceedings (see Finding of Fact 27). In this, the first such ECAC in which the DIER is being litigated, PG&E is already proposing a change in the formula.

Although the Diablo Canyon settlement decision called for use of the full UEG gas rate in calculating the DIER, PG&E now proposes that only the G-PC and Tier II volumetric gas rates be used for the determination of the DIER. According to PG&E, this should be done because the demand/customer charges and the Tier I volumetric charge are fixed in the AER/ECAC rates and will not change if the Diablo Canyon generation changes. PG&E argues that since the fixed demand charges do not go up or down with variations in Diablo Canyon production, their inclusion in the DIER would cause PG&E to collect more or less for the difference in production than actual variable cost would go up or down.

DRA supports PG&E's position. The QFs argue that the full UEG gas rates should be used. We agree with the QFs. The decision accepting the Diablo Canyon settlement specified that the same UEG rate used in the IER calculation should be used in the DIER.

We are not convinced that using the full UEG rate as opposed to using only variable portions of that rate will have any effect on the balance of payments to PG&E stemming from the performance of Diablo Canyon. In converting the results of the model runs to the DIER, the cost of gas appears in the denominator of the calculation (DIER = $ divided by kWh divided by cost of gas). In converting the DIER to an AER adjustment, the cost of gas appears in the numerator of the calculation (AER $ = DIER times kWh

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22 D.88-12-083, pp. 177-178.

times cost of gas). So long as the same UEG rate is used both for calculating and applying the DIER, the nonvariable portions of the rate will not influence the results. For the sake of simplicity, we will continue to require that the UEG rate be applied in the DIER calculation in the same manner it is applied in the IER calculation.

B. Differences in Results

DRA, PG&E, and CCC all derived similar results when calculating the DIER. On the other hand, IEP proposed a significantly higher DIER. IEP attributes this difference to its use of a chronological modeling approach which, it argues, more accurately mimics actual performance. PG&E argues, on the other hand, that IEP's calculation is flawed because it applied inappropriate assumptions as to which resources would be added when Diablo's performance was reduced and which would be subtracted when Diablo's performance improved. According to PG&E, all modelers agree that conventional units would be added before additional Northwest purchases when Diablo production is down. However, only IEP assumes that the conventional units would be backed out first when Diablo production is higher.

PG&E's argument is not supported by the record. This may be a result of PG&E's reliance on IEP's workpapers, which were not placed into evidence. Nonetheless, we are not persuaded that PROSYM is a more reliable tool for calculating the DIER. We will adopt PG&E's DIER (7811), which is virtually identical to that of CCC.

VII. Differences Among the Models

As was the case last year, three different computer models were used in order to simulate the performance of PG&E's system under various assumptions. These computer simulations help us to understand PG&E's fuel costs, the value of power generated and capacity provided by QFs, and the computational factor to be used for adjusting the AER to remove the affects of Diablo Canyon's performance in the past year.

DRA used ELFIN, a computer model which has been used by our staff and various utilities for over a decade. PG&E and CCC used PROMOD, a more complex and costly modeling approach, which has been used by PG&E in several past proceedings. IEP used PROSYM, a relatively new model, which was also used in the ECAC proceeding last year.

ELFIN and PROMOD are load duration curve models, which convert chronological demand levels into load duration curves, representing the percent of time that each level of demand occurs. PROSYM is a chronological model, which considers the system's operation in relation to time and which uses multiple runs to develop its forecast of the system's operation. IEP refers to this multiple run method as the Monte Carlo approach, under which the computer generates random numbers, intended to simulate chance occurrences in the performance of PG&E's generating sources. Numerous runs are used to bring the results closer to probable performance, instead of relying on one random set of numbers to forecast activities over the course of a year.

Because it is important to determine whether or not computer-generated forecasts are reliable and in order to understand the differences between these models, we have continued to employ workshops and common data set runs. While the use of a common data set cannot pinpoint all of the differences between the models, it does create a focus which, hopefully will uncover serious disagreements and flaws. In good faith, the parties have worked this year to help us understand how the models produce different results. Perhaps most important of all, the parties have worked with modeling constraints and conventions to make the results of their runs compatible.

Perhaps not surprisingly, the models continue to produce very similar results. In IEP's words, for most purposes, it is a coin toss to determine which model's results should be used. Through the workshop process, we have been able to identify differences in the way the models work and can see how accommodations are made in the modeling process to overcome limitations. However, despite the fact that we have justifiably referred to this multiple model process as a "Battle of the Models," it is not a process which is likely to produce a clear winner. In fact, the use of different models has raised questions about assumptions and technique which might not come to light if everyone relied on the same tools. To that extent, the use of multiple models is beneficial.

One modeling distinction that was discussed during the hearings was PG&E's use of a criterion it calls Dispatcher Risk Aversion. According to PG&E, this feature is intended to mimic the dispatcher's concern with the amount of energy available from various sources. Not all sources of generating capacity can provide endless amounts of energy. PG&E says that the dispatcher must have additional plants up and running when there is a high risk of an energy shortfall at an operating facility. The company argues that its heavy dependence on hydro power underscores the importance of this modeling feature, since a hydro plant cannot reliably supply as much energy when its reservoir is low. This makes this modeling feature especially significant in dry years.

In using the Dispatcher Risk Aversion feature, the modeler must decide just how risk averse the dispatcher should be assumed to be. This value is expressed in a percentage from zero to 100. In last year's ECAC, PG&E applied the following values to the Dispatcher Risk Aversion feature:

Weekday	50%
Nighttime	50%
Weekend	33%

In this proceeding, PG&E has applied the following values:

Weekday	100%
Nightime	100%
Weekend	33%

PG&E's witness Claudia Greif acknowledged that Dispatcher Risk Aversion has a relatively high impact on fuel costs compared to other model features. Nonetheless, she had not measured the impact of the changed values on the IER and revenue requirements.

It is important that the impacts associated with model features such as Dispatcher Risk Aversion be clearly identified and documented, especially when the feature is one which is given relatively greater weight than others. We will direct PG&E to include, in its next ECAC filing, the results of a study on the use of the Dispatcher Risk Aversion modeling convention. At a minimum the study should meet the following requirements and justify the company's choice of values to be applied to the modeling convention:

1. Describe the model feature and the system operation which it is designed to represent.

2. Describe, review and explain the algorithm through which this model feature claims to mimic the system operation being represented.

3. Test the model feature by applying the default variable, the variable as it was applied in the 1988 ECAC filing, the 1989 ECAC filing, and the 1990 filing to the values adopted in this decision. In addition, run the model with the values adopted herein without activating the Dispatcher Risk Aversion feature. In each instance, report on the impacts on IERs and revenue requirements.

4. Report on the relationship between the Dispatcher Risk Aversion assumptions and actual operation.

In considering the results of the different models in these ECAC proceedings, our greatest concern is in ensuring the effective participation of the DRA in this process. We need that balance in order to assure that all ratepayers are adequately represented. Whether or not all parties are limited to using one model, it would be best if resources were available to enable DRA to use and be familiar with the model offered by the utility. Then it would be clear that DRA and the utility were speaking the same language when discussing modeling conventions and assumptions.

We are not prepared to tell any of the parties that they must abandon their favored models. Prior to this proceeding, we required each party in ECAC proceedings for all utilities to include in its showing a base case run using ELFIN. We eliminated that requirement for PG&E this year because we were interested in focusing the base case comparison on the way that the various models handled the same input assumptions. However, this led to an unintended result. Without the benefit of an ELFIN run accompanying PG&E's application, the DRA was forced into a perilous game of "Beat the Clock". When the application was filed in April, DRA had only a few weeks in which to analyze PG&E's PROMOD results, complete the trial-and-error process of developing the modeling conventions needed to produce comparable data when using ELFIN, participate in the modeling workshops, and prepare its testimony. All this had to be done with a core computer team consisting of one person.

Despite long hours and a concerted effort, the results were unsatisfactory. DRA was unable to provide input to the workshop process on a timely basis, could not meet its schedule for filing testimony, and made substantive changes to its initial case after the last day of hearings.

We need not force DRA to begin its ECAC investigation under this handicap again. Instead, we will reinstitute the requirement that PG&E's application be supported by an ELFIN run, regardless of the model PG&E wishes to rely on for its preferred case. At the time of its filing, PG&E shall be prepared to work with DRA in interpreting the ELFIN run and to provide DRA with a complete explanation of the modeling conventions employed to make the ELFIN run comparable to that of any other model used.[23]

PG&E argues that DRA's desire for this assistance is an indication of the quality of DRA's modeling expertise. This is an unfortunate and inappropriate argument which misses the point. DRA's experts are expected to apply their skills to a full range of computer analyses in the telecommunications, transportation, and energy fields on a continuous basis. It is unnecessary and wasteful to ask them to start each analysis with a clean slate. With PG&E's ELFIN run in hand, DRA should be more quickly able to focus its own computer work and determine where there is a need to develop more or better conventions and modeling techniques. As always, DRA will remain responsible for its own analysis. With PG&E's ELFIN run in hand, however, it should be better able to deal with the increasingly complex ECAC issues within the short time available for considering these cases.

VIII. Hydro Conditions

In ECAC proceedings, we normally apply average precipitation assumptions when forecasting hydro generation for a future period. That is because, even in the short-term it is not possible to make reliable forecasts of precipitation. However, prospective estimates can be tempered by existing conditions. For instance, PG&E conducts snowpack surveys which can tell it

23 In its comments to this proposed decision, PG&E asked that the ELFIN run due date be delayed until one week after the rest of the ECAC filing. Although we are sympathetic to the problems of producing the ELFIN run at an earlier date, we cannot agree to this delay. PG&E should make a sincere effort to submit its ELFIN run and the rest of its application at the same time. Any request for an extension of this deadline should explain why the rest of the schedule should not be similarly extended.

something about the availability of water in the months ahead. When PG&E filed this application (April 3, 1989), its analysis included the latest snow survey data available, which was issued at the beginning of February. PG&E offered April data when it became available and June data when it was developed.

Since the forecast period begins November 1, which is within the next rain season, the question was raised as to the benefits of using prior year snow survey data. Would it be preferable always to apply average year assumptions, since the actual performance will fluctuate above and below average over the years? Some parties questioned the merits of changing hydro assumptions as the case progressed. One concern is that each party might advocate using the data which is most favorable to its case. The most repeated position is that some rule should be applied consistently. Either average year data should exclusively apply, or snow data from a specific report should always be relied on.

We are convinced that there is some merit to taking current conditions into account. While much of the snow pack may disappear by November, the late winter and spring hydro conditions may affect stream flows and reservoir levels well into a forecast period which begins the following fall. At the same time, we agree that consistency is important. Last year, we relied on June snow survey information. We are relying on the June data this year as well. This is the most recent report available which can be fully examined during the hearings. In future years as well, we intend to ask that PG&E provide an update based on the June report and to rely on that information when assessing the hydro forecast.

IX. Revenue Requirements

Because the proposed decision made some adjustment to factors which can affect revenue requirements, it was necessary for each of the parties to make additional calculations. The assigned

Commissioner directed the parties to do this and file the results with their comments on the proposed decision, so they could be reflected in the final decision.

Table 2 reflects the final calculations of each contributing party for the IER, ERI, O&M adder, and revenue requirements. As this table indicates, the revenue requirements and other calculated factors of the various parties are relatively close. At the time when Responsive Comments to the Proposed Decision were filed, DRA and CCC reported that there had been slight errors in their calculations of the O&M adder. The revised calculations are reflected in Table 2. DRA's revenue requirements number is listed as unknown because DRA did not offer a final revised calculation. Its most recent figure of $282 M would have been reduced by the change in the O&M adder.

Although we are not endorsing a single computer model, we must adopt a set of final calculations. On balance, PG&E's calculations reflect internal consistency. CCC used the same computer model as PG&E and generated virtually identical numbers. This lends confidence to our use of PG&E's calculations. We will adopt PG&E's most recent calculations for the IER, O&M adder, ERI, and net revenue requirements as reflected in Table 2. The adopted energy costs and changes in revenue requirements are contained in Appendix C and summarized in Appendix D.

TABLE 2

Party	Average IER	O&M Adder	Equivalent IER	ERI	Net Revenue Increase
PG&E	9,443	2.326	10,387	1.0	$ 272.048 M
DRA	9,427	2.42	unknown	1.0	unknown
CCC	9,444	2.321	10,386	1.0	272.684 M
IEP	9,459	2.44	10,430	1.0	274.272

Findings of Fact

1. PG&E filed this application on April 3, 1989, requesting an increase of $378.3 million to its electric rates on an annualized basis effective November 1, 1989.

2. Since the last AER revision only forecasted costs through end of July 1989, we suspended PG&E's AER as of August 1, allowing 100% of the fuel costs incurred since that date to be tracked in the ECAC balancing account.

3. All revenue allocation and rate design issues have been heard on a consolidated basis in A.88-12-005, the general rate case.

4. In a ruling dated May 24, 1989, ALJ Cragg granted PG&E's motion asking that the sales forecast developed in this proceeding be used in the general rate case for purposes of consolidated consideration of revenue allocation and rate design issues.

5. The Rancho Seco Nuclear Power Plant (Rancho Seco) has been closed.

6. Without the benefit of power generated at Rancho Seco, SMUD will have to purchase more electricity from other entities.

7. It is reasonable to assume that SMUD will make use of its existing contracts with PG&E, SCE, and utilities in the Pacific Northwest.

8. The agricultural customer class is intended to include only those customers who use electricity predominantly to serve agricultural end-uses.

9. Agricultural end-uses include growing crops, raising livestock, pumping water for irrigation, and other uses that involve production for sale and that do not change the form of the agricultural product.

10. As of the time when the results of this year's ECAC proceeding go into effect, agricultural schedules will be reserved for those customers who meet the condition that 70% or more of their energy usage is dedicated to agricultural end-uses.

11. PG&E has yet to reach its goal of identifying the affected customers in the newly defined agricultural class.

12. The number of active agricultural accounts does not equal the number of customers with agricultural end-uses.

13. Each time a new agricultural pump is connected to the utility lines, a new account is opened.

14. Despite overall reductions in farmed acreage during the last few years, drought conditions have resulted in many new accounts being opened.

15. Many accounts are opened or closed simply because farm property changes hands and the electric billing is transferred to a new name.

16. Starting with a base of 99,599 customers in 1985, PG&E had forecasted 100,951 customers for 1988, reflecting a net increase of 1,352 customers.

17. An actual tally of accounts opened and closed during those years yields a net reduction of 804 accounts, leading to 98,795 customers in 1988.

18. The growth in the number of agricultural accounts forecast by PG&E's econometric model does not coincide with recorded openings and closings in the years for which data was provided.

19. Despite the disagreements as to the size of the agricultural class, the various estimates of agricultural sales are very close.

20. The Pacific Northwest has experienced two exceptionally dry years.

21. All parties are in agreement with PG&E's forecast of available installed capacity for transmission from the Pacific Northwest during the forecast period.

22. Even if current river flows and reservoir levels are at or near normal, the reality of two prior dry years is likely to restrain deliveries to California.

23. Sufficient energy available in the Pacific Northwest to fill all of its entitlement on the transmission interties during peak periods and 50% of its entitlement during off-peak hours.

24. In 1988, PG&E purchased Northwest power at the fixed price of 22 mills.

25. BPA has offered to provide energy to PG&E in October 1989 at a price of 23 mills.

26. In 1988, reservoir levels in the Northwest were dramatically lower than they are in 1989.

27. Actual practice confirms PG&E's ability to obtain energy at 22 mills under less favorable conditions.

28. For the general rate case, PG&E produced a forecast of Northwest Energy availability based on what the QFs refer to as a quantitative model.

29. The key characteristic of a quantitative model is its relative verifiability; assumptions as to what may affect energy supplies are clearly defined and subject to critique for conceptual soundness; once the conceptual framework is understood, results can be checked and replicated by others willing to undertake the same analysis.

30. For the ECAC Northwest energy forecast, PG&E undertook a largely empirical study.

31. The goal of the general rate case Pacific Northwest analysis was to prepare a long-term forecast.

32. In an ECAC forecast, the reliance is on short-range vision and the factors that are recognizable from where we stand today.

33. Properly executed quantitative analysis does not necessarily provide a more reliable forecast than empirical judgment.

34. Experts must always be able to show that their judgments flow logically from an assessment of facts and that the full range of essential facts have been considered.

35. The price of Northwest purchases from March 1, 1990 through October, 1990 is assumed to equal 90% of PG&E's average incremental fossil-fired steam generation costs.

36. All parties support PG&E's assumption that its purchases of economy energy from the Pacific Northwest from March 1, 1990 through October, 1990 will be priced at 90% of PG&E's incremental fossil-fired steam generation costs.

37. All parties agreed that if Northwest supplies were considered limited during the first stage of the ECAC period, the price of purchases from the California Department of Water Resources should be assumed to be 20 mills and that the price for the remainder of the ECAC period should be assumed to be the same as the price for Northwest purchases during the second stage.

38. In 1987, the Geysers field began to experience frequent steam curtailments, when there was insufficient steam to run all of the units although the units were available for service.

39. Geysers Unit 15 is now out of service for an indefinite period and is assumed to be unavailable during the forecast period, due to insufficient steam.

40. Geothermal steam curtailments have continued to grow. This year, PG&E was able to shed little new light on the reasons for the geothermal steam curtailments.

41. PG&E proposes that the geothermal steam price be based on its contractual formula involving recorded and forecasted fossil costs and recorded and forecasted nuclear fuel costs, as in past years.

42. DRA has proposed that the nuclear fuel cost component of the geothermal steam price be decreased to reflect what it asserts to have been unreasonable delays in the completion of the Diablo Canyon Nuclear Plant (Diablo Canyon).

43. The necessity of shutting down a generating unit and removing the reactor head during the refueling process makes the refueling outage an ideal time to perform necessary maintenance on various parts of a nuclear power plant.

44. The maintenance and refueling process for a nuclear power plant may enable the engineers to uncover damaged parts and unexpected maintenance tasks that could extend the length of the outage; these are usually problems that could not be detected before the plant was shut down and various components were dismantled.

45. Diablo Canyon Units 1 and 2 have each had 2 refueling outages.

46. The last outage was for Diablo Canyon Unit 2 and it was completed in 2 days less than 12 weeks.

47. The last refueling outage for Diablo Canyon Unit 1 was not completed for more than 18 weeks.

48. For modeling purposes, PG&E imposes a minimum 72-hour downtime for its larger steam units and a 48-hour minimum donwtime for its smaller units.

49. The practical effect of PG&E's minimum downtime modeling convention is that the model assumes that smaller units will not be shut down overnight, for economic reasons, if they are perceived as being needed the next day and that the larger units will not be shut down for less than three days.

50. Startup costs are also used in production simulation models to allow for a comparison of the cost of shutting units down for fuel economy with the cost of keeping units on-line at minimum load in anticipation of the next time a particular unit is needed to serve load.

51. Startup costs include fuel, distilled water, labor, and auxiliary power required to start up a unit; for modeling purposes, PROMOD reflects all of these costs as if they were related to fuel.

52. PG&E's calculations of the IER and revenue requirements do not include the value of the auxiliary power, distilled water, and labor which were removed because these costs are recovered elsewhere (the nonfuel costs in the general rate case and the auxiliary power costs in the general steam rate).

53. PG&E has certain oil and gas generating units that are kept on standby.

54. PG&E says that its standby units are not likely to be needed in 1990.

55. The parties were able to reach agreement as to many of the resource and modeling assumptions to apply to IER and revenue requirements calculations, which are listed in Appendix A to this decision.

56. Variable QF prices are the sum of three basic components: a payment for capacity, a payment for avoided O&M, and a variable payment for energy.

57. The IER, which reflects the utility system's incremental efficiency in converting heat energy to electricity, is multiplied by the utility's incremental fuel cost to produce the energy price to be paid to variably priced QFs.

58. The ERI is a way of expressing whether the value of additional capacity on an electric utility system in a given year is the same as, or greater or less than the utility's marginal capacity investment, assumed to be a combustion turbine.

59. The ERI is a fraction that is multiplied by the cost of a combustion turbine to produce the capacity price to be paid to variably priced QFs.

60. The O&M adder reflects the operation and maintenance costs that are avoided when variably priced QFs are available.

61. In D.89-06-048, we adopted a floor/ceiling methodology, modified in response to comments on an earlier proposal, to calculate the short-term ERI for PG&E.

62. PG&E has argued that dry year hydro conditions should not apply to the ERI forecast, because it is only a one-year forecast.

63. We have always used adverse hydro conditions when doing reliability planning because it is impossible to forecast what the actual hydro conditions will be in a following year.

64. Because of its heavy reliance on hydro power, PG&E's system is particularly sensitive to changes in hydro availability. PG&E states that it could, if necessary "firm up" more capacity in the Pacific Northwest than is indicated in its IER forecast and that it should be allowed to do so for the purpose of its ERI calculation.

65. The goal of the ERI calculation is not to reinvent PG&E's resource plant, but to place a value on the added reliability stemming from the presence of a variably priced QF.

66. It is appropriate to use consistent assumptions as to QF capacity when calculating the IER and the ERI.

67. Parties to this proceeding were instructed to calculate the O&M component of payments to variable QFs (O&M adder) according to the method which we approved in D.89-09-093.

68. As we stated in D.89-09-093, the same QFs-in and QFs-out runs used for the IER calculation should form the basis of the O&M adder calculation.

69. Moss Landing Units 4 and 5 are neither operational nor in cold standby; instead, they occupy the relatively unique status of near-term standby units.

70. Although no party contests PG&E's claim that its O&M costs for Moss Landing Units 4 and 5 are virtually the same whether or not the plants are operated, certain consumables can be saved when the plants are not operated.

71. On balance, the O&M adder adopted in this order is reasonable.

72. Although the Diablo Canyon settlement decision called for use of the full UEG gas rate in calculating the DIER, PG&E now proposes that only the G-PC and Tier II volumetric gas rates be used for the determination of the DIER.

73. In converting the results of the model runs to the DIER, the cost of gas appears in the denominator of the calculation (DIER = $ divided by kWh divided by cost of gas).

74. In converting the DIER to an AER adjustment, the cost of gas appears in the numerator of the calculation (AER $ = DIER times kWh times cost of gas).

75. So long as the same UEG rate is used both for calculating and applying the DIER, the nonvariable portions of the rate will not influence the results.

76. We are not persuaded that PROSYM is a more reliable tool than other models for calculating the DIER; we will adopt PG&E's DIER.

77. As was the case last year, three different computer models were used in order to simulate the performance of PG&E's system under various assumptions.

78. DRA used ELFIN, a computer model which has been used by our staff and various utilities for over a decade.

79. PG&E and CCC used PROMOD, a more complex and costly modeling approach, which has been used by PG&E in several past proceedings.

80. IEP used PROSYM, a relatively new model, which was also used in the ECAC proceeding last year.

81. ELFIN and PROMOD are load duration curve models, which convert chronological demand levels into load duration curves, representing the percent of time that each level of demand occurs.

82. PROSYM is a chronological model, which considers the system's operation in relation to time and which uses multiple runs to develop its forecast of the system's operation.

83. The use of different models has raised questions about assumptions and technique which might not come to light if everyone relied on the same tools.

84. Dispatcher Risk Aversion is a computer modeling feature employed by PG&E to mimic the dispatcher's concern with the amount of energy available from various sources.

85. In its past two ECAC filings, PG&E has applied different values to the Dispatcher Risk Aversion feature.

86. It is important that the impacts associated with model features such as Dispatcher Risk Aversion be clearly identified and documented, especially when the feature is one which is given relatively greater weight than others.

87. Without the benefit of an ELFIN run accompanying PG&E's application, DRA's participation in this proceeding was impaired.

88. In ECAC proceedings, we normally apply average precipitation assumptions when forecasting hydro generation for a future period.

89. Prospective hydro estimates can be tempered by existing conditions.

90. PG&E conducts snowpack surveys which can tell it something about the availability of water in the months ahead.

91. While much of the snow pack may disappear by November, the late winter and spring hydro conditions may affect stream flows and reservoir levels well into a forecast period which begins the following fall.

Conclusions of Law

1. It is reasonable to use a forecast of 98,765 agricultural customers for the ECAC forecast year and calendar year 1990.

2. The Commission should adopt PG&E's overall sales forecast: PG&E sales of 69,300 GWh and a total area load of 94,343 GWh for the ECAC forecast year; PG&E sales of 69,668 GWh and a total area load of 94,612 for the general rate case calendar year 1990.

3. We should not change a reasonable assumption just to make the modeling results look better; even if we were otherwise inclined, there would be no compelling reason to do so in a situation where the change would have virtually no effect on the IER or on the overall revenue requirement.

4. It would be inappropriate to apply the results of a long-term forecast to the short-term issues of IERs and ECAC revenue requirements for the next 12 months.

5. We should encourage PG&E, DRA, or any other party to develop a quantitative approach to forecasting short-term Pacific Northwest energy availability; however, we are not prepared to require such analysis in this situation.

6. Twenty-two mills is an appropriate price assumption to apply to the PG&E's purchases from the Pacific Northwest from November 1, 1989 through February 1990.

7. The price for purchases from the California Department of Water Resources for the portion of the ECAC period running from March 1, 1990 through October 1990 should be assumed to be the same as the price for Northwest purchases during the same period.

8. PG&E has not provided a convincing basis for predicting curtailments during the forecast period.

9. Two years' worth of data is insufficient to predict a trend in geothermal steam curtailments.

10. For the purposes of setting rates and IERs, it is reasonable to assume that geothermal steam curtailments during the forecast period will be the same as those during the last 12 months for which data was available prior to the final IER calculation.

11. PG&E should present information with its next ECAC filing that will reflect specific study of the problems affecting PG&E's Geysers plants including a verifiable method for determining the likely yield from the Geysers during the next forecast period.

12. The consideration of DRA's proposal to disallow a portion of the geothermal steam costs should be consolidated for hearing with related issues in the reasonableness phase; thus, it is reasonable to adopt PG&E's geothermal price assumptions without prejudice to later consideration of the DRA position.

13. Because of the unpredictability and the variable length of nuclear power plant refueling outages, it would not be meaningful to forecast overall performance simply by considering the plant's performance while in operation without considering the amount of time it is down for refueling.

14. A nuclear power plant that had previously experienced only one fuel cycle per unit does not suddenly become mature after the second fuel cycle.

15. We should adhere to our current approach for forecasting Diablo Canyon operation because the performance of the each unit is more appropriately reflected by its performance across the fuel cycle.

16. PG&E should offer minimum downtime assumptions that do not simply reflect the optimal operating conditions, but take into account the downtimes that are actually experienced.

17. In its next ECAC filing, PG&E should demonstrate the actual amount of time each plant was down in each instance and provide the reason for the duration of the outage.

18. PG&E's assumptions for minimum downtimes and startup fuel costs for steam plants using fossil fuel should be adopted.

19. In D.88-11-052, we required all modelers to model standby units that can be restarted in short time as being available for the entire forecast period; nothing has changed that should cause us to alter our position this year.

20. We should adopt all of the assumptions listed in Appendix A, with the exception of the sales forecast (which has been adjusted as described in an earlier section) and hydro generation (which has been changed to reflect June snow survey information).

21. Dry year hydro assumptions should apply to this short-term ERI calculation.

22. For the purposes of all short-term forecasting, PG&E should present a unified picture of its expected purchases and resource plans during the forecast period.

23. The Pacific Northwest firm capacity assumptions applied in the IER calculation shall apply to the ERI as well.

24. It is inappropriate to include long-term standby units in a short-term ERI calculation.

25. When calculating the O&M adder, it is most appropriate to use the same assumptions for Moss Landing Units 4 and 5 as were applied in the IER calculation.

26. For the purposes of this proceeding, it was acceptable for the parties to calculate the O&M adder to reflect the assumption that Moss Landing Units 4 and 5 are available in the QFs-out run only, and that the related O&M savings is zero.

27. For the sake of simplicity, we should continue to require that the UEG rate be applied in the DIER calculation in the same manner it is applied in the IER calculation.

28. PG&E should include, in its next ECAC filing, the results of a study on the use of the Dispatcher Risk Aversion modeling convention.

29. We should reinstitute the requirement that PG&E's application be supported by an ELFIN run, regardless of the model PG&E wishes to rely on for its preferred case.

30. In future years, we intend to ask that PG&E provide an update based on the June snow survey and to rely on that information when assessing the hydro forecast.

31. Because this decision makes some adjustment to factors which can affect revenue requirements, it will be necessary for each of the parties to run its model again.

32. The suspension of PG&E's AER authorized in D.89-01-040 should be lifted and PG&E's AER should be resinstated at the time when the rates resulting from the decision become effective.

33. PG&E's final calculations of the IER, O&M adder, ERI, and net revenue requirement found in Table 2 should be adopted.

O R D E R

IT IS ORDERED that:

1. In its next Energy Cost Adjustment Clause (ECAC) application, Pacific Gas and Electric Company (PG&E) shall provide information which reflects a specific study of the problems affecting its Geysers geothermal plants including a verifiable method for determining the likely yield from the Geysers during the next forecast period.

2. In its next ECAC application, PG&E shall report on the actual amount of time each of its fossil steam plants was out of service for every outage experienced during 1986 and 1989 and the specific reason for each outage.

3. In its next ECAC filing, PG&E shall provide the results of a study on the use of the Dispatcher Risk Aversion modeling convention that, at a minimum, satisfies the requirements set forth in this decision.

4. PG&E's next ECAC application shall be supported by an ELFIN run, whether or not ELFIN is the model chosen by PG&E for its preferred case. At the time of its filing, PG&E shall be prepared to work with Division of Ratepayer Advocates (DRA) in interpreting the ELFIN run and to provide DRA with a complete explanation of the modeling conventions employed to make the ELFIN run comparable to that of any other model used.

5. In future ECAC proceedings, PG&E should present updated hydroelectric forecast information based on its June snow survey as that information becomes available.

6. PG&E is authorized to increase its ECAC revenue requirement by $613,855; to increase its Annual Energy Rate (AER) revenue requirement by $26,479,000; and to decrease its Electric Revenue Adjustment Mechanism revenue requirement by $368,286,000.

7. The revenue requirement adopted in this order shall be consolidated with that of the current general rate case, Application 88-12-005, for the purposes of revenue allocation and rate design.

8. The suspension of PG&E's AER authorized in D.89-01-040 shall be lifted and PG&E's AER shall be reinstated at the time that the rates resulting from this decision become effective.

This order is effective today.

Dated December 6, 1989, at San Francisco, California.

G. MITCHELL WILK
President
FREDERICK R. DUDA
STANLEY W. HULETT
JOHN B. OHANIAN
PATRICIA M. ECKERT
Commissioners

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

Wesley Franklin

WESLEY FRANKLIN, Acting Executive Director

APPENDIX A
Page 1
PG&E 1989 ECAC

FORECAST PHASE - UNCONTESTED RESOURCE ASSUMPTIONS

1. Sales Forecast - area load

ECAC test year	94,344 Gwh
1990 GRC test year	94,610

2. Hydroelectric Generation - based on April 1 snow survey

		Generation	Cost
a.	PG&E owned Hydro w/o Helms	13,347 Gwh	$ 4,029,000
b.	Irrigation Districts	4,842 Gwh	$50,464,000
c.	USBR (WAPA) Hydro	2,746 Gwh	N/A
d.	SMUD Hydro	1,506 Gwh	N/A
e.	NCPA Hydro	479 Gwh	N/A
f.	CCSF Hydro	1,683 Gwh	N/A

3. Helms Generation
   - modeled to include generation from upstream runoff and to allow for generation from off-peak and weekend pumping, when such pumping is economically advantageous, when required for reliability, or when needed to alleviate minimum load conditions. (D.88-11-052, p. 52)

4. Northwest Purchases by NCPA - 73 Gwh
   - 36 Gwh in November 1989; 37 Gwh in December 1989

5. Northwest firm purchases by PG&E from PP&L - 250 Gwh, priced at 27 mills/kwh
   - 23.6 Gwh monthly Nov-Mar; 18.9 Gwh monthly Apr-Oct

6. Southwest miscellaneous purchases by PG&E 384 Gwh
   - taken during off-peak hours at 32 Gwh/month and priced at 15.5 mills/kwh

7. California Power Pool Transactions
   - sales of 288 Gwh to Edison and SDG&E at 2 Gwh/month Nov-Feb and 35 Gwh/month Mar-Oct for revenue of $6,758,000
   - purchases made when PG&E incremental heat rate exceeds 11,000 btu/kwh, priced at share-the-savings rates

8. Sierra Pacific purchases for service at Echo Summit 3.6 Gwh at a cost of $324,000

9. Miscellaneous purchases for others 35.4 Gwh

10. NCPA resources includes - 1833.6 Gwh of Geothermal, 479.4 Gwh of hydro, 32.3 Gwh of cogeneration, and combustion turbines
    - NCPA utilizes its own resources to meet its own load, and then buys or sells the shortfall or excess from or to PG&E.

UNCONTESTED RESOURCE ASSUMPTIONS - PAGE 2

11. SMUD
   - Rancho Seco is assumed shut down
   - SMUD uses its own resources to meet its load, including 1506 Gwh of hydro, 860.3 Gwh of geothermal, combustion turbines, SMUD's photovoltaic unit, and purchases from WAPA. SMUD's shortfall is made up first by purchases from the Northwest up to its 200 MW of intertie entitlement in all hours during 1990. Remaining purchases are divided equally between PG&E and Southern California Edison. Edison purchases are scheduled during non-minimum load periods. PG&E meets the remaining needs, thereby implicitly following load.

12. (WAPA) Western Area Power Administration
   a. Northwest purchases by WAPA*
      11/89 - 178.5 Gwh
      12/89 - 172.7
      1/90 - 172.7
      2/90 - 158.5
      3/90 - 182.2
      4/90 - 187.9
      5/90 - 188.9
      6/90 - 187.9
      7/90 - 188.9
      8/90 - 209.7
      9/90 - 209.3
      10/90 - 204.1
   b. excess WAPA energy and/or capacity is banked with PG&E* at contractual rates
   c. WAPA shortfalls are unbanked (returned) at contractual rates

13. QF Generation - 16,425.7 Gwh, including hydro QFS and allowed curtailments.
    This amount includes 7620.4 Gwh of variably-priced QF generation.

14. Conventional Thermal Generation
    The remaining area load is made up by conventional thermal generation.
    a. Gas is assumed to be available to the power plants. The average dispatch price of gas of $2.16/MMbtu. The overall cost of gas to the power plant is assumed to be those costs approved in the ACAP decision and contained in the G-UEG tariff schedule plus the G-PC tariff schedule, effective June 1, 1989, multiplied by the amount of MMbtu necessary to run the power plants, less generation during oil test burns.

* subject to backdown order

UNCONTESTED RESOURCE ASSUMPTIONS - PAGE 3

b. Under normal conditions, residual fuel oil is required in the power plants only for test burn purposes, requiring a total of 504,000 barrels of fuel oil at PG&E's forecasted delivered prices, which range from $18.50/barrel to $19.40/barrel.

15. Combustion Turbines
Combustion turbines are used only to meet peak loads or to protect against forced outages when other resources are not readily available. The delivered cost of distillate oil for these units will be based on PG&E's estimated prices, which range from $24.10/barrel to $25.10/barrel.

16. Unserved Energy
Emergency firm purchases are made from the California Power Pool to meet load when all of the above resources are exhausted or unavailable. They are priced at 115% of the dispatch gas cost times an 11,000 Btu/kWh heat rate.

17. Sales to the City of Redding of 40 Gwh, and to a number of Southern California cities of 171 Gwh are assumed.

18. Fuel Oil Inventory Levels

Maximum Oil Inventory Level	7,450,000 Barrels
Average Oil Inventory Level	7,200,000 Barrels
Forecasted Carrying Cost	$9,154,000

(END OF APPENDIX A)

APPENDIX B
Page 1

List of Appearances

Applicant: Robert B. McLennan, Attorney at Law, for Pacific Gas and Electric Company.

Interested Parties: C. Hayden Ames, Attorney at Law, for Chickering & Gregory; Jackson, Tufts, Cole & Black, by William H. Booth and Joseph S. Faber, Attorneys at Law, for California Large Energy Consumers Association; Morrison & Foerster, by Jerry R. Bloom, Attorney at Law, for California Cogeneration Council; Matthew V. Brady, for California Department of General Services; David Branchcomb, for Henwood Energy Services, Inc.; McCracken, Byers & Martin, by David J. Byers, Attorney at Law, for California City-County Street Light Association; Brobeck, Phleger & Harrison, by Gordon E. Davis, Attorney at Law, for California Manufacturers Association; Karen Edson, for KKE & Associates; Michel P. Florio and Joel R. Singer, Attorneys at Law, for Toward Utility Rate Normalization (TURN); Norman Furuta, Attorney at Law, for Federal Executive Agencies; Steven Geringer, Attorney at Law, for California Farm Bureau Federation; Dian M. Grueneich, Attorney at Law, for California Department of General Services; Hanna & Morton, by Douglas K. Kerner, Attorney at Law, for Santa Fe Geothermal, Inc., Unocal Corporation, Freeport-McMoRan Resource Partners; Joseph G. Meyer, for Joseph Meyer Associates; Jeff Nahigian, for JBS Energy Inc.; John D. Quinley, for Cogeneration Service Bureau; Kathi Robertson, for Simpson Paper Company; Chester/Schmidt Consultants, by Reed V. Schmidt, for County of Marin and City of Bakersfield; Jan Smutny-Jones, Attorney at Law, for Independent Energy Producers; Downey, Brand, Seymour & Rohwer, by Philip A. Stohr, Attorney at Law, for Industrial Users; Nancy Thompson, for Barakat, Howard & Chamberlain; John Vickland, Attorney at Law, by Alice Loo, for Bay Area Rapid Transit; Philip J. DiVirgilio, for PSE Inc.; Robert B. Weisenmiller, for Morse, Richard, Weisenmiller & Associates, Inc.; Don Salow, for Association of California Water Agencies; Armour, St. John, Wilcox, Goodin & Schlotz, by James D. Squeri, Attorney at Law, for Kelco Division of Merck; Richard O. Baish, Michael D. Ferguson, and Randolph L. Wu, Attorneys at Law, by Phyllis Huckabee, for El Paso Natural Gas Company; Hanna & Morton, by Douglas K. Kerner, Attorney at Law, for Geothermal Resources Association and Independent Energy Producers Association; Thomas P. Corr, Attorney at Law, for Independent Power Corporation; Wayne Meeks, for Simpson Paper/Investment Company; Selby Mohr, for Sacramento Municipal Utility District;

APPENDIX B
Page 2

Thomas R. Sparks and Michael L. McQueen, Attorney at Law, for Unocal Geothermal; and Harry Winters, for Regents, University of California.

Division of Ratepayer Advocates: Catherine Johnson, Attorney at Law, James Barnes, and Geoffrey Meloche.

Commission Advisory and Compliance Division: Ali Miremadi.

(END OF APPENDIX B)

APPENDIX C

PACIFIC GAS & ELECTRIC COMPANY
Electric Department - Total Company
ADOPTED ENERGY COSTS
ECAC Forecast Period November 9, 1989 to October 31, 1990

	Type of energy	Purchases/ Generation (Gwh)	%	Average cost (cents/Kwh)	Total costs (000's of $)	Total CPUC costs 4/ (000's of $)	ECAC costs (000's of $)	AER costs (000's of $)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Fossil Fuel							
1	Gas - UEG	17,607	22.9%	3.26	$574,455	$571,181	$519,774	$51,406 1/
2	Oil - Residual	308	0.4	2.85	8,764	8,714	7,930	784 2/
3	Oil - Distillate	71	0.1	5.46	3,878	3,856	3,509	347 3/
4	Subtotal Fossil Fuel	17,986	23.4	3.26	587,097	583,751	531,213	52,538
5	Geothermal Steam Plants	8,018	10.4	1.54	123,793	123,087	112,010	11,078
	Purchased Power							
6	Irrigation Dist.	4,669	6.1	1.08	50,464	50,176	45,660	4,516
7	CVP (Capacity & Energy)	(2,899)	(3.8)	0.86	(24,938)	(24,796)	(22,564)	(2,232)
8	SMUD	(533)	(0.7)	4.03	(21,497)	(21,374)	(19,451)	(1,924)
	Cogeneration & other QFs							
9	Variably priced QF energy payment	7,620	9.9	3.05	232,672	231,346	210,525	20,821 5/
10	Other	8,805	11.4	10.48	922,900	917,639	835,052	82,588
11	Pacific Northwest	6,681	8.7	2.01	134,434	133,668	121,638	12,030
12	Southwest, incl. power pool sales	141	0.2	0.20	286	284	259	26
13	Others - CDWR	990	1.3	1.84	18,189	18,085	16,458	1,628
14	- Other	6	0.0	5.48	329	327	298	29
15	Subtotal Purchased Power	25,480	33.1	5.15	1,312,839	1,305,356	1,187,874	117,482
16	Water for Power	13,432	17.5	0.03	4,029	4,006	3,645	361
17	O[illegible]ventory Carrying Cost				9,154	9,102	8,283	819
18	St[illegible]by Charges				151	150	137	14
19	Variable Wheeling				1,631	1,622	1,476	146
20	Revenue Credits				0	0	0	0
21	Losses(Gains) on Fuel Oil Sales				0	0	0	0
22	Subtotal	64,916	84.4%	3.14	$2,038,694	$2,027,073	$1,844,637	$182,437
23	Write-down of Fuel Oil Inventory				0	0	0	0
24	Interest on unamortized write-down				0	0	0	0
25	Excess oil inventory carrying cost				(213)	(212)	(212)	0
26	DC Settlement Revenues	12,026	15.6	8.80	1,058,071	1,052,040	1,052,040	0 6/
27	DC Basic Revenue Requirment				(211,523)	(211,523)	(211,523)	0
28	TOTALS	76,942	100.0%	3.75	2,885,029	2,867,379	2,684,942	182,437

Note: ECAC costs are 91% of Total costs and AER costs are 9% of Total costs, unless otherwise specified.

1/ = Equivalent to 187,955 billion BTU at an average heat rate of 10,675 BTU/Kwh.
2/ = Equivalent to 3,156 billion BTU at an average heat rate of 10,247 BTU/Kwh.
3/ = Equivalent to 923 billion BTU at an average heat rate of 13,000 BTU/Kwh.
4/ = Jurisdictionalized at 99.43%.
5/ = Associated capacity payments included in Other QF.
6/ = Rate excludes Safety Committee fee and includes Basic Revenue requirement; FF&U removed from revenues.

APPENDIX D

PACIFIC GAS & ELECTRIC COMPANY
Electric Department - CPUC Jurisdiction
SUMMARY OF REVENUE CHANGES
ECAC Forecast Period November 9, 1989 to October 31, 1990

Line	Rate Element	Change in Revenue Requirement ($000)
1	ECAC	$613,835
2	AER	26,499
3	ERAM	(368,286)
4	Total	$272,048

(END APPENDIX D)

ALJ/SAW/vdl

Decision ______________________________

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of PACIFIC GAS AND ELECTRIC COMPANY for Authority to Adjust its Electric Rates Effective November 1, 1989; and for Commission Order Finding that PG&E's Gas and Electric Operations during the Reasonableness Review Period from February 1, 1988, to December 31, 1988, were Prudent. (U 39 M)	Application 89-04-001 (Filed April 3, 1989)

(See Appendix B for appearances.)

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OPINION

I. Background

A. Procedural History

Pacific Gas and Electric Company (PG&E) filed this application on April 3, 1989, requesting an increase of $378.3 million in its electric revenues on an annualized basis effective November 1, 1989. This requested increase was based on the following revenue requirements changes:

1. An increase of $815.2 million under PG&E's Energy Cost Adjustment Clause (ECAC),
2. An increase of $32.7 million under PG&E's Annual Energy Rate (AER), and
3. A decrease of $469.9 million under PG&E's Electric Revenue Adjustment Mechanism (ERAM).

Although PG&E never formally changed its rate request, the company did change many of its forecast assumptions during the course of its hearings and expressed the opinion that the revenue requirements should be less than that indicated in the application. On June 28, 1989, John E. Kerler, testifying for PG&E, offered a revised revenue requirement increase estimate of $146.22 million with the following elements (See Ex. 9; Tr. 123):

1. An ECAC increase of $597.1 million,
2. An AER increase of $22.6 million, and
3. An ERAM decrease of $473.5 million.

This ECAC filing is PG&E's first since we issued Decision (D.) 89-01-040, which modified the rate case plan and the schedule for processing energy cost offset proceedings. Prior to that decision, PG&E's rates reflecting ECAC, AER, and ERAM revenue requirements were adjusted on an annual basis effective August 1st.

In order to spread the Commission's workload more evenly across the year and to facilitate coordination with PG&E's general rate case, we changed PG&E's revision date to November 1st. As a result, during this transitional year, PG&E's balancing accounts have registered over- and undercollections for 15 months without revision. In addition, since the last AER revision only forecasted costs through the end of July 1989, we suspended PG&E's AER as of August 1st, allowing 100% of the fuel costs incurred since that date to be tracked in the ECAC balancing account.[1] The AER remains in suspension in anticipation of this decision.[2] Normally, an ECAC application will include a request for approval of the reasonableness of gas and electric operations during a preceeding 12-month period. As directed in D.89-01-040, however, the pending application covers a shorter period, from February 1, 1988 to December 31, 1988.[3]

Because there was also a pending PG&E general rate case this year, the Commission faced the potential of end-of-the-year decisions that would have developed two different revenue requirements calculations and allowed for two separate considerations of revenue allocation and rate design issues. Soon after filing this application, PG&E filed a Motion to Consolidate Revenue Allocation and Rate Design Issues in the general rate case Proceeding. Appropriately, this motion was granted in a joint administrative law judge (ALJ) ruling issued April 24, 1989. The

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1 See D.89-01-040, mimeo. p. 23.

2 Ibid. p. 26.

3 In future ECAC filings, PG&E's reasonableness review period will return to the normal 12-month span, ending 60-75 days prior to the ECAC (see D.89-01-040, mimeo. p. 26). The next reasonableness review period may need to be slightly longer than 12 months, in order bring the process up to date.

revenue requirement derived from this proceeding has been merged with the revenue requirement determination in the general rate case. All revenue allocation and rate design issues have been heard on a consolidated basis in Application 88-12-005, the general rate case.

The determination of sales forecasts provides another area of substantial overlap between the two proceedings. In the general rate case, forecasted sales were needed for all of 1990. In this proceeding, sales projections were needed for the forecast period, November 1, 1989 through October 31, 1990. PG&E moved that the sales forecast developed in this proceeding be used in the general rate case for purposes of consolidated consideration of revenue allocation and rate design issues. In a ruling dated May 24, 1989, ALJ Cragg granted that motion.

We have recently issued two orders that affect calculations to be made in this proceeding.

In D.89-06-048, we adopted a floor/ceiling methodology to calculate the short-term Energy Reliability Index (ERI) affecting capacity payments to variably priced qualifying facilities (QFs).[4] In addition, we directed PG&E to submit late-filed exhibits in this proceeding to conform its showings on marginal costs, revenue requirements, and others where appropriate to the adopted methodology (see Ordering Paragraph 2).

4 QFs are certain cogeneration and small power production facilities that qualify for specified benefits under the federal Public Utility Regulatory Policies Act of 1978 (PURPA). PURPA establishes that the prices a utilitiy pays for power generated by QFs are to be based on the costs the utility avoids by purchasing the QFs' power rather than generating the electricity from the utility's own plants. The costs avoided by such purchases include energy, capacity, and operation and maintenance costs.

In D.89-09-093, we adopted a method for calculating the operations and maintenance (O&M) costs that PG&E avoids because of its purchases from variably priced QFs. The proposed order that was to become D.89-09-093 was issued after the commencement of this proceeding. Parties to this proceeding were instructed to calculate the O&M component of payments to variable QFs (O&M adder) according to the method in the proposed order. Subsequently, in D.89-09-093 we affirmed the reasonableness of that method.

Hearings in the current proceeding were divided into three phases. The first phase encompassed those issues relating to the forecasts of fuel costs, resource mix, and variable payments to QFs. The second phase relates to the reasonableness of prices in special contracts entered into between PG&E and certain large electricity customers. We added this subject to the ECAC menu in D.89-05-067. The third phase will address the reasonableness of PG&E's operation during the period discussed above. This opinion decides only the first phase issues.

Eight days of hearings in the forecast phase of this proceeding were held between June 26 and September 6, 1989, in San Francisco, California. Concurrent opening and closing briefs were filed July 21, 1989 on the issue of sales forecasts. Concurrent opening briefs on resource assumptions and modeling issues were filed July 28, 1989. Concurrent reply briefs were filed August 4, 1989. A ruling by the ALJ, dated August 15, 1989, listed the resource plan input assumptions for parties to use in preparing their final calculations of revenue requirements and other relevant factors. Additional hearings were held on September 1 and September 6, 1989, to discuss the implications of these final calculations, and concurrent opening and closing briefs were filed on September 25, 1989.

The parties filing briefs in this proceeding included PG&E, the Commission's Division of Ratepayer Advocates (DRA), the California Cogeneration Council (CCC), the Geothermal Resources Council, the Independent Energy Producers Association (IEP), the Independent Power Corporation (IPC), the Association of California Water Agencies (ACWA) and the California Farm Bureau Federation (CFBF).

B. The Framing of the Issues

Consistent with last year's PG&E ECAC proceeding, this application combines consideration of ECAC issues with an updating of key components of the calculation of prices paid for power sold to the utility by QFs. The ECAC process enables a utility's rates to reflect changes in its fuel and purchase power expenses on an annual basis outside of the three-year general rate case cycle. The QF calculation issues relate to the prices to be paid to QFs that do not have contracts specifying fixed prices.

Variable QF prices are the sum of three basic components: a payment for capacity, a payment for avoided O&M, and a variable payment for energy. Critical to the determination of these payments are the utility's ERI and Incremental Energy Rate (IER).

The ERI is used to adjust the value of a generic combustion turbine, which we have used as a proxy for a utility's avoided capacity costs and which therefore forms the basis for capacity payments to QFs. In another proceeding, while this matter was pending, we approved a method for calculating PG&E's ERI. All active parties used this method to calculate the ERI and differences arose as to how the adopted method should be implemented.

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 which is multiplied by the utility's incremental fuel cost to produce the price the utility pays for the variably priced QFs' energy.

There is a logical relationship between conventional ECAC issues and the bases for QF prices. The forecast used to develop a utility's ECAC revenue requirement is derived from the estimated production and expense levels related to hydroelectric, nuclear, purchased power, alternative and renewable power, and oil- and gas-fired resources. The forecasts of energy production and availability affect the determination of the utility's generating efficiency at the margin as measured by the IER. Similarly, the expected availability of resources to meet forecasted demand is reflected in the ERI.

ERI and IER values are generally derived from the results produced by production cost models. These models are designed to 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. However, these inputs are not mere abstractions. In many cases, the inputs to the models are the resolutions of conventional ECAC issues that constitute the heart of the ECAC proceeding.

The use of computer models introduces another set of issues concerning how the modeler and the model translate and simplify the complexities of the utility system into terms that the model can understand, and what manipulations the model makes of this information. This category of issues is referred to as the modeling conventions.

As we have faced more ECAC applications that include IER and ERI considerations, we have instituted and modified procedures designed to ensure the full exchange of information pertinent to an understanding of the computer models used and a full exchange of data used to develop the IER and ERI. At an earlier time, we required that all parties to ECAC and general rate case proceedings of the major electric utilities use the ELFIN production cost model in developing a "base case" run. (D.87-12-066, at p. 203.) The Commission reasoned that use of the same model "to present a base case will aid the Commission, as a starting point, in determining whether model, assumption, or methodological differences are causing the different results." Each party, however, was also given the opportunity to present additional testimony using its model of choice.

Additionally, the Commission directed that "a workshop be held no later than one week following [the] ECAC filing to determine the data sets, resource plans, load shape, heat rate input, unit commitment and dispatch, minimum load conditions, resource assumptions, marginal fuel assumptions, and all other pertinent data that [the utility] used to calculate its IER." (D.87-12-066, at p. 205.) The workshop was also to serve as a forum for the parties to agree, to the extent possible, on the assumptions to be used and the appropriate source of those assumptions. The Director of the Commission Advisory and Compliance Division (CACD) was to appoint an arbiter for the workshop to resolve any issues related to the development of a common data set upon which agreement could not be reached. This workshop procedure was employed in PG&E's last ECAC proceeding.

This year brought at least one major change to the workshop process. In D.88-11-052, which followed the first phase of PG&E's 1988 ECAC proceeding, we concluded that the base case run that had resulted from having all modelers use the ELFIN model had not been useful. We determined that a more useful comparison would have been among the models. Therefore, we directed those parties to the 1989 ECAC who intended to sponsor a model run to present a base case run that was the result of using inputs from a common data set applied to its favored model. The workshops became the forum for developing the common data set and identifying and resolving, if possible, the differences among the parties.[5]

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5 See D.88-11-052, mimeo. p. 68.

The modeling workshop was made a requirement for future ECAC proceedings in D.89-01-040. The workshops were held on April 19 and May 18, 1989, with Linda Gustafson of the CACD serving as arbiter to develop common data set assumptions for computer model runs to be used in this proceeding.

Another change introduced in this ECAC proceeding is that the active parties were asked to develop a consensus document allowing for a comparison of the positions taken by various parties on each of the contested issues. The resulting Comparison Exhibit (Exhibit 1) listed contested and uncontested resource assumptions as well as the modeling conventions used by all parties. The parties are to be congratulated for their work in developing the Comparison Exhibit, which appears to have helped the parties to limit the areas of contention and shorten the hearing time needed for this proceeding.

The issues litigated in the forecast phase of this proceeding thus included not only PG&E's revenue requirement for the ECAC forecast period, but also the development of the IER and the calculation of the ERI and O&M adder used in determining variable QF payments.

In reviewing these issues, we will first examine the issues that must be resolved before the production cost models may be run: the load forecast, resource assumptions, and modeling conventions. Next, we will discuss the calculation of the IER, ERI, and O&M adder. Then we will consider the differences between the three production cost models that were used in this proceeding.

II. Load Forecast

With only one exception, the active parties agreed with PG&E's sales projections. PG&E's initial forecast was set forth in Exhibit 2, Table 2-1. The table was revised in Exhibit 3 by adding information concerning area load during the forecast period and comparative figures for the 1990 test year covered by the general rate case. PG&E later revised its sales forecast (Exhibit 25) to reflect the announcement that the Rancho Seco Nuclear Power Plant (Rancho Seco) would be closed.

A. The Effect on Sales of Closing Rancho Seco

Rancho Seco is owned and was operated by the Sacramento Municipal Utility District (SMUD). Without the benefit of power generated at Rancho Seco, SMUD will have to purchase more electricity from other entities. For various reasons, it is not yet possible to know with certainty how SMUD will meet its needs. However, it is reasonable to assume that SMUD will make use of its existing contracts with PG&E, Southern California Edison Company (SCE), and utilities in the Pacific Northwest. PG&E has divided the additional purchases among those three sources in a manner found acceptable by all parties.

B. Agricultural Customer and Sales Forecasts

The one source of controversy in this area involved the appropriate forecasts for the total number of agricultural customers and the project level of agricultural sales. The CFBF presented evidence contesting the number of agricultural customers predicted by PG&E. The ACWA presented evidence conflicting with PG&E's forecast of agricultural sales.

The agricultural customer class is intended to include only those customers who use electricity predominantly to serve agricultural end-uses. Agricultural end-uses include growing crops, raising livestock, pumping water for irrigation, and other uses that involve production for sale and that do not change the form of the agricultural product.

In last year's ECAC proceeding, PG&E proposed that the agricultural schedules be reserved for those customers who meet the condition that 70% or more of their energy usage is dedicated to agricultural end-uses. PG&E also recommended that the new definition of the agricultural class be implemented in the 1989 ECAC decision. The intervening year would give PG&E time to identify affected customers and inform them of their options in their new rate classes. We adopted PG&E's proposed redefinition and ordered that it would become applicable on the effective date of the decision adopting specific rates in the 1989 ECAC proceeding.[6]

In the intervening year, PG&E did not reach its goal of identifying affected customers. This undermined the company's ability to produce, in this proceeding, an accurate estimate of the number of customers in the agricultural class.

The number of active agricultural accounts does not equal the number of customers with agricultural end-uses. For instance, each time a new pump is connected to the utility lines, a new account is opened. Despite overall reductions in farmed acreage during the last few years, many new accounts have been opened. This is largely because of the increased need for pumps to deliver water to irrigated fields in drought years such as those recently experienced in California. In addition, many accounts are opened or closed simply because farm property changes hands and the electric billing is transferred to a new name. The interaction of these forces adds to the challenge of accurately predicting the number of agricultural accounts in any future year.

6 See D.88-12-031, Ordering Paragraph 10.

Michael Robinson, testifying for PG&E, explained that the company used an econometric model to develop its forecast of agricultural customers. Such a model attempts to forecast and explain changes in the number of customers over time. PG&E's model suggests that the number of agricultural customers will continue to grow.

CFBF challenges that assessment. Using its econometric model, PG&E predicts an average of 101,858 agricultural customers during the ECAC period. In order to test the assumptions underlying this number, CFBF sent data requests to PG&E asking for a comparison of the numbers of all of its agricultural customers on a year-to-year basis. The request sought a tally of accounts actually opened and closed during a given year. CFBF argues that relating this account activity to the number of accounts in existence in the prior year provides the most accurate assessment of the number of agricultural customers for each year. Starting with a base of 99,599 customers in 1985, PG&E had forecasted 100,951 customers for 1988, reflecting a net increase of 1,352 customers. CFBF showed that an actual tally of accounts opened and closed during those years yields a net reduction of 804 accounts, leading to 98,795 customers in 1988. This is 2,156 customers below PG&E's estimate.

PG&E disputed the usefulness of the information provided to CFBF in response to its data request (Exhibit 5). Robinson said he did not know where the data came from, but assumed that it was accumulated for some other purpose and cannot be used for CFBF's purposes. Despite repeated opportunities, PG&E did not provide any evidence to support its effort to refute its own numbers.

CFMB's analysis has brought into question PG&E's forecast of agricultural customers. The most compelling factor is that the growth in the number of accounts projected by the model does not coincide with recorded openings and closings in the years for which data was provided. PG&E argues that its econometric projection is conservative, predicting that the survey necessary to find out who is an agricultural customer within the newly adopted customer class definition will ultimately increase the number of customers in the class. DRA seems to agree. However, CFBF argues that the new definition will result in fewer customers in the class because of the 70% usage requirement. The parties debated as to whether or not Standard Industrial Code classifications could be used to predict the ultimate size of the agricultural class. The record on this issue is inconclusive. All that is clear is that the study has not been done yet and no one knows for sure what it will show.

We are not persuaded by PG&E's claim that the data offered to show actual openings and closings should be disregarded because PG&E's witness is not sure where these numbers came from. These numbers were provided by PG&E in response to a clearly worded data request from CFBF. In order to support its position, PG&E is trying to undermine the credibility of its own data. This argument is disingenuous. PG&E did not take the opportunity of providing evidence to support its position.

CFBF has offered 96,000 customers as a proxy for PG&E's forecast for both the ECAC forecast period and the general rate case calendar year of 1990. However, CFBF has also stated that it calculates the number of agricultural customers in 1988 to be 98,765. CFBF's testimony does not adequately explain why it would expect the number of customers to decrease by 2,765 in two years. Due to the apparent unreliability of PG&E's calculation and the uncertain effects of the new class definition, we will adopt the 98,765 figure for the purposes of this forecast.

Despite the disagreements as to the size of the agricultural class, the various estimates of agricultural sales are very close. In fact, ACWA endorses DRA's numbers because there is little difference between the two and DRA endorses PG&E's numbers for the same reason. We see no compelling reasons that PG&E's projections should not be adopted. Changes in the number of customers may reflect little more than the number of new pumps installed or old pumps disconnected. Sales is more a reflection of the overall irrigation needs. PG&E has lowered its forecast in response to improved hydro conditions. As the parties are all quite close in their current projections, we will adopt PG&E's forecast: PG&E sales of 69,300 gigawatt hours (GWh) and a total area load of 94,343 GWh for the ECAC forecast year; PG&E sales of 69,668 GWh and a total area load of 94,612 for the general rate case calendar year 1990.

C. Sales Forecasts for All Other Classes

For all other purposes, the parties agreed with PG&E's sales forecasts. We will adopt that forecast as reflected in Exhibit 25.

TABLE 1
Sales Forecast Assumptions

Class of Service		ECAC[7] Amount in Gigawatt-hours	GRC[8] Amount in Gigawatt-hours
Residential		23,479	23,557
Small Light & Power		7,268	7,274
Medium Light & Power		16,732	16,756
Large Light & Power:		15,523	15,558
CCSF	702		
Other	14,821		
Agriculture		3,099	3,091
Street Lighting		363	365
BART		256	256
Public Authority		512	526
SMUD		982	1,191
Other non-CPUC		931	1,114
Interdepartmental		155	155
Total PG&E Sales		69,300	69,843
SMUD		7,638	7,471
LUAF		7,956	7,964
Electric Department Usage		26	26
Other Area Load		9,422	9,483
Total Area Load		94,343	94,612
Deliveries out of Area		69	40
Total Planning Load		94,412	94,827

7 November 1, 1989 to October 31, 1990.

8 January 1, 1990 to December 31, 1990.

III. Resources

A. Purchases of Economy Energy from the Pacific Northwest

As was the case in the ECAC proceeding last year, this was a highly contested issue. The predominant source of power imported from the Pacific Northwest is hydroelectric. The Northwest has experienced two exceptionally dry years. While all parties assume that rainfall will now return to normal, there are disagreements as to the lingering impact of drought conditions on price and the amount of energy that Northwest suppliers are likely to make available. In addition, this issue has raised two other questions for our consideration: Should PG&E be required to rely on quantitative analysis in making its short-term forecasts? Should apparently illogical computer outputs persuade us to abandon an otherwise reasonable price forecast? All parties agreed that the Pacific Northwest forecast should be considered in two stages: November 1989 through February 1990 and March through October 1990.

1. Stage 1: November 1989 through February 1990

a. Installed Capacity

PG&E's ability to import energy from the Pacific Northwest is limited by the amount of carrying capacity to which it has access over existing transmission lines. PG&E calculated its entitlement on the installed capacity of AC and DC lines, plus any layoffs from unused Western Area Power Administration (WAPA) entitlements, minus any periods of time when a line is down for maintenance. All parties agree with PG&E's forecast of installed transmission capacity. We will adopt PG&E's figures.

b. Availability

PG&E and the QFs (CCC and IEP) agree that the drought in the Northwest will limit the availability of economy energy purchases from the Northwest through next February. PG&E predicts that the reservoirs will not be filled to 100% level during this period and that the experience of the last two years will cause suppliers to be cautious in dispensing the energy that is available. DRA disagrees. A key factor influencing the availability of energy is the nature of flows on the Columbia River, which generates electricity supplied to California utilities by the Bonneville Power Administration (BPA).

There is little dispute as to the expected size of Columbia River flows, just disagreement as to what it means. PG&E predicts 90% of normal flow and characterizes this as "below normal." DRA says 90-94% of flow is "normal" for forecasting purposes. BPA says there is a 99% chance that reservoir levels will be at 100%. PG&E's witness Jack Kerler says this is optimistic, but offers no empirical support for his position.

Even if current river flows and reservoir levels are at or near normal, the reality of two prior dry years is likely to restrain deliveries to California. Kerler argues persuasively that Northwest suppliers will be cautious. This perspective is supported by the fact that BPA, the largest supplier in the region, curtailed all deliveries to the south on the intertie as of July 5, 1989. It appears that BPA is sensitive to monthly changes in precipitation and will carefully husband its supplies if current rainfall levels suggest the possibility that the accumulations this season may be less than normal.

While all parties agree that some energy will be made available to PG&E during the first stage, no two parties agree as to how much. DRA's estimate is unacceptable because it assumes that normal rainfall year quantities apply. IEP acknowledges that there is very little difference between its estimate and those of PG&E and CCC. We will adopt PG&E's forecast, which is the most consistently moderate across the period.

PG&E also assumed that its forecasted energy availability would be sufficient to fill all of its entitlement on the transmission interties during peak periods and 50% of its entitlement during off peak hours. We will adopt this assumption as well.

c. Price

PG&E predicts that the average price for purchases from the Pacific Northwest during the first stage of the ECAC period will be 25 mills. CCC and IEP agree with PG&E. DRA, which is more optimistic about hydro conditions in the Northwest, predicts that the price on average will be equal to 90% of PG&E's incremental fossil fuel cost.

To support its 25 mill price prediction, PG&E referred to the less-than-normal energy expectation during the first stage, the 1988 fixed price of 22 mills, a contract for 1988 deliveries from BPA to SCE at a price of 25 mills, and a recent BPA offer to provide energy in October 1989 at a price of 23 mills. We are not convinced that these factors support a 25 mill price.

In 1988, reservoir levels in the Northwest were dramatically lower than they are in 1989. That fact certainly does not suggest that the price this year would be even higher. The fact that SCE signed a 25 mill contract in 1988 says little about what PG&E may need to pay this year. The only thing it clearly shows is that in 1988 PG&E was able to purchase power from the Northwest at a lower price than was SCE. Finally, while the evidence indicates that BPA made a 23 mill offer this fall, there is no reason to expect that the two parties would have settled on a 23 mill price. Nor do we know whether or not the agreed-upon price would apply in any or all of the November 1989 through February 1990 period.

In his August 15th ruling, the ALJ directed the modelers to assume that energy would be available from the Northwest at the levels advocated by PG&E at a 22 mill price during the first stage. Modelers for PG&E, CCC, and IEP found that these assumptions produced an unexpected result. Normally, one would expect that the cost of an additional increment of energy and the IER would be higher during peak periods than during off peak. However, under the assumptions adopted in the ALJ's ruling, the IER for winter partial peak was lower than the IER for winter off peak. PG&E and the QFs blamed their unexpected modeling results on the 22 mill price assumption. IEP went so far as to suggest that the price assumption must be changed to eliminate this effect.

Applying the same assumptions, the DRA's ELFIN run did not produce this result. According to DRA's calculations, the partial peak IER was larger than the off-peak IER. DRA argues that there is nothing unreasonable with the 22 mill assumption and the record does not suggest that changing the assumption would have a significant effect on either the revenue requirement or the IER. In fact, IEP tested the affect of changing the assumption to 25 mills and concurred with DRA's assertion.

However, even if we were to determine that the unexpected results were a matter of concern, there is no logical basis for concluding that the 22 mill is incorrect. While the QFs place the blame for the "counter intuitive" results on the 22 mill price assumption and advocate a return to the 25 mill level, DRA points out that there are other equally likely causes for this result. For instance, higher availability assumptions would be likely to bring the results within traditional expectations. Further, even if it was determined that the price has to change in order to have the model results fit within expectations, there is nothing to suggest that the price should be changed to 25 mills. No party has offered a sensitivity analysis to demonstrate where the cross-over point would be on a price continuum between 22 and 25 mills.

In its concurrent brief dated September 25, 1989, DRA raises a significant policy question stemming from the suggestion that the 22 mill price should be changed. Starting at page 3, DRA states:

> "Implicit in HESI's suggestion to abandon the 22 mills price and adopt 25 mills is the assumption that the Commission should tailor its decisions to satisfy the production cost models. This may be the first time such a recommendation has been made and it raises a broad and important policy question which will sooner or later demand resolution.
>
> "When models are unable to reach intuitively expected results based on apparently reasonable assumptions, we must ask what role the models should play in our proceedings. DRA believes that in an instance such as this one, an assumption which appears to be reasonable, should not be rejected strictly because it may create one counter-intuitive result. The Commission should be the ultimate decision maker. Whether one model or all models produce unexpected results, the Commission must decide whether a given assumption, is reasonable.
>
> "In this instance, because one of the models is not producing the unexpected IERs, the Commission is not forced to resolve the underlying policy question. If the Commission wishes to maintain the 22 mills price adopted in the ALJ's ruling, it appears that ELFIN will produce intuitively correct results." (Ex. 54.)

We agree that 22 mills is an appropriate price assumption to apply to the first stage of purchases from the Pacific Northwest. While PG&E and the QFs have offered little more than a best guess to support the 25 mills prediction, actual practice confirms PG&E's ability to obtain energy at 22 mills under less favorable conditions. Further, we will not change a reasonable assumption just to make the modeling results look better. Even if we were otherwise inclined, there would be no compelling reason to do so in a situation where the change would have virtually no effect on the IER or on the overall revenue requirement.

2. Stage 2: March through October 1990

a. Installed Capacity

During this stage as well, all parties are in agreement with PG&E's forecast of installed transmission capacity, whether or not loop flow is a factor. We will adopt PG&E's figures.

b. Availability

One goal of an ECAC proceeding is to apply the most current information to derive a short-term forecast of resource availability, load requirements, and related costs. However, since we are not able to make reliable forecasts of seasonal precipitation, we conventionally assume normal precipitation during the forecast period. All parties have applied such an assumption in predicting Pacific Northwest energy availability. While PG&E argued that past drought conditions would stifle sales during the first four months of the period, it is not predicting any unusual limits to the availability of energy during the remaining eight months.

PG&E and DRA predict the same energy availability during this stage. The QFs, on the other hand, rely on PG&E's long-term forecast as submitted in this year's general rate case, which predicts significantly lower energy availability in 7 of the 8 months.

The QFs argue that PG&E should not be allowed to be inconsistent in its forecasts in two proceedings that are heard concurrently. They assert that there are unexplained inconsistencies between the two forecasts. Perhaps most significantly, they fault PG&E for developing its ECAC forecast in a way that lacks sufficient analytical rigor.

For the general rate case, PG&E produced a forecast based on what the QFs refer to as a quantitative model. The key characteristic of such a model is its relative verifiability. Assumptions as to what may affect energy supplies are clearly defined and subject to critique for conceptual soundness. Once the conceptual framework is understood, results can be checked and replicated by others willing to undertake the same analysis.

For the ECAC forecast, PG&E undertook a largely empirical study. PG&E's forecasters talked to people in relevant decision-making positions, considered recent events, reflected on the methods available to the Northwest utilities to control energy releases and relied on their collective experience to produce an informed judgment. Robert Weisenmiller, testifying for CCC, characterized this as the crystal ball approach.

The QFs assert that PG&E should be required to rely on a quantitative approach, arguing that PG&E's analysis is difficult, if not impossible to verify because it relies on the subjective experience and judgments of power control personnel rather than on an analytical model. Because PG&E's forecast in the general rate case relied on an analytical model, the QFs argue that it is preferable to the forecast offered in this case.

PG&E responds by pointing out that the goal of the general rate case analysis was to prepare a long-term forecast. The utility further points out that the use of the long-term analysis is to calculate the cost-effectiveness of long-term demand-side management programs, not to determine the revenue requirement. PG&E argues that the use of such analysis in an ECAC proceeding would negate the benefit of using more recently available information to develop a short-term forecast.

There are two separate issues raised by this debate. One goes to the merits of applying the results of a long-term forecast to the short-term issues of IERs and ECAC revenue requirements for the next 12 months. Using PG&E's long-term analysis for such a purpose is inappropriate and that is why we will not adopt the availability forecasts put forth by the QFs. When the purpose of analysis is to determine the life cycle cost-effectiveness of a program, one can be much more forgiving of potential year-to-year variations. Because the projections extend into periods for which forecasts cannot be dependable, the use of averages and hypothetical assumptions may be more acceptable. We can and must expect more in an ECAC forecast. The reliance is on short-range vision and the factors that are recognizable from where we stand today.

That aside, we are still left with one important issue. Should PG&E be required to develop and rely on a quantitative analytical framework for preparing its ECAC forecasts of availability of energy from the Pacific Northwest?

We do not pretend to be at a point where we can say that properly executed quantitative analysis will always provide a more reliable forecast than empirical judgment. In most of our proceedings, we are offered the opinion of experts who are relying to a large extent on their professional judgment based on a perspective harvested from years of experience. Without a doubt, such expert testimony should always be put to the test. Experts must be prepared to demonstrate to the Commission how their experiences were brought to bear on their judgments. Experts must always be able to show that their judgments flow logically from an assessment of facts and that the full range of essential facts have been considered. Nonetheless, we cannot negate the merits of such testimony out of hand.

In this instance, PG&E's expert was available for scrutiny. Where there were apparent inconsistencies, the QFs or other parties were free to test his judgment through discovery and cross-examination. He could have (and most likely should have) been asked to set out the full array of factors he considered and had his judgments challenged with apparently contrary facts.

However, this was largely not done. Instead, QFs raised many questions in the relative vacuum of post-hearing briefs where they could not result in an enhancement of the factual record.

It is undeniable that a well developed quantitative analysis would carry great evidentiary weight. We would encourage PG&E, DRA, or any other party to develop such an approach to forecasting short-term Pacific Northwest energy availability. To be certain, the expertise applied to empirical judgment could be equally as valuable if a more analytically rigorous approach were applied. However, we are not prepared to require such analysis in this situation.

c. Price

For this stage, PG&E applied the same pricing assumption that we adopted in last year's ECAC.[9] The price of Northwest purchases would be assumed to equal 90% of PG&E's average incremental fossil-fired steam generation costs. All other parties support PG&E's assumption and we will adopt it.

B. Purchases from the California Department of Water and Power

All parties agreed that the determination of price for these purchases is linked to the assumption of energy available from the Northwest. It was agreed that if Northwest supplies were considered limited during the first stage of the ECAC period, the price should be assumed to be 20 mills. All parties agreed that the price for the remainder of the ECAC period should be assumed to be the same as the price for Northwest purchases during the second stage. Since we are assuming limitations to availability during the first stage, we adopt the prices as just described.

9 See D.88-11-052, discussion on p. 36.

C. Geysers Generation

1. Availability

In 1987, the Geysers field began to experience frequent steam curtailments, when there was insufficient steam to run all of the units although the units were available for service. PG&E expects these curtailments to continue and increase during the forecast period. In addition, Unit 15 is now out of service for an indefinite period and is assumed to be unavailable during the forecast period, due to insufficient steam. PG&E's estimates reflect these expectations.

These curtailments were at issue during the last ECAC, by which time they had been a factor for about a year. At the time, PG&E argued that the year's curtailments represented a trend that was likely to continue. DRA had argued that the basis of the curtailments was unknown and there was no reason to expect them to continue. We felt that a year's experience did not provide a basis for projecting a trend of increased curtailments, but expressed skepticism concerning DRA's assumption that the problem would disappear. Instead, we projected curtailments for the next year based on the five most recent months of curtailment data.

The problem did not disappear. In fact, curtailments have continued to grow. This year, PG&E was able to shed little new light on the reasons for these developments, or provide a convincing basis for predicting curtailments during the forecast period. PG&E has once again proposed that a trend of increasing curtailments be assumed. CCC and IEP agree. DRA argues that two years' worth of data is insufficient to predict such a trend, a problem that is aggravated by our continuing lack of understanding as to why the curtailments are occurring and proposes that an average of historical curtailments be used to forecast performance during the test year.

Because of the continuing uncertainty about the status of Unit 15, which is currently down, and the fact that we are no more enlightened than we were a year ago about the causes of the curtailments, we are not persuaded that a predictable pattern of curtailments has been set. The staff's recommended approach of averaging the last two years' curtailments for use in the forecast period may be too conservative of an approach to take. As PG&E has pointed out, actual curtailments in 1989 already exceed DRA's predictions for the forecast period.

We have chosen to assume, for the purposes of setting rates and IERs, that curtailments during the forecast period will be the same as those during the last 12 months for which data was available prior to the final IER calculation. That data indicates that curtailments are still increasing.

At the same time, we are concerned about PG&E's failure to gain a more sophisticated understanding of the nature and magnitude of the problem during the last year. During the hearings, anecdotal information was provided of studies conducted by other users of steam from the Geysers concerning curtailments in other fields. We will expect PG&E to present information during with its next ECAC filing that will reflect specific study of the problems affecting PG&E's Geysers plants including a verifiable method for determining the likely yield from the Geysers during the next forecast period.

2. <u>Price</u>

PG&E proposes that the assumed price be based on its contractual formula involving recorded and forecasted fossil costs and recorded and forecasted nuclear fuel costs, as in past years. DRA has proposed that the nuclear fuel cost component be decreased to reflect what it asserts to have been unreasonable delays in the completion of the Diablo Canyon Nuclear Plant (Diablo Canyon). In its report for the reasonableness review portion of this application, DRA has proposed a disallowance, couched on a related theory. We feel that the consideration of these DRA proposals should be consolidated for hearing in the reasonableness phase. Thus, we are adopting PG&E's geothermal price assumptions without prejudice to later consideration of the DRA position.

D. Diablo Canyon Generation

In the last ECAC proceeding, the appropriate method of characterizing the forecast performance of Diablo Canyon was heavily debated. We determined that it was inappropriate to ignore the effect that refueling outages may have on the performance of the plant.

The necessity of shutting down a generating unit and removing the reactor head during the refueling process makes the refueling outage an ideal time to perform necessary maintenance on various parts of the plant. Although those activities are carefully planned, they may take longer to perform than was originally anticipated. In addition, the maintenance and refueling process may enable the engineers to uncover damaged parts and unexpected maintenance tasks that could extend the length of the outage. These are usually problems that could not be detected before the plant was shut down and various components were dismantled. Because of the unpredictability and the variable length of these outages, it would not be meaningful to simply consider the plant's performance while in operation without considering the amount of time it is down for refueling.

For that reason, we chose to rely on the full cycle capacity factor. This is a measure that includes consideration of the length of a refueling outage. It is measured from the time a unit begins generating electricity after a refueling outage to the comparable time--the start of generation--in the following cycle, approximately an 18-month period. We found that it is a measure that seems particularly well suited for the Diablo Canyon units; to the extent that Diablo Canyon's very high operating capacity factor is the result of maintenance performed during its longer than average refueling outages, the full cycle capacity factor balances these influences. Unfortunately, predicting generation from a full cycle capacity factor is difficult, because the percentage factor depends not only on the length of the refueling outage, but also on the actual length of the full cycle. Therefore we converted the full cycle capacity factor (OCF) to an expected operating capacity factor by assuming that the full cycle performance occurred over a typical fuel cycle of 18 months and a typical refueling outage of 12 weeks.[10]

CCC and IEP have recommended that the same formula be used this year, yielding an OCF of 80.5%. On the basis of one additional fuel cycle for each unit, PG&E has now recommended that the formula be changed. PG&E still is assuming a 12-week refueling outage. However, instead of applying that assumption to the historical full cycle performance, the company would apply it to the historical operating capacity factor. The result is a recommended OCF of 85.4%. DRA supports the PG&E proposal. PG&E argues that Diablo Canyon is now a mature plant, with predictable refueling outages.

There have now been two refueling outages each for Units 1 and 2. The last outage was for Unit 2 and it was completed in 2 days less than 12 weeks. PG&E argues that this fact demonstrates that refueling outages should be expected never to exceed 12 weeks.

10 The implications of the OCF chosen for the the ECAC period have changed with the approval of the settlement of the Diablo Canyon Reasonableness Review in D.88-12-083. PG&E now receives a specified payment for each kilowatt hour of net generation from Diablo Canyon. The AER will be adjusted to become indifferent to the performance of the plant. The generation forecast adopted in this proceeding will allow us to establish a Diablo Canyon component of the ECAC revenue requirement in anticipation of expected performance. In additon, forecasted Diablo Canyon performance is still a factor in planning for other fuel needs and in calculating the IER.

However, this outage was preceded by a Unit 1 refueling outage of more than 18 weeks. PG&E's witness explained that the company was able to learn enough during that lengthy Unit 1 outage to allow them to anticipate and plan for the repairs to be completed during the Unit 2 outage. That is because the two units are mirror images of each other.

CCC and IEP argue that a plant that had previously experienced only one fuel cycle per unit does not suddenly become mature after the second fuel cycle. We agree. It makes no more sense to assume that the last Unit 2 outage is typical of future outages than to assume the same of the last Unit 1 outage. 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. As CCC points out, if the two data points available for Unit 1 could constitute a trend, they would suggest that the outages will become longer and longer. As further defense of its proposed change, PG&E asserts that the industry averages show that refueling outages become shorter with time. CCC appropriately reminds us that the methodology that we adopted in the last ECAC proceeding relies on Diablo Canyon's performance, not on the industry average. We prefer to adhere to our earlier approach because the performance of the each unit is more appropriately reflected by its performance across the fuel cycle. We will adopt the 80.5 % figure offered by CCC and HESI.

E. Minimum Downtime and Startup Fuel Requirements for Fossil Plants

In order to simulate the dispatching decisions that will be made in practice, computer modelers must establish certain modeling conventions. These function as rules or constraints that help shape the hypothetical dispatcher's resource choices. One such modeling convention is the concept of minimum downtimes for fossil plants. Another is an assumption as to the amount of fuel needed to start up a unit that has been down.

As PG&E explains, for modeling purposes, it imposes a minimum 72-hour downtime for its larger steam units and a 48-hour minimum downtime for its smaller units. The practical effect is that the smaller units will not be shut down overnight, for economic reasons, if they are perceived as being needed the next day and the larger units will not be shut down for less than three days. Startup costs are also used in production simulation models to allow for a comparison of the cost of shutting units down for fuel economy with the cost of keeping units on-line at minimum load in anticipation of the next time a particular unit is needed to serve load. PG&E argues that to ensure that the decision to startup a unit is correct, the full cost of startup must be considered. Those costs include fuel, distilled water, labor, and auxiliary power required to start up a unit. For modeling purposes, PROMOD reflects all of these costs as if they were related to fuel.

IEP argues that these assumed minimum downtimes and startup costs are excessive. The modeling implication is that the fossil plants are less likely to ever be decommitted either because they could not comfortably be brought back on-line without violating the minimum downtime constraint, or because the assumed startup costs are too high to make a temporary shut down appear economically justified. IEP asserts that if these constraints are excessive, the value of variably priced QFs may be understated.

IEP presents two types of evidence to support its claim that PG&E's assumed minimum downtimes are excessive. IEP refers to PG&E's submissions before the California Energy Commission (CEC) in its Biennial Update Proceeding (CFM7) concerning startup time requirements. These ranged from three to ten hours for "hot" startups and six to 18 hours for "cold" startups. PG&E responds that startup time requirement is a concept independent of the minimum downtime requirement. As PG&E explains it, startup time is the number of hours required to bring a unit from shut down to the point where it can begin to serve load, while minimum downtime is the number of hours from the time when a unit is taken off-line until it can begin to be started up again. PG&E goes on to explain that the minimum downtime requirement is used to minimize unit on- and off-line cycling, which causes thermal and mechanical stresses and vibrations that in turn result in increased wear and tear on mechanical components. PG&E says that, as a result, its dispatchers will not shut down and restart units for less than the minimum downtimes except in the case of emergencies.

IEP responds by saying that although this concept might make theoretical sense, it does not reflect reality. IEP reports that it reviewed PG&E's hour by hour oil and gas steam plant production data as provided in the ECAC reasonableness review last year. According to IEP, combined with the hourly production data provided by PG&E was an explanation of each outage incurred by a power plant. David Branchcomb, testifying for IEP, stated that this data indicated that in a number of instances, PG&E took some of its oil and gas steam plants off-line on a reserve status for as little as three hours. Branchcomb argues that this shows that the minimum downtime concept is not meaningful.

PG&E responds by saying that most of the reserve shutdowns of less than 48 to 72 hours appear in the records as short term because they were immediately preceded or followed by scheduled maintenance or a forced outage. The implication is that the plants were usually shut down for longer than the data examined by IEP might suggest. IEP responds by pointing out that in several instances, very short downtimes were recorded and were neither adjacent to a longer outage nor associated with some emergency. PG&E counters by saying that IEP is only discussing nine starts out of a total of about 200 cold starts over the course of a year. IEP says that PG&E's data from its CFM8 submissions should be adopted, instead of the numbers offered by PG&E in this proceeding.

As was the case with the question of Pacific Northwest availability, IEP is asking us to reject PG&E's showing in this case largely because PG&E has said something elsewhere that appears to be contradictory. Although truly contradictory showings in two proceedings would seriously undermine the credibility of the presentations in either case, the existence of a contradiction does not lend instant reliability to the "other" showing. In this instance, we are not convinced either that a true contradiction exists or that the CFM8 numbers are more reliable.

PG&E has testified that the downtimes are not as short as they appear and that there are technical reasons to keep the plants down longer. IEP has not offered engineering support for its claims that shorter downtimes can be assumed. The IEP showing has, nonetheless, placed a spotlight on a subject that merits greater scrutiny. In its next ECAC filing, we will expect PG&E to demonstrate the actual amount of time each plant was down in each instance and provide the reason for the duration of the outage. PG&E should offer minimum downtime assumptions that do not simply reflect the optimal operating conditions, but take into account the downtimes that are actually experienced.

IEP also raised the possibility that PG&E's technique of including all startup costs as a fuel cost equivalent may lead to double counting. The nonfuel costs such as labor and distilled water would normally be considered in a general rate case, not in a fuel cost offset proceeding. The ALJ directed PG&E to provide evidence showing which costs are already accounted for in the general rate case and the revenue requirement associated with those costs. PG&E reported that for the IER and revenue requirements calculations, the value of the auxiliary power, distilled water, and labor were removed because there are recovered elsewhere (the nonfuel costs in the general rate case and the auxiliary power

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For dispatching purposes, it is realistic to consider the full cost of start-up. It is not, however, reasonable to double count dollars. The additional information provided by PG&E assures us that the company is not asking for the same dollars in two separate proceedings. Thus, we will adopt PG&E's assumptions for minimum downtimes and startup fuel costs for steam plants using fossil fuel.

F. <u>Restart of Standby Oil and Gas Units for QF-Out Simulation</u>

PG&E has certain oil and gas generating units that are kept on standby. PG&E says that these units are not likely to be needed in 1990. Placing the units in standby, according to PG&E, saves costs associated with keeping the units in as-available status. Nonetheless, these units are capable of being put into service relatively quickly. PG&E argues that, in modeling the utility's dispatch decisions in the absence of variably priced QFs, it is inappropriate to treat these units as if they were available for use.

IEP points out that PG&E has made this argument before. In fact, PG&E made the same argument in its ECAC proceeding last year. In D.88-11-052 (at p. 64) we said:

> "We believe that it is appropriate to model standby units that can be restarted in a short time as being available for the entire forecast period. Presumably, these plants were put on standby because they were less efficient than other plants. Since the model dispatches generation on an economic basis, except for certain constraints, these plants would not be employed by the models unless and until they were cheaper than alternatives."

In that decision, we required all modelers to model standby units that can be restarted in short time as being available for the entire forecast period. Nothing has changed that should cause us to alter our position this year. As proposed by IEP, we will ask all modelers to assume that all six units in question will remain available for the entire forecast period.

G. Uncontested Assumptions

The parties were able to reach agreement as to many of the resource and modeling assumptions to apply to IER and revenue requirements calculations. Appendix A to this decision contains the portion of Exhibit 1 that lists the uncontested resource assumptions and modeling conventions. We adopt all of those assumptions as listed, with the exception of the sales forecast (which has been adjusted as described in an earlier section) and hydro generation (which has been changed to reflect June snow survey information).

IV. Calculation of the ERI

There are three computational factors set in the ECAC proceeding that govern the payments to be made by PG&E to variably priced QFs. The IER, which reflects the utility system's incremental efficiency in converting heat energy to electricity, is multiplied by the utility's incremental fuel cost to produce the energy price to be paid to variably priced QFs. The ERI is a way of expressing whether the value of additional capacity on an electric utility system in a given year is the same as, or greater or less than the utility's marginal capacity investment, assumed to be a combustion turbine. It is a fraction that is multiplied by the cost of a combustion turbine to produce the capacity price to be paid to variably priced QFs. The O&M adder reflects the operation and maintenance costs that are avoided when variably priced QFs are available. It is added to the energy and capacity prices to form the total price paid to variably priced QFs. The modeling parties were directed to present their IER, ERI, and O&M adder calculations in the hearings which followed the ALJ's resource assumption ruling.

The first ERI was adopted in PG&E's test year 1984 general rate case D.83-12-068. Since then, this Commission has considered aspects of the ERI in a number of other decisions.[11] The ERI capacity value adjustment is calculated using either short-term or long-term forecasts of utility loads and resources, depending on the type of standard offer.[12] Short-term ERIs are updated annually in the Energy Cost Adjustment Clause (ECAC) proceedings. Long-term ERIs are updated as part of the Biennial Resource Plan Update (BRPU) in A.82-04-44 et al.[13]

Prior to June 22, 1989, we had adopted methods for calculating the long-term ERIs for PG&E, SCE, and San Diego Gas & Electric Company (SDG&E).[14] We had also adopted methods for calculating short-term ERIs for SCE and SDG&E. However, in D.88-03-079, we deferred final adoption of a short-term method for PG&E.

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11 See D.86-07-004, pp. 27-30 and 81; D.86-11-071, pp. 1-17; D.88-03-079, pp. 3-18; and D.89-06-048 in its entirety.

12 Capacity payments under our as-available offers (SO1 and SO3) are based on ERI calculations using <u>short-term</u> forecasts of loads and resources. Capacity payments under SO2 and our "long-run" final Standard Offer 4 are based on ERI calculations using <u>long-term</u> forecasts.

13 See D.88-03-026, Table A and D.88-03-079, pp. 6-8.

14 In D.88-03-079, we directed SDG&E and SCE to adjust the capacity cost of a CT using an ERI based on expected unserved energy. We directed PG&E to use a CEC-based Target Reserve Margin method. See D.88-03-079, pp. 6-8, 18.

Instead, we continued the use of PG&E's 1987 capacity price for 1988, and requested comments on a "floor/ceiling" proposal.[15]

In D.89-06-048, we adopted a floor/ceiling methodology, modified in response to comments on an earlier proposal, to calculate the short-term ERI for PG&E.

Until further action by this Commission, PG&E's short-term ERI will have a ceiling of 1.0 and a floor of 0.4. The ceiling ERI will be used to calculate capacity payments whenever PG&E's projected reserve margin for the forecast year is equal to or less than the target reserve margin established in the most recent Electricity Report of the CEC. The ERI will decline exponentially as the projected reserve margin increases above the target, until the projected reserve margin is six percentage points over the target. At or beyond that point, the ERI will be the floor value of 0.4.

Our adopted floor/ceiling approach is to be used consistently for all applications involving short-term capacity valuation on PG&E's system, including pricing for as-available QFs, forecasts of energy-related revenue requirements, revenue allocation, and rate design.

Since this ECAC proceeding and the general rate case were already in progress when the floor/ceiling approach was adopted, we directed PG&E to make late filings in both cases to assure that its ERI calculations conformed to the new approach. The timing of the ERI decision allowed for PG&E and other parties to present responsive ERI calculations along with their final IER runs. When asked to prepare its calculation, PG&E sought guidance as to how the calculation should be made. There were two lengthy off-the-record discussions dedicated to answering PG&E's questions. One of those discussions was preceeded by the issuance of a letter from

15 D.88-03-079, pp. 16-18.

the ALJ (dated July 12, 1989) setting forth for discussion a format for calculating the ERI. Since the company continued to request more explicit guidance, the ALJ included the following instructions in his August 15, 1989 ruling on resource input assumptions, which reiterated the format discussed in his earlier letter:

1. Calculate projected reserve margin based on QF-in run.

2. Calculate projected reserve margin based on QF-out run.[16]

3. Calculate the average of these two values.

4. Calculate ERI, based on the average projected reserve margin, using the CEC's adopted target reserve margin of 17.5%[17] and the floor/ceiling methodology adopted in D.89-06-048.

5. Incorporate the ERI in the revenue requirements calculation.

Ultimately, PG&E calculated the ERI as .40, while DRA and the QFs all calculated the ERI as 1.0. There were four major areas of disagreement between PG&E and the other parties as to how the calculation should be made.

A. Dry Year Hydro Assumption

When placing a value on contribution of new capacity to the reliability of the utility system, it is important to take into account any conditions which could reasonably apply in the period under consideration. We have consistently required that this

16 QF-in/QF-out should be defined in a manner consistent with the IER runs. Consistent with the Commission's determination in D.86-11-071 (see Finding of Fact 7 and p. 10), "dry hydro" conditions should be assumed for the ERI calculation.

17 Derived from the CEC's Electricity Supply Planning Assumptions Report, Docket 87-ER-7, p. A-50.

analysis include an assumption that in any given year the utility may face dry hydro conditions. In this proceeding PG&E has argued that dry year hydro conditions should not apply to the ERI forecast, because it is only a one-year forecast. PG&E suggests that there is sufficient predictability in the short-term hydro forecast process to make this planning exception.

In this regard, we agree with the comments of DRA witness Robert Kinosian that we have always used adverse hydro conditions when doing reliability planning because it is impossible to forecast what the actual hydro conditions will be in a following year. In D.86-11-071, this Commission responded to an earlier request by PG&E to reconsider that requirement. The Commission said (at p. 11), "...we reaffirm that adverse hydro conditions are to be the basis of capacity planning in California....[S]ince we are using the perspective of system operability, we think the reliability target must ensure smooth operation in dry years."

In its testimony and brief, PG&E has put much effort into explaining to us what we meant in earlier rulings on this point. We will not attempt to explain further what the Commission may have had in mind in earlier decisions. One need do little more than examine the nature of PG&E's system. Because of its heavy reliance on hydro power, PG&E's system is particularly sensitive to changes in hydro availability. This makes its system relatively less reliable in dry years. This increases the value of other sources of capacity and must be considered, even in short-term forecasts.

We are aware that, in some years, the use of dry hydro assumptions will create the potential for higher-than-needed capacity payments to variably priced QFs. That is why we adopted a ceiling for PG&E's ERI. However, in many dry years, the ERI could exceed the ceiling of 1.0. As a matter of equity, we have also adopted a floor level of .4, which will assure QFs of some revenue consistency. As we stated in D.88-03-079, ceiling and floor provisions for PG&E's short-term ERI provide a reasonable balance of interests on a system where hydro plays such an important part. One of the factors being balanced is the use of dry hydro assumptions for the planning process. We agree with DRA and the QFs that dry year hydro assumptions should apply to the short-term ERI calculation.

B. <u>Northwest Capacity Assumption</u>

PG&E's witness (Kerler) testifies that the company could, if necessary, "firm up" more capacity in the Pacific Northwest than is indicated in its IER forecast and that it should be allowed to do so for the purpose of its ERI calculation. The company argues that it is being unrealistically constrained by being told to factor in a high reserve margin while not being able to assume greater capacity purchases from the Northwest. PG&E argues that, operating under such constraints, the inevitable result will be an ERI of 1.0.

CCC asserts that any potential extra capacity in the Northwest should not be counted because it is not "committed". Mark Younger, testifying for CCC, states that the CEC already took into account the possibility that PG&E could firm up extra Northwest capacity when it established the reserve margin which is being used for the ERI calculation. He argues that to allow PG&E to assume greater Northwest capacity to meet that reserve margin would constitute double counting, understating the value of added capacity.

CCC points out that there are other inconsistencies in PG&E's capacity assumptions between the ERI and IER calculations. In the ERI calculation, PG&E has added 100 MW to the assumed firm capacity purchases from the Northwest by SMUD. In addition, PG&E has added the assumption that all WAPA purchases are firm. CCC argues that, instead, firm capacity should be consistently defined throughout the proceeding.[18]

We agree. Perhaps the main benefit in merging the processes for calculating the IER and ERI in one proceeding is to ensure the integrity of the forecasting process. For the purposes of all short-term forecasting, PG&E should present a unified picture of its expected purchases and resource plans during the forecast period. It must be remembered that the goal of the ERI calculation is not to reinvent PG&E's resource plant, but to place a value on the added reliability stemming from the presence of a variably priced QF. The capacity assumptions applied in the IER calculation shall apply to the ERI as well.

C. QF Capacity

For purposes of calculating the IER, PG&E, and all other parties used the expected average capacity of QFs offering firm capacity. DRA, CCC, and IEP have used the same figure in calculating their ERIs. In its ERI calculation, PG&E has relied, instead, on the full contractual capacity of the QF facilities. The result understates the value of the added reliability introduced by variably priced QFs. Again, inconsistency is part of the problem. The same assumptions should apply when calculating the IER and the ERI. We agree with the DRA and QFs and will adopt their position.[19]

18 DRA and IEP comments are consistent with those of CCC.

19 On October 3, 1989, DRA moved to strike a portion of PG&E's brief that concerned the ERI calculation. DRA is concerned that PG&E was using its brief to propose a change in the short-term ERI methodology in this proceeding. DRA is correct in stating that this ECAC proceeding is not the appropriate forum for questioning the methodology. In its October 13, 1989 response, PG&E stated that it is not proposing a new methodology, but advocating a

(Footnote continues on next page)

We determined that, in this ECAC proceeding, the calculation of the adder would begin with the QFs-in/QFs-out runs that are used to determine the IER. For purposes of calculating the adder, standby reserve units should be modeled as being available for dispatch in the QFs-out run. We concluded that the avoided O&M costs should be calculated separately for three types of generating units: operating units, cold standby units, and retired plants. Operating units form a residual category that includes regularly operating units and reserve units that have not yet been placed in cold standby status. The change in generation between the QFs-in and QFs-out runs for each operating unit should be multiplied by the appropriate variable O&M figure from PG&E's filings in CFM6 and CFM7 to develop a total avoided O&M cost for that unit. The avoided costs for all operating units should then be added together to arrive at the total O&M savings from operating units.[21]

There are two areas of contention between the parties as to how the O&M adder should be calculated this year.

First, just as it did for its ERI calculation, PG&E would deviate from its IER assumptions concerning firm capacity arrangements in the Pacific Northwest for itself, SMUD, and WAPA. PG&E asserts that the same arguments support the use of different assumptions for O&M calculation as support deviating from the IER assumptions for the ERI calculation. As we stated in D.89-09-093, the same QFs-in and QFs-out runs used for the IER calculation should form the basis of the O&M adder calculation. Consistent with our earlier consideration of the ERI calculation, we reject PG&E's effort to modify our recently adopted O&M formula.

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21 See D.89-09-093, pp. 33-34.

Second, parties disagree as to the proper consideration of Moss Landing Units 4 and 5. As PG&E argues, these units are neither operational nor in cold standby. Instead, they occupy the relatively unique status of near-term standby units. According to PG&E, these generating units are maintained in such a way as to remain available to come on-line in 2-3 days. PG&E claims that this status results in virtually the same O&M expenditures for the two units whether or not they are placed into operation. Therefore, PG&E would change its QFs-in calculation to include Moss Landing Units 4 and 5. The effect would be to eliminate any assumed O&M savings for those units resulting from the contributions of variably priced QFs.

It is DRA's position that Moss Landing Units 4 and 5 should be considered operational in the QFs-out run, but not the QFs-in run. This is consistent with the IER assumptions and with D.89-09-093, which says that the IER runs should be used for this purpose. We agree with DRA that, when calculating the O&M adder, it is more appropriate to use the same assumptions for Moss Landing Units 4 and 5 as were applied in the IER calculation. After all, these units are not expected to generate power during the forecast period. If these units were included in the QFs-in run, the overall generation mix would be changed in a way that no party predicts would actually occur.

This assumption, alone, merely affects the amount of additional generation for each of the two units predicted to occur if the variably priced QFs were not available. Additional generation leads to avoided O&M costs only after the change in generation for each unit is multiplied by a variable which reflects incremental O&M savings. No party contests PG&E's claim that its O&M costs for these units are virtually the same whether or not the plants are operated. Therefore, the appropriate factor by which the predicted change in generation should be multiplied is zero. The result is that no avoided O&M costs for these units will be assumed. Finally, we also agree with DRA that Moss Landing Units 4 and 5 should be considered firm capacity for the purposes of calculating the avoided cold standby capacity related O&M costs. This will appropriately reflect the fact that these units are not in cold standby status. We will direct the parties to recalculate the O&M adder to reflect these assumptions.

VI. Calculating the DIER

A. Use of the Full UEG Rate

In D.88-12-083, we adopted a settlement in the Diablo Canyon Reasonableness Review. Among many other things, the settlement requires that Diablo Canyon revenues be excluded from PG&E's AER. In particular, PG&E expenses for replacement or displacement fuel due to operation of Diablo Canyon will be removed from AER recovery, through an annual adjustment at the end of each AER forecast period. For example, if Diablo Canyon production over a given period is greater than was forecast in a given ECAC proceeding, then PG&E expenses for other fuels would be lower than expected and PG&E would be in a position to increase its earnings through the AER. The annual AER adjustment will reduce customer costs by crediting the ECAC balancing account with the AER fraction of the displacement fuel expenses foregone by PG&E. If Diablo Canyon production is less than forecast, an opposite adjustment will be made to prevent PG&E losses through the AER.

The settlement proponents proposed a formula for making this annual adjustment utilizing the system average heat rate. We determined, however, that it would be better to use a production cost model to calculate incremental costs, than to use the system average heat rate found in the proposed tariff formula. Therefore we changed the formula to substitute an appropriate IER for the proposed system average heat rate.

generation should be multiplied is zero. The result is that no avoided O&M costs for these units would be assumed.

In their comments, DRA and the QFs pointed out that this assumption is not precisely correct, since certain consumable commodities such as distilled water and oil can be saved when the units are not placed in operation. We agree that it would be most appropriate for future O&M adder calculations to place a value on these avoided consumables. However, we feel that, on balance, the O&M adder adopted in this proceeding is fair.

Finally, we also agree with DRA that Moss Landing Units 4 and 5 should be considered firm capacity for the purposes of calculating the avoided cold standby capacity related O&M costs. This will appropriately reflect the fact that these units are not in cold standby status. We will direct the parties to recalculate the O&M adder to reflect these assumptions.

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In D.88-12-083, we adopted a settlement in the Diablo Canyon Reasonableness Review. Among many other things, the settlement requires that Diablo Canyon revenues be excluded from PG&E's AER. In particular, PG&E expenses for replacement or displacement fuel due to operation of Diablo Canyon will be removed from AER recovery, through an annual adjustment at the end of each AER forecast period. For example, if Diablo Canyon production over a given period is greater than was forecast in a given ECAC proceeding, then PG&E expenses for other fuels would be lower than expected and PG&E would be in a position to increase its earnings through the AER. The annual AER adjustment will reduce customer costs by crediting the ECAC balancing account with the AER fraction of the displacement fuel expenses foregone by PG&E. If Diablo

We found in D.88-12-083 that the IER used to calculate QF payments is the wrong IER for the annual AER adjustment. We ordered PG&E to calculate an appropriate IER, to be called the Diablo Incremental Energy Rate (DIER) to distinguish it from the QF IER, as follows.

> "In each ECAC case the QF IER is developed by calculating the difference in operating costs between two scenarios, QFs-in and QFs-out, then dividing that difference by the energy purchased from the QFs and by the Utility Electric Generation (UEG) gas rate. The total costs for each scenario are computed using production cost models. The DIER should be developed in much the same way, by calculating operating costs for two scenarios, both of which should assume QFs-in, for which Diablo Canyon output is 10% above and 10% below the capacity factor or availability factor assumed in the calculation of the QF IER. The DIER is then the difference in costs between the two scenarios, divided by the difference in Diablo Canyon generation and by the same UEG gas rate used in the QF calculation. This calculation should not be difficult because all model assumptions have been made in the process of determining the QF IER. If the specified 10% deviations are so small as to yield erratic DIER values, PG&E should revise the deviations appropriately and justify its revisions.
>
> "PG&E should make the calculations using the model conventions and resource assumptions adopted in A.88-04-057, its current ECAC proceeding, and report the resulting DIER with its first annual Diablo Canyon compliance filing. Future DIERs should be litigated in ECAC proceedings, not simply provided by PG&E."[22]

In the same decision, we stated that the formula described above may be modified in ECAC proceedings (see Finding of Fact 27). In this, the first such ECAC in which the DIER is being litigated, PG&E is already proposing a change in the formula.

22 D.88-12-083, pp. 177-178.

Although the Diablo Canyon settlement decision called for use of the full UEG gas rate in calculating the DIER, PG&E now proposes that only the G-PC and Tier II volumetric gas rates be used for the determination of the DIER. According to PG&E, this should be done because the demand/customer charges and the Tier I volumetric charge are fixed in the AER/ECAC rates and will not change if the Diablo Canyon generation changes. PG&E argues that since the fixed demand charges do not go up or down with variations in Diablo Canyon production, their inclusion in the DIER would cause PG&E to collect more or less for the difference in production than actual variable cost would go up or down.

DRA supports PG&E's position. The QFs argue that the full UEG gas rates should be used. We agree with the QFs. The decision accepting the Diablo Canyon settlement specified that the same UEG rate used in the IER calculation should be used in the DIER.

We are not convinced that using the full UEG rate as opposed to using only variable portions of that rate will have any effect on the balance of payments to PG&E stemming from the performance of Diablo Canyon. In converting the results of the model runs to the DIER, the cost of gas appears in the denominator of the calculation (DIER = $ divided by kWh divided by cost of gas). In converting the DIER to an AER adjustment, the cost of gas appears in the numerator of the calculation (AER $ = DIER times kWh times cost of gas). So long as the same UEG rate is used both for calculating and applying the DIER, the nonvariable portions of the rate will not influence the results. For the sake of simplicity, we will continue to require that the UEG rate be applied in the DIER calculation in the same manner it is applied in the IER calculation.

B. Differences in Results

DRA, PG&E, and CCC all derived similar results when calculating the DIER. On the other hand, IEP proposed a significantly higher DIER. IEP attributes this difference to its use of a chronological modeling approach which, it argues, more accurately mimics actual performance. PG&E argues, on the other hand, that IEP's calculation is flawed because it applied inappropriate assumptions as to which resources would be added when Diablo's performance was reduced and which would be subtracted when Diablo's performance improved. According to PG&E, all modelers agree that conventional units would be added before additional Northwest purchases when Diablo production is down. However, only IEP assumes that the conventional units would be backed out first when Diablo production is higher.

PG&E's argument is not supported by the record. This may be a result of PG&E's reliance on IEP's workpapers, which were not placed into evidence. Nonetheless, we are not persuaded that PROSYM is a more reliable tool for calculating the DIER. We will adopt PG&E's DIER (7811), which is virtually identical to that of CCC.

VII. Differences Among the Models

As was the case last year, three different computer models were used in order to simulate the performance of PG&E's system under various assumptions. These computer simulations help us to understand PG&E's fuel costs, the value of power generated and capacity provided by QFs, and the computational factor to be used for adjusting the AER to remove the affects of Diablo Canyon's performance in the past year.

DRA used ELFIN, a computer model which has been used by our staff and various utilities for over a decade. PG&E and CCC used PROMOD, a more complex and costly modeling approach, which has been used by PG&E in several past proceedings. IEP used PROSYM, a relatively new model, which was also used in the ECAC proceeding last year.

ELFIN and PROMOD are load duration curve models, which convert chronological demand levels into load duration curves, representing the percent of time that each level of demand occurs. PROSYM is a chronological model, which considers the system's operation in relation to time and which uses multiple runs to develop its forecast of the system's operation. IEP refers to this multiple run method as the Monte Carlo approach, under which the computer generates random numbers, intended to simulate chance occurrences in the performance of PG&E's generating sources. Numerous runs are used to bring the results closer to probable performance, instead of relying on one random set of numbers to forecast activities over the course of a year.

Because it is important to determine whether or not computer-generated forecasts are reliable and in order to understand the differences between these models, we have continued to employ workshops and common data set runs. While the use of a common data set cannot pinpoint all of the differences between the models, it does create a focus which, hopefully will uncover serious disagreements and flaws. In good faith, the parties have worked this year to help us understand how the models produce different results. Perhaps most important of all, the parties have worked with modeling constraints and conventions to make the results of their runs compatible.

Perhaps not surprisingly, the models continue to produce very similar results. In IEP's words, for most purposes, it is a coin toss to determine which model's results should be used. Through the workshop process, we have been able to identify differences in the way the models work and can see how accommodations are made in the modeling process to overcome limitations. However, despite the fact that we have justifiably referred to this multiple model process as a "Battle of the Models," it is not a process which is likely to produce a clear winner. In fact, the use of different models has raised questions about assumptions and technique which might not come to light if everyone relied on the same tools. To that extent, the use of multiple models is beneficial.

One modeling distinction that was discussed during the hearings was PG&E's use of a criterion it calls Dispatcher Risk Aversion. According to PG&E, this feature is intended to mimic the dispatcher's concern with the amount of energy available from various sources. Not all sources of generating capacity can provide endless amounts of energy. PG&E says that the dispatcher must have additional plants up and running when there is a high risk of an energy shortfall at an operating facility. The company argues that its heavy dependence on hydro power underscores the importance of this modeling feature, since a hydro plant cannot reliably supply as much energy when its reservoir is low. This makes this modeling feature especially significant in dry years.

In using the Dispatcher Risk Aversion feature, the modeler must decide just how risk averse the dispatcher should be assumed to be. This value is expressed in a percentage from zero to 100. In last year's ECAC, PG&E applied the following values to the Dispatcher Risk Aversion feature:

Weekday	50%
Nighttime	50%
Weekend	33%

In this proceeding, PG&E has applied the following values:

Weekday	100%
Nightime	100%
Weekend	33%

PG&E's witness Claudia Greif acknowledged that Dispatcher Risk Aversion has a relatively high impact on fuel costs compared to other model features. Nonetheless, she had not measured the impact of the changed values on the IER and revenue requirements.

It is important that the impacts associated with model features such as Dispatcher Risk Aversion be clearly identified and documented, especially when the feature is one which is given relatively greater weight than others. We will direct PG&E to include, in its next ECAC filing, the results of a study on the use of the the Dispatcher Risk Aversion modeling convention. At a minimum the study should meet the following requirements and justify the company's choice of values to be applied to the modeling convention:

1. Describe the model feature and the system operation which it is designed to represent.

2. Describe, review and explain the algorithm through which this model feature claims to mimic the system operation being represented.

3. Test the model feature by applying the default variable, the values assumed in the 1988 ECAC filing and those assumed in the 1989 ECAC filing to the data otherwise relevant to the 1990 ECAC filing. In addition, run the model with otherwise relevant 1990 data without activating the Dispatcher Risk Aversion feature. In each instance, report on the impacts on IERs and revenue requirements.

4. Report on the relationship between the Dispatcher Risk Aversion assumptions and actual operation.

Our greatest concern is in ensuring the effective participation of the DRA in this process. We need that balance in order to assure that all ratepayers are adequately represented. Whether or not all parties are limited to using one model, it would be best if resources were available to enable DRA to use and be familiar with the model offered by the utility. Then it would be clear that DRA and the utility were speaking the same language when discussing modeling conventions and assumptions.

We are not prepared to tell any of the parties that they must abandon their favored models. Prior to this proceeding, we required each party to include in its showing a base case run using ELFIN. We eliminated that requirement this year because we were interested in focusing the base case comparison on the way that the various models handled the same input assumptions. However, this led to an unintended result. Without the benefit of an ELFIN run accompanying PG&E's application, the DRA was forced into a perilous game of Beat the Clock. When the application was filed in April, DRA had only a few weeks in which to analyze PG&E's PROMOD results, complete the trial-and-error process of developing the modeling conventions needed to produce comparable data when using ELFIN, participate in the modeling workshops, and prepare its testimony. All this had to be done with a core computer team consisting of one person.

Despite long hours and a concerted effort, the results were unsatisfactory. DRA was unable to provide input to the workshop process on a timely basis, could not meet its schedule for filing testimony, and made substantive changes to its initial case after the last day of hearings.

We need not force DRA to begin its ECAC investigation under this handicap. Instead, we will reinstitute the requirement that PG&E's application be supported by an ELFIN run, regardless of the model PG&E wishes to rely on for its preferred case. At the time of its filing, PG&E shall be prepared to work with DRA in interpreting the ELFIN run and to provide DRA with a complete explanation of the modeling conventions employed to make the ELFIN run comparable to that of any other model used.

PG&E argues that DRA's desire for this assistance is an indication of the quality of DRA's modeling expertise. This is an unfortunate and inappropriate argument which misses the point. DRA's experts are expected to apply their skills to a full range of computer analyses in the telecommunications, transportation, and energy fields on a continuous basis. It is unnecessary and wasteful to ask them to start each analysis with a clean slate. With PG&E's ELFIN run in hand, DRA should be more quickly able to focus its own computer work and determine where there is a need to develop more or better conventions and modeling techniques. As always, DRA will remain responsible for its own analysis. With PG&E's ELFIN run in hand, however, it should be better able to deal with the increasingly complex ECAC issues within the short time available for considering these cases.

VIII. Hydro Conditions

In ECAC proceedings, we normally apply average precipitation assumptions when forecasting hydro generation for a future period. That is because, even in the short-term it is not possible to make reliable forecasts of precipitation. However, prospective estimates can be tempered by existing conditions. For instance, PG&E conducts snowpack surveys which can tell it something about the availability of water in the months ahead. When PG&E filed this application (April 3, 1989), its analysis included the latest snow survey data available, which was issued at the beginning of February. It offered April data when it became available and June data when it was developed.

Since the forecast period begins November 1, which is within the next rain season, the question was raised as to the benefits of using prior year snow survey data. Would it be preferable always to apply average year assumptions, since the actual performance will fluctuate above and below average over the years? Some parties questioned the merits of changing hydro assumptions as the case progressed. One concern is that each party might advocate using the data which is most favorable its case. The most repeated position is that some rule should be applied consistently. Either average year data should exclusively apply, or snow data from a specific report should always be relied on.

We are convinced that there is some merit to taking current conditions into account. While much of the snow pack may disappear by November, the late winter and spring hydro conditions may affect stream flows and reservoir levels well into a forecast period which begins the following fall. At the same time, we agree that consistency is important. Last year, we relied on June snow survey information. We are relying on the June data this year as well. This is the most recent report available which can be fully examined during the hearings. In future years as well, we intend to ask that PG&E provide an update based on the June report and to rely on that information when assessing the hydro forecast.

IX. Revenue Requirements

Because this decision makes some adjustment to factors which can affect revenue requirements, it will be necessary for each of the parties to run its model again. We direct the parties to do this and file the results with their comments on this proposed decision, so they can be reflected in the final decision.

The final model runs already in the record provide an approximation of the final revenue requirement. Based on the assumptions contained in the ALJ ruling, the parties recommended the following increases: PG&E, $255.6 million; DRA, $279.7 million; CCC, $270.4 million; and IEP, $272.1 million. Although the ERAM adjustment is not in dispute, we will itemize all of the changes in our next order related to this proceeding.

X. Comments on This Proposed Decision

Due to the short time available for review and decision before the end of the year, parties are requested to serve two copies of their comments, together with any attachments, on this proposed decision on Commissioner Hulett, the Assigned Commissioner.

<u>Findings of Fact</u>

1. PG&E filed this application on April 3, 1989, requesting an increase of $378.3 million to its electric rates on an annualized basis effective November 1, 1989.

2. Since the last AER revision only forecasted costs through end of July 1989, we suspended PG&E's AER as of August 1, allowing 100% of the fuel costs incurred since that date to be tracked in the ECAC balancing account.

3. All revenue allocation and rate design issues have been heard on a consolidated basis in A.88-12-005, the general rate case.

4. In a ruling dated May 24, 1989, ALJ Cragg granted PG&E's motion asking that the sales forecast developed in this proceeding be used in the general rate case for purposes of consolidated consideration of revenue allocation and rate design issues.

5. The Rancho Seco Nuclear Power Plant (Rancho Seco) has been closed.

6. Without the benefit of power generated at Rancho Seco, SMUD will have to purchase more electricity from other entities.

7. It is reasonable to assume that SMUD will make use of its existing contracts with PG&E, SCE, and utilities in the Pacific Northwest.

8. The agricultural customer class is intended to include only those customers who use electricity predominantly to serve agricultural end-uses.

9. Agricultural end-uses include growing crops, raising livestock, pumping water for irrigation, and other uses that involve production for sale and that do not change the form of the agricultural product.

Commissioner directed the parties to do this and file the results with their comments on the proposed decision, so they could be reflected in the final decision.

Table 2 reflects the final calculations of each contributing party for the IER, ERI, O&M adder, and revenue requirements. As this table indicates, the revenue requirements and other calculated factors of the various parties are relatively close. Only DRA's revenue requirements numbers are substantially higher. While it is not clear why DRA's figures are higher, this does not appear to be a direct result of the IER, O&M adder, or ERI calculations. Although we are not endorsing a single computer model, we must adopt a set of final calculations. On balance, PG&E's calculations reflect internal consistency. CCC used the same computer model as PG&E and generated virtually identical numbers. This lends confidence to our use of PG&E's calculations. We will adopt PG&E's most recent calculations for the IER, O&M adder, ERI, and net revenue requirements as reflected in Table 2. The adopted energy costs and changes in revenue requirements are contained in Appendix C and summarized in Appendix D.

TABLE 2

Party	Average IER	O&M Adder	Equivalent IER	ERI	Net Revenue Increase
PG&E	9,443	2.326	10,387	1.0	$ 272.048 M
DRA	9,427	2.64	unknown	1.0	282.174
CCC	9,444	2.34	10,392	1.0	272.684 M
IEP	9,459	2.44	10,430	1.0	274.272

Findings of Fact

1. PG&E filed this application on April 3, 1989, requesting an increase of $378.3 million to its electric rates on an annualized basis effective November 1, 1989.

10. As of the time when the results of this year's ECAC proceeding go into effect, agricultural schedules will be reserved for those customers who meet the condition that 70% or more of their energy usage is dedicated to agricultural end-uses.

11. PG&E has yet to reach its goal of identifying the affected customers in the newly defined agricultural class.

12. The number of active agricultural accounts does not equal the number of customers with agricultural end-uses.

13. Each time a new agricultural pump is connected to the utility lines, a new account is opened.

14. Despite overall reductions in farmed acreage during the last few years, drought conditions have resulted in many new accounts being opened.

15. Many accounts are opened or closed simply because farm property changes hands and the electric billing is transferred to a new name.

16. Starting with a base of 99,599 customers in 1985, PG&E had forecasted 100,951 customers for 1988, reflecting a net increase of 1,352 customers.

17. An actual tally of accounts opened and closed during those years yields a net reduction of 804 accounts, leading to 98,795 customers in 1988.

18. The growth in the number of agricultural accounts forecast by PG&E's econometric model does not coincide with recorded openings and closings in the years for which data was provided.

19. Despite the disagreements as to the size of the agricultural class, the various estimates of agricultural sales are very close.

20. The Pacific Northwest has experienced two exceptionally dry years.

21. All parties are in agreement with PG&E's forecast of available installed capacity for transmission from the Pacific Northwest during the forecast period.

22. Even if current river flows and reservoir levels are at or near normal, the reality of two prior dry years is likely to restrain deliveries to California.

23. Sufficient energy available in the Pacific Northwest to fill all of its entitlement on the transmission interties during peak periods and 50% of its entitlement during off-peak hours.

24. In 1988, PG&E purchased Northwest power at the fixed price of 22 mills.

25. BPA has offered to provide energy to PG&E in October 1989 at a price of 23 mills.

26. In 1988, reservoir levels in the Northwest were dramatically lower than they are in 1989.

27. Actual practice confirms PG&E's ability to obtain energy at 22 mills under less favorable conditions.

28. For the general rate case, PG&E produced a forecast of Northwest Energy availability based on what the QFs refer to as a quantitative model.

29. The key characteristic of a quantitative model is its relative verifiability; assumptions as to what may affect energy supplies are clearly defined and subject to critique for conceptual soundness; once the conceptual framework is understood, results can be checked and replicated by others willing to undertake the same analysis.

30. For the ECAC Northwest energy forecast, PG&E undertook a largely empirical study.

31. The goal of the general rate case Pacific Northwest analysis was to prepare a long-term forecast.

32. In an ECAC forecast, the reliance is on short-range vision and the factors that are recognizable from where we stand today.

33. Properly executed quantitative analysis does not necessarily provide a more reliable forecast than empirical judgment.

34. Experts must always be able to show that their judgments flow logically from an assessment of facts and that the full range of essential facts have been considered.

35. The price of Northwest purchases from March 1, 1990 through October, 1990 is assumed to equal 90% of PG&E's average incremental fossil-fired steam generation costs.

36. All parties support PG&E's assumption that its purchases of economy energy from the Pacific Northwest from March 1, 1990 through October, 1990 will be priced at 90% of PG&E's incremental fossil-fired steam generation costs.

37. All parties agreed that if Northwest supplies were considered limited during the first stage of the ECAC period, the price of purchases from the California Department of Water Resources should be assumed to be 20 mills and that the price for the remainder of the ECAC period should be assumed to be the same as the price for Northwest purchases during the second stage.

38. In 1987, the Geysers field began to experience frequent steam curtailments, when there was insufficient steam to run all of the units although the units were available for service.

39. Geysers Unit 15 is now out of service for an indefinite period and is assumed to be unavailable during the forecast period, due to insufficient steam.

40. Geothermal steam curtailments have continued to grow. This year, PG&E was able to shed little new light on the reasons for the geothermal steam curtailments.

41. PG&E proposes that the geothermal steam price be based on its contractual formula involving recorded and forecasted fossil costs and recorded and forecasted nuclear fuel costs, as in past years.

42. DRA has proposed that the nuclear fuel cost component of the geothermal steam price be decreased to reflect what it asserts to have been unreasonable delays in the completion of the Diablo Canyon Nuclear Plant (Diablo Canyon).

43. The necessity of shutting down a generating unit and removing the reactor head during the refueling process makes the refueling outage an ideal time to perform necessary maintenance on various parts of a nuclear power plant.

44. The maintenance and refueling process for a nuclear power plant may enable the engineers to uncover damaged parts and unexpected maintenance tasks that could extend the length of the outage; these are usually problems that could not be detected before the plant was shut down and various components were dismantled.

45. Diablo Canyon Units 1 and 2 have each had 2 refueling outages.

46. The last outage was for Diablo Canyon Unit 2 and it was completed in 2 days less than 12 weeks.

47. The last refueling outage for Diablo Canyon Unit 1 was not completed for more than 18 weeks.

48. For modeling purposes, PG&E imposes a minimum 72-hour downtime for its larger steam units and a 48-hour minimum donwtime for its smaller units.

49. The practical effect of PG&E's minimum downtime modeling convention is that the model assumes that smaller units will not be shut down overnight, for economic reasons, if they are perceived as being needed the next day and that the larger units will not be shut down for less than three days.

50. Startup costs are also used in production simulation models to allow for a comparison of the cost of shutting units down for fuel economy with the cost of keeping units on-line at minimum load in anticipation of the next time a particular unit is needed to serve load.

51. Startup costs include fuel, distilled water, labor, and auxiliary power required to start up a unit; for modeling purposes, PROMOD reflects all of these costs as if they were related to fuel.

52. PG&E's calculations of the IER and revenue requirements do not include the value of the auxiliary power, distilled water, and labor which were removed because these costs are recovered elsewhere (the nonfuel costs in the general rate case and the auxiliary power costs in the general steam rate).

53. PG&E has certain oil and gas generating units that are kept on standby.

54. PG&E says that its standby units are not likely to be needed in 1990.

55. The parties were able to reach agreement as to many of the resource and modeling assumptions to apply to IER and revenue requirements calculations, which are listed in Appendix A to this decision.

56. Variable QF prices are the sum of three basic components: a payment for capacity, a payment for avoided O&M, and a variable payment for energy.

57. The IER, which reflects the utility system's incremental efficiency in converting heat energy to electricity, is multiplied by the utility's incremental fuel cost to produce the energy price to be paid to variably priced QFs.

58. The ERI is a way of expressing whether the value of additional capacity on an electric utility system in a given year is the same as, or greater or less than the utility's marginal capacity investment, assumed to be a combustion turbine.

59. The ERI is a fraction that is multiplied by the cost of a combustion turbine to produce the capacity price to be paid to variably priced QFs.

60. The O&M adder reflects the operation and maintenance costs that are avoided when variably priced QFs are available.

61. In D.89-06-048, we adopted a floor/ceiling methodology, modified in response to comments on an earlier proposal, to calculate the short-term ERI for PG&E.

62. PG&E has argued that dry year hydro conditions should not apply to the ERI forecast, because it is only a one-year forecast.

63. We have always used adverse hydro conditions when doing reliability planning because it is impossible to forecast what the actual hydro conditions will be in a following year.

64. Because of its heavy reliance on hydro power, PG&E's system is particularly sensitive to changes in hydro availability. PG&E states that it could, if necessary "firm up" more capacity in the Pacific Northwest than is indicated in its IER forecast and that it should be allowed to do so for the purpose of its ERI calculation.

65. The goal of the ERI calculation is not to reinvent PG&E's resource plant, but to place a value on the added reliability stemming from the presence of a variably priced QF.

66. It is appropriate to use consistent assumptions as to QF capacity when calculating the IER and the ERI.

67. Parties to this proceeding were instructed to calculate the O&M component of payments to variable QFs (O&M adder) according to the method which we approved in D.89-09-093.

68. As we stated in D.89-09-093, the same QFs-in and QFs-out runs used for the IER calculation should form the basis of the O&M adder calculation.

69. Moss Landing Units 4 and 5 are neither operational nor in cold standby; instead, they occupy the relatively unique status of near-term standby units.

70. No party contests PG&E's claim that its O&M costs for Moss Landing Units 4 and 5 are virtually the same whether or not the plants are operated.

71. Although the Diablo Canyon settlement decision called for use of the full UEG gas rate in calculating the DIER, PG&E now proposes that only the G-PC and Tier II volumetric gas rates be used for the determination of the DIER.

72. In converting the results of the model runs to the DIER, the cost of gas appears in the denominator of the calculation (DIER = $ divided by kWh divided by cost of gas).

73. In converting the DIER to an AER adjustment, the cost of gas appears in the numerator of the calculation (AER $ = DIER times kWh times cost of gas).

74. So long as the same UEG rate is used both for calculating and applying the DIER, the nonvariable portions of the rate will not influence the results.

75. We are not persuaded that PROSYM is a more reliable tool than other models for calculating the DIER; we will adopt PG&E's DIER.

76. As was the case last year, three different computer models were used in order to simulate the performance of PG&E's system under various assumptions.

77. DRA used ELFIN, a computer model which has been used by our staff and various utilities for over a decade.

78. PG&E and CCC used PROMOD, a more complex and costly modeling approach, which has been used by PG&E in several past proceedings.

79. IEP used PROSYM, a relatively new model, which was also used in the ECAC proceeding last year.

80. ELFIN and PROMOD are load duration curve models, which convert chronological demand levels into load duration curves, representing the percent of time that each level of demand occurs.

81. PROSYM is a chronological model, which considers the system's operation in relation to time and which uses multiple runs to develop its forecast of the system's operation.

82. The use of different models has raised questions about assumptions and technique which might not come to light if everyone relied on the same tools.

83. Dispatcher Risk Aversion is a computer modeling feature employed by PG&E to mimic the dispatcher's concern with the amount of energy available from various sources.

84. In its past two ECAC filings, PG&E has applied different values to the Dispatcher Risk Aversion feature.

85. It is important that the impacts associated with model features such as Dispatcher Risk Aversion be clearly identified and documented, especially when the feature is one which is given relatively greater weight than others.

86. Without the benefit of an ELFIN run accompanying PG&E's application, DRA's participation in this proceeding was impaired.

87. In ECAC proceedings, we normally apply average precipitation assumptions when forecasting hydro generation for a future period.

88. Prospective hydro estimates can be tempered by existing conditions.

89. PG&E conducts snowpack surveys which can tell it something about the availability of water in the months ahead.

90. While much of the snow pack may disappear by November, the late winter and spring hydro conditions may affect stream flows and reservoir levels well into a forecast period which begins the following fall.

Conclusions of Law

1. It is reasonable to use a forecast of 98,765 agricultural customers for the ECAC forecast year and calendar year 1990.

2. The Commission should adopt adopt PG&E's overall sales forecast: PG&E sales of 69,300 GWh and a total area load of 94,343 GWh for the ECAC forecast year; PG&E sales of 69,668 GWh and a total area load of 94,612 for the general rate case calendar year 1990.

3. We should not change a reasonable assumption just to make the modeling results look better; even if we were otherwise inclined, there would be no compelling reason to do so in a situation where the change would have virtually no effect on the IER or on the overall revenue requirement.

4. It would be inappropriate to apply the results of a long-term forecast to the short-term issues of IERs and ECAC revenue requirements for the next 12 months.

5. We should encourage PG&E, DRA, or any other party to develop a quantitative approach to forecasting short-term Pacific Northwest energy availability; however, we are not prepared to require such analysis in this situation.

6. Twenty-two mills is an appropriate price assumption to apply to the PG&E's purchases from the Pacific Northwest from November 1, 1989 through February 1990.

7. The price for purchases from the California Department of Water Resources for the portion of the ECAC period running from March 1, 1990 through October 1990 should be assumed to be the same as the price for Northwest purchases during the same period.

8. PG&E has not provided a convincing basis for predicting curtailments during the forecast period.

9. Two years' worth of data is insufficient to predict a trend in geothermal steam curtailments.

10. For the purposes of setting rates and IERs, it is reasonable to assume that geothermal steam curtailments during the forecast period will be the same as those during the last 12 months for which data was available prior to the final IER calculation.

11. PG&E should present information with its next ECAC filing that will reflect specific study of the problems affecting PG&E's Geysers plants including a verifiable method for determining the likely yield from the Geysers during the next forecast period.

12. The consideration of DRA's proposal to disallow a portion of the geothermal steam costs should be consolidated for hearing with related issues in the reasonableness phase; thus, it is reasonable to adopt PG&E's geothermal price assumptions without prejudice to later consideration of the DRA position.

13. Because of the unpredictability and the variable length of nuclear power plant refueling outages, it would not be meaningful to forecast overall performance simply by considering the plant's performance while in operation without considering the amount of time it is down for refueling.

14. A nuclear power plant that had previously experienced only one fuel cycle per unit does not suddenly become mature after the second fuel cycle.

15. We should adhere to our current approach for forecasting Diablo Canyon operation because the performance of the each unit is more appropriately reflected by its performance across the fuel cycle.

16. PG&E should offer minimum downtime assumptions that do not simply reflect the optimal operating conditions, but take into account the downtimes that are actually experienced.

17. In its next ECAC filing, PG&E should demonstrate the actual amount of time each plant was down in each instance and provide the reason for the duration of the outage.

18. PG&E's assumptions for minimum downtimes and startup fuel costs for steam plants using fossil fuel should be adopted.

19. In D.88-11-052, we required all modelers to model standby units that can be restarted in short time as being available for the entire forecast period; nothing has changed that should cause us to alter our position this year.

20. We should adopt all of the assumptions listed in Appendix A, with the exception of the sales forecast (which has been adjusted as described in an earlier section) and hydro generation (which has been changed to reflect June snow survey information).

21. Dry year hydro assumptions should apply to the short-term ERI calculation.

22. For the purposes of all short-term forecasting, PG&E should present a unified picture of its expected purchases and resource plans during the forecast period.

23. The Pacific Northwest firm capacity assumptions applied in the IER calculation shall apply to the ERI as well.

24. It is inappropriate to include long-term standby units in a short-term ERI calculation.

25. When calculating the O&M adder, it is most appropriate to use the same assumptions for Moss Landing Units 4 and 5 as were applied in the IER calculation.

26. The parties should recalculate the O&M adder to reflect the assumption that Moss Landing Units 4 and 5 are available in the QFs-out run only, and that the related O&M savings is zero.

27. For the sake of simplicity, we should continue to require that the UEG rate be applied in the DIER calculation in the same manner it is applied in the IER calculation.

28. PG&E should include, in its next ECAC filing, the results of a study on the use of the Dispatcher Risk Aversion modeling convention.

29. We should reinstitute the requirement that PG&E's application be supported by an ELFIN run, regardless of the model PG&E wishes to rely on for its preferred case.

30. In future years, we intend to ask that PG&E provide an update based on the June snow survey and to rely on that information when assessing the hydro forecast.

31. Because this decision makes some adjustment to factors which can affect revenue requirements, it will be necessary for each of the parties to run its model again.

32. The suspension of PG&E's AER authorized in D.89-01-040 should be lifted and PG&E's AER should be resinstated at the time when the rates resulting from the decision become effective.

ORDER

IT IS ORDERED that:

1. In its next Energy Cost Adjustment Clause (ECAC) application, Pacific Gas and Electric Company (PG&E) shall provide information which reflects a specific study of the problems affecting its Geysers geothermal plants including a verifiable method for determining the likely yield from the Geysers during the next forecast period.

2. In its next ECAC application, PG&E shall report on the actual amount of time each of its fossil steam plants was out of service for every outage experienced during the 12-month period prior to the application and the specific reason for each outage.

3. In its next ECAC filing, PG&E shall provide the results of a study on the use of the Dispatcher Risk Aversion modeling convention that, at a minimum, satisfies the requirements set forth in this decision.

4. PG&E's next ECAC application shall be supported by an ELFIN run, whether or not ELFIN is the model chosen by PG&E for its preferred case. At the time of its filing, PG&E shall be prepared to work with Division of Ratepayer Advocates (DRA) in interpreting the ELFIN run and to provide DRA with a complete explanation of the modeling conventions employed to make the ELFIN run comparable to that of any other model used.

5. In future ECAC proceedings, PG&E should present updated hydroelectric forecast information based on its June snow survey as that information becomes available.

6. All modeling parties shall recalculate the operations and maintenance adder based on the assumptions adopted in this decision.

7. Those parties whose most recent incremental energy rate and/or energy reliability index calculations are inconsistent with assumptions adopted in this proceeding shall produce new model runs applying the appropriate assumptions.

8. New revenue requirements calculations shall be prepared to reflect the assumptions approved in this decision. The model runs and reporting of the results shall be coordinated as necessary by the assigned administrative law judge.

9. A final decision on the revenue requirements issues in this proceeding will issue at the Commission's second meeting in December 1989.

10. The suspension of PG&E's Annual Energy Rate (AER) authorized in D.89-01-040 shall be lifted and PG&E's AER shall be reinstated at the time that the rates resulting from this decision become effective.

11. Parties shall serve two complete copies of their comments, with any attachments, on this proposed decision on Commissioner Hulett, at that same time as they serve other parties.

This order is effective today.

Dated ____________________, at San Francisco, California.

ORDER

IT IS ORDERED that:

1. In its next Energy Cost Adjustment Clause (ECAC) application, Pacific Gas and Electric Company (PG&E) shall provide information which reflects a specific study of the problems affecting its Geysers geothermal plants including a verifiable method for determining the likely yield from the Geysers during the next forecast period.

2. In its next ECAC application, PG&E shall report on the actual amount of time each of its fossil steam plants was out of service for every outage experienced during the 12-month period prior to the application and the specific reason for each outage.

3. In its next ECAC filing, PG&E shall provide the results of a study on the use of the Dispatcher Risk Aversion modeling convention that, at a minimum, satisfies the requirements set forth in this decision.

4. PG&E's next ECAC application shall be supported by an ELFIN run, whether or not ELFIN is the model chosen by PG&E for its preferred case. At the time of its filing, PG&E shall be prepared to work with Division of Ratepayer Advocates (DRA) in interpreting the ELFIN run and to provide DRA with a complete explanation of the modeling conventions employed to make the ELFIN run comparable to that of any other model used.

5. In future ECAC proceedings, PG&E should present updated hydroelectric forecast information based on its June snow survey as that information becomes available.

6. PG&E is authorized to increase its ECAC revenue requirement by $613,855; to increase its Annual Energy Rate (AER) revenue requirement by $26,479,000; and to decrease its Electric Revenue Adjustment Mechanism revenue requirement by $368,286,000.

<u>O R D E R</u>

IT IS ORDERED that:

1. In its next Energy Cost Adjustment Clause (ECAC) application, Pacific Gas and Electric Company (PG&E) shall provide information which reflects a specific study of the problems affecting its Geysers geothermal plants including a verifiable method for determining the likely yield from the Geysers during the next forecast period.

2. In its next ECAC application, PG&E shall report on the actual amount of time each of its fossil steam plants was out of service for every outage experienced during 1986 and 1989 and the specific reason for each outage.

3. In its next ECAC filing, PG&E shall provide the results of a study on the use of the Dispatcher Risk Aversion modeling convention that, at a minimum, satisfies the requirements set forth in this decision.

4. PG&E's next ECAC application shall be supported by an ELFIN run, whether or not ELFIN is the model chosen by PG&E for its preferred case. At the time of its filing, PG&E shall be prepared to work with Division of Ratepayer Advocates (DRA) in interpreting the ELFIN run and to provide DRA with a complete explanation of the modeling conventions employed to make the ELFIN run comparable to that of any other model used.

5. In future ECAC proceedings, PG&E should present updated hydroelectric forecast information based on its June snow survey as that information becomes available.

6. PG&E is authorized to increase its ECAC revenue requirement by $613,855; to increase its Annual Energy Rate (AER) revenue requirement by $26,479,000; and to decrease its Electric Revenue Adjustment Mechanism revenue requirement by $368,286,000. costs in the general steam rate). These costs represent $585,000

APPENDIX B
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List of Appearances

Applicant: Robert B. McLennan, Attorney at Law, for Pacific Gas and Electric Company.

Interested Parties: C. Hayden Ames, Attorney at Law, for Chickering & Gregory; Jackson, Tufts, Cole & Black, by William H. Booth and Joseph S. Faber, Attorneys at Law, for California Large Energy Consumers Association; Morrison & Foerster, by Jerry R. Bloom, Attorney at Law, for California Cogeneration Council; Matthew V. Brady, for California Department of General Services; David Branchcomb, for Henwood Energy Services, Inc.; McCracken, Byers & Martin, by David J. Byers, Attorney at Law, for California City-County Street Light Association; Brobeck, Phleger & Harrison, by Gordon E. Davis, Attorney at Law, for California Manufacturers Association; Karen Edson, for KKE & Associates; Michel P. Florio and Joel R. Singer, Attorneys at Law, for Toward Utility Rate Normalization (TURN); Norman Furuta, Attorney at Law, for Federal Executive Agencies; Steven Geringer, Attorney at Law, for California Farm Bureau Federation; Dian M. Grueneich, Attorney at Law, for California Department of General Services; Hanna & Morton, by Douglas K. Kerner, Attorney at Law, for Santa Fe Geothermal, Inc., Unocal Corporation, Freeport-McMoRan Resource Partners; Joseph G. Meyer, for Joseph Meyer Associates; Jeff Nahigian, for JBS Energy Inc.; John D. Quinley, for Cogeneration Service Bureau; Kathi Robertson, for Simpson Paper Company; Chester/Schmidt Consultants, by Reed V. Schmidt, for County of Marin and City of Bakersfield; Jan Smutny-Jones, Attorney at Law, for Independent Energy Producers; Downey, Brand, Seymour & Rohwer, by Philip A. Stohr, Attorney at Law, for Industrial Users; Nancy Thompson, for Barakat, Howard & Chamberlain; John Vickland, Attorney at Law, by Alice Loo, for Bay Area Rapid Transit; Philip J. DiVirgilio, for PSE Inc.; Richard B. Weisenmiller, for Morse, Richard, Weisenmiller & Associates, Inc.; Don Salow, for Association of California Water Agencies; Armour, St. John, Wilcox, Goodin & Schlotz, by James D. Squeri, Attorney at Law, for Kelco Division of Merck; Richard O. Baish, Michael D. Ferguson, and Randolph L. Wu, Attorneys at Law, by Phyllis Huckabee, for El Paso Natural Gas Company; Hanna & Morton, by Douglas K. Kerner, Attorney at Law, for Geothermal Resources Association and Independent Energy Producers Association; Thomas P. Corr, Attorney at Law, for Independent Power Corporation; Wayne Meeks, for Simpson Paper/Investment Company; Selby Mohr, for Sacramento Municipal Utility District;