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ORIGINAL

Decision 88 11 052 NOV 23 1988

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of PACIFIC GAS AND ELECTRIC COMPANY for Commission order finding that PG&E's gas and electric operations during the reasonableness review period from February 1, 1987 to January 31, 1988, were prudent.	Application 88-04-020 (Filed April 7, 1988)
Application of PACIFIC GAS AND ELECTRIC COMPANY for authority to adjust its electric rates effective August 1, 1988.	Application 88-04-057 (Filed April 21, 1988)

(See Appendix A for appearances.)

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OPINION

I. Background

A. Procedural History

Pacific Gas and Electric Company (PG&E) filed Application (A.) 88-04-020 and A.88-04-057 on April 7 and 21, 1988. A.88-04-057, which is the subject of this decision, requested an increase of $129.3 million to PG&E's electric rates on an annualized basis effective August 1, 1988. This requested increase of approximately 2.6% above present rate levels was based on revenue requirement increases related to PG&E's Energy Cost Adjustment Clause (ECAC), Annual Energy Rate (AER), Electric Revenue Adjustment Mechanism (ERAM), and Diablo Canyon Adjustment Clause (DCAC). During hearings, PG&E added a request to reflect an adjustment related to its Conservation Financing Adjustment (CFA).

In A.88-04-057, PG&E also asked the Commission to establish a balancing account for the recovery of costs incurred in connection with deferring the operation of qualifying facilities (QFs). However, PG&E later withdrew this request (Tr. 15:1525).

In A.88-04-020, PG&E sought approval of the reasonableness of its gas and electric operations during the period from February 1, 1987, through January 31, 1988. The two applications were consolidated and the proceeding was divided into two phases by order of the Administrative Law Judge (ALJ) at the prehearing conference of May 12, 1988, as stated in the ALJ's ruling of May 26, 1988. The first phase was to consider those issues relating to the forecasts of fuel costs, resource mix, and variable payments to QFs. The second phase, to be heard following the issuance of the forecast decision, will address the reasonableness of PG&E's operations. This opinion decides only the first phase issues.

The evidence presented at the hearings during the forecast phase resulted in various adjustments to PG&E's requested rate increase. In its brief of September 19, 1988, PG&E states that its final proposed annual revenue increase is $64.5 million. The components of this request are an ECAC increase of $271.4 million, an AER increase of $18.4 million, an ERAM decrease of $201.6 million, a DCAC decrease of $14.1 million, and a CFA decrease of $9.6 million.

On May 16, 1988, PG&E filed a motion to suspend the AER mechanism and to recover the difference between AER revenues and AER expenses in the ECAC balancing account until the date of any rate revision resulting from this proceeding. We granted the relief requested by PG&E in Decision (D.) 88-09-036. In today's decision we affirm our intent to reinstate the AER when new rates become effective.

Twenty-one days of hearings in the forecast phase of this proceeding were held between June 27 and September 1, 1988, in San Francisco, California. This matter was submitted on the filing of concurrent opening briefs on September 19, 1988, and concurrent reply briefs on September 26, 1988. The parties filing briefs in this proceeding included PG&E; the Commission's Division of Ratepayer Advocates (DRA); the California Cogeneration Council, Independent Energy Producers, and Midset Cogeneration Company (CCC); the Federal Executive Agencies (FEA); the California Manufacturers Association (CMA); the California Large Energy Consumers Association (CLECA); Toward Utility Rate Normalization (TURN); Santa Fe Geothermal, Inc., Unocal Corporation, and Freeport-McMoRan Resource Partners (Santa Fe); Independent Power Corporation (IPC); San Francisco Bay Area Rapid Transit District (BART); Contra Costa County (Contra Costa); the California Department of General Services (DGS); and the California Farm Bureau Federation (Farm Bureau). In addition, on August 31, 1988, the Association of California Water Agencies (ACWA) submitted a letter to the ALJ which described its position on some of the issues in this case.

The procedures of Public Utilities Code § 311(d) were followed in developing this decision. The ALJ's proposed decision was issued on October 24, 1988. PG&E, DRA, CCC, Santa Fe, TURN, DGS, IPC, and Energy Management Associates, Inc. filed comments on the proposed decision.

We have reviewed and carefully considered the comments. We have incorporated appropriate changes from these comments in this decision.

B. <u>The Framing of the Issues</u>

In recent years, the focus and purpose of an ECAC proceeding has been to enable 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. PG&E's current ECAC continues the consideration of these ECAC-related issues. In addition, this proceeding marks the beginning of annual updating in ECAC cases of key components of the calculation of prices paid for power sold to the utility by QFs.

Variable QF prices are the sum of two basic components: a variable payment for capacity and a variable payment for energy. Critical to the determination of these payments are the utility's Energy Reliability Index (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 this case, consideration of the ERI was simplified by the fact that we have not yet approved a method for calculating PG&E's ERI, and the parties differed only on when a previously adopted capacity payment value should be revised.

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 price the utility pays for the variably priced QFs' energy.

These QF issues have been added to the ECAC as a result of D.88-03-026 in the continuing standard offer proceeding, A.82-04-44, et al. In that decision, we concluded that annual updating of variable QF payments should take place in a utility's ECAC proceeding. We reasoned that it was preferable "not to create a unique proceeding for QFs [for this purpose], but rather to make optimal use of ECAC by setting QF prices at the same time (and from the same assumptions) that we adjust utility rates." (D.88-03-026, at p. 3.)

Logic links conventional ECAC issues with 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.

To smooth the introduction of ERI- and IER-related issues and the computer models used to derive them into the Commission's periodic proceedings, the Commission in D.87-12-066 (the decision in the test year 1988 general rate case of Southern California Edison Company (Edison)) adopted a procedure to be followed in developing and presenting testimony related to the IER and ERI. The purpose of this procedure was to ensure the full exchange and understanding of models and data used to develop the IER and ERI.

Specifically, the Commission required that all parties to future 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 Edison's 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 which Edison 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.

The workshop procedure set up for Edison's ECAC was also followed in this case. On April 6, 1988, the CACD noticed a workshop to develop common data set assumptions for ELFIN computer model runs to be used in this proceeding. The workshops were held on May 2, 3, and 19, 1988, with Linda Gustafson of the CACD serving as arbiter. On June 29, 1988, the common data set for a base case ELFIN run to which the workshop participants had agreed was served on all parties by the CACD.

Developments soon overcame the schedule the Commission set up in D.87-12-066, however. Around the time of the May workshops, ELFIN was revised, and the new version, known as ELFIN 1.6, was quickly adopted by those parties using the ELFIN model. The base case run using the common data set, which employed the old version known as ELFIN 1.58, proved to be of little use in these circumstances.

In addition, three different production cost models were advocated and used by parties in this case, adding to the complexity of the issues. DRA and CCC used ELFIN 1.6, the new version. CCC also used PROMOD in its analyses, and PG&E used PROMOD as its preferred model. Santa Fe used PROSYM, another new model. 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 with some random elements to develop its forecast of the system's operation.

In response to these circumstances, the ALJ divided the forecast phase into two parts, roughly corresponding to the inputs and outputs of the models. The first part addressed what was described as the "initial determination of the issues needed to perform a more refined run on the various computer models" or the "resource plan input assumptions." At the conclusion of this part, the ALJ received short briefs on these issues and prepared a ruling of August 5, 1988, which directed the parties to use a specified set of assumptions in runs of the three models. This was an attempt to provide a common basis for comparison of the models based on assumptions that reflected the hearing record and in place of the outdated ELFIN 1.58 base run. The second part of the hearing considered the results of the runs using the assumptions from the ALJ's ruling, the parties' recommended IERs, revenue requirements, revenue allocation, and positions on the few rate design issues.

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 used in determining variable QF payments. The issues also included the allocation of any revenue changes resulting from this proceeding, and rate design "necessary to deal with current problems" for agricultural and residential time-of-use rates, as directed in D.88-01-016.

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. Then we will consider the differences between the three production cost models that were used in this proceeding. For reasons described in this decision, we will defer our consideration of the revenue allocation and rate design issues until a later decision.

II. Load Forecast

Many of the issues in this category were common issues in past ECAC cases. Because PG&E presented a complete description of its position on many of these issues in the testimony accompanying its application, other parties tended to describe their positions by referring to or adjusting PG&E's initial recommendations.

In addition, many of the issues in this area were influenced by two important factors. First, PG&E's initial sales figures were based on an economic forecast that weighed optimistic economic forecasts against more pessimistic forecasts to develop what PG&E believed was the most probable outcome. By the time of the hearings, economic forecasts were more consistently optimistic; DRA's forecasts, for example, were based on an undiluted optimistic forecast of economic activity.

Second, PG&E's initial filing contained recommendations based on its March snow survey of its potential for producing power from its hydroelectric units. However, PG&E was able to present the results of its June survey as part of the record in this case (Ex. 41). The forecast for hydropower primarily affects the outlook for PG&E's hydroelectric resources, but it also influences the hydroelectric production from some of PG&E's public agency customers. To the extent that these customers are unable to produce power from their hydroelectric facilities, PG&E's sales to these customers will increase.

PG&E's large service territory surrounds several utilities operated by public entities. Because of interconnections among the utilities, power flows freely and ignores service territory boundaries. In forecasting PG&E's load, it is also necessary to consider the load and resources of some of these other entities to derive PG&E's net load or sales resulting from exchanges with these utilities.

In the final briefs, most of the parties expressed their satisfaction with most of the elements of the load forecast assumptions of the ALJ's August 5 ruling. We will briefly set out the rationale supporting those elements, and will address the remaining contested issues more thoroughly.

A. Residential Sales

We will adopt DRA's recommendation of 22,485 gigawatt-hours (gWh), which reflects a more recent and more optimistic economic forecast.

B. Small Light and Power Sales

DRA's forecast of 7,171 gWh, reflecting its optimistic economic forecast, will be adopted.

C. Medium Light and Power Sales

DRA's recommendation was independently derived because PG&E's approach underforecasted actual sales through March 1988. We will adopt DRA's figure of 16,096 gWh.

D. Large Light and Power Sales

Sales to the industrial customers PG&E shares with the City and County of San Francisco (CCSF) are forecasted to be 603 gWh. When CCSF's hydroelectric facilities are unable to generate as much power as in normal years, PG&E will sell more power to the shared customers. The adopted figure was advocated by TURN and reflects the effect of the current drought on these sales.

The forecast of sales to other large light and power customers of 14,803 gWh is based on the optimistic economic forecast.

The resulting total sales figure is 15,406 gWh.

E. Agricultural Sales

DRA noted that PG&E's forecasting approach had underforecasted actual agricultural sales by 20.5% for the six months ending March 1988. DRA therefore developed an independent, econometrically derived forecast of these sales. We will adopt the resulting recommendation of 3,192 gWh.

TURN argued that 13 gWh should be added to DRA's forecast to reflect the effect of the drought. TURN's original adjustment reflected both adjustments to agricultural rates and drought effects. The rate aspect has become moot, but most of TURN's written and oral testimony focused on these price effects. TURN's reference to use of PG&E's and DRA's agricultural price forecasting models leaves unclear the basis for its drought recommendation. In light of the ambiguous state of the record and the small level of TURN's recommended adjustment, we decline to adopt TURN's adjustment.

F. Street Lighting

DRA's independently derived estimate of 355 gWh is more in line with recent sales trends than PG&E's estimate and will be adopted.

G. Railway and Public Authority

PG&E's estimates of 249 gWh for railway sales and 757 gWh for public authority sales were uncontested.

H. Resale

The sales for resale category has two components.

First are the sales to the Modesto Irrigation District and the Turlock Irrigation District (MID/TID). TURN argues that the figures presented by PG&E and accepted by DRA should be increased by 198 gWh to reflect the effect of the drought. MID/TID's own hydroelectric units will produce less electricity in this drought year, and therefore these entities must purchase more power from PG&E. TURN reasons from information presented by TID and some indirect facts to develop its estimate.

All parties seem to agree that the drought will tend to increase sales to MID/TID, but TURN's method of developing an estimate of those increased sales presents problems. TURN has made a clever, if somewhat rough, use of available information, but its estimate assumes that all of MID/TID's shortfall will be purchased from PG&E and that these entities have no other sources of power to make up the hydroelectric shortfall. This assumption is contradicted, however, in TURN's own testimony. TURN's Ex. 30, which developed an earlier estimate, assumed that only some of the shortfall would be made up by PG&E. No clarification of this apparent contradiction about a key assumption appears elsewhere in the record.

Despite the cloudy state of the record, we will adopt TURN's proposed adjustment. Neither the cross-examination nor the briefs of other parties challenged these assumptions or pointed out the contradiction in TURN's testimony. We will take this silence as evidence that the assumptions underlying TURN's estimate are roughly correct. Thus, we will increase the sales to MID/TID by 198 gWh, spread out over August through December 1988. The revised sales to MID/TID total 573 gWh.

An adjustment must also be made to PG&E's base forecast of sales for resale to other customers. The results of the June snow survey (Ex. 41) show that production from CCSF's hydroelectric units will be 198 gWh less than previously forecasted. Because of this lower production, sales to CCSF should also increase by 198 gWh. (This 198 gWh adjustment is separate from the 198 gWh adjustment discussed in the preceding paragraphs.) PG&E agreed with this adjustment (Tr. 16:1692-1693). Although the oral stipulation stated that this increase should be added to sales to MID/TID, other evidence indicates that an adjustment to sales to CCSF is correct (see Ex. 62). The net effect is the same in either case, and we will treat this as an increase in sales to CCSF for resale. A compensating reduction will be made in the Other Area Load line. When this 198 gWh is added to the uncontested base forecast of 604 gWh, the revised total for other sales for resale is 802 gWh.

The total sales for resale amount is 1,375 gWh.

I. Interdepartmental Sales

PG&E's estimate of 150 gWh was uncontested and will be adopted.

J. Total PG&E Sales

The total resulting from our adopted figures is 67,236 gWh.

K. SMUD Sales

Sales by the Sacramento Municipal Utility District (SMUD) to its customers are estimated by SMUD to be 8,084 gWh. We will adopt this figure rather than the estimate resulting from PG&E's independent analysis because we believe that SMUD is more likely to have an accurate assessment of its own needs.

L. Lost and Unaccounted for Power

Lost and unaccounted for power (LUAF) varies with the amount of sales. The exact figure must be calculated from the total sales we have adopted. DRA's approach to calculating LUAF showed a better statistical reliability than PG&E's, and DRA's method should be used to develop the appropriate estimate of LUAF. Applying DRA's method to the estimates of sales that we have adopted results in forecasted LUAF of 7,062 gWh.

M. Other Area Load

Two adjustments should be made to PG&E's initial estimates of Other Area Load.

First, the total should be decreased to reflect 121 gWh of increased sales to the industrial customers that PG&E shares with CCSF, as mentioned in the discussion of sales to large light and power customers.

Second, the total should reduced by 198 gWh to compensate for the increased sales that result from CCSF's decreased hydroelectric generation, as discussed in the section on sales for resale.

The resulting total for Other Area Load is 9,226 gWh.

N. Total Area Load

The estimate of Total Area Load resulting from the preceding figures is 91,608 gWh.

O. Deliveries Out of Area

The filed testimony contained an error that remained undetected until after the ALJ's ruling of August 5. All parties now agree that the correct estimate for deliveries out of area should be increased, although slight differences remain in what the parties view as the correct figure. We will adopt 196.8 gWh (rounded to 197 gWh for purposes of this decision) as the estimate for deliveries out of area. (See Ex. 50; Tr. 17: 1852-1856.)

P. Total Planning Load

The sum of all the above components is a total planning load of 91,805 gWh. Table 1 summarizes our conclusions on this topic.

TABLE 1

Sales Forecast Assumptions

Class of Service		Amount in Gigawatt-hours
Residential		22,485
Small Light & Power		7,171
Medium Light & Power		16,096
Large Light & Power:		15,406
CCSF	603	
Other	14,803	
Agriculture		3,192
Street Lighting		355
Railway		249
Public Authority		757
Resale:		1,375
MID/TID	573	
Other	802	
Interdepartmental		150
TOTAL PG&E SALES		67,236
SMUD		8,084
LUAF		7,062
Other Area Load		9,226
TOTAL AREA LOAD		91,608
Deliveries Out of Area		197
TOTAL PLANNING LOAD		91,805

III. Resources

A. Hydroelectric Generation

The estimate of hydroelectric generation developed from the June 1 snow survey (Ex. 41) was accepted by all parties. We will adopt the estimate of 21,007 gWh for hydroelectric generation, including hydroelectric QFs, and the associated costs of $3,767,000 for PG&E's facilities, and $47,065,000 for the irrigation districts' generation.

B. Geothermal Generation

1. PG&E's Plants

a. Amount of Generation

PG&E originally estimated that a capacity factor of 74% was reasonable for the forecast period. This capacity factor was considerably reduced from recent years' experience. Beginning last year, however, 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, and its estimates reflect this expectation.

DRA forecast a capacity factor of 87.1%. DRA rejects PG&E's fears about the steam curtailments, and points out that PG&E's claims of confidentiality have prevented DRA from adequately investigating the basis for the steam curtailments. DRA contends that PG&E acknowledged that removal of the steam curtailments would increase the Geysers' capacity factor to more than DRA's recommendation.

The issue of how much consideration to give to the steam reservoir problems is central to developing a forecast of geothermal generation. PG&E expects the steam-related curtailments to increase during the forecast period; DRA expects them to cease. The short history of these reservoir problems provides little basis for evaluating these competing assertions.

From the start of these problems in February 1987 through December 1987, steam-related curtailments amounted to 598,965 megawatt-hours (MWh). For the 12-month forecast period, PG&E projects that curtailments related to insufficient steam will be 1,749,096, a considerable increase (Ex. 26). PG&E acknowledged that this figure was somewhat based on guesswork, and we are not persuaded that there is a reasonable basis for accepting PG&E's estimate. However, in light of recent experience with the steam curtailments, we are also skeptical that the problem will cease, as DRA has assumed.

We will develop a capacity factor which reflects recent experience with the steam curtailments. PG&E's witness testified that curtailments due to insufficient steam from January through May 1988 added up to 353,947 MWh. If we project this level of curtailment for a 12-month period, the result is 849,473 MWh per year. If we use this level of curtailments due to insufficient steam and the same estimates of period hours, scheduled outages, and forced outages used by PG&E (Ex. 26, p. 5), the result is a capacity factor of 81.4%. This capacity factor provides a reasonable estimate of geothermal generation, and neither overemphasizes nor ignores the steam reservoir problems.

We will therefore adopt an overall capacity factor of 81.4% for PG&E's geothermal units. This capacity factor results in generation of 9734.8 gWh (Ex. 50, p. 2; Ex. 59, p. 8.). Better information on the status of the steam reservoir and any trend in curtailments due to insufficient steam should be available by the time of the next forecast proceeding.

b. Price

The price of steam for generation of geothermal energy for 1988 is based on recorded 1987 data and is fixed at 14.93 mills/kWh for all of 1988. The price for 1989 will depend on the assumed level of conventional steam generation and nuclear generation for 1988 and will depend on the resolution of these issues for forecast purposes. PG&E estimated that the assumption contained in the ALJ's ruling of August 5 resulted in a 1989 price for geothermal steam of 15.16 mills/kWh. Since the assumptions we adopt differ from those contained in the ALJ's ruling, the 1989 price for geothermal steam will have to be recalculated. Parties should report the results of their calculations in their comments on the proposed decision.

2. <u>Other Geothermal Generation</u>

SMUD, the Northern California Power Agency (NCPA), and the Central California Power Agency (CCPA) operate geothermal units. The generation from these units is not sold directly to PG&E, but it is available to meet area load. No party contested PG&E's estimates of the availability of geothermal energy from these units. Based on recorded 1986 and 1987 data, PG&E estimated that SMUD's units' availability of generation would be 100% of capacity before scheduled maintenance and that NCPA and CCPA's units' availability of generation would be 96.1% of capacity before scheduled maintenance. We will adopt these estimates.

C. <u>Nuclear Generation</u>

1. <u>Diablo Canyon</u>

a. <u>Amount of Generation</u>

(1) <u>Position of the Parties</u>

PG&E originally recommended an operating capacity factor (capacity factor before accounting for any refueling outage and scheduled maintenance) of 78%, with a 12-week refueling outage for Unit 2 beginning September 15, 1988. This capacity factor was above the national average for similar plants and was consistent with Diablo Canyon's history, according to PG&E.

DRA forecasted an operating capacity factor of 86%, with a 12-week refueling outage for Unit 2. DRA based its position on the annual operating capacity factors that the Diablo Canyon units had achieved in the past, ranging from 84% to 91.5%. In addition, DRA argued that PG&E had historically underforecasted the performance of the Diablo Canyon units. Furthermore, national averages show an increase of 3.6% in the operating capacity factor between nuclear plants' first fuel cycle and second cycle. DRA's estimates are in line with these trends, according to DRA.

CCC advocates an operating capacity factor of 75.2% for the Diablo Canyon plant. According to CCC, the Commission has ruled in D.86-07-004 that when five years of a plant's operating data are not available, the forecast should be based on the industry's average performance. Since Diablo Canyon has operated for only three years, this estimating technique should be followed. The second-cycle average operating capacity factors of comparable units is 75.2%, and CCC argues that this figure should be adopted for Diablo Canyon.

Santa Fe supports PG&E's proposed 78% operating capacity factor as being similar to historical operating records. However, Santa Fe argues that the 12-week refueling outage for Unit 2 is unreasonably short and that a 14-week outage better reflects PG&E's experience with the Diablo Canyon units. Santa Fe points out that all refueling outages to date for Diablo Canyon have taken more than 12 weeks and that the average refueling outage for the industry is 14 weeks. Santa Fe concludes that the forecast should be consistent with that history. Thus, Santa Fe's recommended cycle capacity factor would be somewhat lower than PG&E's.

TURN notes, apparently without making a recommendation, that the capacity factor and refueling outage adopted in the ALJ's ruling exceeds the assumed capacity factor underlying the proposed Diablo Canyon settlement. TURN argues that the adopted 12-week refueling outage is shorter than both the experience at Diablo Canyon and the industry's average. TURN therefore supports Santa Fe's recommendation of a 14-week refueling outage.

(2) Discussion

The variety of the parties' positions on this issue arises from their emphases in trying to accommodate two facts of Diablo Canyon's brief operating history: its high operating capacity factor and its long refueling outages. DRA, for example, emphasizes the high annual operating capacity factors that the Diablo Canyon units have recorded so far. Table 2 sets out these annual operating capacity factors for each unit.

TABLE 2

Annual Operating Capacity Factors
Diablo Canyon

Year	Unit 1	Unit 2
1985	86.1%	
1986	85.0%	84.0%
1987	91.5%	84.7%

These operating capacity factors are much higher than the average for comparable units of 75.2% that CCC argues should be adopted.

Santa Fe, now supported by TURN, emphasizes the length of the refueling outages to date and argues that a 14-week refueling outage should be assumed for the refueling of Unit 2 scheduled for Fall 1988.

The problem with both of these emphases is that they ignore the link between long refueling outages and high operating capacity factors. PG&E's witnesses testified that maintenance is performed during the refueling outages and that this maintenance reduces forced outages (Tr. 12:1209-1210). This assertion is supported by the high operating capacity factors achieved by the Diablo Canyon units so far.

None of the parties' approaches successfully reconciles these considerations. DRA's approach combines high historical operating capacity factors but ignores the long refueling outages that helped sustain the plants' operation. CCC uses industry averages, but does not consider that the history of this plant has been anything but typical. PG&E developed its estimate by increasing its previous forecast somewhat but neglected to compare that earlier forecast to the plant's actual operation. Santa Fe would lengthen the refueling outage but soft-pedal the high plant performance recorded so far.

For forecasting purposes, we prefer to retain the 12-week refueling outage. Twelve weeks is the expected or target time for completion of refueling, and the units are designed to allow this target to be met. The 12-week estimate already provides two weeks above the 10-week optimum refueling time to allow for contingencies that may arise (Tr. 12:1200). To build in an additional two weeks, even though it may be supported by the brief history of the Diablo Canyon units, would amount to a forecast that greater-than-normal problems will arise during the refueling of Unit 2. In light of the fact that the average second-cycle refueling outage in the industry is just slightly less than 12 weeks (Ex. 35), we are unwilling to forecast unusual problems for the coming refueling.

Retaining the 12-week refueling outage, however, requires us to take into account the maintenance that PG&E claims was performed during the longer outages to date. The record provides a basis for resolving this problem by considering the full cycle capacity factors of the units.

The full cycle capacity factor 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. 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.

The full cycle capacity factor provides a desirable flexibility in forecasting generation from the Diablo Canyon units. For example, if the refueling outage is longer than forecasted but maintenance outages are shorter than the outages implied in the full cycle capacity factor, the forecasted generation would remain reasonably accurate.

Use of the full cycle capacity factor also moderates the extremes of Diablo Canyon's performance to date. So far, Diablo Canyon's operating capacity factors have been much higher than the average for the industry or for comparable units. Similarly, the lengths of its refueling outages have been greater than average. But the full cycle capacity factors recorded in the first few cycles are closer to the performance expected of such units and show considerable stability. For the first cycle, the full cycle capacity factor was 67.9% for Unit 1 and 66.2% for Unit 2, and Unit 1's second cycle capacity factor was slightly lower (Ex. 35; Tr. 12: 1192, 1204). From these figures, we conclude that a full cycle capacity factor of 67% is reasonable to expect from the Diablo Canyon units.

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. The latter information was not presented in this case. However, a rough conversion to an expected operating capacity factor may be made by assuming a typical cycle of 18 months and a typical refueling outage of 12 weeks. Using these assumptions and the 67% cycle capacity we have found reasonable to use, we calculate a corresponding operational capacity factor of 79.1%. In light of Diablo Canyon's historical operation, and the tendency of units to improve capacity factor after their first cycle (see Ex. 19, p. 10-4), we believe that this estimate is a reasonable forecast of the generation that the Diablo units will produce during the forecast year.

When we apply this operating capacity factor to the ratings of the Diablo Canyon units and take into account the 12-week refueling outage we have adopted, the resulting predicted generation for the forecast period is 7,435 gWh for Unit 1 and 5,799 gWh for Unit 2, for a total of 13,234 gWh.

However, a slight adjustment must be made to these figures. PG&E testified without challenge that after refueling, the generation of a restarted unit is increased to full power gradually over two weeks. This ramp-up reduces the total generation slightly, by approximately 146 gWh (Tr. 15:1529; Ex.50). Although the full cycle capacity factors we have relied on would ordinarily take this ramp-up into account, the first cycle is measured from commercial operation date and begins with the capability to operate at full power. Because of our reliance on the full cycle capacity factors from the first cycles, it is appropriate to account for the ramp-up in the generation expected from Unit 2, which will be refueled during the forecast period. Accordingly we will subtract 146 gWh from the expected generation of Unit 2, for a total of 5,653 gWh from Unit 2 and 13,088 gWh from both units.

We note that the actual generation during the reasonableness period of February 1, 1987 through January 31, 1988, which included the first refueling of Unit 2, totaled 8,607 gWh for Unit 1 and 5,755 gWh for Unit 2, a total of 14,362 gWh (Tr. 12:1197-1198). Even after taking into account the extraordinary operating capacity factor achieved by Unit 1 during 1987, we believe that our adopted forecast of generation is reasonable.

The 67% full cycle capacity factor that underlies our estimates is considerably higher than the capacity factor of about 58% that parties have used to calculate an equivalent disallowance to the proposed settlement in the Diablo Canyon case

(A.84-06-014, A.85-08-025). However, the capacity factor used in this case is the forecasted performance for only one year. The proposed Diablo Canyon settlement covers the full life of the plant, roughly 30 years. In addition, the particular year covered by our forecast occurs early in the plant's life, when higher capacity factors are typical and expected. Thus, we see no contradiction between our forecast in this case and the proposed settlement in the Diablo Canyon case.

b. <u>Nuclear Fuel Cost</u>

PG&E's method for calculating the nuclear fuel revenue requirement was uncontested and will be adopted. The estimates in the record suggest that the nuclear fuel revenue requirement associated with our adopted level of generation from the Diablo Canyon plant will be about $100 million. (See Ex. 1, p. 5-13, Ex. 62.)

2. <u>Rancho Seco</u>

SMUD voters on June 7, 1988, approved a ballot measure that permits Rancho Seco to operate for an 18-month fuel cycle. PG&E's original estimate was adopted with certain modifications proposed by Santa Fe in the August 5 ALJ ruling, and most parties now support that estimate.

We believe that the estimate of generation from the August 5 ruling is reasonable. That estimate assumes that the plant will operate at a 65% operating capacity factor during power ascension and after full power is achieved. Full power is assumed to be reached in November 1988. The 65% operating capacity factor converts to a cycle capacity factor of 53.6%, which approximates the historic cycle capacity factor of 52.8% for nuclear plants of similar design (Ex. 8).

CCC continues to argue for a 41% capacity factor based on historical performance of the plant. However, the plant has undergone extensive modifications under intensive scrutiny by the Nuclear Regulatory Commission since that historic record was established, and better performance may reasonably be expected as a result of the modifications. In addition, the recent ballot measure requires SMUD's Board of Directors to shut the plant down if the monthly capacity factor falls below 50% for four consecutive months (see Ex. 25, Attach. M). This provision creates an incentive to maintain a high capacity factor.

We agree, however, that the most likely prospects for the plant are that it will either operate near the level we have forecasted or that it will be shut down entirely. To take this latter possibility into account, we will calculate an alternate IER which assumes that Rancho Seco is not in service during the forecast period and we will permit payments to QFs to incorporate this alternate IER if Rancho Seco is in fact shut down by SMUD's Board of Directors during the forecast period.

The estimate of generation resulting from the adopted assumptions is 4735.7 gWh. However, under certain circumstances, power from Rancho Seco could be backed down. Thus, the amount of generation that the models attribute to Rancho Seco could be somewhat smaller than this figure.

D. Qualifying Facilities' Generation

Except for a few issues, the parties now accept the determinations made in the August 5 ALJ's ruling. We will briefly discuss the bases of those determinations and the remaining disputed issues.

1. Generation by Wind QFs

PG&E developed its recommendation by using historical capacity factors of wind QFs to estimate generation by projects that were not yet in operation, rather than relying on the estimates of the projects' developers. The resulting estimate of 1045.0 gWh is reasonable and will be adopted. DRA's criticisms appeared to misunderstand PG&E's approach.

2. Generation by Hydroelectric QFs

PG&E's original estimate used a built-in delay to estimate the on-line dates of projects under construction. The delay was derived from the observed lag between the developers' estimates of on-line dates and actual on-line dates achieved by hydroelectric QFs. Other parties proposed adjustments to individual projects based on information obtained from the specific project's developer.

We prefer PG&E's general approach because it eliminates the need for every party who is concerned with this estimate to contact each developer whose project has not yet come on-line. In addition, any information presented about the status of specific projects will be difficult to verify at the hearings. PG&E's approach should shift the focus of dispute from the status of many individual projects to the accuracy of the delay factor, a simpler issue to address in our proceedings. So long as PG&E's approach leads to reasonably accurate results, we favor developing estimates derived from this method.

Making the individual adjustments for delays in specific projects is inconsistent with PG&E's approach, which uses an average delay. Even if it is shown that a particular project will be delayed beyond the average delay, that specific delay should not be taken into account in developing the overall estimate, since other projects may come on-line with less than the average delay. If the average is accurate, the individual variances should balance out without affecting the accuracy of the overall estimate.

PG&E revised its original approach in Exhibit 41 to reflect the results of the June 1 snow survey. The expected generation by hydroelectric QFs during the forecast year, according to Exhibit 41, is 460 gWh. However, in Exhibit 7, PG&E accepted several adjustments proposed by DRA. Among those was the removal of a hydroelectric project that had lost the required license from the Federal Energy Regulatory Commission (FERC). Removal of that project from the estimate reduces the forecasted generation to 458.7 gWh.

After the issuance of the ALJ's ruling, PG&E reclassified the Sand Bar Powerhouse project to the hydroelectric QF category (Ex. 49, p.5). This change increases the total generation from hydroelectric QFs by 8.7 gWh. No party challenged this change.

We will adopt the resulting total of 467.4 gWh for generation from hydroelectric QFs.

3. Generation from Large Geothermal, Solar, and Small QFs

PG&E's initial estimates, as broken down by DRA in Exhibit 14, for generation from large geothermal and solar QFs were uncontested. We will adopt these estimates of 691.1 gWh from large geothermal QFs and 12.9 gWh from solar QFs.

In addition, PG&E and Santa Fe stipulated on the allocation of the generation from QFs smaller than 1 MWh in size between fixed- and variably priced energy (Tr. 12:1183-1184). Other parties have tacitly concurred in this stipulation, which allocates 32% to fixed-price energy and 68% to variably priced energy. This allocation was applied to PG&E's original estimate of generation from these small QFs of 107.3 gWh. (Exhibit 14, in which DRA summarized PG&E's recommendations, contained two slightly different figures for generation from small QFs. The ALJ ruling copied 107.9 gWh from one page. However, it appears that the proper number is 107.3 gWh, which appears in a table and in the text of Exhibit 14. This small difference appears to be overwhelmed by rounding in the models.)

4. Generation from Thermal QFs

DRA proposed several adjustments for individual projects to PG&E's original estimate of generation from the QFs of 9,412.6 gWh. PG&E accepted some of DRA's proposed adjustments (Ex. 7). The ALJ's ruling, as revised on August 10, endorsed PG&E's revised position.

The adjustments arose from a project that had terminated its contract with PG&E (6.9 gWh), double counting of the generation from a phased project (7.7 gWh), and confirmation that a project will use all of its generation internally and will not sell power to PG&E (34.0 gWh). PG&E has persuasively countered DRA's other proposed adjustments, and has confirmed that negotiations to defer the on-line date of a project were not successful.

Thus, we will adopt the revised figure of 9450.8 gWh for thermal QF generation. According to PG&E, the associated fixed-variable split is 3617.0 gWh fixed-priced energy and 5833.8 gWh variably priced energy (Ex. 49, p. 6).

5. Total Generation from QFs

The total generation from QFs is 11,774.5 gWh, as shown in Table 3.

TABLE 3

Generation from Qualifying Facilities

Wind	1,045.0 gWh
Hydro	467.4
Large Geothermal	691.1
Solar	12.9
Less than 1 MW	107.3
Thermal	9,450.8
Total	11,774.5 gWh

The parties vary slightly in their estimates of how much of this total should be allocated to variably priced energy. The variance appears to result from rounding within the models. CCC's and PG&E's estimates match, perhaps because they used the same model, and the rounding variances of the components appear to be somewhat less than the other models. We will adopt these parties' estimate of 6,992 gWh for the amount of variably priced energy. We recognize that the limitations of the models will not allow all runs to match this precise figure.

In addition, some QFs' contracts with PG&E allow PG&E to curtail their generation at times. This curtailment should occur in the models, as in PG&E's operation, at times that are most beneficial in reducing overall costs.

6. Price

No party disputed PG&E's general approach to calculating the cost of purchases from QFs, and, based on the ALJ's ruling, PG&E calculates the total cost of QFs' generation to be $716,784,000. However, the capacity price paid to QFs requires some discussion.

The theoretically correct price to pay QFs for their contribution to capacity is the product of the Energy Reliability Index (ERI), which is a measure of a utility's need for capacity, and the capacity cost a utility avoids by purchasing power from QFs for a specified period. For several years we have used the annualized cost of a combustion turbine as a measure of the capacity costs avoided in the short term. We have also determined that QFs who do not commit to provide capacity on a firm basis nevertheless allow the utility to avoid some capacity commitments because of the diversity and randomness of their energy contributions. We therefore have directed utilities to pay for this as-available capacity on a cents per kilowatt-hour basis.

Because of various difficulties we have had in calculating PG&E's short-term avoided capacity costs, we have previously adopted a value of $42/kW/year as the capacity price to be paid for as-available capacity through 1988 (D.88-03-079). All parties seem to agree that for purposes of forecasting revenue requirements, the current $42/kW/year should be used for the entire forecast period. We agree.

We have not yet approved a method for adjusting PG&E's ERI. Until such a method is adopted and approved, a precise calculation of the capacity price that theoretically should be paid to QFs is impossible. Although D.88-03-026 stated that ERIs were to be revised in the ECAC proceeding, that decision acknowledged that no method for calculating PG&E's ERI had been developed. A proposed adjustment method has been circulated (D.88-03-079), but no final determination of the appropriate method has been made at this time.

Because of this uncertain status, we will not adopt an ERI value for 1989. However, all parties should be aware that this question is being considered in A.82-04-44, and a decision in that proceeding could establish a level of capacity payments to as-available QFs that differs from the $42/kW/yr that we adopt for purposes of the forecast.

An additional aspect of payments to QFs concerns the treatment of avoided operations and maintenance (O&M) costs. This issue will be addressed in a later section of this decision.

E. Gas-fired Generation

Because PG&E's gas- and oil-fueled generation units are typically the most expensive resources, the precise amount of this generation is determined by the availability of cheaper resources. As the resource relied on to meet the residual need for power, oil- and gas-fueled generation is determined in the model runs, and the amount of generation becomes an output of the model. The total price of gas depends on the volume consumed, so calculation of this expense must also await the results of the model runs. Thus, we do not need to adopt specific figures for the amount of fossil-fuel generation or the total gas expense at this time.

Two issues related to gas-fired generation must be resolved, however, before the model runs can be performed.

1. Dispatch Price of Gas

DRA and PG&E developed a stipulation on the forecast of PG&E's utility electric generation (UEG) gas dispatch price for the forecast period (Ex. 45). No other party disputed this stipulation, and we will adopt the terms of the stipulation as the forecasted dispatch price of gas, as shown in Table 4.

TABLE 4

Forecast of PG&E UEG Dispatch Price

($/MMBtu at the Burnertip)

Average Monthly and Forecast Period Dispatch Price

1988

Aug.	Sept.	Oct.	Nov.	Dec.
1.940	1.940	1.952	1.974	2.323

1989

Jan.	Feb.	Mar.	Apr.	May	June	July
2.382	2.323	2.149	1.955	1.955	1.955	1.955

Average for Forecast Period = 2.067

2. Fuel Oil Inventory Requirement

DRA and PG&E developed different estimates of the required fuel inventory inventory levels. The difference centered on expectations of gas availability from the pipeline system of El Paso Natural Gas Company (El Paso).

PG&E argues that El Paso's desire to get out of the market as a gas seller has forced PG&E to rely more on spot gas supplies to meet its needs for gas. During particularly cold winters, when the fuel oil inventory provides insurance against curtailments of gas supply, PG&E believes that the shortfall in gas supplies will average 240 million cubic feet per day (MMcf/d). During a cold streak last winter, PG&E was repeatedly unsuccessful in getting as much gas as it needed, forcing it to burn oil from inventory. PG&E believes that these developments in the gas market support its recommended oil inventory of 6.9 million barrels.

DRA believes that PG&E has overstated the shortfalls that may reasonably be expected this winter. Although El Paso has reduced its firm supplies, the spot market has grown dramatically in the last few years, and PG&E has been and will be able to rely increasingly on the operation of that market. DRA predicts that the average shortfall if this is a cold winter would be 97 MMcf/d. DRA points out that PG&E has exaggerated the actual shortfall from last winter because it did not always request the maximum amount of gas that could be transported to it through El Paso's pipeline. When the amount actually delivered last winter is compared to the amounts PG&E requested, the shortfall was only 103 MMcf/d, which is very close to the figure underlying DRA's estimate.

In its brief, PG&E argues further that developments that led to the curtailment of gas in Southern California this summer add weight to its position that the operation of the spot market is not always sufficient to supply its gas needs in a cold winter.

The recent situation in Southern California demonstrated that under certain circumstances, gas shortages can arise even in summer months. However, many of these circumstances are not related to the situation that the fuel oil inventory is designed to remedy. Although the shortages seemed to result in part from the problems El Paso was having in securing gas supplies and transporting gas to California, we also determined in Investigation (I.) 88-08-052 that there were adequate supplies and capability on the El Paso system to deliver at least 100 MMBtu/d more to California than the assumed limit of the system.

The complexities of the Southern California problem do not necessarily support the conclusion that PG&E argues. Rather, they demonstrate that there is still considerable volatility in the gas market. But the immediate problem in this case is to forecast how that immature market will function in the event that this winter is a cold one.

When the question is framed in this fashion, we feel that the evidence most on point is the record from last winter. Although the presentation of the facts was somewhat confusing, the average shortfall in December and January of last winter was 103

MMcf/d (Ex. 33). This figure is very close to DRA's recommendation, which assumes an average shortfall of 97 MMcf/d, and we will adopt the fuel oil inventory resulting from that recommendation, 5.6 million barrels.

3. Oil Test Burns

It is not disputed that testing of some of PG&E's steam units requires oil test burns of 3,324 MMBtu, or 504,000 barrels. The expense of these burns totals $8.9 million. The volume of gas needed to meet the fossil generation requirement decreases by the 3,324 MMBtu of the oil test burns.

F. Power Purchases from the Southwest

The record on Southwest power purchases is completely jumbled, and the parties have provided us with little basis to understand, let alone decide, the differences in their positions. However, since this is a significant input to the models, we do not have the usual option of rejecting all testimony, and we will state our understanding of the way in which the components of these purchases should be modeled.

Up to 170 gWh of power is available during off-peak periods from the Western Systems Power Pool and other Southwest sources from coal-fired plants (Ex. 1, pp. 3-30; Ex. 49, p. 7). The price for this power is 15 mills/kWh. These purchases should not be modeled as peak-shaving resources, but this power may be backed down during periods of minimum load, consistent with the backdown order we discuss later in this decision.

The amount of purchases from the California Power Pool (CPP) will be determined by the model, subject to a capacity limitation of 200 MW (Ex. 49, p. 7). These purchases should be made whenever PG&E's incremental heat rate reaches 11,500 Btu/kWh (Ex. 48, Attachment, p. 5). These purchases may also be backed down during periods of minimum load. Offsetting these purchases are forecasted sales to the CPP of 60 gWh at 22.4 mills/kWh, based on records from 1987 (Ex. 1, pp. 3-30).

G. Other Purchased Power

Several components of this category were uncontested. Purchases from Sierra Pacific of 3.6 gWh at 1987 recorded costs and purchases from the Lewiston Powerhouse of the Western Area Power Administration (WAPA), also at 1987 recorded prices, were uncontested.

The largest component of this category is the purchases from the California Department of Water Resources (DWR). All parties agree that no purchases from DWR are expected before 1989, when normal water conditions are assumed to resume. In 1989, DWR purchases should be assumed to be at the same price as purchases from the Pacific Northwest. Purchases will be made only when it is economically advantageous to do so, and purchases from DWR may be backed down according to the backdown order discussed later in this decision.

A final element of the other purchased power category is the power supplied from PG&E's wind turbine in Solano County. The forecast amount of energy supplied by this turbine is 3.3 gWh. This amount of energy should be included in the resource mix. However, the costs of this power are in base rates and should not be included in the ECAC revenue requirement.

H. Purchases from the Pacific Northwest

This issue turned out to be one of the most significant and contentious issues in the case. Several background facts were undisputed, however.

The Northwest is one of PG&E's primary sources of cheap purchased power. However, the Northwest, like California, has received less rainfall than normal in recent years, and thus the availability of cheap power from the Northwest became an issue in this case.

The drought in California also had an effect on the need for power from the Northwest. Generally, PG&E will favor certain of its resources, such as in-state hydroelectric power and generation from Diablo Canyon, over purchases of Northwest power. The reduced amount of California hydroelectric generation assumed for 1988 means that there will be a greater need for purchases from the Northwest. However, all parties assume that normal precipitation patterns will resume in 1989, both reducing the need for Northwest purchases to some degree and increasing the availability of Northwest hydroelectric power.

The interaction between the supply of power available in the Northwest and PG&E's demand for Northwest power creates the different recommendations on the price that should be assumed for these purchases. The price, in turn, is used by the models to determine the amount of power that is forecasted to be purchased from the Northwest. Purchases from the Northwest are one of the largest contested influences on the IER.

1. Purchases in 1988

a. Availability

All parties concede that the drought in the Northwest will limit the availability of economy energy purchases from the Northwest through the end of the year.

PG&E forecasts that enough higher priced on-peak power will be available to fill its 1639 MW entitlement on the Pacific Intertie transmission lines during 1988. Off-peak availability will be limited to 50% of the entitlement, according to PG&E.

Santa Fe and CCC project that no economy energy from hydroelectric resources in the Northwest will be available in 1988, even when power from BC Hydro, the British Colombia power agency, is taken into account. Any power that may be available would command a higher price, as explained in the discussion of price for Northwest power.

b. Price

PG&E derives its estimated prices from historical trends, modified to include the effect of the drought. PG&E projects that average prices in 1988 would be 23 mills/kWh for on-peak purchases and 21 mills/kWh for off-peak purchases.

PG&E argues that prices that prevailed in 1988 up to the time that the record in this case was closed demonstrate the accuracy of its estimate. It presented evidence that prices in June and part of July were very close to these estimates, even after taking into account the effect of the annual fish flush, when required releases from the Northwest's reservoirs increase the amount of cheap energy available. Even the prices prevailing in August, clearly after the fish flush, were very close to PG&E's estimates.

CCC and Santa Fe both presented price estimates based on a three-tiered structure. In both cases, the cheapest block was assumed to be produced from hydroelectric facilities. The source of power for the second price block would be produced from cheap thermal resources, primarily coal plants, and would cost 24.4 mills/kWh. The composition of the third tier varied slightly. Santa Fe postulated that power from this tier would come from the most expensive coal resources and would cost 28.9 mills/kWh. CCC's third tier consisted of oil- and gas-fired resources, with a price of 30.3 mills/kWh.

Both parties argue that a tiered structure more accurately reflects the workings of the power market. Although agreeing with PG&E that prices in the first tier would be based on PG&E's costs and would compete with PG&E's marginal resources, Santa Fe and CCC argue that the lack of hydropower would force reliance on more expensive thermal units. These units would respond to the market only to the extent that market prices allowed the selling Northwest utilities to recover the cost of generating power from these plants. These parties believed that the drought would increase prices because demand would exceed the supply of cheap hydropower, and the tiered approach simulates the expected operation of the market.

Santa Fe projected that purchases in 1988 would all be supplied from coal plants at the Tier II rate of 24.44 mills/kWh.

CCC argued that because of the forecasted unavailability of economy energy from hydroelectric facilities in the Northwest, purchases in 1988 would be made at least at the second tier price of 24.4 mills/kWh, and substantial amounts of power would also be purchased from the third tier at 30.3 mills/kWh.

These parties support their arguments by pointing out that in February 1988, when no fish flush or spring run-off influenced the price of power, PG&E's purchases were at prices very close to the second tier prices of their recommendation.

c. Discussion

After considering these arguments and the evidence supporting them, we conclude that PG&E's proposed prices and availability for 1988 are most likely to be correct. Several considerations lead us to this conclusion.

First, the evidence so far is that prevailing prices in 1988 are much closer to the level of PG&E's recommendation than to CCC's and Santa Fe's. The average price of PG&E's purchases from the Northwest was 19.75 mills/kWh in June, 21.01 mills/kWh in July, and 21.47 mills/kWh through August 17, 1988 (Tr. 15:1534). Also, BPA made at least a preliminary offer to sell PG&E between 288 gWh and 298 gWh per month from September to December 1988 at 22 mills/kWh (Ex. 42, Attachment 2). In addition, the record of PG&E's purchases from April through July (Exs. 41 and 42) demonstrate that there are a number of sources of power in the Northwest that we assume will compete to some degree. An implicit assumption of CCC's and Santa Fe's approach is that the Northwest market will be dominated and coordinated by the Bonneville Power Administration (BPA). The pattern of purchases in June and July demonstrate a surprising diversity among the Northwest sellers.

Second, the presence of BC Hydro in the Northwest market will have a moderating effect on prices, we believe. British

Columbia has had normal rainfall in recent years, and BC Hydro has regularly sold power to PG&E (Exs. 41 and 42).

Third, the block structure assumes discrete jumps in market prices as generation from the cheaper resources is exhausted. With the many potential sellers in the market, we expect a more gradual supply curve and we expect that some thermal contribution will be made even at lower prices.

Finally, PG&E has increased its estimate from normal years to take the drought and shortage of hydroelectric energy into account. The forecasted prices are four and five mills/kWh higher than PG&E's initial estimates for 1989, which assumed a return to normal patterns. We believe that PG&E's higher prices are reasonably accurate for purposes of the forecast.

Thus we will adopt PG&E's estimate of prices of 23 mill/kWh for on-peak purchases and 21 mills/kWh for off-peak purchases, and PG&E's estimated availability of 100% of its 1639 MW entitlement to the Pacific Intertie during peak hours and 50% of the entitlement during off-peak hours.

2. <u>Purchases in 1989</u>

a. <u>Availability</u>

The shared assumption is that normal precipitation patterns will return in 1989. Although there was some testimony that normal precipitation would not entirely refill the Northwest's reservoirs, parties seem to expect a return to normal availability of purchased power from the Northwest. It is assumed that power will be available up to 90% of PG&E's entitlement on the Pacific Intertie at all times. PG&E's entitlement increases from 1639 MW to 1775 MW on April 1, 1989. We will adopt this assumption of availability.

b. <u>Price</u>

PG&E proposed pricing Northwest power for 1989 at 90% of its average incremental fossil-fired steam generation cost. It derived this percentage from its actual purchases in 1986 and 1987, a dry year. Since this is an average price that includes prices in a dry year, PG&E does not believe that the tiered approach suggested by CCC and Santa Fe is appropriate.

Determination of the target average incremental fossil-fired steam generation cost would be performed by the model during a preliminary or "seed" run. The seed run begins by setting a price for Northwest power at 90% of a price based on the average incremental heat rates (IHRs) for conventional units. PG&E assumed IHRs of 9,500 Btu/kWh for on-peak and 8,500 Btu/kWh for off-peak periods. The seed run chooses between Northwest power purchases and incremental conventional generation on an economic basis. The seed run thus provides more refined approximations of the incremental fossil generation costs. The final run uses 90% of the resulting costs as the price of Northwest power.

Santa Fe and CCC continued to urge their tiered approach to pricing. The changed precipitation assumptions, however, required a different basis for the price of the first tier for 1989. These parties argued that the price of the first block of economy energy, which is assumed to be generated from hydro electric units, would be set at 90% of PG&E's system incremental cost. Blocks 2 and 3 would remain at the prices forecasted for 1988.

Because the ALJ's August 5 ruling rejected the tiered approach of the pricing of Northwest power, these parties presented a single priced alternative. This alternative is similar to PG&E's but is based on 90% of PG&E's system incremental cost, rather than 90% of its fossil-fired steam units' cost. These parties argue that this assumption better reflects the competition among the various Northwest sellers for sales to PG&E. Because they are in competition, the sellers would gear their prices to PG&E's system costs and would try to maximize their revenues by making sales at just under PG&E's incremental cost of power.

c. Discussion

We will adopt PG&E's assumptions on availability of power in 1989, as stated in the preceding section.

The price assumption is a more difficult issue. However, we believe that the basis for PG&E's recommendation makes more sense.

It is logical to key the price of Northwest power to PG&E's fossil-fired steam units, since those are the primary sources of generation that would be displaced by Northwest purchases. The marginal running costs of resources like PG&E's hydroelectric units and the Diablo Canyon plant are so cheap that PG&E would usually prefer them to more distant Northwest generation. But the higher running costs of the fossil-fired units allows PG&E to reduce their operation when more economical power is available, as it often is, from the Northwest.

In addition, there is a tautological aspect to keying Northwest prices to PG&E's system incremental cost. At times, the system incremental cost includes the costs of purchases from the Northwest, leading, at least in part, to the logical difficulty of pricing a commodity at a fraction of the same commodity's price.

Finally, to the extent that Ex. 54 accurately reflects these price assumptions, the results of PG&E's assumptions appear to be more reasonable and more stable than prices resulting from the other parties' assumptions.

Therefore, we will direct the parties to assume that prices of Northwest purchases in 1989 will equal 90% of PG&E's average incremental fossil-fired steam generation costs.

We note that the question of the pricing of Northwest power is raised again in the discussion of the calculation of the IER.

I. WAPA's Northwest Purchases

The best estimate of WAPA's Northwest purchases is the estimate provided by WAPA itself (Ex. 22, Table 4-6), and this estimate was adopted in the ALJ's ruling of August 5. However, as PG&E pointed out, that estimate was the quantity of power (1,998.1 gWh) expected to be available at the Tracy pumping plant (see Ex. 41). To make these figures consistent with other Northwest purchases, the total amount should be increased by 4.5%, to adjust for line losses over the alternating current (AC) transmission line from the California-Oregon border to Tracy. Thus, for purposes of the resource assumptions, WAPA's Northwest purchases are forecasted to be 2,088 gWh.

This amount should be considered the maximum amount of WAPA's Northwest purchases. WAPA's purchases may be backed down according to the backdown order we discuss later in this decision, so the amount of WAPA's Northwest purchases used in the models may be less than 2,088 gWh.

J. SMUD/NCPA/CSC's Northwest Purchases

SMUD has a 200 MW share of the 500 kilovolt AC line to the Northwest. NCPA and the City of Santa Clara (CSC) have each purchased 25 MW of this 200 MW.

An issue arose because CCC argued that PG&E's assumptions about the use of this share of the AC line was inconsistent with these entities' rights. Specifically, CCC presented evidence that SMUD, NCPA, and CSC did not expect to use their full rights to the line, and as a result a portion of their capacity should be laid off to PG&E.

PG&E presented evidence that demonstrated that SMUD made use of any capacity that NCPA and CSC did not use to purchase power from the Northwest (Ex. 42, p. 8, Attachment 5). PG&E's resulting assumption is that SMUD, NCPA, and CSC, in combination, will fully use the 200 MW capacity to import Northwest energy, except when minimum load conditions or the operation of Rancho Seco requires SMUD to back down its purchases. This assumption is reasonable and will be adopted.

K. Combustion Turbines

PG&E's use of its combustion turbines is limited to satisfying needs for local or system reliability or meeting unexpected peak loads. The amount of generation from these turbines will be determined by the models.

The necessary assumptions are uncontested. PG&E and DRA agree that a reasonable estimate of the cost of distillate oil is $23.53 per barrel, or $4.06 per MMBtu, and that a reasonable distillate oil inventory for combustion turbine use is 100,000 barrels. We will adopt these assumptions.

L. Emergency Power

The models will develop estimates of expected unserved energy (EUE) when outages leave the system with insufficient resources to meet demand. The source of emergency power in these situations is the California Power Pool, and it is undisputed that the price of emergency power from the power pool should be priced at the price of power from the California Power Pool (the monthly gas dispatch price times 11,500 Btu/kWh) plus a premium of 15%.

M. Helms' Upstream Runoff Generation

In addition to its operation as a pumped storage unit, a certain amount of generation is available from the Helms pumped storage plant because of upstream runoff and normal water management. PG&E's forecast of this generation of 34.5 gWh reflects the June 1 snow survey (Ex. 49, pp. 3-4). We will adopt this estimate.

IV. Modeling Conventions

The goal of the production cost models is to simulate the operation of PG&E's system. But necessarily some simplification of the complexities of the operation of PG&E's system must occur to provide the models information in a form they can use. Modeling conventions are some of the conversions or translations of information that modelers employ to make these simplifications. Some of these conventions and related issues were the subject of controversy in this case.

A. System Constraints

In deploying generating resources to meet expected load, a model, like a real dispatcher, tries to dispatch the least expensive available unit or purchase. However, various limitations on PG&E's system require the dispatcher to deviate from the goal of economic dispatch at certain times. These limitations may arise because of transmission constraints, reliability requirements, contractual requirements, or other limitations.

As this issue developed in the hearings, the parties differed not so much about how these constraints were modeled as how extensive the legitimate constraints were.

1. The Parties' Positions

PG&E claims that the actual operation of its system is subject to many constraints that require some resources to be run out of a strict economic sequencing dispatch order. PG&E asserts that these operational constraints must be recognized in the models to simulate its system accurately. The constraints arise from transmission line constraints, local requirements for reactive power support, needs for local reliability and load following ability, and other reasons.

One large category of constraints is designated as the reliability requirements. Because of the physical arrangement of its system, PG&E believes that it must maintain local generation at some minimum level at various times throughout the year. This local generation is supplied by fossil-fired steam units, which at some of these times would not be dispatched on an economic basis. These area reliability constraints arise in PG&E's San Francisco, East Bay, Coastal, and Humboldt Bay areas. In addition, requirements for protection of striped bass in the Delta compel the Pittsburg 7 unit to be run at certain times.

These constraints have two implications for modeling, according to PG&E. First, the constraints require some units to be modeled as must-run units, plants that must be committed and run at minimum levels at certain times, even though economic sequencing would not necessarily dispatch these units at these times. Second, PG&E also sets minimum generation requirements for units in the constrained areas to represent the minimum generation needed to meet the local reliability, reactive power, and load following needs.

A second broad category of constraints is the backdown order. At times of minimum load, PG&E reduces generation from certain resources. After backing down its own baseload units to their minimums, PG&E has the contractual right to back down purchases from other utilities and QFs, to limit other utilities' purchases from the Northwest, and to limit generation by some other utilities.

PG&E believes that the constraints it has proposed reflect the actual operation of its system and must be included in any modeling effort to simulate its system accurately.

Santa Fe argued that PG&E's constraints imposed an extreme limitation on the ability of the model to dispatch the system economically.

First, Santa Fe contends that PG&E has presented no evidence to support its statement that its system requires minimum oil or gas fuel burns ranging from 600 to 700 gWh per month. Apart from naked assertions that these levels were the minimum required, PG&E presented no analyses, studies, or even reasons to support these levels, according to Santa Fe.

Second, several of the area reliability requirements are also unsupported. Although Santa Fe acknowledges the need for the Humboldt Bay and striped bass requirements, it disputes the asserted bases for the other area reliability requirements.

The San Francisco requirement, for example, is supposed to allow local generation units to supply 50% of the generation needed to serve San Francisco's daytime loads, except for Sundays, Santa Fe states. But PG&E was unable to determine what San Francisco's loads are. PG&E provided no basis for its estimate that about 140 gWh per month are needed to meet this requirement.

Similarly, the East Bay and Coastal constraints were based only on assertions that they are needed, not on any reasons or studies to document their necessity, according to Santa Fe.

Santa Fe recommends that the Commission reject these undocumented and unsupported constraints.

Third, Santa Fe argues that PG&E's must-run list is excessive and consists of about 75% of all of PG&E's own oil- and gas-fired generation. The extent of this limitation makes a mockery of models based on economic dispatch, since very little is left of the system for the model to dispatch. Santa Fe points out that this excessive must-run list lowers the IER because the IER is a measure of the difference in generation when variable QFs are removed from the system. Normally, the lost QF generation would be made up by fossil units, raising the IER. However, when these fossil units are already dispatched in the QFs-in run, because of the must-run list, the difference measured by the IER is smaller to that extent.

Santa Fe argues that if legitimate local generation and other reliability concerns are satisfied, the models should be free to dispatch on an economic basis and should not be further subject to the limitations of a long must-run list; the Commission should reject most of PG&E's list.

CCC also argues, for many of the same reasons, that PG&E's must-run list is too extensive and that the East Bay, Coastal, and San Francisco area reliability requirements were not supported by any evidence.

Furthermore, CCC presented an analysis that showed that PG&E's modeling of the minimum fuel burns for San Francisco inefficiently overallocates generation to nights and weekends. CCC proposed an allocation based more closely on PG&E's actual practice. Even if the Commission accepts the constraints proposed by PG&E, CCC argues, it should adopt the fuel limit allocation proposed by CCC.

DRA accepted some of PG&E's constraints, but opposed the minimum generation levels as being unsubstantiated. DRA believes that a pure economic dispatch should be used and should not be subject to these minimum generation requirements.

TURN opposes the constraints on economic dispatch because these constraints also substantially raise PG&E's fuel cost and thus its revenue requirement. TURN is particularly distressed by Santa Fe's Branchcomb's estimate that the constraints prevent economic dispatch of about 75% of PG&E's oil and gas units, and by the suggestion that the Coastal area reliability requirement was discovered only as part of a PROMOD input file. TURN believes that Branchcomb has presented a preferable representation of the real operation of the system without the objectionable features of PG&E's proposal.

2. Discussion

In part, the differences among the parties result from overstatements and misunderstandings. As PG&E points out in its reply brief, the must-run list and the minimum generation requirements are not additive. Rather, the minimum generation amounts includes the operation of the plants on the must-run list at minimum levels. From our rough calculations, based on Ex. 25, Appendix R, and Ex. 79, it appears that the minimum generation requirement is substantially higher than the minimum generation produced from the must-run plants.

Also, Santa Fe's assertion that PG&E's constraints involve 75% of PG&E's oil and gas plants, which seems true, does not mean that only 25% of this generation is subject to economic dispatch, as DRA and TURN have apparently understood this claim. The plants on the must-run list are assumed to operate at minimum loads, not at full generation, although other requirements appear to raise the out-of-economic-order generation somewhat. But even the higher minimum generation requirements presented by PG&E amount to less than 10% of the planning load for any month, are less than half of PG&E's forecasted conventional thermal generation, and are well below the maximum capacity of these plants. Thus, we conclude that the asserted constraints do not in themselves pose an unacceptable limitation on the models.

Finally, the claim that the Coastal area reliability requirement was somehow hidden by PG&E must be rejected. Ex. 48 includes an attachment that was distributed at the modeling workshop of May 2 and 3, 1988. That attachment clearly lists as must-run units the generating plants operated in response to the Coastal constraint.

Having clarified these items, we can turn to the real questions whether these constraints accurately represent the operation of PG&E's system and whether they are necessary for purposes of modeling.

In answer to the second question, we can emphatically state that it is imperative that any models used in this type of proceeding accurately reflect the actual operation of the utility's system. Although it may be possible to state operational criteria in different ways, the models must have the ability to produce a reasonably accurate simulation of the actual operation of the system. The purpose of employing these models in our proceedings is to give us a more accurate basis for our forecasts of costs and of the IER. Presumably, these models have an ability to mimic the complexities of the system, resulting in improved accuracy over the less sophisticated statistical methods of the past. If the models cannot produce this desired accuracy, we would prefer to revert to the more comprehensible methods of former times.

Thus, if the constraints proposed by PG&E reflect the facts of the efficient operation of its system, then the models should account for these limitations in some manner.

The more difficult question is whether PG&E's constraints are both typical of and necessary to the efficient operation of its system. No party now disputes the need for the Humboldt Bay or striped bass constraints. The remaining area constraints present more controversy.

PG&E's support for the East Bay, Coastal, and San Francisco constraints consisted primarily of repeated assertions by various witnesses that these constraints actually reflected the way the system is operated. These criteria were not based so much on studies as on the experience of the operators responsible for running the system. The opposing parties were unable to counter this assertion by showing that the actual operation of the system did not follow these requirements. These parties pointed out that additional QFs in the East Bay could help PG&E meet its reactive power requirements, but PG&E countered with evidence that several generation units had been retired during the same period. CCC pointed out PG&E's overallocation of the San Francisco minimum generation to off-peak periods, but the overall basis for the requirement was undisturbed. Little information was presented by either side on the Coastal requirements.

For purposes of this case, we are satisfied that the area reliability requirements reflect the way that PG&E has operated its system and will operate its system during the forecast period. Thus, it is appropriate for the models to reflect these limitations in the forecasts they produce. However, the evidence presented in this case does not permit us to evaluate the more significant questions raised by some of the parties. We cannot tell if the area requirements could be expressed in another way that would permit greater levels of economic dispatch by the models. We have no way of telling whether the way PG&E operates its system is in fact the most efficient way, although we hope we have created incentives to promote efficiency. The lack of information also prevents PG&E from receiving the benefit of the instructional aspects of at least some of the models; with better information, some of the models may be able to suggest alternative, more efficient ways to maneuver around the area limitations.

For these reasons, we will direct PG&E in its next ECAC application to include a detailed description of the reasons for the area reliability requirements and a detailed justification for the minimum generation requirements associated with these constraints.

Having concluded that the models should satisfy the area reliability requirements, we are not persuaded that PG&E's approach is the only way to meet those requirements. As we have stated, PG&E has presented little information on the specific requirements that require special provision in the models. Since the minimum generation requirements seem to subsume the must-run designations, it is not clear that models must necessarily include both limitations to meet the constraints successfully. In light of the hazy record in this area, we will not require modelers to specify the must-run units in the manner proposed by PG&E. Our intent is to allow the models to meet the minimum generation requirements as efficiently as possible. Since must-run designations restrict the models' ability to dispatch on an economic basis, must-run designations should be minimized. For the Coastal, East Bay, and San Francisco areas, modelers should avoid designating units as must-run and should use other features of their models to satisfy these requirements. Must-run designations should be made only if a model has no other reasonably convenient way of meeting minimum generation requirements.

The reliability requirements for the striped bass run and for the Humboldt Bay area have been justified, and modelers should reflect these constraints in their runs.

Unfortunately, the record leaves us with little basis for determining whether the models have satisfied the area reliability requirements. We will allow modelers to meet the area reliability requirements by meeting the minimum generation requirements, which appear to be more closely related to the reliability requirements than the must-run requirements.

The amounts of the minimum generation requirements, ranging from 600-700 gWh per month, are consistent with recent experience, according to the limited information in the record (Ex. 25, Appendix R). We will require the models to meet this level of minimum generation and to follow the allocation discussed below.

Our determination on this point may be clarified somewhat by referring to Santa Fe's contention that PROSYM is able to meet the area reliability requirements and the minimum generation requirements without specifying certain units as must-run (Ex. 78, p. 4). As we understand the reasons for these requirements, Santa Fe's approach is acceptable, provided that PROSYM provides adequate generation to meet these requirements.

Although PG&E's recommended level of minimum generation for the San Francisco area seems reasonable, CCC has argued that allowing PROMOD to allocate the fuel limit for San Francisco by default overallocates power to nights and weekends, contradicting both the purpose of the generation and the practice of PG&E. A similar problem appears to occur for the allocation of minimum generation for the East Bay and Coastal areas (Ex. 58, pp. I-14, I-15; Tr. 18:1903-1904). We will therefore adopt CCC's recommended allocation of minimum generation for the San Francisco, East Bay, and Coastal areas of 62% day time, 12% nighttime, and 26% weekends.

Finally, we are satisfied that the backdown order listed in the attachment to Ex. 48 reasonably reflects PG&E's abilities to back down its purchases, other utilities' purchases, and other utilities' generation. In addition, when the reductions on this list are exhausted, PG&E appears to have the ability to reduce Rancho Seco generation, followed by reductions in Diablo Canyon. Modelers should follow the backdown order of Ex. 48 and, if levels of minimum load are sufficiently low, should back down Rancho Seco and Diablo Canyon (see Ex. 14, p. 6-5). The question of the backdown order will be revisited in our discussion of the calculation of the IER.

B. Commitment Target and Spinning Reserve

ELFIN, like PROMOD, is a load duration curve model that approaches the utility's system on a weekly basis. For every week of the simulation, at what may be viewed as the beginning of the week, ELFIN anticipates the expected peak load for the week and commits, or starts up, enough units to meet expected demand. Once a unit is started, it is available for dispatch, which requires increased generation from that unit.

ELFIN does not permit a modeler to specify a spinning reserve target, and the modeler must take some care to ensure that the model does not overcommit resources above the generation needed to meet load and spinning reserve. CCC, joined by PG&E, criticized the way in which DRA determined the commitment target for ELFIN.

The Western States Coordinating Council (WSSC) requires PG&E to maintain a spinning reserve of either 7% or the utility's largest single contingency. The ELFIN modeler must choose a commit target value to get the model to commit enough units to meet the system's needs plus spinning reserve. CCC recommends two adjustments to make sure that ELFIN does not overcommit resources.

The first point has to do with the derating of a unit's capacity for both forced outages and maintenance outages. In trying to meet a commit target, ELFIN will derate a plant's capacity by its historical forced outage rate. Thus, if a 1000 MW plant has a 15% historical forced outage rate, ELFIN will use only 850 MW of the plant's capacity toward meeting the commit target. DRA did not make any compensating adjustment for this derating of capacity.

CCC argues that in reality a plant will be committed up to its full available capacity, and unscheduled outages will not be taken into account in meeting the commitment target. If the capacity is derated and the spinning reserve is maintained at 7%, then essentially a double derating of capacity has occurred, which reduces the expected availability of the unit and thus results in an overcommitment of resources. CCC believes that only derating for scheduled maintenance should be allowed. CCC cites PG&E's testimony that DRA's approach does not reflect the actual operation of PG&E's system.

We agree with CCC's point, for slightly different reasons. Although it is desirable to have a model reflect the precise operation of a system, we recognize that in many cases simplifications must be made; thus, the mere fact that ELFIN approaches the commitment of units in a different fashion from PG&E's human operators is not persuasive. However, ELFIN's automatic derating of capacity for forced outages produces an inconsistent result in this case. One of the primary functions of spinning reserve is to allow the system to endure an unexpected outage by a generating unit, and the level of spinning reserve is set high enough so that even the outage of the largest single unit can be covered instantaneously. The derating of capacity by historical forced outage rates essentially results in a higher spinning reserve than targeted because it anticipates outages that are by definition unexpected. Thus, we agree that modelers should correct for ELFIN's derating of capacity for forced outages in committing units to meet commitment targets.

Second, both PG&E and CCC believe that ELFIN's attempt to meet the commitment target needs to be checked to see that the model does not commit more than the needed resources. Because of necessary adjustments to ELFIN's commitment process, the results of the model's attempt to meet a particular commitment target are variable. By adjusting the target and repeating the process, the model can eventually be used to meet the target commitment without overcommitting resources.

We are persuaded that this iterative process is needed to ensure that ELFIN does not overcommit resources in its effort to meet a commitment target,and we will require ELFIN modelers to employ this process.

A related issue is DRA's contention that nonfirm energy increases spinning reserve requirement. CCC's Weisenmiller's testimony persuaded us that accepting economy energy neither increases nor decreases the spinning reserve requirement (Ex. 25, p. II-52). Although nonfirm purchases must be entirely covered by spinning reserve, they do not require commitment of additional generation.

C. <u>Helms' Generation</u>

All parties now seem to accept that the Helms pumped storage plant should be 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. As has been discussed, we forecast generation of 34.5 gWh from upstream runoff and normal water management. (See Ex. 49, pp. 3-4.)

D. <u>Line Losses</u>

All parties recognize that purchases from the Northwest transmitted over the AC line and the direct current (DC) transmission line incur line losses of 4.5% and that purchases transmitted over the DC line incur additional conversion losses of 4.5%. Parties differ on the details and implications of these facts, however.

One issue concerns how these line losses should be accounted for. DRA argues that when Northwest purchases replace QFs in the QFs-out run, the line losses should be accounted for by increasing the price of Northwest purchases to reflect the losses that occur during transmission. DRA believes that this adjustment is equivalent to, but simpler than, increasing the amount of purchases to adjust for losses. For example, if PG&E needed 100 units to meet demand, it might have to buy 105 units to accommodate line losses. DRA's approach is to raise slightly the price of the 100 units received to reflect the total cost of the 105 units purchased.

PG&E agrees that for dispatch purposes, losses should be accounted for by price adjustments to determine whether Northwest purchases are economic. However, PG&E does not believe that adjustments should be included in the calculations of the IER or the revenue requirement. PG&E argues that line losses are already included in the calculation of the lost and unaccounted for energy (LUAF) amount included in the planning load, and that making a special adjustment for Northwest purchases double counts the line losses.

We suspect that the proper determination of losses in the QF-out case lies between the positions taken by the parties. Making only the adjustment for the Northwest purchases ignores the fact that removal of the variable QFs will somewhat reduce the losses already included in the LUAF figure. Since the meters that measure the power produced by a QF are usually at the point of interconnection with PG&E's system, PG&E bears the transmission losses associated with QFs' generation and includes these losses in its LUAF. On the other hand, because of their location, generation from QFs located near load centers may incur lower losses than the losses associated with replacement power from the Northwest.

DRA's approach, however, assumes that Northwest purchases will result in greater losses than those associated with the replaced QFs. This assumption excludes the possibility that some QFs may be located far from load centers or that some QFs' power may be transmitted over lines that are less efficient than the Pacific Intertie. Without better information on the effect on losses from the removal of QFs in the QFs-out case, we decline to make this assumption. Although PG&E's approach may understate the losses resulting in the QFs-out case, we conclude that it is more likely to represent the losses in this hypothetical situation accurately.

Thus, we conclude that for purposes of determining whether purchases from the Northwest are economic, line loss factors of 4.5% for the AC and DC lines and an additional conversion loss of 4.5% for the DC line should be accounted for through price adjustments. Because of the interaction between the conversion losses and the line losses on the DC line, the total losses for transmission on the DC line is 9.2%. No such adjustments should be made in the determination of the IER and the calculation of revenue requirements other than the LUAF amount.

E. Other Utilities' Northwest Purchases

An additional issue had to do with whether the amount of power purchased by SMUD, WAPA, and NCPA/CSC should be allowed to vary between the QFs-in and QFs-out simulation. PG&E concedes that the purchases by NCPA/SCS are based on those utilities' needs only and are scheduled independent of PG&E, and thus should not vary between the QFs-in and QFs-out simulations. However, PG&E asserts that its contractual relations with SMUD and WAPA give PG&E the right to require these utilities to reduce their Northwest takes during times of PG&E's minimum load. This assertion is consistent with the backdown order we have adopted and with the evidence in this proceeding. Therefore modelers should allow for reductions of Northwest purchases by SMUD and WAPA during minimum load periods, which may vary between the QFs-in and QFs-out runs.

V. Calculation of the IER

The incremental energy rate is a somewhat artificial concept. It first arose in the negotiating conference that developed the interim Standard Offer Number 4 as a way of relating forecasted fossil fuel prices to the utility system's marginal energy costs. A utility's marginal cost of generating energy (expressed in cents per kWh) is a combination of the price it pays for fuel (stated in $/MMBtu) and the system's efficiency in converting that fuel into kilowatt-hours. The IER, as a measure of the system's incremental efficiency in making this conversion, is therefore expressed in Btu/kWh.

In D.88-03-079, we adopted the QFs-in/QFs-out approach to calculating IERs. A QFs-in model run includes generation from all variably priced QFs expected to be in operation during the forecast period. A QFs-out run dispatches the system with generation from all variably priced QFs removed. The QFs-in/QFs-out approach measures the costs avoided by the system by comparing the QFs-in run and the QFs-out run. The IER used to calculate energy payments to QFs is the average of the IERs resulting from the QFs-in and QFs-out runs.

In terms of a formula, the IER equals the difference between the total costs in the QFs-in run and the QFs-out run, divided by the generation in gWh provided by variably priced QFs, with the resulting quotient divided by the UEG rate, in $/MMBtu. (See Ex. 46, p. 3.)

The IER is often and understandably confused with the incremental heat rate, or IHR. The IHR is typically used to express the incremental efficiency of an individual generating unit, and measures the unit's efficiency in producing one more kWh. A unit's IHR will vary with changes in the generation it produces, and most generating units are designed to operate most efficiently within a certain range. References to a system's IHR usually refer to the IHR of the last unit dispatched to meet load. The IHR is also expressed in Btu/kWh.

To add to the confusion, it appears that the term IER has been used in several different ways in different aspects of the Commission's activities. This difference makes comparisons between these different uses very tricky.

For example, PG&E's quarterly filings in compliance with Ordering Paragraph 12(b) of D.82-12-120 (12(b) filings) report "actual" IERs, but these figures are not directly comparable to the IERs considered in this case. The 12(b) filings' IERs are essentially the marginal running costs in the QFs-in run (Tr. 15:1574, Tr. 21:2224-2225). Furthermore, the IERs in this case reflect forecasted circumstances, including normal rainfall in 1989 and the operation of Rancho Seco; the 12(b) filings' IERs are based on actual conditions during the three months that are the subject of the report.

The IER is great concern to QFs, since the level of energy payments to variably priced QFs rises or falls with the IER.

Several issues related to the calculation of the IER were contested in this proceeding.

A. UEG Rate

One of the elements in the calculation of the IER is the assumed price of gas. All parties agree that the proper price for gas should be the Utility Electric Generation (UEG) rate, the tariff rate for sales from PG&E's gas department to its electric department for electrical generation. Some differences about this rate nevertheless remain.

PG&E urges that the annual average UEG rate should be used throughout the calculation of the IER, for both the QF-out run's production expenses and as the denominator in the calculation of the annual IER. PG&E points out that payments to QFs are calculated by multiplying the adopted annual average UEG rate by the adopted IER, and that consistency requires using the same basis for the calculation of the IER. PG&E argues that the approach used by Santa Fe is inconsistent and artificially inflates the IER.

Santa Fe contends that the annual average IER should be based on the monthly value of energy displaced by QFs, and determination of the monthly value of this QF generation requires use of the monthly average UEG rate. Because resource availability and fuel prices change from month to month, Santa Fe argues that the value of the generation provided by QFs also varies monthly. An accurate IER should reflect this variation in value. Santa Fe therefore believes that the calculation of the annual average IER should be the sum of the monthly value of QFs' generation, divided by the sum of the monthly production by QFs, with the result divided by the annual average UEG rate, the gas price used to determine short-run energy payments to QFs.

We believe that the calculations of the IER should use a consistent UEG rate assumption throughout the calculation. In calculating an annual IER, use of the annual average UEG rate in all stages of the calculation is a consistent approach. PG&E has used such an approach and we will adopt its recommendations in this case.

Santa Fe's arguments suggest another approach. To reflect the variations in the value of QFs' generation, a period shorter than a full year could be examined, such as the monthly calculation suggested by Santa Fe. To develop a consistent IER, however, the UEG rate for that month could be employed in all stages of the calculation. The resulting monthly IERs could then be averaged in a logical fashion to calculate the annual IER.

Santa Fe did not follow this approach, however. Santa Fe, for reasons we find unpersuasive, mixed the monthly UEG rate with an annual average UEG rate in developing its recommended IER. This results in a higher IER than the monthly approach we have just suggested and than some of the corrections that PG&E suggested. Because we do not accept the underlying reasoning, we reject the approach advocated by Santa Fe.

B. Avoided Operating and Maintenance Costs

IPC and CCC raised issues about how avoided operating and maintenance (O&M) costs are calculated and how they are paid to QFs as part of the variable energy payment.

1. IPC's Position

IPC first argues that the avoided O&M payment should be added on to the base energy payment to QFs, rather than rolled into the calculation of the IER, as has been PG&E's practice. It points out that Edison makes such payments as an adder. More important, IPC argues that including the avoided O&M in the IER calculation is illogical. The IER is intended to measure the efficiency of the system in converting thermal energy to electric energy, a conversion that is only remotely related to the costs of O&M.

In addition, reflecting O&M costs in the IER will cause the O&M costs included in the energy prices paid to QFs to vary with changes in prices of the marginal fuel, rather than with changes in the amount of generation produced, as logic would suggest. According to IPC, PG&E's present approach increases the risk that QFs will be either overpaid or underpaid for avoided O&M costs, because the payment varies with changes in their marginal fuel price, which is unrelated to the level of avoided O&M costs.

IPC also argues that the O&M adder should include all variable O&M costs, including appropriate labor costs and associated administrative and general (A&G) expenses. IPC finds PG&E's definition of avoided O&M costs to be too narrow, and this narrowness results in undervaluation of the contribution of QFs in allowing the utility to avoid costs. Merely including the items PG&E listed as generation-related variable O&M in its filing in the seventh Common Forecasting Methodology (CFM-7) proceeding before the California Energy Commission raises the value of variable O&M from 0.332 mills/kWh to 1.82 mills/kWh, according to IPC.

IPC goes on to argue that some labor costs, which PG&E excludes, should be included in variable O&M. The presence of QFs frees existing personnel from O&M tasks related to the amount of generation so that they can perform other tasks, resulting in overall productivity improvements and labor costs savings. When inefficient units are totally displaced by QFs' generation and are retired or placed in standby, even the "fixed" O&M costs associated by these plants are avoided. Routine and extraordinary maintenance can be deferred as the operating hours of fossil-fueled units are reduced.

Furthermore, IPC argues, when labor costs are reduced, A&G costs, which the Commission has always associated with labor costs, will also be avoided.

PG&E's understating of avoided O&M costs has two consequences, according to IPC. First, the contribution of QFs is undervalued, in violation of the Public Utility Regulatory Policies Act (PURPA) and the Commission's stated policies. Second, the utility receives a windfall when costs are avoided by QFs and not reflected in avoided costs, because annual O&M costs are estimated in the utility's general rate case and included in base rates. As a result, the utility receives revenues for which it does not incur a corresponding expense.

IPC believes that the O&M adder should be set at 3 mills/kWh. Lack of data prevents it from quantifying the precise amount that PG&E avoids because of the QFs' generation, but the 3 mill/kWh figure is a reasonable approximation. IPC notes that the Commission has approved a 3 mill/kWh adder for Southern California Edison Company. After comparing the two utility systems and referring to the 1.82 mills/kWh figure PG&E submitted to the Energy Commission, IPC believes that 3 mills/kWh is a reasonable estimate of PG&E's variable O&M costs.

Finally, IPC asks the Commission to order PG&E to present a detailed study of its O&M costs as part of its test year 1990 general rate case.

2. CCC's Position

CCC joins in many of IPC's arguments.

CCC adds its concern about the narrowness of PG&E's definition of variable O&M costs. PG&E's definition seems to be tied to a one-year horizon. CCC points out that a longer-term definition, such as the planning framework of the CFM cases, is more appropriate in considering the O&M costs avoided by the contributions of QFs. Both Standard Offer 2 and the variable energy option Standard Offer 4 contracts are paid variable energy rates, but these contracts require reliable operation for 20 to 30 years. The reliability and longevity of these facilities will allow PG&E to reduce its costs for O&M items that vary over a longer period than one year.

CCC points out that QFs' generation has permitted PG&E to reduce the work force at the Avon, Oleum, and Martinez plants from 125 workers to around 5 workers. Although even the CFM filings do not include avoided labor O&M, this reduction in work force demonstrates that some labor O&M costs are avoided by the presence of QFs, according to CCC.

Finally, CCC argues that PG&E has presented no evidence in support of its position. In reviewing the various available sources of information, particularly PG&E's CFM-7 and CFM-8 filings, CCC concludes that an adder of 3 mills/kWh is a reasonable estimate of the O&M costs the QFs' generation allows PG&E to avoid.

3. PG&E's Position

PG&E disputes IPC's and CCC's recommendations. O&M costs avoided by the QFs' generation are limited to "the costs of nonfuel consumable items whose consumption is directly linked to the generating output of conventional fossil units." Labor costs are not avoided, and therefore no A&G costs are avoided, according to PG&E.

When the costs of these actually avoided items are considered, and when the proportion of total generation that is provided by conventional steam units is considered, PG&E calculates that the actual avoided O&M cost is 0.157 mills/kWh.

PG&E believes that the references to the CFM-7 filing are deceptive. Those costs are part of a long-term planning analysis and include many items not avoided when a conventional steam unit reduces generation, which is the appropriate measure for the short term considered in this case.

PG&E points out that the number adopted in the ALJ's ruling contained a transcription error and was not adjusted to reflect the fact that only a portion of the variably priced QF generation replaces conventional fossil units. When Northwest purchases are displaced by QFs, for example, no O&M costs are avoided. Thus, PG&E believes that the corrected figure from the ALJ's ruling should be adjusted to reflect the avoided O&M costs per kilowatt of avoided conventional fossil generation.

PG&E states that each set of inputs into the model will result in different avoided O&M costs and different amounts of conventional generation. Thus, PG&E recommends that the easiest way to calculate avoided O&M costs is to divide the change in variable O&M costs resulting from the QFs-in and QFs-out models runs by the amount of energy expected to be generated by variably priced QFs. When this calculation was performed on PG&E's run following the ALJ's ruling, the result was an avoided O&M payment of 0.157 mills/KWh.

4. <u>Discussion</u>

We are persuaded 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 paid to QFs. Expressing these payments in mills/KWh and allowing them to vary with the amount generated in the swing units, rather than with changes in the price of the marginal fuel, is logical.

Determining the amount to include in the avoided O&M payment is more difficult. IPC and CCC made strong arguments that additional items are avoided by QFs, labor and associated A&G costs in particular. PG&E urged a narrower definition of the variable O&M costs, but little persuasive evidence was presented by any party.

The question of what costs are variable necessarily involves a definition of a time horizon. In the very long run, all costs are variable. PG&E's appears to limit its definition of variable costs to those that vary within one year. IPC and CCC urge a longer time frame.

We conclude that at least some costs that are variable over more than one year are avoided by generation from QFs and should be part of the avoided O&M payment. QFs have demonstrated that they make a dependable contribution to the utility's resources, which PG&E has relied on and can reasonably rely on in the future. In counting on the generation from QFs, PG&E should adjust its maintenance practices accordingly. These adjustments may be reasonably assumed to reduce some costs, and we suspect that at least some of those reduced costs are labor costs.

We are concerned that so little good information is available to help us quantify the amount of variable O&M. IPC pointed out that PG&E has not complied with our order that "the assumptions regarding the derivation of variable O&M should be included" in the utilities' quarterly energy price filings (D.82-12-120, 10 CPUC 2d 553,624).

The information available in this record does not permit us to specify the appropriate time frame for consideration or to quantify exactly the avoided O&M costs. Based on the record, we will adopt as a base number the 1.82 mills/kWh that results from PG&E's CFM-7 filing. This figure does not include any avoided labor costs, and it may include some items that vary over an inappropriately long period. However, these two drawbacks tend to cancel each other out, and we conclude that this figure is the most reasonable estimate provided on this record.

We adopt this amount as a base amount of variable O&M. PG&E has argued that since most variable O&M is attributable to conventional fossil plants, that some adjustment should be made for the large proportion of other resources in its generation base. We agree with these arguments. To make the appropriate adjustment for the various resources in PG&E's resource mix, parties should determine the change in the amount of conventional fossil generation between the QFs-in and QFs-out runs. This represents the amount of fossil generation displaced by the presence of QFs and provides an estimate of the O&M costs that QFs avoid. This amount should be multiplied by the 1.82 mills/kWh figure we have adopted. The product should then be divided by the total generation of variably priced QFs (the generation removed in the QFs-out run), to yield the amount, expressed in mills/kWh, that will paid QFs as an adder for avoided variable O&M costs.

As we have repeatedly mentioned, the lack of information on variable O&M costs presented a formidable obstacle to the resolution of this issue. We will direct PG&E to present a study of the O&M costs avoided by QFs' generation in its test year 1990 general rate case. At a minimum, the study should examine the reductions in costs--including materials costs, labor costs, and any other appropriate costs--that occur when generation is reduced at its existing conventional fossil plants. The study should also calculate the savings in O&M that have resulted from the retiring or removal to standby status of similar plants in the last five years. PG&E should attempt to identify and quantify the O&M costs that vary in one-, three-, and five-year time frames and should expand on these minimum requirements and present any other relevant information available to it.

C. Substitute Resources

The QFs-out run of the models calculates the characteristics of PG&E's system for the forecast year if all generation from variably priced QFs was removed. PG&E argued that this assumption is unrealistic. QFs were added to the system over a number of years, and if no QFs had been added to the system, PG&E would have gradually taken other steps, such as adding new resources or contracting for additional purchases, to meet the system's long-term needs. The QFs-out case essentially assumes the sudden disappearance of a major contribution to PG&E's resources, argues PG&E, and calculates the cost of short-term replacements, primarily increased fossil-fueled generation and purchased power, for those lost resources. To compensate for this unrealistic assumption, PG&E believes that the prices of resources calculated in the QFs-in run should carry over to the QFs-out run.

We have already addressed this issue, at least in part. In D.88-03-079, we heard similar arguments about the soundness of the QFs-out assumption. We acknowledged that this assumption does not reflect what a utility would actually do in the absence of QFs, but we declined to make any adjustments to the QFs-out approach at that time. Since circumstances have not changed since that decision, we will not adopt PG&E's proposed modifications to the adopted QFs-in/QFs-out method.

CCC urged the Commission to sustain the position on substitute resources taken in D.88-03-079.

Santa Fe, however, raised an issue that is a variation of the substitute resources issue. PG&E currently has several plants in standby (see Ex. 22, p. 75, Table 9-1). PG&E acknowledged that four of these units have always been available and four others could be restarted within 8 hours to four days, if needed (Tr. 3:249-251). Santa Fe argues that these units should be considered available for modeling purposes for the entire forecast period. PG&E includes them in 1988, but models them as being unavailable in 1989.

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.

We distinguish such existing plants from the substitute units addressed in D.88-03-079. In that decision we contemplated the construction of new plants or the entering into of new contracts for purchases on other than a short-term basis. The rationale for excluding those types of resources does not apply to existing standby units. We conclude that the units listed in Table 9-1 of Ex. 22, except for Contra Costa 3, Moss Landing 1 (Ex. 49, p. 9), and the Kern units, should be modeled to be available during the entire forecast period and may be employed in the QFs-out run.

D. The Treatment of Northwest Power Prices

A related issue concerns the treatment of the purchases of Northwest economy energy in 1989. We have previously determined that prices in 1989 should be set at 90% of PG&E's average incremental fossil-fired steam generation costs. Under the QFs-out assumptions, however, it is likely that the removal of QFs will increase the cost of steam generation.

The QFs' representatives argue that the price of Northwest power should rise accordingly. PG&E argues that the price should remain fixed. The primary basis for PG&E's position seems to be that it is unfair to prevent the utility from assuming that substitute resources would be added to make up for the lost QF generation while assuming higher prices for existing resources.

The issue is even more artificial than the parties have defined it. The essential question is whether a separate seed run to develop estimates of PG&E's incremental steam generation costs should be performed for both the QFs-in and QFs-out runs. The question turns on what response Northwest sellers would make to the removal of a large block of QFs. PG&E's approach concludes that sellers would increase the amount of their sales, corresponding to PG&E's increased need to purchase economy energy. The QFs' representatives' approach holds that the Northwest sellers would choose to raise the price but maintain roughly the same level of sales. If this situation were anything but hypothetical, of course, something in-between would happen: quantities of purchases would increase and prices would probably rise somewhat.

We are thus forced to choose between two unrealistic alternatives to resolve a hypothetical problem. In keeping with our adopted QFs-in/QFs-out approach to calculating the IER, we conclude that the price of Northwest power should be permitted to vary in the QFs-out run. A separate seed run for the QFs-out case will simulate the expected reaction of Northwest sellers to the hypothetical loss of variably priced power from QFs and PG&E's consequent greater reliance on thermal generation. Thus, modelers should do a separate seed run to determine the price of Northwest power in the QFs-out case for 1989.

In the seed runs using the assumptions of the ALJ's ruling, the parties used slightly different initial estimates of PG&E's average incremental heat rates for conventional units. This difference elicited little discussion or evidence, but it is desirable for all parties to use the same initial figures. The estimates used by PG&E and CCC--9,500 Btu/kWh for on-peak and 8,500 Btu/kWh for off-peak--should be used in all parties' seed runs.

E. <u>IER Without Rancho Seco</u>

As we have already discussed, there remains some possibility that the Rancho Seco nuclear unit would be shut down during the forecast period because of poor performance, under the terms of an initiative adopted by voters in June. We will allow the parties to calculate an alternate IER which assumes no generation from Rancho Seco. In the event that Rancho Seco is shut down, we will adjust payments to QFs by employing the alternate IER in the revision of energy payments to QFs following the official determination to shut the plant down.

F. <u>Development of Final Results</u>

The exact combination of variables that we adopt in this decision has not been run through the models before in this proceeding, and the resulting IER may vary slightly from those that have previously been presented in this case. Under these circumstances, the parties sponsoring models should submit the IER, revenue requirement, and other appropriate figures that result when the variables decided in this opinion are run through the models. The development and filing of these results will be coordinated by the ALJ.

VI. Differences Among the Models

When this case began, it appeared that this would be the forum for the "battle of the models," to determine which of the three models used in this proceeding provided superior results. As the case developed, it became clear that the assumptions used by the models would have a much greater effect than any inherent differences in the models.

At the completion of hearings, the most noteworthy development was how close the three models were in their results. When PROMOD and ELFIN 1.6 used the same assumptions for economy energy from the Northwest, the resulting IERs differed by only 1.1% (Ex. 54, p. 2). A similar comparison between ELFIN and PROSYM yields a variation of about 1.7% (compare Ex. 54, p. 3 with Ex. 77, Table 9). Other checks on the models also indicate generally similar results (Ex.77, Table 11).

One conclusion that can be drawn is that no party supports use of the old version of ELFIN, version 1.58. That version did not allow prices to be time-differentiated, and all parties agree that the addition of this feature in ELFIN 1.6 was a needed improvement.

At this stage, we are not prepared to say that any of the three models used in this proceeding was inadequate. PROMOD has many features that make certain changes or simulations relatively easy. However, it is expensive to run and access to it is limited. ELFIN 1.6 is relatively cheap and can be run on most personal computers. Although it does not have all the features of PROMOD, modelers are able to overcome most of its limitations to arrive at reasonably accurate simulations. PROSYM is still unfamiliar to parties other than its sponsors. It is intriguing because it takes a different approach to modeling from the other models. We will reserve judgment on PROSYM at least until we have seen it applied in a proceeding when parties are more familiar with its operation.

Eventually we hope to simplify our proceedings by having all parties use the same model. At the same time, however, we do not want to lock into a certain model and ignore the improvements that are made to other models. However, it is imperative that we have some basis for comparison of the various models. In this case, we found ourselves in the same situation we did in the last Edison general rate case, with three models yielding similar results for poorly understood reasons. In the Edison case we ordered that "all parties [in ECAC proceedings] presenting testimony requiring the use of a production simulation model must present a 'base case' run using the same model," and we named ELFIN as the common model (D.87-12-066, mimeo., p. 201). As we have discussed, these base case runs did not prove to be useful in this case. A more useful comparison would have been among the models. We will therefore alter the base case requirement slightly. Parties sponsoring model runs in PG&E's next ECAC proceeding must present a base case run that is the result of using inputs from a common data set in their favored model. Workshops will be held to develop the common data set and to identify and resolve, if possible, differences among the parties.

VII. Revenue Requirement

As we mentioned in the discussion of the calculation of the IER, we have changed many of the determinations of the ALJ's August ruling, and the revenue requirements that the parties calculated using the ruling's assumptions will undoubtedly change.

To calculate a revenue requirement that is consistent with the determinations we have made in this decision, the models will have to be run again. We direct the parties to do this, and we will set out our conclusions in a subsequent decision.

We expect some changes for the initial calculations, but the estimates provided from the ALJ's August ruling should give a general idea of the level of the increase that is likely to result from this proceeding. DRA's final recommended net revenue requirement increase resulting from the ALJ's August ruling was $56.7 million. PG&E's corresponding recommendation was $64.5 million.

The models affect only the ECAC and AER portions of the revenue requirement increase. DRA and PG&E agree on the adjustments in the ERAM, DCAC, and CFA (Ex.73). We will defer our decision on all revenue changes so that all revenue changes considered in this case (ECAC, ERAM, DCAC, and CFA) can be made at the same time.

TURN raises a point related to revenue requirement. TURN points out that firm capacity contracts with QFs allow for a derating of the facility's contractual capacity and associated payments if the QF fails to meet a specified capacity factor at certain times. PG&E's forecast does not reflect any such reduction in payments to QF. TURN asks us to direct PG&E to provide data in its next ECAC application on the extent of these deratings and reduced payments. TURN has raised an issue worth pursuing, and we will direct PG&E to provide the information TURN has identified.

VIII. Revenue Allocation and Rate Design

The testimony presented in the hearings on these issues focused on a potential revenue requirement increase of about $60 million, consistent with the recommendations of DRA and PG&E mentioned in the preceding section. That testimony has been largely superseded by later developments. On October 4, 1988, PG&E and DRA filed a motion for leave to file a late-filed exhibit on the topics of revenue allocation and rate design. The proposed exhibit stated guidelines to be applied to the rate changes resulting not only from this proceeding, but also from PG&E's attrition case and the Diablo Canyon settlement, if it is adopted. The potential increase from the latter two cases amounts to $420 million, well beyond any increases contemplated in the hearings in this case.

An ALJ's ruling of October 6, 1988, requested comments on the motion and the proposed exhibit. Because we are still analyzing the comments that were received in response to the motion, we will issue our decision on revenue allocation and rate design at a later time.

IX. Reinstatement of the AER

In D.88-09-036 we temporarily suspended the AER for PG&E because of the delay in reaching a decision in this case and because PG&E's system faced substantially different circumstances from those contemplated when the AER was last revised.

With the adoption of a revised AER, which will take place in a subsequent decision, the AER should be reinstated. When the revised AER rates take effect, PG&E should again be subject to the incentives of the AER. We expect to have those rates in effect on January 1, 1989.

Findings of Fact

1. PG&E filed A.88-04-020 and A.88-04-057 on April 7 and 21, 1988. A.88-04-057 requested an increase of $129.3 million to PG&E's electric rates on an annualized basis beginning August 1, 1988.

2. PG&E's current ECAC proceeding marks the beginning of the regular revision in its ECAC case of key components in the calculation of prices paid for power sold to the utility by QFs.

3. It is the Commission's goal to develop both a utility's rates and QF prices on a consistent basis.

4. DRA's economic forecast reflects recent economic projections.

5. The June 1 snow survey was the most recent information on potential hydroelectric generation available at the time of the hearing.

6. When PG&E's method underforecasted recent recorded sales, DRA developed independent methods that provided reasonable results.

7. The basis for TURN's recommended adjustment to agricultural sales for drought effects was unclear.

8. The drought will tend to increase sales to MID/TID, and no party challenged the assumptions underlying TURN's recommended adjustment.

9. SMUD's estimate of its sales to its customers should be the best estimate of expected sales.

10. DRA developed a reliable method for estimating lost and unaccounted for power.

11. Some of the Geysers geothermal units have been curtailed because of insufficient steam in recent months.

12. In their brief operating histories, the Diablo Canyon nuclear units have had higher operating capacity factors and longer refueling outages than comparable plants.

13. A 12-week target refueling outage for nuclear plants allows two weeks for contingencies.

14. The average second-cycle refueling outage in the nuclear industry is just under 12 weeks.

15. When a plant is restarted after refueling, power is gradually increased to full power over a period of two weeks.

16. Extensive modifications to and scrutiny of the Rancho Seco plant should result in a higher capacity factor than experienced in the past.

17. Under the terms of an initiative adopted by SMUD voters in June, if the monthly capacity factor of Rancho Seco falls below 50% for four consecutive months, it will be shut down.

18. Shortages may cause shortfalls in PG&E's ability to obtain gas from the El Paso system during cold periods.

19. Shortfalls in deliveries on the El Paso system last year averaged around 103 MMcf/d.

20. Up to 170 gWh is available during off-peak periods from the Western Systems Power Pool and other Southwest sources at 15 mills/kWh. These purchases may be backed down. Up to 200 MW may be purchased from the CPP, and these purchases should be made whenever PG&E's incremental heat rate reaches 11,500 Btu/kWh. Sales to CPP are forecasted at 60 gWh at 24.4 mills/kWh.

21. Emergency power may be purchased at the price of power from the CPP (the monthly gas dispatch price times 11,500 Btu/kWh) plus a premium of 15%.

22. The price and amount of purchases from Sierra Pacific and the Lewiston Powerhouse are undisputed.

23. Both PG&E's service territory and the Pacific Northwest have received less rainfall than normal in recent years.

24. Low precipitation in the Northwest will limit the availability of PG&E's economy energy purchases from the Northwest in 1988.

25. The drought has reduced the supply of, and increased the demand for, low-cost economy energy. As a result, prices of economy energy from the Northwest will be higher than normal in 1988.

26. The average price of PG&E's purchases from the Northwest was 19.75 mills/kWh in June, 21.01 mills/kWh in July, and 21.47 mills/kWh through August 17, 1988.

27. In July, BPA made a preliminary offer to sell PG&E between 288 gWh and 298 gWh per month from September to December 1988 at 22 mills/kWh.

28. BC Hydro's territory has received normal rainfall in recent years. BC Hydro has regularly sold power to PG&E.

29. PG&E's entitlement on the Pacific Intertie will increase from 1639 MW to 1775 MW on April 1, 1989.

30. The chief resources displaced by purchases of Northwest economy energy are PG&E's fossil-fired steam generation units.

31. WAPA estimates that its Northwest purchases during the forecast period, delivered to the Tracy pumping plant, to be 1,998.1 gWh.

32. In recent years, SMUD has made use of any capacity on the AC line that NCPA and CSC did not use to purchase power from the Northwest.

33. Transmission constraints, reliability requirements, contractual requirements, load following requirements, and other limitations can cause PG&E's fossil-fueled generation units to be dispatched at times when they would not be dispatched on an economic basis.

34. PG&E has identified area reliability constraints in its East Bay, Humboldt Bay, and San Francisco areas. In addition, required protection of striped bass requires some units to be dispatched out of economic order.

35. PG&E has the contractual rights to back down purchases from some other utilities and QFs, to limit other utilities' purchases from the Northwest, and to limit generation by some other utilities.

36. PG&E currently operates its system in a way that meets the area reliability constraints.

37. PROMOD's default allocation of fuel limits overallocates generation to night and weekend periods.

38. ELFIN derates a unit's capacity before committing it to account for the plant's historical forced outage rate.

39. Accepting economy energy neither increases nor decreases PG&E's spinning reserve requirement.

40. Transmission over the AC and DC lines incurs line losses of 4.5%, and transmission over the DC line incurs an additional conversion loss of 4.5%.

41. Variable O&M costs are not related to changes in the cost of the marginal fuel but are related to variation in the generation by the swing units.

42. Some O&M costs that the generation by QFs allows PG&E to avoid vary over more than one year.

43. When modelers use the same assumptions and consistent modeling conventions, PROMOD, ELFIN 1.6, and PROSYM yield nearly the same results, within the range of variables pertinent to this case.

Conclusions of Law

1. The Commission should adopt load forecasts for the forecast year as follows: total PG&E sales of 67,236 gWh, total area load of 91,608 gWh, and total planning load of 91,805 gWh.

2. A reasonable estimate of hydroelectric generation for the forecast year is 21,007 gWh, including hydroelectric QFs. Reasonable costs are $3,767,000 for PG&E's facilities and $47,065,000 for the irrigations districts' generation.

3. It is reasonable for forecast purposes to assume the curtailments of the Geysers geothermal units because of insufficient steam will continue during the forecast period at about the same rate as was experienced in the first five months of this year.

4. Geothermal generation of 9734.8 gWh, based on a capacity factor of 81.4%, should be adopted as a reasonable forecast for PG&E's units. Reasonable estimates of the capacity of SMUD's units

and NCPA/CCPA's units are 100% and 96.1%, before scheduled maintenance.

5. Use of a full cycle capacity factor for nuclear plants is a fair way to balance maintenance done during refueling outages against reduced outages for scheduled maintenance.

6. For the Diablo Canyon nuclear units, a full cycle capacity factor of 67% and a 12-week refueling outage for Unit 2 should be adopted. For a typical 18-month cycle, this cycle capacity factor converts to an operating capacity factor of 79.1%. With a two-week ramp-up for Unit 2, generation of 13,088 gWh is a reasonable forecast.

7. PG&E's method for calculating nuclear fuel costs should be adopted.

8. A 65% capacity factor for the Rancho Seco nuclear plant during power ascension and during operation should be adopted for the forecast.

9. PG&E's approaches to estimating expected generation from wind QFs and hydroelectric QFs are reasonable.

10. PG&E's estimates of generation by large geothermal, solar, and small QFs are reasonable, as is the Santa Fe-PG&E stipulation of the proportions of fixed- and variably priced small QFs.

11. PG&E's estimate of generation by thermal QFs, after certain corrections proposed by DRA, is reasonable.

12. A forecast of total generation by QFs of 11,679.6 gWh, as shown in Table 3, should be adopted.

13. No purchases from DWR should be forecasted for 1988. In 1989, the price of purchases from DWR should be assumed to be at the same price as purchases from the Pacific Northwest.

14. The Solano County wind turbine's generation of 3.3 gWh should be included in the resource mix, but its cost should not be included in the revenue requirement in this case.

15. The capacity price paid to QFs for as-available capacity should remain at $42/kW/yr, until further order of the Commission. This figure should also be used in forecasting PG&E's revenue requirement.

16. The DRA-PG&E stipulation of gas prices, as shown in Table 4, should be adopted.

17. A reasonable fuel oil inventory is 5.6 million barrels.

18. Reasonable estimates of the price of Northwest economy energy in 1988 are 23 mills/kWh on peak and 21 mills/kWh off peak.

19. It is reasonable to assume that enough Northwest economy energy will be available to fill 100% of PG&E's entitlement on the Pacific Intertie during on-peak periods and 50% of the entitlement during off-peak periods in 1988.

20. It is reasonable to assume that Northwest economy energy will be available up to 90% of PG&E's entitlement on the Pacific Intertie at all times in 1989.

21. It is reasonable to assume that the average price of economy energy from the Northwest in 1989 will be 90% of PG&E's average incremental fossil-fired steam generation cost.

22. A reasonable estimate of the maximum purchases of Northwest power by WAPA is 2,088 gWh.

23. It is reasonable to assume that SMUD, NCPA, and CSC, in combination, will fully use their allotted 200 MW of capacity on the AC line to import Northwest power, except when minimum load conditions or the operation of Rancho Seco requires SMUD to back down its purchases.

24. A reasonable estimate of the cost of distillate oil is $23.53 per barrel, or $4.06 per MMBtu, and a reasonable distillate oil inventory for combustion turbine use is 100,000 barrels.

25. A reasonable estimate of the amount of generation available from the Helms pumped storage plant because of upstream runoff and normal water management is 34.5 gWh.

26. To be useful in this type of proceeding, a model must accurately reflect the actual operation of the utility's system.

27. Models should reflect the minimum generation requirements associated with the area reliability requirements identified by PG&E. Minimum generation should not be allocated by default by PROMOD for the East Bay, Coastal, or San Francisco areas, but should be allocated 62% to day time, 12% to nighttime, and 26% to weekends.

28. The backdown order listed in Ex. 48 is reasonable and should be followed in the models. In addition, if minimum load is sufficiently low, Rancho Seco and Diablo Canyon should be backed down.

29. Modelers should correct for ELFIN's derating of capacity for forced outages in committing units to meet commitment targets.

30. In attempting to meet a commitment target, ELFIN modelers should check to see that the model does not commit more than the needed resources and if necessary should choose a different target and repeat the process.

31. The Helms pumped storage plant should be 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.

32. Line and conversion losses associated with transmission over the AC and DC lines should be taken into account when determining whether purchases from the Northwest are economic, but no adjustments should be made for these losses in the determination of the IER or for the calculation of the revenue requirement other than the LUAF amount.

33. Northwest purchases by NCPA/CSC should not vary between the QFs-in and QFs-out simulations, but modelers should allow for reductions of Northwest purchases by SMUD and WAPA during minimum load periods, which may vary between the QFs-in and QFs-out runs.

34. The annual average UEG rate should be used throughout the calculation of the IER.

35. The avoided O&M payment should be removed from the calculation of the IER and added as a separate payment to the base energy rates paid to QFs.

36. A reasonable base estimate of the variable O&M cost that the contribution of QFs allows PG&E to avoid is 1.82 mills/kWh. This base figure should be adjusted to reflect the proportion of conventional fossil generation in PG&E's resource mix. Parties should calculate the O&M adder by determining the amount of conventional fossil generation added between the QFs-in and QFs-out runs. This amount should be multiplied by 1.82 mill/kWh. The product should be divided by the total generation of variably priced QFs (the generation removed in the QFs-out run).

37. PG&E should present a study of the O&M costs avoided by QFs' generation in its test year 1990 general rate case.

38. Standby units that can be restarted in a short time should be modeled to be available during the entire forecast period and may be dispatched in the QFs-out run. Substitute units--newly constructed plants or new contracts for purchases--should not be assumed to be in existence or available in the QFs-out run.

39. Parties should be permitted to calculate an IER that assumes no generation from Rancho Seco. If Rancho Seco is shut down during the forecast period, this alternate IER should be used in revising the energy payments to QFs.

40. The models should be rerun to reflect the determinations of this decision.

41. Many QFs' contracts to provide firm capacity allow for derating of the contractual capacity and associated payments if the QF fails to meet a specified capacity factor at certain times. In its next ECAC application, PG&E should file information on the extent of these deratings and reduced payments.

O R D E R

IT IS ORDERED that:

1. The temporary suspension of PG&E's Annual Energy Rate (AER) authorized in D.88-09-036 shall be lifted, and PG&E's AER shall be reinstated at the time that the rates resulting from this decision become effective.

2. The capacity price paid to qualifying facilities (QFs) for as-available capacity shall remain at $42/kW/yr until further order of the Commission.

3. PG&E shall present a study of the operations and maintenance costs avoided by QFs' generation in its test year 1990 general rate case.

4. In its next Energy Cost Adjustment Clause application, PG&E shall provide information on the extent of the derating of contractual capacity in QFs' contracts for firm capacity and associated reductions in payments to these QFs.

5. Parties sponsoring model runs in this proceeding shall run their models with inputs reflecting the determinations of this decision. The model runs and reporting of the results shall be coordinated by the Administrative Law Judge.

This order is effective today.

Dated NOV 23 1988, at San Francisco, California.

STANLEY W. HULETT
President
DONALD VIAL
FREDERICK R. DUDA
G. MITCHELL WILK
JOHN B. OHANIAN
Commissioners

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

Victor Weisser

Victor Weisser, Executive Director

APPENDIX A
Page 1

List of Appearances

Applicant: Roger J. Peters, Robert B. McLennan, and Mark R. Huffman, Attorneys at Law, for Pacific Gas and Electric Company.

Interested Parties: Messrs. Lindsay, Hart, Neil & Weigler, by Michael Peter Alcantar, Attorney at Law, for Cogenerators of Southern California and its individual members; C. Hayden Ames, Attorney at Law, for Chickering & Gregory; John K. Van de Kamp, Attorney General, by Andrea Sheridan Ordin, Michael J. Strumwasser, Mark J. Urban, Peter H. Kaufman, and Peter Van der Naillen, Deputy Attorneys General, for the Attorney General's Office, State of California; Messrs. Morrison & Foerster, by Jerry R. Bloom, Attorney at Law, for California Cogeneration Council; Messrs. Jackson, Tufts, Cole & Black, by William H. Booth and Allan J. Thompson, Attorneys at Law, for California Large Energy Consumers Association; David R. Branchcomb, for Henwood Energy Services, Inc.; Messrs. McCracken, Byers & Martin, by David J. Byers, Attorney at Law, and Reed V. Schmidt, for California City County Street Light Association; Thomas P. Corr, Attorney at Law, for Independent Power Corporation; Messrs. Brobeck, Phleger & Harrison, by Gordon E. Davis, Attorney at Law, for California Manufacturers Association; Messrs. Biddle & Hamilton, by Richard L. Hamilton and Terri A. De Mitchell, Attorneys at Law, for Western Mobilehome Association; Lawrence E. De Simone, for Energy Management Associates, Inc.; Michel Peter Florio, Attorney at Law, for Toward Utility Rate Normalization (TURN); Norman J. Furuta, Attorney at Law, Thomas Vargo, and Sam De Frawi, for the Department of the Navy; Steven Geringer and Karen Mills, Attorneys at Law, for California Farm Bureau Federation; Michael Golden, Attorney at Law, for Redwood Alliance; Jerry W. Green, for Resource Management International, Inc.; Law Office of Dian M. Grueneich, by Dian M. Grueneich, Barry H. Epstein, and Matthew V. Brady, Attorneys at Law, for California Department of General Services; Messrs. Hanna & Morton, by Douglas K. Kerner, Attorney at Law, for Santa Fe Geothermal, Inc., Union Oil Company of California, Freeport-McMoRan Resource Partners; John D. Quinley, for Cogeneration Service Bureau; Messrs. Armour, St. John, Wilcox, Goodin & Schlotz, by James D. Squeri, Attorney at Law, for UNOCAL; Messrs. Downey, Brand, Seymour & Rohwer, by Philip A. Stohr and Deborah K. Teltier, Attorneys at Law, for Industrial Users; Messrs. Barakat, Howard & Chamberlin, Inc., by Nancy C. Thompson, for Barakat, Howard & Chamberlin; John Vickland, Attorney at Law, for BART; Robert B. Weisenmiller, for Morse, Richard, Weisenmiller & Associates, Inc.; Sara Hoffman, Deputy County Administrator, for Contra Costa County; William B. Marcus and Jeffrey A. Nahagian, for JBS Energy, Inc. and TURN; Jan Smutny-Jones, Attorney at Law, for Independent Energy Producers and California Cogeneration Council; Randolph L. Wu, Attorney at Law, for El Paso Natural Gas Company; Messrs. Lindsay, Hart, Neil & Weigler, by Frederick J. Dorey, Attorney at Law, for Midset Cogeneration Company, et al.; A. Kirk McKenzie, Attorney at Law, for California Energy Commission; David R. Clark, Attorney at Law, and Lynn G. Van Wagenen, for San Diego Gas & Electric Company; Graham & James, by Michael P. Hurst and Martin A. Mattes, Attorneys at Law, for Amerada Hess Corporation; and Karen Edson and Joseph G. Meyer, for themselves.

Division of Ratepayer Advocates: Catherine A. Johnson, Attorney at Law, Meg S. Gottstein, and James H. Barnes.

(END OF APPENDIX A)

Decision ___________

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of PACIFIC GAS AND ELECTRIC COMPANY for Commission order finding that PG&E's gas and electric operations during the reasonableness review period from February 1, 1987 to January 31, 1988, were prudent.	Application 88-04-020 (Filed April 7, 1988)
Application of PACIFIC GAS AND ELECTRIC COMPANY for authority to adjust its electric rates effective August 1, 1988.	Application 88-04-057 (Filed April 21, 1988)

(See Appendix A for appearances.)

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OPINION

I. Background

A. Procedural History

Pacific Gas and Electric Company (PG&E) filed Application (A.) 88-04-020 and A.88-04-057 on April 7 and 21, 1988. A.88-04-057, which is the subject of this decision, requested an increase of $129.3 million to PG&E's electric rates on an annualized basis effective August 1, 1988. This requested increase of approximately 2.6% above present rate levels was based on revenue requirement increases related to PG&E's Energy Cost Adjustment Clause (ECAC), Annual Energy Rate (AER), Electric Revenue Adjustment Mechanism (ERAM), and Diablo Canyon Adjustment Clause (DCAC). During hearings, PG&E added a request to reflect an adjustment related to its Conservation Financing Adjustment (CFA).

In A.88-04-057, PG&E also asked the Commission to establish a balancing account for the recovery of costs incurred in connection with deferring the operation of qualifying facilities (QFs). However, PG&E later withdrew this request (Tr. 15:1525).

In A.88-04-020, PG&E sought approval of the reasonableness of its gas and electric operations during the period from February 1, 1987, through January 31, 1988. The two applications were consolidated and the proceeding was divided into two phases by order of the Administrative Law Judge (ALJ) at the prehearing conference of May 12, 1988, as stated in the ALJ's ruling of May 26, 1988. The first phase was to consider those issues relating to the forecasts of fuel costs, resource mix, and variable payments to QFs. The second phase, to be heard following the issuance of the forecast decision, will address the reasonableness of PG&E's operations. This opinion decides only the first phase issues.

The evidence presented at the hearings during the forecast phase resulted in various adjustments to PG&E's requested rate increase. In its brief of September 19, 1988, PG&E states that its final proposed annual revenue increase is $64.5 million. The components of this request are an ECAC increase of $271.4 million, an AER increase of $18.4 million, an ERAM decrease of $201.6 million, a DCAC decrease of $14.1 million, and a CFA decrease of $9.6 million.

On May 16, 1988, PG&E filed a motion to suspend the AER mechanism and to recover the difference between AER revenues and AER expenses in the ECAC balancing account until the date of any rate revision resulting from this proceeding. We granted the relief requested by PG&E in Decision (D.) 88-09-036. In today's decision we affirm our intent to reinstate the AER when new rates become effective.

Twenty-one days of hearings in the forecast phase of this proceeding were held between June 27 and September 1, 1988, in San Francisco, California. This matter was submitted on the filing of concurrent opening briefs on September 19, 1988, and concurrent reply briefs on September 26, 1988. The parties filing briefs in this proceeding included PG&E; the Commission's Division of Ratepayer Advocates (DRA); the California Cogeneration Council, Independent Energy Producers, and Midset Cogeneration Company (CCC); the Federal Executive Agencies (FEA); the California Manufacturers Association (CMA); the California Large Energy Consumers Association (CLECA); Toward Utility Rate Normalization (TURN); Santa Fe Geothermal, Inc., Unocal Corporation, and Freeport-McMoRan Resource Partners (Santa Fe); Independent Power Corporation (IPC); San Francisco Bay Area Rapid Transit District (BART); Contra Costa County (Contra Costa); the California Department of General Services (DGS); and the California Farm Bureau Federation (Farm Bureau). In addition, on August 31, 1988, the Association of California Water Agencies (ACWA) submitted a letter to the ALJ which described its position on some of the issues in this case.

B. The Framing of the Issues

In recent years, the focus and purpose of an ECAC proceeding has been to enable 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. PG&E's current ECAC continues the consideration of these ECAC-related issues. In addition, this proceeding marks the beginning of annual updating in ECAC cases of key components of the calculation of prices paid for power sold to the utility by QFs.

Variable QF prices are the sum of two basic components: a variable payment for capacity and a variable payment for energy. Critical to the determination of these payments are the utility's Energy Reliability Index (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 this case, consideration of the ERI was simplified by the fact that we have not yet approved a method for calculating PG&E's ERI, and the parties differed only on when a previously adopted capacity payment value should be revised.

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 price the utility pays for the variably priced QFs' energy.

These QF issues have been added to the ECAC as a result of D.88-03-026 in the continuing standard offer proceeding, A.82-04-44, et al. In that decision, we concluded that annual updating of variable QF payments should take place in a utility's ECAC proceeding. We reasoned that it was preferable "not to create a unique proceeding for QFs [for this purpose], but rather to make optimal use of ECAC by setting QF prices at the same time (and from the same assumptions) that we adjust utility rates." (D.88-03-026, at p. 3.)

Logic links conventional ECAC issues with 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.

To smooth the introduction of ERI- and IER-related issues and the computer models used to derive them into the Commission's periodic proceedings, the Commission in D.87-12-066 (the decision in the test year 1988 general rate case of Southern California Edison Company (Edison)) adopted a procedure to be followed in developing and presenting testimony related to the IER and ERI. The purpose of this procedure was to ensure the full exchange and understanding of models and data used to develop the IER and ERI.

Specifically, the Commission required that all parties to future 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 Edison's 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 which Edison 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.

The workshop procedure set up for Edison's ECAC was also followed in this case. On April 6, 1988, the CACD noticed a workshop to develop common data set assumptions for ELFIN computer model runs to be used in this proceeding. The workshops were held on May 2, 3, and 19, 1988, with Linda Gustafson of the CACD serving as arbiter. On June 29, 1988, the common data set for a base case ELFIN run to which the workshop participants had agreed was served on all parties by the CACD.

Developments soon overcame the schedule the Commission set up in D.87-12-066, however. Around the time of the May workshops, ELFIN was revised, and the new version, known as ELFIN

1.6, was quickly adopted by those parties using the ELFIN model. The base case run using the common data set, which employed the old version known as ELFIN 1.58, proved to be of little use in these circumstances.

In addition, three different production cost models were advocated and used by parties in this case, adding to the complexity of the issues. DRA and CCC used ELFIN 1.6, the new version. CCC also used PROMOD in its analyses, and PG&E used PROMOD as its preferred model. Santa Fe used PROSYM, another new model. 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 with some random elements to develop its forecast of the system's operation.

In response to these circumstances, the ALJ divided the forecast phase into two parts, roughly corresponding to the inputs and outputs of the models. The first part addressed what was described as the "initial determination of the issues needed to perform a more refined run on the various computer models" or the "resource plan input assumptions." At the conclusion of this part, the ALJ received short briefs on these issues and prepared a ruling of August 5, 1988, which directed the parties to use a specified set of assumptions in runs of the three models. This was an attempt to provide a common basis for comparison of the models based on assumptions that reflected the hearing record and in place of the outdated ELFIN 1.58 base run. The second part of the hearing considered the results of the runs using the assumptions from the ALJ's ruling, the parties' recommended IERs, revenue requirements, revenue allocation, and positions on the few rate design issues.

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 used in determining variable QF payments. The issues also included the allocation of any revenue changes resulting from this proceeding, and rate design "necessary to deal with current problems" for agricultural and residential time-of-use rates, as directed in D.88-01-016.

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. Then we will consider the differences between the three production cost models that were used in this proceeding. For reasons described in this decision, we will defer our consideration of the revenue allocation and rate design issues until a later decision.

II. Load Forecast

Many of the issues in this category were common issues in past ECAC cases. Because PG&E presented a complete description of its position on many of these issues in the testimony accompanying its application, other parties tended to describe their positions by referring to or adjusting PG&E's initial recommendations.

In addition, many of the issues in this area were influenced by two important factors. First, PG&E's initial sales figures were based on an economic forecast that weighed optimistic economic forecasts against more pessimistic forecasts to develop what PG&E believed was the most probable outcome. By the time of the hearings, economic forecasts were more consistently optimistic; DRA's forecasts, for example, were based on an undiluted optimistic forecast of economic activity.

Second, PG&E's initial filing contained recommendations based on its March snow survey of its potential for producing power from its hydroelectric units. However, PG&E was able to present the results of its June survey as part of the record in this case (Ex. 41). The forecast for hydropower primarily affects the outlook for PG&E's hydroelectric resources, but it also influences the hydroelectric production from some of PG&E's public agency customers. To the extent that these customers are unable to produce power from their hydroelectric facilities, PG&E's sales to these customers will increase.

PG&E's large service territory surrounds several utilities operated by public entities. Because of interconnections among the utilities, power flows freely and ignores service territory boundaries. In forecasting PG&E's load, it is also necessary to consider the load and resources of some of these other entities to derive PG&E's net load or sales resulting from exchanges with these utilities.

In the final briefs, most of the parties expressed their satisfaction with most of the elements of the load forecast assumptions of the ALJ's August 5 ruling. We will briefly set out the rationale supporting those elements, and will address the remaining contested issues more thoroughly.

A. <u>Residential Sales</u>

We will adopt DRA's recommendation of 22,485 gigawatt-hours (gWh), which reflects a more recent and more optimistic economic forecast.

B. <u>Small Light and Power Sales</u>

DRA's forecast of 7,171 gWh, reflecting its optimistic economic forecast, will be adopted.

C. <u>Medium Light and Power Sales</u>

DRA's recommendation was independently derived because PG&E's approach underforecasted actual sales through March 1988. We will adopt DRA's figure of 16,096 gWh.

D. Large Light and Power Sales

Sales to the industrial customers PG&E shares with the City and County of San Francisco (CCSF) are forecasted to be 603 gWh. When CCSF's hydroelectric facilities are unable to generate as much power as in normal years, PG&E will sell more power to the shared customers. The adopted figure was advocated by TURN and reflects the effect of the current drought on these sales.

The forecast of sales to other large light and power customers of 14,803 gWh is based on the optimistic economic forecast.

The resulting total sales figure is 15,406 gWh.

E. Agricultural Sales

DRA noted that PG&E's forecasting approach had underforecasted actual agricultural sales by 20.5% for the six months ending March 1988. DRA therefore developed an independent, econometrically derived forecast of these sales. We will adopt the resulting recommendation of 3,192 gWh.

TURN argued that 13 gWh should be added to DRA's forecast to reflect the effect of the drought. TURN's original adjustment reflected both adjustments to agricultural rates and drought effects. The rate aspect has become moot, but most of TURN's written and oral testimony focused on these price effects. TURN's reference to use of PG&E's and DRA's agricultural price forecasting models leaves unclear the basis for its drought recommendation. In light of the ambiguous state of the record and the small level of TURN's recommended adjustment, we decline to adopt TURN's adjustment.

F. Street Lighting

DRA's independently derived estimate of 355 gWh is more in line with recent sales trends than PG&E's estimate and will be adopted.

G. Railway and Public Authority

PG&E's estimates of 249 gWh for railway sales and 757 gWh for public authority sales were uncontested.

H. Resale

The sales for resale category has two components.

First are the sales to the Modesto Irrigation District and the Turlock Irrigation District (MID/TID). TURN argues that the figures presented by PG&E and accepted by DRA should be increased by 198 gWh to reflect the effect of the drought. MID/TID's own hydroelectric units will produce less electricity in this drought year, and therefore these entities must purchase more power from PG&E. TURN reasons from information presented by TID and some indirect facts to develop its estimate.

All parties seem to agree that the drought will tend to increase sales to MID/TID, but TURN's method of developing an estimate of those increased sales presents problems. TURN has made a clever, if somewhat rough, use of available information, but its estimate assumes that all of MID/TID's shortfall will be purchased from PG&E and that these entities have no other sources of power to make up the hydroelectric shortfall. This assumption is contradicted, however, in TURN's own testimony. TURN's Ex. 30, which developed an earlier estimate, assumed that only some of the shortfall would be made up by PG&E. No clarification of this apparent contradiction about a key assumption appears elsewhere in the record.

Despite the cloudy state of the record, we will adopt TURN's proposed adjustment. Neither the cross-examination nor the briefs of other parties challenged these assumptions or pointed out the contradiction in TURN's testimony. We will take this silence as evidence that the assumptions underlying TURN's estimate are roughly correct. Thus, we will increase the sales to MID/TID by 198 gWh, spread out over August through December 1988. The revised sales to MID/TID total 573 gWh.

An adjustment must also be made to PG&E's base forecast of sales for resale to other customers. The results of the June snow survey (Ex. 41) show that production from CCSF's hydroelectric units will be 198 gWh less than previously forecasted. Because of this lower production, sales to CCSF should also increase by 198 gWh. (This 198 gWh adjustment is separate from the 198 gWh adjustment discussed in the preceding paragraphs.) PG&E agreed with this adjustment (Tr. 16:1692-1693). Although the oral stipulation stated that this increase should be added to sales to MID/TID, other evidence indicates that an adjustment to sales to CCSF is correct (see Ex. 62). The net effect is the same in either case, and we will treat this as an increase in sales to CCSF for resale. A compensating reduction will be made in the Other Area Load line. When this 198 gWh is added to the uncontested base forecast of 604 gWh, the revised total for other sales for resale is 802 gWh.

The total sales for resale amount is 1,375 gWh.

I. Interdepartmental Sales

PG&E's estimate of 150 gWh was uncontested and will be adopted.

J. Total PG&E Sales

The total resulting from our adopted figures is 67,236 gWh.

K. SMUD Sales

Sales by the Sacramento Municipal Utility District (SMUD) to its customers are estimated by SMUD to be 8,084 gWh. We will adopt this figure rather than the estimate resulting from PG&E's independent analysis because we believe that SMUD is more likely to have an accurate assessment of its own needs.

L. Lost and Unaccounted for Power

Lost and unaccounted for power (LUAF) varies with the amount of sales. The exact figure must be calculated from the total sales we have adopted. DRA's approach to calculating LUAF showed a better statistical reliability than PG&E's, and DRA's method should be used to develop the appropriate estimate of LUAF. Based on the estimates of sales that we have adopted, LUAF will amount to approximately 7,060 gWh. DRA should supply the precise LUAF figure in its comments on the proposed decision.

M. <u>Other Area Load</u>

Two adjustments should be made to PG&E's initial estimates of Other Area Load.

First, the total should be decreased to reflect 121 gWh of increased sales to the industrial customers that PG&E shares with CCSF, as mentioned in the discussion of sales to large light and power customers.

Second, the total should reduced by 198 gWh to compensate for the increased sales that result from CCSF's decreased hydroelectric generation, as discussed in the section on sales for resale.

The resulting total for Other Area Load is 9,226 gWh.

N. <u>Total Area Load</u>

The estimate of Total Area Load resulting from the preceding figures is 91,606 gWh.

O. <u>Deliveries Out of Area</u>

The filed testimony contained an error that remained undetected until after the ALJ's ruling of August 5. All parties now agree that the correct estimate for deliveries out of area should be increased, although slight differences remain in what the parties view as the correct figure. We will adopt 196.8 gWh (rounded to 197 gWh for purposes of this decision) as the estimate for deliveries out of area. (See Ex. 50; Tr. 17: 1852-1856.)

P. <u>Total Planning Load</u>

The sum of all the above components is a total planning load of 91,803 gWh. Table 1 summarizes our conclusions on this topic.

TABLE 1

Sales Forecast Assumptions

Class of Service		Amount in Gigawatt-hours
Residential		22,485
Small Light & Power		7,171
Medium Light & Power		16,096
Large Light & Power:		15,406
CCSF	603	
Other	14,803	
Agriculture		3,192
Street Lighting		355
Railway		249
Public Authority		757
Resale:		1,375
MID/TID	573	
Other	802	
Interdepartmental		150
TOTAL PG&E SALES		67,236
SMUD		8,084
LUAF		7,060*
Other Area Load		9,226
TOTAL AREA LOAD		91,606
Deliveries Out of Area		197
TOTAL PLANNING LOAD		91,803

* For illustration only; precise figure should be developed as a function of sales (DRA's method).

III. Resources

A. Hydroelectric Generation

The estimate of hydroelectric generation developed from the June 1 snow survey (Ex. 41) was accepted by all parties. We will adopt the estimate of 21,007 gWh for hydroelectric generation, including hydroelectric QFs, and the associated costs of $3,767,000 for PG&E's facilities, and $47,065,000 for the irrigation districts' generation.

B. Geothermal Generation

1. PG&E's Plants

a. Amount of Generation

PG&E originally estimated that a capacity factor of 74% was reasonable for the forecast period. This capacity factor was considerably reduced from recent years' experience. Beginning last year, however, 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, and its estimates reflect this expectation.

DRA forecast a capacity factor of 87.1%. DRA rejects PG&E's fears about the steam curtailments, and points out that PG&E's claims of confidentiality have prevented DRA from adequately investigating the basis for the steam curtailments. DRA contends that PG&E acknowledged that removal of the steam curtailments would increase the Geysers' capacity factor to more than DRA's recommendation.

The issue of how much consideration to give to the steam reservoir problems is central to developing a forecast of geothermal generation. PG&E expects the steam-related curtailments to increase during the forecast period; DRA expects them to cease. The short history of these reservoir problems provides little basis for evaluating these competing assertions.

From the start of these problems in February 1987 through December 1987, steam-related curtailments amounted to 598,965 megawatt-hours (MWh). For the 12-month forecast period, PG&E projects that curtailments related to insufficient steam will be 1,749,096, a considerable increase (Ex. 26). PG&E acknowledged that this figure was somewhat based on guesswork, and we are not persuaded that there is a reasonable basis for accepting PG&E's estimate. However, in light of recent experience with the steam curtailments, we are also skeptical that the problem will cease, as DRA has assumed.

We will develop a capacity factor which reflects recent experience with the steam curtailments. PG&E's witness testified that curtailments due to insufficient steam from January through May 1988 added up to 353,947 MWh. If we project this level of curtailment for a 12-month period, the result is 849,473 MWh per year. If we use this level of curtailments due to insufficient steam and the same estimates of period hours, scheduled outages, and forced outages used by PG&E (Ex. 26, p. 5), the result is a capacity factor of 81.4%. This capacity factor provides a reasonable estimate of geothermal generation, and neither overemphasizes nor ignores the steam reservoir problems.

We will therefore adopt an overall capacity factor of 81.4% for PG&E's geothermal units. This capacity factor results in generation of 9734.8 gWh (Ex. 50, p. 2; Ex. 59, p. 8.). Better information on the status of the steam reservoir and any trend in curtailments due to insufficient steam should be available by the time of the next forecast proceeding.

b. <u>Price</u>

The price of steam for generation of geothermal energy for 1988 is based on recorded 1987 data and is fixed at 14.93 mills/kWh for all of 1988. The price for 1989 will depend on the assumed level of conventional steam generation and nuclear generation for 1988 and will depend on the resolution of these issues for forecast purposes. PG&E estimated that the assumption contained in the ALJ's ruling of August 5 resulted in a 1989 price for geothermal steam of 15.16 mills/kWh. Since the assumptions we adopt differ from those contained in the ALJ's ruling, the 1989 price for geothermal steam will have to be recalculated. Parties should report the results of their calculations in their comments on the proposed decision.

2. Other Geothermal Generation

SMUD, the Northern California Power Agency (NCPA), and the Central California Power Agency (CCPA) operate geothermal units. The generation from these units is not sold directly to PG&E, but it is available to meet area load. No party contested PG&E's estimates of the availability of geothermal energy from these units. Based on recorded 1986 and 1987 data, PG&E estimated that SMUD's units' availability of generation would be 100% of capacity before scheduled maintenance and that NCPA and CCPA's units' availability of generation would be 96.1% of capacity before scheduled maintenance. We will adopt these estimates.

C. Nuclear Generation

1. Diablo Canyon

a. Amount of Generation

(1) Position of the Parties

PG&E originally recommended an operating capacity factor (capacity factor before accounting for any refueling outage and scheduled maintenance) of 78%, with a 12-week refueling outage for Unit 2 beginning September 15, 1988. This capacity factor was above the national average for similar plants and was consistent with Diablo Canyon's history, according to PG&E.

DRA forecasted an operating capacity factor of 86%, with a 12-week refueling outage for Unit 2. DRA based its position on the annual operating capacity factors that the Diablo Canyon units had achieved in the past, ranging from 84% to 91.5%. In addition, DRA argued that PG&E had historically underforecasted the performance of the Diablo Canyon units. Furthermore, national averages show an increase of 3.6% in the operating capacity factor between nuclear plants' first fuel cycle and second cycle. DRA's estimates are in line with these trends, according to DRA.

CCC advocates an operating capacity factor of 75.2% for the Diablo Canyon plant. According to CCC, the Commission has ruled in D.86-07-004 that when five years of a plant's operating data are not available, the forecast should be based on the industry's average performance. Since Diablo Canyon has operated for only three years, this estimating technique should be followed. The second-cycle average operating capacity factors of comparable units is 75.2%, and CCC argues that this figure should be adopted for Diablo Canyon.

Santa Fe supports PG&E's proposed 78% operating capacity factor as being similar to historical operating records. However, Santa Fe argues that the 12-week refueling outage for Unit 2 is unreasonably short and that a 14-week outage better reflects PG&E's experience with the Diablo Canyon units. Santa Fé points out that all refueling outages to date for Diablo Canyon have taken more than 12 weeks and that the average refueling outage for the industry is 14 weeks. Santa Fe concludes that the forecast should be consistent with that history. Thus, Santa Fe's recommended cycle capacity factor would be somewhat lower than PG&E's.

TURN notes, apparently without making a recommendation, that the capacity factor and refueling outage adopted in the ALJ's ruling exceeds the assumed capacity factor underlying the proposed Diablo Canyon settlement. TURN argues that the adopted 12-week refueling outage is shorter than both the experience at Diablo Canyon and the industry's average. TURN therefore supports Santa Fe's recommendation of a 14-week refueling outage.

(2) Discussion

The variety of the parties' positions on this issue arises from their emphases in trying to accommodate two facts of Diablo Canyon's brief operating history: its high operating capacity factor and its long refueling outages. DRA, for example, emphasizes the high annual operating capacity factors that the Diablo Canyon units have recorded so far. Table 2 sets out these annual operating capacity factors for each unit.

TABLE 2

Annual Operating Capacity Factors
Diablo Canyon

Year	Unit 1	Unit 2
1985	86.1%	
1986	85.0%	84.0%
1987	91.5%	84.7%

These operating capacity factors are much higher than the average for comparable units of 75.2% that CCC argues should be adopted.

Santa Fe, now supported by TURN, emphasizes the length of the refueling outages to date and argues that a 14-week refueling outage should be assumed for the refueling of Unit 2 scheduled for Fall 1988.

The problem with both of these emphases is that they ignore the link between long refueling outages and high operating capacity factors. PG&E's witnesses testified that maintenance is performed during the refueling outages and that this maintenance reduces forced outages (Tr. 12:1209-1210). This assertion is supported by the high operating capacity factors achieved by the Diablo Canyon units so far.

None of the parties' approaches successfully reconciles these considerations. DRA's approach combines high historical operating capacity factors but ignores the long refueling outages that helped sustain the plants' operation. CCC uses industry averages, but does not consider that the history of this plant has been anything but typical. PG&E developed its estimate by increasing its previous forecast somewhat but neglected to compare that earlier forecast to the plant's actual operation. Santa Fe would lengthen the refueling outage but soft-pedal the high plant performance recorded so far.

For forecasting purposes, we prefer to retain the 12-week refueling outage. Twelve weeks is the expected or target time for completion of refueling, and the units are designed to allow this target to be met. The 12-week estimate already provides two weeks above the 10-week optimum refueling time to allow for contingencies that may arise (Tr. 12:1200). To build in an additional two weeks, even though it may be supported by the brief history of the Diablo Canyon units, would amount to a forecast that greater-than-normal problems will arise during the refueling of Unit 2. In light of the fact that the average second-cycle refueling outage in the industry is just slightly less than 12 weeks (Ex. 35), we are unwilling to forecast unusual problems for the coming refueling.

Retaining the 12-week refueling outage, however, requires us to take into account the maintenance that PG&E claims was performed during the longer outages to date. The record provides a basis for resolving this problem by considering the full cycle capacity factors of the units.

The full cycle capacity factor 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. 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.

Use of the full cycle capacity factor also moderates the extremes of Diablo Canyon's performance to date. So far, Diablo Canyon's operating capacity factors have been much higher than the average for the industry or for comparable units. Similarly, the lengths of its refueling outages have been greater than average. But the full cycle capacity factors recorded in the first few cycles are closer to the performance expected of such units and show considerable stability. For the first cycle, the full cycle capacity factor was 67.9% for Unit 1 and 66.2% for Unit 2, and Unit 1's second cycle capacity factor was slightly lower (Ex. 35; Tr. 12: 1192, 1204). From these figures, we conclude that a full cycle capacity factor of 67% is reasonable to expect from the Diablo Canyon units.

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. The latter information was not presented in this case. However, a rough conversion to an expected operating capacity factor may be made by assuming a typical cycle of 18 months and a typical refueling outage of 12 weeks. Using these assumptions and the 67% cycle capacity we have found reasonable to use, we calculate a corresponding operational capacity factor of 79.1%. In light of Diablo Canyon's historical operation, and the tendency of units to improve capacity factor after their first cycle (see Ex. 19, p. 10-4), we believe that this estimate is a reasonable forecast of the generation that the Diablo units will produce during the forecast year.

When we apply this operating capacity factor to the ratings of the Diablo Canyon units and take into account the 12-week refueling outage we have adopted, the resulting predicted generation for the forecast period is 7,435 gWh for Unit 1 and 5,799 gWh for Unit 2, for a total of 13,234 gWh.

However, a slight adjustment must be made to these figures. PG&E testified without challenge that after refueling, the generation of a restarted unit is increased to full power gradually over two weeks. This ramp-up reduces the total generation slightly, by approximately 146 gWh (Tr. 15:1529; Ex.50). Although the full cycle capacity factors we have relied on would ordinarily take this ramp-up into account, the first cycle is measured from commercial operation date and begins with the capability to operate at full power. Because of our reliance on the full cycle capacity factors from the first cycles, it is appropriate to account for the ramp-up in the generation expected from Unit 2, which will be refueled during the forecast period. Accordingly we will subtract 146 gWh from the expected generation of Unit 2, for a total of 5,653 gWh from Unit 2 and 13,088 gWh from both units.

We note that the actual generation during the reasonableness period of February 1, 1987 through January 31, 1988, which included the first refueling of Unit 2, totaled 8,607 gWh for Unit 1 and 5,755 gWh for Unit 2, a total of 14,362 gWh (Tr. 12:1197-1198). Even after taking into account the extraordinary operating capacity factor achieved by Unit 1 during 1987, we believe that our adopted forecast of generation is reasonable.

b. Nuclear Fuel Cost

PG&E's method for calculating the nuclear fuel revenue requirement was uncontested and will be adopted. The estimates in the record suggest that the nuclear fuel revenue requirement associated with our adopted level of generation from the Diablo Canyon plant will be about $100 million. (See Ex. 1, p. 5-13, Ex. 62.)

2. Rancho Seco

SMUD voters on June 7, 1988, approved a ballot measure that permits Rancho Seco to operate for an 18-month fuel cycle. PG&E's original estimate was adopted with certain modifications proposed by Santa Fe in the August 5 ALJ ruling, and most parties now support that estimate.

We believe that the estimate of generation from the August 5 ruling is reasonable. That estimate assumes that the plant will operate at a 65% operating capacity factor during power ascension and after full power is achieved. Full power is assumed to be reached in November 1988. The 65% operating capacity factor converts to a cycle capacity factor of 53.6%, which approximates the historic cycle capacity factor of 52.8% for nuclear plants of similar design (Ex. 8).

CCC continues to argue for a 41% capacity factor based on historical performance of the plant. However, the plant has undergone extensive modifications under intensive scrutiny by the Nuclear Regulatory Commission since that historic record was established, and better performance may reasonably be expected as a result of the modifications. In addition, the recent ballot measure requires SMUD's Board of Directors to shut the plant down if the monthly capacity factor falls below 50% for four consecutive months (see Ex. 25, Attach. M). This provision creates an incentive to maintain a high capacity factor.

We agree, however, that the most likely prospects for the plant are that it will either operate near the level we have forecasted or that it will be shut down entirely. To take this latter possibility into account, we will calculate an alternate IER which assumes that Rancho Seco is not in service during the forecast period and we will permit payments to QFs to incorporate this alternate IER if Rancho Seco is in fact shut down by SMUD's Board of Directors during the forecast period.

The estimate of generation resulting from the adopted assumptions is 4735.7 gWh. However, under certain circumstances, power from Rancho Seco could be backed down. Thus, the amount of generation that the models attribute to Rancho Seco could be somewhat smaller than this figure.

D. Qualifying Facilities' Generation

Except for a few issues, the parties now accept the determinations made in the August 5 ALJ's ruling. We will briefly discuss the bases of those determinations and the remaining disputed issues.

1. Generation by Wind QFs

PG&E developed its recommendation by using historical capacity factors of wind QFs to estimate generation by projects that were not yet in operation, rather than relying on the estimates of the projects' developers. The resulting estimate of 1045.0 gWh is reasonable and will be adopted. DRA's criticisms appeared to misunderstand PG&E's approach.

2. Generation by Hydroelectric QFs

PG&E's original estimate used a built-in delay to estimate the on-line dates of projects under construction. The delay was derived from the observed lag between the developers' estimates of on-line dates and actual on-line dates achieved by hydroelectric QFs. Other parties proposed adjustments to individual projects based on information obtained from the specific project's developer.

We prefer PG&E's general approach because it eliminates the need for every party who is concerned with this estimate to contact each developer whose project has not yet come on-line. In addition, any information presented about the status of specific projects will be difficult to verify at the hearings. PG&E's approach should shift the focus of dispute from the status of many individual projects to the accuracy of the delay factor, a simpler issue to address in our proceedings. So long as PG&E's approach leads to reasonably accurate results, we favor developing estimates derived from this method.

Making the individual adjustments for delays in specific projects is inconsistent with PG&E's approach, which uses an average delay. Even if it is shown that a particular project will be delayed beyond the average delay, that specific delay should not be taken into account in developing the overall estimate, since other projects may come on-line with less than the average delay. If the average is accurate, the individual variances should balance out without affecting the accuracy of the overall estimate.

PG&E revised its original approach in Exhibit 41 to reflect the results of the June 1 snow survey. The expected generation by hydroelectric QFs during the forecast year, according to Exhibit 41, is 460 gWh. However, in Exhibit 7, PG&E accepted several adjustments proposed by DRA. Among those was the removal of a hydroelectric project that had lost the required license from the Federal Energy Regulatory Commission (FERC). Removal of that project from the estimate reduces the forecasted generation to 458.7 gWh.

After the issuance of the ALJ's ruling, PG&E reclassified the Sand Bar Powerhouse project to the hydroelectric QF category (Ex. 49, p.5). This change increases the total generation from hydroelectric QFs by 8.7 gWh. No party challenged this change.

We will adopt the resulting total of 467.4 gWh for generation from hydroelectric QFs.

3. <u>Generation from Large Geothermal, Solar, and Small QFs</u>

PG&E's initial estimates, as broken down by DRA in Exhibit 14, for generation from large geothermal and solar QFs were uncontested. We will adopt these estimates of 691.1 gWh from large geothermal QFs and 12.9 gWh from solar QFs.

In addition, PG&E and Santa Fe stipulated on the allocation of the generation from QFs smaller than 1 MWh in size between fixed- and variably priced energy (Tr. 12:1183-1184).

Other parties have tacitly concurred in this stipulation, which allocates 32% to fixed-price energy and 68% to variably priced energy. This allocation was applied to PG&E's original estimate of generation from these small QFs of 107.3 gWh. (Exhibit 14, in which DRA summarized PG&E's recommendations, contained two slightly different figures for generation from small QFs. The ALJ ruling copied 107.9 gWh from one page. However, it appears that the proper number is 107.3 gWh, which appears in a table and in the text of Exhibit 14. This small difference appears to be overwhelmed by rounding in the models.)

4. <u>Generation from Thermal QFs</u>

DRA proposed several adjustments for individual projects to PG&E's original estimate of generation from the QFs of 9,412.6 gWh. PG&E accepted some of DRA's proposed adjustments (Ex. 7). The ALJ's ruling, as revised on August 10, endorsed PG&E's revised position.

The adjustments arose from a project that had terminated its contract with PG&E (6.9 gWh), double counting of the generation from a phased project (7.7 gWh), and confirmation that a project will use all of its generation internally and will not sell power to PG&E (34.0 gWh). PG&E has persuasively countered DRA's other proposed adjustments, and has confirmed that negotiations to defer the on-line date of a project were not successful.

Thus, we will adopt the revised figure of 9450.8 gWh for thermal QF generation. According to PG&E, the associated fixed-variable split is 3617.0 gWh fixed-priced energy and 5833.8 gWh variably priced energy (Ex. 49, p. 6).

5. <u>Total Generation from QFs</u>

The total generation from QFs is 11,774.5 gWh, as shown in Table 3.

TABLE 3

Generation from Qualifying Facilities

Wind	1,045.0 gWh
Hydro	467.4
Large Geothermal	691.1
Solar	12.9
Less than 1 MW	107.3
Thermal	9,450.8
Total	11,774.5 gWh

The parties vary slightly in their estimates of how much of this total should be allocated to variably priced energy. The variance appears to result from rounding within the models. CCC's and PG&E's estimates match, perhaps because they used the same model, and the rounding variances of the components appear to be somewhat less than the other models. We will adopt these parties' estimate of 6,992 gWh for the amount of variably priced energy. We recognize that the limitations of the models will not allow all runs to match this precise figure.

In addition, some QFs' contracts with PG&E allow PG&E to curtail their generation at times. This curtailment should occur in the models, as in PG&E's operation, at times that are most beneficial in reducing overall costs.

6. Price

No party disputed PG&E's general approach to calculating the cost of purchases from QFs, and, based on the ALJ's ruling, PG&E calculates the total cost of QFs' generation to be $716,784,000. However, the capacity price paid to QFs requires some discussion.

The theoretically correct price to pay QFs for their contribution to capacity is the product of the Energy Reliability Index (ERI), which is a measure of a utility's need for capacity, and the capacity cost a utility avoids by purchasing power from QFs for a specified period. For several years we have used the annualized cost of a combustion turbine as a measure of the capacity costs avoided in the short term. We have also determined that QFs who do not commit to provide capacity on a firm basis nevertheless allow the utility to avoid some capacity commitments because of the diversity and randomness of their energy contributions. We therefore have directed utilities to pay for this as-available capacity on a cents per kilowatt-hour basis.

Because of various difficulties we have had in calculating PG&E's short-term avoided capacity costs, we have previously adopted a value of $42/kW/year as the capacity price to be paid for as-available capacity through 1988 (D.88-03-079). All parties seem to agree that for purposes of forecasting revenue requirements, the current $42/kW/year should be used for the entire forecast period. We agree.

We have not yet approved a method for adjusting PG&E's ERI. Until such a method is adopted and approved, a precise calculation of the capacity price that theoretically should be paid to QFs is impossible. Although D.88-03-026 stated that ERIs were to be revised in the ECAC proceeding, that decision acknowledged that no method for calculating PG&E's ERI had been developed. A proposed adjustment method has been circulated (D.88-03-079), but no final determination of the appropriate method has been made at this time.

Because of this uncertain status, we will not adopt an ERI value for 1989. However, all parties should be aware that this question is being considered in A.82-04-44, and a decision in that proceeding could establish a level of capacity payments to as-available QFs that differs from the $42/kW/yr that we adopt for purposes of the forecast.

An additional aspect of payments to QFs concerns the treatment of avoided operations and maintenance (O&M) costs. This issue will be addressed in a later section of this decision.

E. Gas-fired Generation

Because PG&E's gas- and oil-fueled generation units are typically the most expensive resources, the precise amount of this generation is determined by the availability of cheaper resources. As the resource relied on to meet the residual need for power, oil- and gas-fueled generation is determined in the model runs, and the amount of generation becomes an output of the model. The total price of gas depends on the volume consumed, so calculation of this expense must also await the results of the model runs. Thus, we do not need to adopt specific figures for the amount of fossil-fuel generation or the total gas expense at this time.

Two issues related to gas-fired generation must be resolved, however, before the model runs can be performed.

1. Dispatch Price of Gas

DRA and PG&E developed a stipulation on the forecast of PG&E's utility electric generation (UEG) gas dispatch price for the forecast period (Ex. 45). No other party disputed this stipulation, and we will adopt the terms of the stipulation as the forecasted dispatch price of gas, as shown in Table 4.

TABLE 4

Forecast of PG&E UEG Dispatch Price

($/MMBtu at the Burnertip)

Average Monthly and Forecast Period Dispatch Price

1988

Aug.	Sept.	Oct.	Nov.	Dec.
1.940	1.940	1.952	1.974	2.323

1989

Jan.	Feb.	Mar.	Apr.	May	June	July
2.382	2.323	2.149	1.955	1.955	1.955	1.955

Average for Forecast Period = 2.067

2. Fuel Oil Inventory Requirement

DRA and PG&E developed different estimates of the required fuel inventory inventory levels. The difference centered on expectations of gas availability from the pipeline system of El Paso Natural Gas Company (El Paso).

PG&E argues that El Paso's desire to get out of the market as a gas seller has forced PG&E to rely more on spot gas supplies to meet its needs for gas. During particularly cold winters, when the fuel oil inventory provides insurance against curtailments of gas supply, PG&E believes that the shortfall in gas supplies will average 240 million cubic feet per day (MMcf/d). During a cold streak last winter, PG&E was repeatedly unsuccessful in getting as much gas as it needed, forcing it to burn oil from inventory. PG&E believes that these developments in the gas market support its recommended oil inventory of 6.9 million barrels.

DRA believes that PG&E has overstated the shortfalls that may reasonably be expected this winter. Although El Paso has reduced its firm supplies, the spot market has grown dramatically in the last few years, and PG&E has been and will be able to rely increasingly on the operation of that market. DRA predicts that the average shortfall if this is a cold winter would be 97 MMcf/d. DRA points out that PG&E has exaggerated the actual shortfall from last winter because it did not always request the maximum amount of gas that could be transported to it through El Paso's pipeline. When the amount actually delivered last winter is compared to the amounts PG&E requested, the shortfall was only 103 MMcf/d, which is very close to the figure underlying DRA's estimate.

In its brief, PG&E argues further that developments that led to the curtailment of gas in Southern California this summer add weight to its position that the operation of the spot market is not always sufficient to supply its gas needs in a cold winter.

The recent situation in Southern California demonstrated that under certain circumstances, gas shortages can arise even in summer months. However, many of these circumstances are not related to the situation that the fuel oil inventory is designed to remedy. Although the shortages seemed to result in part from the problems El Paso was having in securing gas supplies and transporting gas to California, we also determined in Investigation (I.) 88-08-052 that there were adequate supplies and capability on the El Paso system to deliver at least 100 MMBtu/d more to California than the assumed limit of the system.

The complexities of the Southern California problem do not necessarily support the conclusion that PG&E argues. Rather, they demonstrate that there is still considerable volatility in the gas market. But the immediate problem in this case is to forecast how that immature market will function in the event that this winter is a cold one.

When the question is framed in this fashion, we feel that the evidence most on point is the record from last winter. Although the presentation of the facts was somewhat confusing, the average shortfall in December and January of last winter was 103 MMcf/d (Ex. 33). This figure is very close to DRA's recommendation, which assumes an average shortfall of 97 MMcf/d, and we will adopt the fuel oil inventory resulting from that recommendation, 5.6 million barrels.

3. Oil Test Burns

It is not disputed that testing of some of PG&E's steam units requires oil test burns of 3,324 MMBtu, or 504,000 barrels. At an average price of $18.29 per barrel, the expense of these burns totals $8.9 million. The volume of gas needed to meet the fossil generation requirement decreases by the 3,324 MMBtu of the oil test burns.

F. Power Purchases from the Southwest

The record on Southwest power purchases is completely jumbled, and the parties have provided us with little basis to understand, let alone decide, the differences in their positions. However, since this is a significant input to the models, we do not have the usual option of rejecting all testimony, and we will state our understanding of the way in which the components of these purchases should be modeled.

Up to 170 gWh of power is available during off-peak periods from the Western Systems Power Pool and other Southwest sources from coal-fired plants (Ex. 1, pp. 3-30; Ex. 49, p. 7). The price for this power is 15 mills/kWh. These purchases should not be modeled as peak-shaving resources, but this power may be backed down during periods of minimum load, consistent with the backdown order we discuss later in this decision.

The amount of purchases from the California Power Pool (CPP) will be determined by the model, subject to a capacity limitation of 200 MW (Ex. 49, p. 7). These purchases should be made whenever PG&E's incremental heat rate reaches 11,500 Btu/kWh (Ex. 48, Attachment, p. 5). These purchases may also be backed down during periods of minimum load. Offsetting these purchases are forecasted sales to the CPP of 60 gWh at 22.4 mills/kWh, based on records from 1987 (Ex. 1, pp. 3-30).

G. Other Purchased Power

Several components of this category were uncontested. Purchases from Sierra Pacific of 3.6 gWh at 1987 recorded costs and purchases from the Lewiston Powerhouse of the Western Area Power Administration (WAPA), also at 1987 recorded prices, were uncontested.

The largest component of this category is the purchases from the California Department of Water Resources (DWR). All parties agree that no purchases from DWR are expected before 1989, when normal water conditions are assumed to resume. In 1989, DWR purchases should be assumed to be at the same price as purchases from the Pacific Northwest. Purchases will be made only when it is economically advantageous to do so, and purchases from DWR may be backed down according to the backdown order discussed later in this decision.

A final element of the other purchased power category is the power supplied from PG&E's wind turbine in Solano County. The forecast amount of energy supplied by this turbine is 3.3 gWh. This amount of energy should be included in the resource mix. However, the costs of this power are in base rates and should not be included in the ECAC revenue requirement.

H. Purchases from the Pacific Northwest

This issue turned out to be one of the most significant and contentious issues in the case. Several background facts were undisputed, however.

The Northwest is one of PG&E's primary sources of cheap purchased power. However, the Northwest, like California, has received less rainfall than normal in recent years, and thus the availability of cheap power from the Northwest became an issue in this case.

The drought in California also had an effect on the need for power from the Northwest. Generally, PG&E will favor certain of its resources, such as in-state hydroelectric power and generation from Diablo Canyon, over purchases of Northwest power. The reduced amount of California hydroelectric generation assumed for 1988 means that there will be a greater need for purchases from the Northwest. However, all parties assume that normal precipitation patterns will resume in 1989, both reducing the need for Northwest purchases to some degree and increasing the availability of Northwest hydroelectric power.

The interaction between the supply of power available in the Northwest and PG&E's demand for Northwest power creates the different recommendations on the price that should be assumed for these purchases. The price, in turn, is used by the models to determine the amount of power that is forecasted to be purchased from the Northwest. Purchases from the Northwest are one of the largest contested influences on the IER.

1. <u>Purchases in 1988</u>

a. <u>Availability</u>

All parties concede that the drought in the Northwest will limit the availability of economy energy purchases from the Northwest through the end of the year.

PG&E forecasts that enough higher priced on-peak power will be available to fill its 1639 MW entitlement on the Pacific Intertie transmission lines during 1988. Off-peak availability will be limited to 50% of the entitlement, according to PG&E.

Santa Fe and CCC project that no economy energy from hydroelectric resources in the Northwest will be available in 1988, even when power from BC Hydro, the British Colombia power agency, is taken into account. Any power that may be available would command a higher price, as explained in the discussion of price for Northwest power.

b. <u>Price</u>

PG&E derives its estimated prices from historical trends, modified to include the effect of the drought. PG&E projects that average prices in 1988 would be 23 mills/kWh for on-peak purchases and 21 mills/kWh for off-peak purchases.

PG&E argues that prices that prevailed in 1988 up to the time that the record in this case was closed demonstrate the accuracy of its estimate. It presented evidence that prices in June and part of July were very close to these estimates, even after taking into account the effect of the annual fish flush, when required releases from the Northwest's reservoirs increase the amount of cheap energy available. Even the prices prevailing in August, clearly after the fish flush, were very close to PG&E's estimates.

CCC and Santa Fe both presented price estimates based on a three-tiered structure. In both cases, the cheapest block was assumed to be produced from hydroelectric facilities. The source of power for the second price block would be produced from cheap thermal resources, primarily coal plants, and would cost 24.4 mills/kWh. The composition of the third tier varied slightly. Santa Fe postulated that power from this tier would come from the most expensive coal resources and would cost 28.9 mills/kWh. CCC's third tier consisted of oil- and gas-fired resources, with a price of 30.3 mills/kWh.

Both parties argue that a tiered structure more accurately reflects the workings of the power market. Although agreeing with PG&E that prices in the first tier would be based on PG&E's costs and would compete with PG&E's marginal resources, Santa Fe and CCC argue that the lack of hydropower would force reliance on more expensive thermal units. These units would respond to the market only to the extent that market prices allowed the selling Northwest utilities to recover the cost of generating power from these plants. These parties believed that the drought would increase prices because demand would exceed the supply of cheap hydropower, and the tiered approach simulates the expected operation of the market.

Santa Fe projected that purchases in 1988 would all be supplied from coal plants at the Tier II rate of 24.44 mills/kWh.

CCC argued that because of the forecasted unavailability of economy energy from hydroelectric facilities in the Northwest, purchases in 1988 would be made at least at the second tier price of 24.4 mills/kWh, and substantial amounts of power would also be purchased from the third tier at 30.3 mills/kWh.

These parties support their arguments by pointing out that in February 1988, when no fish flush or spring run-off influenced the price of power, PG&E's purchases were at prices very close to the second tier prices of their recommendation.

c. Discussion

After considering these arguments and the evidence supporting them, we conclude that PG&E's proposed prices and availability for 1988 are most likely to be correct. Several considerations lead us to this conclusion.

First, the evidence so far is that prevailing prices in 1988 are much closer to the level of PG&E's recommendation than to CCC's and Santa Fe's. The average price of PG&E's purchases from the Northwest was 19.75 mills/kWh in June, 21.01 mills/kWh in July, and 21.47 mills/kWh through August 17, 1988 (Tr. 15:1534). Also, BPA made at least a preliminary offer to sell PG&E between 288 gWh and 298 gWh per month from September to December 1988 at 22 mills/kWh (Ex. 42, Attachment 2). In addition, the record of PG&E's purchases from April through July (Exs. 41 and 42) demonstrate that there are a number of sources of power in the Northwest that we assume will compete to some degree. An implicit assumption of CCC's and Santa Fe's approach is that the Northwest market will be dominated and coordinated by the Bonneville Power Administration (BPA). The pattern of purchases in June and July demonstrate a surprising diversity among the Northwest sellers.

Second, the presence of BC Hydro in the Northwest market will have a moderating effect on prices, we believe. British Columbia has had normal rainfall in recent years, and BC Hydro has regularly sold power to PG&E (Exs. 41 and 42).

Third, the block structure assumes discrete jumps in market prices as generation from the cheaper resources is exhausted. With the many potential sellers in the market, we expect a more gradual supply curve and we expect that some thermal contribution will be made even at lower prices.

Finally, PG&E has increased its estimate from normal years to take the drought and shortage of hydroelectric energy into account. The forecasted prices are four and five mills/kWh higher than PG&E's initial estimates for 1989, which assumed a return to normal patterns. We believe that PG&E's higher prices are reasonably accurate for purposes of the forecast.

Thus we will adopt PG&E's estimate of prices of 23 mill/kWh for on-peak purchases and 21 mills/kWh for off-peak purchases, and PG&E's estimated availability of 100% of its 1639 MW entitlement to the Pacific Intertie during peak hours and 50% of the entitlement during off-peak hours.

2. Purchases in 1989

a. Availability

The shared assumption is that normal precipitation patterns will return in 1989. Although there was some testimony that normal precipitation would not entirely refill the Northwest's reservoirs, parties seem to expect a return to normal availability of purchased power from the Northwest. It is assumed that power will be available up to 90% of PG&E's entitlement on the Pacific Intertie at all times. PG&E's entitlement increases from 1639 MW to 1775 MW on April 1, 1989. We will adopt this assumption of availability.

b. Price

PG&E proposed pricing Northwest power for 1989 at 90% of its average incremental fossil-fired steam generation cost. It derived this percentage from its actual purchases in 1986 and 1987, a dry year. Since this is an average price that includes prices in a dry year, PG&E does not believe that the tiered approach suggested by CCC and Santa Fe is appropriate.

Determination of the target average incremental fossil-fired steam generation cost would be performed by the model during a preliminary or "seed" run. The seed run begins by setting a price for Northwest power at 90% of a price based on the average incremental heat rates (IHRs) for conventional units. PG&E assumed IHRs of 9,500 Btu/kWh for on-peak and 8,500 Btu/kWh for off-peak periods. The seed run chooses between Northwest power purchases and incremental conventional generation on an economic basis. The seed run thus provides more refined approximations of the incremental fossil generation costs. The final run uses 90% of the resulting costs as the price of Northwest power.

Santa Fe and CCC continued to urge their tiered approach to pricing. The changed precipitation assumptions, however, required a different basis for the price of the first tier for 1989. These parties argued that the price of the first block of economy energy, which is assumed to be generated from hydro electric units, would be set at 90% of PG&E's system incremental cost. Blocks 2 and 3 would remain at the prices forecasted for 1988.

Because the ALJ's August 5 ruling rejected the tiered approach of the pricing of Northwest power, these parties presented a single priced alternative. This alternative is similar to PG&E's but is based on 90% of PG&E's system incremental cost, rather than 90% of its fossil-fired steam units' cost. These parties argue that this assumption better reflects the competition among the various Northwest sellers for sales to PG&E. Because they are in competition, the sellers would gear their prices to PG&E's system costs and would try to maximize their revenues by making sales at just under PG&E's incremental cost of power.

c. <u>Discussion</u>

We will adopt PG&E's assumptions on availability of power in 1989, as stated in the preceding section.

The price assumption is a more difficult issue. However, we believe that the basis for PG&E's recommendation makes more sense.

It is logical to key the price of Northwest power to PG&E's fossil-fired steam units, since those are the primary sources of generation that would be displaced by Northwest purchases. The marginal running costs of resources like PG&E's hydroelectric units and the Diablo Canyon plant are so cheap that PG&E would usually prefer them to more distant Northwest generation. But the higher running costs of the fossil-fired units allows PG&E to reduce their operation when more economical power is available, as it often is, from the Northwest.

In addition, there is a tautological aspect to keying Northwest prices to PG&E's system incremental cost. At times, the system incremental cost includes the costs of purchases from the Northwest, leading, at least in part, to the logical difficulty of pricing a commodity at a fraction of the same commodity's price.

Finally, to the extent that Ex. 54 accurately reflects these price assumptions, the results of PG&E's assumptions appear to be more reasonable and more stable than prices resulting from the other parties' assumptions.

Therefore, we will direct the parties to assume that prices of Northwest purchases in 1989 will equal 90% of PG&E's average incremental fossil-fired steam generation costs.

We note that the question of the pricing of Northwest power is raised again in the discussion of the calculation of the IER.

I. <u>WAPA's Northwest Purchases</u>

The best estimate of WAPA's Northwest purchases is the estimate provided by WAPA itself (Ex. 22, Table 4-6), and this estimate was adopted in the ALJ's ruling of August 5. However, as PG&E pointed out, that estimate was the quantity of power (1,998.1 gWh) expected to be available at the Tracy pumping plant (see Ex. 41). To make these figures consistent with other Northwest purchases, the total amount should be increased by 4.5%, to adjust for line losses over the alternating current (AC) transmission line from the California-Oregon border to Tracy. Thus, for purposes of the resource assumptions, WAPA's Northwest purchases are forecasted to be 2,088 gWh.

This amount should be considered the maximum amount of WAPA's Northwest purchases. WAPA's purchases may be backed down according to the backdown order we discuss later in this decision, so the amount of WAPA's Northwest purchases used in the models may be less than 2,088 gWh.

J. <u>SMUD/NCPA/CSC's Northwest Purchases</u>

SMUD has a 200 MW share of the 500 kilovolt AC line to the Northwest. NCPA and the City of Santa Clara (CSC) have each purchased 25 MW of this 200 MW.

An issue arose because CCC argued that PG&E's assumptions about the use of this share of the AC line was inconsistent with these entities' rights. Specifically, CCC presented evidence that SMUD, NCPA, and CSC did not expect to use their full rights to the line, and as a result a portion of their capacity should be laid off to PG&E.

PG&E presented evidence that demonstrated that SMUD made use of any capacity that NCPA and CSC did not use to purchase power from the Northwest (Ex. 42, p. 8, Attachment 5). PG&E's resulting assumption is that SMUD, NCPA, and CSC, in combination, will fully use the 200 MW capacity to import Northwest energy, except when minimum load conditions or the operation of Rancho Seco requires SMUD to back down its purchases. This assumption is reasonable and will be adopted.

K. <u>Combustion Turbines</u>

PG&E's use of its combustion turbines is limited to satisfying needs for local or system reliability or meeting unexpected peak loads. The amount of generation from these turbines will be determined by the models.

The necessary assumptions are uncontested. PG&E and DRA agree that a reasonable estimate of the cost of distillate oil is $23.53 per barrel and that a reasonable distillate oil inventory for combustion turbine use is 100,000 barrels. We will adopt these assumptions.

L. Emergency Power

The models will develop estimates of expected unserved energy (EUE) when outages leave the system with insufficient resources to meet demand. The source of emergency power in these situations is the California Power Pool, and it is undisputed that the price of emergency power from the power pool is 26.75 mills/kWh. We will adopt this assumption.

M. Helms' Upstream Runoff Generation

In addition to its operation as a pumped storage unit, a certain amount of generation is available from the Helms pumped storage plant because of upstream runoff and normal water management. PG&E's forecast of this generation of 34.5 gWh reflects the June 1 snow survey (Ex. 49, pp. 3-4). We will adopt this estimate.

IV. Modeling Conventions

The goal of the production cost models is to simulate the operation of PG&E's system. But necessarily some simplification of the complexities of the operation of PG&E's system must occur to provide the models information in a form they can use. Modeling conventions are some of the conversions or translations of information that modelers employ to make these simplifications. Some of these conventions and related issues were the subject of controversy in this case.

A. System Constraints

In deploying generating resources to meet expected load, a model, like a real dispatcher, tries to dispatch the least expensive available unit or purchase. However, various limitations on PG&E's system require the dispatcher to deviate from the goal of economic dispatch at certain times. These limitations may arise because of transmission constraints, reliability requirements, contractual requirements, or other limitations.

As this issue developed in the hearings, the parties differed not so much about how these constraints were modeled as how extensive the legitimate constraints were.

1. <u>The Parties' Positions</u>

PG&E claims that the actual operation of its system is subject to many constraints that require some resources to be run out of a strict economic sequencing dispatch order. PG&E asserts that these operational constraints must be recognized in the models to simulate its system accurately. The constraints arise from transmission line constraints, local requirements for reactive power support, needs for local reliability and load following ability, and other reasons.

One large category of constraints is designated as the reliability requirements. Because of the physical arrangement of its system, PG&E believes that it must maintain local generation at some minimum level at various times throughout the year. This local generation is supplied by fossil-fired steam units, which at some of these times would not be dispatched on an economic basis. These area reliability constraints arise in PG&E's San Francisco, East Bay, Coastal, and Humboldt Bay areas. In addition, requirements for protection of striped bass in the Delta compel the Pittsburg 7 unit to be run at certain times.

These constraints have two implications for modeling, according to PG&E. First, the constraints require some units to be modeled as must-run units, plants that must be committed and run at minimum levels at certain times, even though economic sequencing would not necessarily dispatch these units at these times. Second, PG&E also sets minimum generation requirements for units in the constrained areas to represent the minimum generation needed to meet the local reliability, reactive power, and load following needs.

A second broad category of constraints is the backdown order. At times of minimum load, PG&E reduces generation from certain resources. After backing down its own baseload units to their minimums, PG&E has the contractual right to back down purchases from other utilities and QFs, to limit other utilities' purchases from the Northwest, and to limit generation by some other utilities.

PG&E believes that the constraints it has proposed reflect the actual operation of its system and must be included in any modeling effort to simulate its system accurately.

Santa Fe argued that PG&E's constraints imposed an extreme limitation on the ability of the model to dispatch the system economically.

First, Santa Fe contends that PG&E has presented no evidence to support its statement that its system requires minimum oil or gas fuel burns ranging from 600 to 700 gWh per month. Apart from naked assertions that these levels were the minimum required, PG&E presented no analyses, studies, or even reasons to support these levels, according to Santa Fe.

Second, several of the area reliability requirements are also unsupported. Although Santa Fe acknowledges the need for the Humboldt Bay and striped bass requirements, it disputes the asserted bases for the other area reliability requirements.

The San Francisco requirement, for example, is supposed to allow local generation units to supply 50% of the generation needed to serve San Francisco's daytime loads, except for Sundays, Santa Fe states. But PG&E was unable to determine what San Francisco's loads are. PG&E provided no basis for its estimate that about 140 gWh per month are needed to meet this requirement.

Similarly, the East Bay and Coastal constraints were based only on assertions that they are needed, not on any reasons or studies to document their necessity, according to Santa Fe.

Santa Fe recommends that the Commission reject these undocumented and unsupported constraints.

Third, Santa Fe argues that PG&E's must-run list is excessive and consists of about 75% of all of PG&E's own oil- and gas-fired generation. The extent of this limitation makes a mockery of models based on economic dispatch, since very little is left of the system for the model to dispatch. Santa Fe points out that this excessive must-run list lowers the IER because the IER is a measure of the difference in generation when variable QFs are removed from the system. Normally, the lost QF generation would be made up by fossil units, raising the IER. However, when these fossil units are already dispatched in the QFs-in run, because of the must-run list, the difference measured by the IER is smaller to that extent.

Santa Fe argues that if legitimate local generation and other reliability concerns are satisfied, the models should be free to dispatch on an economic basis and should not be further subject to the limitations of a long must-run list; the Commission should reject most of PG&E's list.

CCC also argues, for many of the same reasons, that PG&E's must-run list is too extensive and that the East Bay, Coastal, and San Francisco area reliability requirements were not supported by any evidence.

Furthermore, CCC presented an analysis that showed that PG&E's modeling of the minimum generation requirements for San Francisco inefficiently overallocates generation to nights and weekends. CCC proposed an allocation based more closely on PG&E's actual practice. Even if the Commission accepts the constraints proposed by PG&E, CCC argues, it should adopt the fuel limit allocation proposed by CCC.

DRA accepted some of PG&E's constraints, but opposed the minimum generation levels as being unsubstantiated. DRA believes that a pure economic dispatch should be used and should not be subject to these minimum generation requirements.

TURN opposes the constraints on economic dispatch because these constraints also substantially raise PG&E's fuel cost and thus its revenue requirement. TURN is particularly distressed by Santa Fe's Branchcomb's estimate that the constraints prevent economic dispatch of about 75% of PG&E's oil and gas units and by the suggestion that the Coastal area reliability requirement was discovered only as part of a PROMOD input file. TURN believes that Branchcomb has presented a preferable representation of the real operation of the system without the objectionable features of PG&E's proposal.

2. Discussion

In part, the differences among the parties result from overstatements and misunderstandings. As PG&E points out in its reply brief, the must-run list and the minimum generation requirements are not additive. Rather, the minimum generation amounts includes the operation of the plants on the must-run list at minimum levels. From our rough calculations, based on Ex. 25, Appendix R, and Ex. 79, it appears that the minimum generation requirement is substantially higher than the minimum generation produced from the must-run plants.

Also, Santa Fe's assertion that PG&E's constraints involve 75% of PG&E's oil and gas plants, which seems true, does not mean that only 25% of this generation is subject to economic dispatch, as DRA and TURN have apparently understood this claim. The plants on the must-run list are assumed to operate at minimum loads, not at full generation, although other requirements appear to raise the out-of-economic-order generation somewhat. But even the higher minimum generation requirements presented by PG&E amount to less than 10% of the planning load for any month, are less than half of PG&E's forecasted conventional thermal generation, and are well below the maximum capacity of these plants. Thus, we conclude that the asserted constraints do not in themselves pose an unacceptable limitation on the models.

Finally, the claim that the Coastal area reliability requirement was somehow hidden by PG&E must be rejected. Ex. 48 includes an attachment that was distributed at the modeling workshop of May 2 and 3, 1988. That attachment clearly lists as must-run units the generating plants operated in response to the Coastal constraint.

Having clarified these items, we can turn to the real questions whether these constraints accurately represent the operation of PG&E's system and whether they are necessary for purposes of modeling.

In answer to the second question, we can emphatically state that it is imperative that any models used in this type of proceeding accurately reflect the actual operation of the utility's system. Although it may be possible to state operational criteria in different ways, the models must have the ability to produce a reasonably accurate simulation of the actual operation of the system. The purpose of employing these models in our proceedings is to give us a more accurate basis for our forecasts of costs and of the IER. Presumably, these models have an ability to mimic the complexities of the system, resulting in improved accuracy over the less sophisticated statistical methods of the past. If the models cannot produce this desired accuracy, we would prefer to revert to the more comprehensible methods of former times.

Thus, if the constraints proposed by PG&E reflect the facts of the efficient operation of its system, then the models should account for these limitations in some manner.

The more difficult question is whether PG&E's constraints are both typical of and necessary to the efficient operation of its system. No party now disputes the need for the Humboldt Bay or striped bass constraints. The remaining area constraints present more controversy.

PG&E's support for the East Bay, Coastal, and San Francisco constraints consisted primarily of repeated assertions by various witnesses that these constraints actually reflected the way the system is operated. These criteria were not based so much on studies as on the experience of the operators responsible for running the system. The opposing parties were unable to counter this assertion by showing that the actual operation of the system did not follow these requirements. These parties pointed out that additional QFs in the East Bay could help PG&E meet its reactive power requirements, but PG&E countered with evidence that several generation units had been retired during the same period. CCC pointed out PG&E's overallocation of the San Francisco minimum generation to off-peak periods, but the overall basis for the requirement was undisturbed. Little information was presented by either side on the Coastal requirements.

For purposes of this case, we are satisfied that the area reliability requirements reflect the way that PG&E has operated its system and will operate its system during the forecast period. Thus, it is appropriate for the models to reflect these limitations in the forecasts they produce. However, the evidence presented in this case does not permit us to evaluate the more significant questions raised by some of the parties. We cannot tell if the area requirements could be expressed in another way that would permit greater levels of economic dispatch by the models. We have no way of telling whether the way PG&E operates its system is in fact the most efficient way, although we hope we have created incentives to promote efficiency. The lack of information also prevents PG&E from receiving the benefit of the instructional aspects of at least some of the models; with better information, some of the models may be able to suggest alternative, more efficient ways to maneuver around the area limitations.

For these reasons, we will direct PG&E in its next ECAC application to include a detailed description of the reasons for the area reliability requirements and a detailed justification for the minimum generation requirements associated with these constraints.

Having concluded that the models should satisfy the area reliability requirements, we are not persuaded that PG&E's approach is the only way to meet those requirements. As we have stated, PG&E has presented little information on the specific requirements that require special provision in the models. Since the minimum generation requirements seem to subsume the must-run designations, it is not clear that models must necessarily include both limitations to meet the constraints successfully. In light of the hazy record in this area, we will not require modelers to specify the must-run units in the manner proposed by PG&E. For the Coastal, East Bay, and San Francisco areas, modelers will have the option of satisfying the area reliability requirements in another way, and may use other features of their models to satisfy these requirements. The reliability requirements for the striped bass run and for the Humboldt Bay area have been justified, and modelers should reflect these constraints in their runs.

Unfortunately, the record leaves us with little basis for determining whether the models have satisfied the area reliability requirements. We will allow modelers to meet the area reliability requirements by meeting the minimum generation requirements, which appear to be more closely related to the reliability requirements than the must-run requirements.

The amount of the minimum generation requirements, ranging from 600-700 gWh per month, is consistent with recent experience, according to the limited information in the record (Ex. 25, Appendix R). We will require the models to meet this level of minimum generation and to follow the allocation discussed below.

Our determination on this point may be clarified somewhat by referring to Santa Fe's contention that PROSYM is able to meet the area reliability requirements and the minimum generation requirements without specifying certain units as must-run (Ex. 78, p. 4). As we understand the reasons for these requirements, Santa Fe's approach is acceptable, provided that PROSYM provides adequate generation to meet these requirements.

Although PG&E's recommended level of minimum generation for the San Francisco area seems reasonable, CCC has pointed out that allowing PROMOD to allocate this generation by default overallocates power to nights and weekends, contradicting both the purpose of the generation and the practice of PG&E. A similar problem appears to occur for the allocation of minimum generation for the East Bay and Coastal areas (Ex. 58, pp. I-14-I-15; Tr. 18:1903-1904). We will therefore adopt CCC's recommended allocation of minimum generation for the San Francisco, East Bay, and Coastal areas of 62% day time, 12% nighttime, and 28% weekends.

Finally, we are satisfied that the backdown order listed in the attachment to Ex. 48 reasonably reflects PG&E's abilities to back down its purchases, other utilities' purchases, and other utilities' generation. In addition, when the reductions on this list are exhausted, PG&E appears to have the ability to reduce Rancho Seco generation, followed by reductions in NCPA geothermal (Ex. 77, Table 8). Modelers should follow the backdown order of Ex. 48 and, if levels of minimum load are sufficiently low, should back down Rancho Seco and NCPA geothermal. The question of the backdown order will be revisited in our discussion of the calculation of the IER.

B. <u>Commitment Target and Spinning Reserve</u>

ELFIN, like PROMOD, is a load duration curve model that approaches the utility's system on a weekly basis. For every week of the simulation, at what may be viewed as the beginning of the week, ELFIN anticipates the expected peak load for the week and commits, or starts up, enough units to meet expected demand. Once a unit is started, it is available for dispatch, which requires increased generation from that unit.

ELFIN does not permit a modeler to specify a spinning reserve target, and the modeler must take some care to ensure that the model does not overcommit resources above the generation needed to meet load and spinning reserve. CCC, joined by PG&E, criticized the way in which DRA determined the commitment target for ELFIN.

The Western States Coordinating Council (WSSC) requires PG&E to maintain a spinning reserve of either 7% or the utility's largest single contingency. The ELFIN modeler must choose a commit target value to get the model to commit enough units to meet the system's needs plus spinning reserve. CCC recommends two adjustments to make sure that ELFIN does not overcommit resources.

The first point has to do with the derating of a unit's capacity for both forced outages and maintenance outages. In trying to meet a commit target, ELFIN will derate a plant's capacity by its historical forced outage rate. Thus, if a 1000 MW plant has a 15% historical forced outage rate, ELFIN will use only 850 MW of the plant's capacity toward meeting the commit target. DRA did not make any compensating adjustment for this derating of capacity.

CCC argues that in reality a plant will be committed up to its full available capacity, and unscheduled outages will not be taken into account in meeting the commitment target. If the capacity is derated and the spinning reserve is maintained at 7%, then essentially a double derating of capacity has occurred, which reduces the expected availability of the unit and thus results in an overcommitment of resources. CCC believes that only derating for scheduled maintenance should be allowed. CCC cites PG&E's testimony that DRA's approach does not reflect the actual operation of PG&E's system.

We agree with CCC's point, for slightly different reasons. Although it is desirable to have a model reflect the precise operation of a system, we recognize that in many cases simplifications must be made; thus, the mere fact that ELFIN approaches the commitment of units in a different fashion from PG&E's human operators is not persuasive. However, ELFIN's automatic derating of capacity for forced outages produces an inconsistent result in this case. One of the primary functions of spinning reserve is to allow the system to endure an unexpected outage by a generating unit, and the level of spinning reserve is set high enough so that even the outage of the largest single unit can be covered instantaneously. The derating of capacity by historical forced outage rates essentially results in a higher spinning reserve than targeted because it anticipates outages that are by definition unexpected. Thus, we agree that modelers should correct for ELFIN's derating of capacity for forced outages in committing units to meet commitment targets.

Second, both PG&E and CCC believe that ELFIN's attempt to meet the commitment target needs to be checked to see that the model does not commit more than the needed resources. Because of necessary adjustments to ELFIN's commitment process, the results of the model's attempt to meet a particular commitment target are variable. By adjusting the target and repeating the process, the model can eventually be used to meet the target commitment without overcommitting resources.

We are persuaded that this iterative process is needed to ensure that ELFIN does not overcommit resources in its effort to meet a commitment target,and we will require ELFIN modelers to employ this process.

A related issue is DRA's contention that nonfirm energy increases spinning reserve requirement. CCC's Weisenmiller's testimony persuaded us that accepting economy energy neither increases nor decreases the spinning reserve requirement (Ex. 25, p. II-52). Although nonfirm purchases must be entirely covered by spinning reserve, they do not require commitment of additional generation.

C. Helms' Generation

All parties now seem to accept that the Helms pumped storage plant should be 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. As has been discussed, we forecast generation of 34.5 gWh from upstream runoff and normal water management. (See Ex. 49, pp. 3-4.)

D. Line Losses

All parties recognize that purchases from the Northwest transmitted over the AC line and the direct current (DC) transmission line incur line losses of 4.5% and that purchases transmitted over the DC line incur additional conversion losses of 4.5%. Parties differ on the details and implications of these facts, however.

One issue concerns how these line losses should be accounted for. DRA argues that when Northwest purchases replace QFs in the QFs-out run, the line losses should be accounted for by increasing the price of Northwest purchases to reflect the losses that occur during transmission. DRA believes that this adjustment is equivalent to, but simpler than, increasing the amount of purchases to adjust for losses. For example, if PG&E needed 100 units to meet demand, it might have to buy 105 units to accommodate line losses. DRA's approach is to raise slightly the price of the 100 units received to reflect the total cost of the 105 units purchased.

PG&E agrees that for dispatch purposes, losses should be accounted for by price adjustments to determine whether Northwest purchases are economic. However, PG&E does not believe that adjustments should be included in the calculations of the IER or the revenue requirement. PG&E argues that line losses are already included in the calculation of the lost and unaccounted for energy

(LUAF) amount included in the planning load, and that making a special adjustment for Northwest purchases double counts the line losses.

We suspect that the proper determination of losses in the QF-out case lies between the positions taken by the parties. Making only the adjustment for the Northwest purchases ignores the fact that removal of the variable QFs will somewhat reduce the losses already included in the LUAF figure. Since the meters that measure the power produced by a QF are usually at the point of interconnection with PG&E's system, PG&E bears the transmission losses associated with QFs' generation and includes these losses in its LUAF. On the other hand, because of their location, generation from QFs located near load centers may incur lower losses than the losses associated with replacement power from the Northwest.

DRA's approach, however, assumes that Northwest purchases will result in greater losses than those associated with the replaced QFs. This assumption excludes the possibility that some QFs may be located far from load centers or that some QFs' power may be transmitted over lines that are less efficient than the Pacific Intertie. Without better information on the effect on losses from the removal of QFs in the QFs-out case, we decline to make this assumption. Although PG&E's approach may understate the losses resulting in the QFs-out case, we conclude that it is more likely to represent the losses in this hypothetical situation accurately.

Thus, we conclude that for purposes of determining whether purchases from the Northwest are economic, line loss factors of 4.5% for the AC and DC lines and an additional conversion loss of 4.5% for the DC line should be accounted for through price adjustments. Because of the interaction between the conversion losses and the line losses on the DC line, the total losses for transmission on the DC line is 9.2%. No such adjustments should be made in the determination of the IER and the calculation of revenue requirements other than the LUAF amount.

E. Other Utilities' Northwest Purchases

An additional issue had to do with whether the amount of power purchased by SMUD, WAPA, and NCPA/CSC should be allowed to vary between the QFs-in and QFs-out simulation. PG&E concedes that the purchases by NCPA/SCS are based on those utilities' needs only and are scheduled independent of PG&E, and thus should not vary between the QFs-in and QFs-out simulations. However, PG&E asserts that its contractual relations with SMUD and WAPA give PG&E the right to require these utilities to reduce their Northwest takes during times of PG&E's minimum load. This assertion is consistent with the backdown order we have adopted and with the evidence in this proceeding. Therefore modelers should allow for reductions of Northwest purchases by SMUD and WAPA during minimum load periods, which may vary between the QFs-in and QFs-out runs.

F. Dispatcher's Risk Aversion

We agree with DRA that PROMOD modelers should not employ the dispatcher's risk aversion feature since no evidence was presented to support use of this feature.

V. Calculation of the IER

The incremental energy rate is a somewhat artificial concept. It first arose in the negotiating conference that developed the interim Standard Offer Number 4 as a way of relating forecasted fossil fuel prices to the utility system's marginal energy costs. A utility's marginal cost of generating energy (expressed in cents per kWh) is a combination of the price it pays for fuel (stated in $/MMBtu) and the system's efficiency in converting that fuel into kilowatt-hours. The IER, as a measure of the system's incremental efficiency in making this conversion, is therefore expressed in Btu/kWh.

In D.88-03-079, we adopted the QFs-in/QFs-out approach to calculating IERs. A QFs-in model run includes generation from all variably priced QFs expected to be in operation during the forecast period. A QFs-out run dispatches the system with generation from all variably priced QFs removed. The QFs-in/QFs-out approach measures the costs avoided by the system by comparing the QFs-in run and the QFs-out run. The IER used to calculate energy payments to QFs is the average of the IERs resulting from the QFs-in and QFs-out runs.

In terms of a formula, the IER equals the difference between the total costs in the QFs-in run and the QFs-out run, divided by the generation in gWh provided by variably priced QFs, with the resulting quotient divided by the UEG rate, in $/MMBtu. (See Ex. 46, p. 3.)

The IER is often and understandably confused with the incremental heat rate, or IHR. The IHR is typically used to express the incremental efficiency of an individual generating unit, and measures the unit's efficiency in producing one more kWh. A unit's IHR will vary with changes in the generation it produces, and most generating units are designed to operate most efficiently within a certain range. References to a system's IHR usually refer to the IHR of the last unit dispatched to meet load. The IHR is also expressed in Btu/kWh.

To add to the confusion, it appears that the term IER has been used in several different ways in different aspects of the Commission's activities. This difference makes comparisons between these different uses very tricky.

For example, PG&E's quarterly filings in compliance with Ordering Paragraph 12(b) of D.82-12-120 (12(b) filings) report "actual" IERs, but these figures are not directly comparable to the IERs considered in this case. The 12(b) filings' IERs are essentially the marginal running costs in the QFs-in run (Tr. 15:1574, Tr. 21:2224-2225). Furthermore, the IERs in this case reflect forecasted circumstances, including normal rainfall in 1989 and the operation of Rancho Seco; the 12(b) filings' IERs are based on actual conditions during the three months that are the subject of the report.

The IER is great concern to QFs, since the level of energy payments to variably priced QFs rises or falls with the IER.

Several issues related to the calculation of the IER were contested in this proceeding.

A. UEG Rate

One of the elements in the calculation of the IER is the assumed price of gas. All parties agree that the proper price for gas should be the Utility Electric Generation (UEG) rate, the tariff rate for sales from PG&E's gas department to its electric department for electrical generation. Some differences about this rate nevertheless remain.

PG&E urges that the annual average UEG rate should be used throughout the calculation of the IER, for both the QF-out run's production expenses and as the denominator in the calculation of the annual IER. PG&E points out that payments to QFs are calculated by multiplying the adopted annual average UEG rate by the adopted IER, and that consistency requires using the same basis for the calculation of the IER. PG&E argues that the approach used by Santa Fe is inconsistent and artificially inflates the IER.

Santa Fe contends that the annual average IER should be based on the monthly value of energy displaced by QFs, and determination of the monthly value of this QF generation requires use of the monthly average UEG rate. Because resource availability and fuel prices change from month to month, Santa Fe argues that the value of the generation provided by QFs also varies monthly. An accurate IER should reflect this variation in value. Santa Fe therefore believes that the calculation of the annual average IER should be the sum of the monthly value of QFs' generation, divided by the sum of the monthly production by QFs, with the result divided by the annual average UEG rate, the gas price used to determine short-run energy payments to QFs.

We believe that the calculations of the IER should use a consistent UEG rate assumption throughout the calculation. In calculating an annual IER, use of the annual average UEG rate in all stages of the calculation is a consistent approach. PG&E has used such an approach and we will adopt its recommendations in this case.

Santa Fe's arguments suggest another approach. To reflect the variations in the value of QFs' generation, a period shorter than a full year could be examined, such as the monthly calculation suggested by Santa Fe. To develop a consistent IER, however, the UEG rate for that month could be employed in all stages of the calculation. The resulting monthly IERs could then be averaged in a logical fashion to calculate the annual IER.

Santa Fe did not follow this approach, however. Santa Fe, for reasons we find unpersuasive, mixed the monthly UEG rate with an annual average UEG rate in developing its recommended IER. This results in a higher IER than the monthly approach we have just suggested and than some of the corrections that PG&E suggested. Because we do not accept the underlying reasoning, we reject the approach advocated by Santa Fe.

B. <u>Avoided Operating and Maintenance Costs</u>

IPC and CCC raised issues about how avoided operating and maintenance (O&M) costs are calculated and how they are paid to QFs as part of the variable energy payment.

1. <u>IPC's Position</u>

IPC first argues that the avoided O&M payment should be added on to the base energy payment to QFs, rather than rolled into the calculation of the IER, as has been PG&E's practice. It points out that Edison makes such payments as an adder. More important, IPC argues that including the avoided O&M in the IER calculation is illogical. The IER is intended to measure the efficiency of the system in converting thermal energy to electric energy, a conversion that is only remotely related to the costs of O&M.

In addition, reflecting O&M costs in the IER will cause the O&M costs included in the energy prices paid to QFs to vary with changes in prices of the marginal fuel, rather than with changes in the amount of generation produced, as logic would suggest. According to IPC, PG&E's present approach increases the risk that QFs will be either overpaid or underpaid for avoided O&M costs, because the payment varies with changes in their marginal fuel price, which is unrelated to the level of avoided O&M costs.

IPC also argues that the O&M adder should include all variable O&M costs, including appropriate labor costs and associated administrative and general (A&G) expenses. IPC finds PG&E's definition of avoided O&M costs to be too narrow, and this narrowness results in undervaluation of the contribution of QFs in allowing the utility to avoid costs. Merely including the items PG&E listed as generation-related variable O&M in its filing in the seventh Common Forecasting Methodology (CFM-7) proceeding before the California Energy Commission raises the value of variable O&M from 0.332 mills/kWh to 1.82 mills/kWh, according to IPC.

IPC goes on to argue that some labor costs, which PG&E excludes, should be included in variable O&M. The presence of QFs frees existing personnel from O&M tasks related to the amount of generation so that they can perform other tasks, resulting in overall productivity improvements and labor costs savings. When inefficient units are totally displaced by QFs' generation and are retired or placed in standby, even the "fixed" O&M costs associated by these plants are avoided. Routine and extraordinary maintenance can be deferred as the operating hours of fossil-fueled units are reduced.

Furthermore, IPC argues, when labor costs are reduced, A&G costs, which the Commission has always associated with labor costs, will also be avoided.

PG&E's understating of avoided O&M costs has two consequences, according to IPC. First, the contribution of QFs is undervalued, in violation of the Public Utility Regulatory Policies Act (PURPA) and the Commission's stated policies. Second, the utility receives a windfall when costs are avoided by QFs and not reflected in avoided costs, because annual O&M costs are estimated in the utility's general rate case and included in base rates. As a result, the utility receives revenues for which it does not incur a corresponding expense.

IPC believes that the O&M adder should be set at 3 mills/kWh. Lack of data prevents it from quantifying the precise amount that PG&E avoids because of the QFs' generation, but the 3 mill/kWh figure is a reasonable approximation. IPC notes that the Commission has approved a 3 mill/kWh adder for Southern California Edison Company. After comparing the two utility systems and referring to the 1.82 mills/kWh figure PG&E submitted to the Energy Commission, IPC believes that 3 mills/kWh is a reasonable estimate of PG&E's variable O&M costs.

Finally, IPC asks the Commission to order PG&E to present a detailed study of its O&M costs as part of its test year 1990 general rate case.

2. <u>CCC's Position</u>

CCC joins in many of IPC's arguments.

CCC adds its concern about the narrowness of PG&E's definition of variable O&M costs. PG&E's definition seems to be tied to a one-year horizon. CCC points out that a longer-term definition, such as the planning framework of the CFM cases, is more appropriate in considering the O&M costs avoided by the contributions of QFs. Both Standard Offer 2 and the variable energy option Standard Offer 4 contracts are paid variable energy rates, but these contracts require reliable operation for 20 to 30 years. The reliability and longevity of these facilities will allow PG&E to reduce its costs for O&M items that vary over a longer period than one year.

CCC points out that QFs' generation has permitted PG&E to reduce the work force at the Avon, Oleum, and Martinez plants from 125 workers to around 5 workers. Although even the CFM filings do not include avoided labor O&M, this reduction in work force demonstrates that some labor O&M costs are avoided by the presence of QFs, according to CCC.

Finally, CCC argues that PG&E has presented no evidence in support of its position. In reviewing the various available sources of information, particularly PG&E's CFM-7 and CFM-8 filings, CCC concludes that an adder of 3 mills/kWh is a reasonable estimate of the O&M costs the QFs' generation allows PG&E to avoid.

3. PG&E's Position

PG&E disputes IPC's and CCC's recommendations. O&M costs avoided by the QFs' generation are limited to "the costs of nonfuel consumable items whose consumption is directly linked to the generating output of conventional fossil units." Labor costs are not avoided, and therefore no A&G costs are avoided, according to PG&E.

When the costs of these actually avoided items are considered, and when the proportion of total generation that is provided by conventional steam units is considered, PG&E calculates that the actual avoided O&M cost is 0.157 mills/kWh.

PG&E believes that the references to the CFM-7 filing are deceptive. Those costs are part of a long-term planning analysis and include many items not avoided when a conventional steam unit reduces generation, which is the appropriate measure for the short term considered in this case.

PG&E points out that the number adopted in the ALJ's ruling contained a transcription error and was not adjusted to reflect the fact that only a portion of the variably priced QF generation replaces conventional fossil units. When Northwest purchases are displaced by QFs, for example, no O&M costs are avoided. Thus, PG&E believes that the corrected figure from the ALJ's ruling should be adjusted to reflect the avoided O&M costs per kilowatt of avoided conventional fossil generation.

PG&E states that each set of inputs into the model will result in different avoided O&M costs and different amounts of conventional generation. Thus, PG&E recommends that the easiest way to calculate avoided O&M costs is to divide the change in variable O&M costs resulting from the QFs-in and QFs-out models runs by the amount of energy expected to be generated by variably priced QFs. When this calculation was performed on PG&E's run following the ALJ's ruling, the result was an avoided O&M payment of 0.157 mills/kWh.

4. Discussion

We are persuaded 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 paid to QFs. Expressing these payments in mills/kWh and allowing them to vary with the amount generated in the swing units, rather than with changes in the price of the marginal fuel, is logical.

Determining the amount to include in the avoided O&M payment is more difficult. IPC and CCC made strong arguments that additional items are avoided by QFs, labor and associated A&G costs in particular. PG&E urged a narrower definition of the variable O&M costs, but little persuasive evidence was presented by any party.

The question of what costs are variable necessarily involves a definition of a time horizon. In the very long run, all costs are variable. PG&E's appears to limit its definition of variable costs to those that vary within one year. IEP and CCC urge a longer time frame.

We conclude that at least some costs that are variable over more than one year are avoided by generation from QFs and should be part of the avoided O&M payment. QFs have demonstrated that they make a dependable contribution to the utility's resources, which PG&E has relied on and can reasonably rely on in the future. In counting on the generation from QFs, PG&E should adjust its maintenance practices accordingly. These adjustments may be reasonably assumed to reduce some costs, and we suspect that at least some of those reduced costs are labor costs.

We are concerned that so little good information is available to help us quantify the amount of variable O&M. IEP pointed out that PG&E has not complied with our order that "the assumptions regarding the derivation of variable O&M should be included" in the utilities' quarterly energy price filings (D.82-12-120, 10 CPUC 2d 553,624).

The information available in this record does not permit us to specify the appropriate time frame for consideration or to quantify exactly the avoided O&M costs. Based on the record, we will adopt as a base number the 1.82 mills/kWh that results from PG&E's CFM-7 filing. This figure does not include any avoided labor costs, and it may include some items that vary over an inappropriately long period. However, these two drawbacks tend to cancel each other out, and we conclude that this figure is the most reasonable estimate provided on this record.

We adopt this amount as a base amount of variable O&M. PG&E has argued that since most variable O&M is attributable to conventional fossil plants, that some adjustment should be made for the large proportion of other resources in its generation base. We agree with these arguments. To make the appropriate adjustment for the various resources in PG&E's resource mix, parties should determine the change in the amount of conventional fossil generation between the QFs-in and QFs-out runs. This represents the amount of fossil generation displaced by the presence of QFs and provides an estimate of the O&M costs that QFs avoid. This amount should be multiplied by the 1.82 mills/kWh figure we have adopted. The product should then be divided by the total generation of variably priced QFs (the generation removed in the QFs-out run), to yield the amount, expressed in mills/kWh, that will paid QFs as an adder for avoided variable O&M costs.

As we have repeatedly mentioned, the lack of information on variable O&M costs presented a formidable obstacle to the resolution of this issue. We will direct PG&E to present a study of the O&M costs avoided by QFs' generation in its test year 1990 general rate case. At a minimum, the study should examine the reductions in costs--including materials costs, labor costs, and any other appropriate costs--that occur when generation is reduced at its existing conventional fossil plants. The study should also calculate the savings in O&M that have resulted from the retiring or removal to standby status of similar plants in the last five years. PG&E should attempt the identify and quantify the O&M costs that vary in one-, three-, and five-year time frames and should expand on these minimum requirements and present any other relevant information available to it.

C. Substitute Resources

The QFs-out run of the models calculates the characteristics of PG&E's system for the forecast year if all generation from variably priced QFs was removed. PG&E argued that this assumption is unrealistic. QFs were added to the system over a number of years, and if no QFs had been added to the system, PG&E would have gradually taken other steps, such as adding new resources or contracting for additional purchases, to meet the system's long-term needs. The QFs-out case essentially assumes the sudden disappearance of a major contribution to PG&E's resources, argues PG&E, and calculates the cost of short-term replacements, primarily increased fossil-fueled generation and purchased power, for those lost resources. To compensate for this unrealistic assumption, PG&E believes that the prices of resources calculated in the QFs-in run should carry over to the QFs-out run.

We have already addressed this issue, at least in part. In D.88-03-079, we heard similar arguments about the soundness of the QFs-out assumption. We acknowledged that this assumption does not reflect what a utility would actually do in the absence of QFs, but we declined to make any adjustments to the QFs-out approach at that time. Since circumstances have not changed since that decision, we will not adopt PG&E's proposed modifications to the adopted QFs-in/QFs-out method.

CCC urged the Commission to sustain the position on substitute resources taken in D.88-03-079.

Santa Fe, however, raised an issue that is a variation of the substitute resources issue. PG&E currently has several plants in standby (see Ex. 22, p. 75, Table 9-1). PG&E acknowledged that four of these units have already been restarted (Tr. 3:250) and that the others could be restarted within 8 hours to four days, if needed. Santa Fe argues that these units should be considered available for modeling purposes for the entire forecast period. PG&E includes them in 1988, but models them as being unavailable in 1989.

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.

We distinguish such existing plants from the substitute units addressed in D.88-03-079. In that decision we contemplated the construction of new plants or the entering into of new contracts for purchases on other than a short-term basis. The rationale for excluding those types of resources does not apply to existing standby units. We conclude that the units listed in Table

9-1 of Ex. 25 should be modeled to be available during the entire forecast period and may be employed in the QFs-out run.

D. <u>The Treatment of Northwest Power Prices</u>

A related issue concerns the treatment of the purchases of Northwest economy energy in 1989. We have previously determined that prices in 1989 should be set at 90% of PG&E's average incremental fossil-fired steam generation costs. Under the QFs-out assumptions, however, it is likely that the removal of QFs will increase the cost of steam generation.

The QFs' representatives argue that the price of Northwest power should rise accordingly. PG&E argues that the price should remain fixed. The primary basis for PG&E's position seems to be that it is unfair to prevent the utility from assuming that substitute resources would be added to make up for the lost QF generation while assuming higher prices for existing resources.

The issue is even more artificial than the parties have defined it. The essential question is whether a separate seed run to develop estimates of PG&E's incremental steam generation costs should be performed for both the QFs-in and QFs-out runs. The question turns on what response Northwest sellers would make to the removal of a large block of QFs. PG&E's approach concludes that sellers would increase the amount of their sales, corresponding to PG&E's increased need to purchase economy energy. The QFs' representatives' approach holds that the Northwest sellers would choose to raise the price but maintain roughly the same level of sales. If this situation were anything but hypothetical, of course, something in-between would happen: quantities of purchases would increase and prices would probably rise somewhat.

We are thus forced to choose between two unrealistic alternatives to resolve a hypothetical problem. In keeping with our adopted QFs-in/QFs-out approach to calculating the IER, we conclude that the price of Northwest power should be permitted to vary in the QFs-out run. A separate seed run for the QFs-out case will simulate the expected reaction of Northwest sellers to the hypothetical loss of variably priced power from QFs and PG&E's consequent greater reliance on thermal generation. Thus, modelers should do a separate seed run to determine the price of Northwest power in the QFs-out case for 1989.

In the seed runs using the assumptions of the ALJ's ruling, the parties used slightly different initial estimates of PG&E's average incremental heat rates for conventional units. This difference elicited little discussion or evidence, but it is desirable for all parties to use the same initial figures. The estimates used by PG&E and CCC--9,500 Btu/kWh for on-peak and 8,500 Btu/kWh for off-peak--should be used in all parties' seed runs.

E. IER Without Rancho Seco

As we have already discussed, there remains some possibility that the Rancho Seco nuclear unit would be shut down during the forecast period because of poor performance, under the terms of an initiative adopted by voters in June. We will allow the parties to calculate an alternate IER which assumes no generation from Rancho Seco. In the event that Rancho Seco is shut down, we will adjust payments to QFs by employing the alternate IER in the revision of energy payments to QFs following the official determination to shut the plant down.

VI. Differences Among the Models

When this case began, it appeared that this would be the forum for the "battle of the models," to determine which of the three models used in this proceeding provided superior results. As the case developed, it became clear that the assumptions used by the models would have a much greater effect than any inherent differences in the models.

At the completion of hearings, the most noteworthy development was how close the three models were in their results.

When PROMOD and ELFIN 1.6 used the same assumptions for economy energy from the Northwest, the resulting IERs differed by only 1.1% (Ex. 54, p. 2). A similar comparison between ELFIN and PROMOD yields a variation of about 1.7% (compare Ex. 54, p. 3 with Ex. 77, Table 9). Other checks on the models also indicate generally similar results (Ex.77, Table 11).

One conclusion that can be drawn is that no party supports use of the old version of ELFIN, version 1.58. That version did not allow prices to be time-differentiated, and all parties agree that the addition of this feature in ELFIN 1.6 was a needed improvement.

At this stage, we are not prepared to say that any of the three models used in this proceeding was inadequate. PROMOD has many features that make certain changes or simulations relatively easy. However, it is expensive to run and access to it is limited. ELFIN 1.6 is relatively cheap and can be run on most personal computers. Although it does not have all the features of PROMOD, modelers are able to overcome most of its limitations to arrive at reasonably accurate simulations. PROSYM is still unfamiliar to parties other than its sponsors. It is intriguing because it takes a different approach to modeling from the other models. We will reserve judgment on PROSYM at least until we have seen it applied in a proceeding when parties are more familiar with its operation.

Eventually we hope to simplify our proceedings by having all parties use the same model. At the same time, however, we do not want to lock into a certain model and ignore the improvements that are made to other models. However, it is imperative that we have some basis for comparison of the various models. In this case, we found ourselves in the same situation we did in the last Edison general rate case, with three models yielding similar results for poorly understood reasons. In the Edison case we ordered that "all parties [in ECAC proceedings] presenting testimony requiring the use of a production simulation model must present a 'base case' run using the same model," and we named ELFIN as the common model (D.87-12-066, mimeo., p. 201). This requirement was ignored in this proceeding, perhaps because ELFIN 1.58 was supplanted by ELFIN 1.6. In any event, we reiterate the requirement of a base case run, and we conclude that ELFIN 1.6 is best suited to serve as a common model for such runs.

VII. Revenue Requirement

Because we have changed many of the determinations of the ALJ's ruling, the revenue requirements that the parties calculated using the ruling's assumptions will undoubtedly change. To calculate a revenue requirement that is consistent with the determinations we have made in this decision, the models will have to be run again. We will direct the parties to do this, and we will set out our conclusions in a subsequent decision.

We expect some changes for the initial calculations, but the estimates provided from the ALJ's ruling should give a general idea of the level of the increase that is likely to result from this proceeding. DRA's final recommended net revenue requirement increase resulting from the ALJ's ruling was $56.7 million. PG&E's corresponding recommendation was $64.5 million.

The models affect only the ECAC and AER portions of the revenue requirement increase. DRA and PG&E agree on the adjustments in the ERAM, DCAC, and CFA (Ex.73). We will defer our decision on all revenue changes so that all revenue changes considered in this case (ECAC, ERAM, DCAC, and CFA) can be made at the same time.

VIII. Revenue Allocation and Rate Design

The testimony presented in the hearings on these issues focused on a potential revenue requirement increase of about $60 million, consistent with the recommendations of DRA and PG&E mentioned in the preceding section. That testimony has been largely superseded by later developments. On October 4, 1988, PG&E and DRA filed a motion for leave to file a late-filed exhibit on the topics of revenue allocation and rate design. The proposed exhibit stated guidelines to be applied to the rate changes resulting not only from this proceeding, but also from PG&E's attrition case and the Diablo Canyon settlement, if it is adopted. The potential increase from the latter two cases amounts to $420 million, well beyond any increases contemplated in the hearings in this case.

An ALJ's ruling of October 6, 1988, requested comments on the motion and the proposed exhibit. Because we are still analyzing the comments that were received in response to the motion, we will issue our decision on revenue allocation and rate design at a later time.

IX. Reinstatement of the AER

In D.88-09-036 we temporarily suspended the AER for PG&E because of the delay in reaching a decision in this case and because PG&E's system faced substantially different circumstances from those contemplated when the AER was last revised.

With the adoption of a revised AER, which will take place in a subsequent decision, the AER should be reinstated. When the revised AER rates take effect, PG&E should again be subject to the incentives of the AER. We expect to have those rates in effect on January 1, 1989.

X. Comments on the Proposed Draft Decision

Parties are reminded that the scope of comments on the proposed decision are strictly limited by Rule 77.3 of the Commission's Rules of Practice and Procedure:

> "Comments shall focus on factual, legal, or technical errors in the proposed decision and in citing such error shall make specific references to the record. Comments which merely reargue positions taken in briefs will be accorded no weight and are not to be filed."

In addition to comments allowed in the rules, parties who have sponsored the use of the various models may also attach as an appendix the results of the model runs using the assumptions adopted in the proposed decision. The primary results will be the revenue requirement and the IER resulting from the model runs. Brief explanatory materials may also be attached. In addition, parties filing these results should serve copies of their work papers on the other parties who have sponsored models in this proceeding. Parties with primary interest in the IER need not calculate a revenue requirement, although such a calculation is strongly encouraged and will greatly aid the Commission in its final decision, but these parties should include enough information, clearly identified, to permit the calculation of the revenue requirement.

In addition, parties whose comments identify errors in the proposed decision that affect the revenue requirement or IER are encouraged to calculate and submit the revenue requirement and IER that result from the correction of those errors. Parties should not use this opportunity to repeat their recommendations on revenue requirement and IER that already appear in the record.

To ensure that the models are run on a consistent basis, a workshop on modeling the proposed decision will be held on October 31, starting at 10 a.m., at the Commission's Courtroom in

San Francisco, California. The assigned ALJ will serve as a moderator. All parties who intend to submit the results of model runs should attend this workshop.

If the Commission adopts the proposed decision without significant alteration, then the results of the model runs attached to the comments may be used by the Commission in arriving at its final decision on revenue requirement and IER. However, the Commission may change some of the important assumptions, which could require an additional run of the models. The intended date for the decision on the topics discussed in this decision is November 23, 1988. Parties sponsoring models should telephone the ALJ on the afternoon of November 23 for the results of the Commission's action. If the Commission changes any of the important assumptions, a workshop will be held on November 28 to clarify those changes so that the results of the final model runs may be arrived at quickly. The time and location of that workshop will be set by the ALJ.

Findings of Fact

1. PG&E filed A.88-04-020 and A.88-04-057 on April 7 and 21, 1988. A.88-04-057 requested an increase of $129.3 million to PG&E's electric rates on an annualized basis beginning August 1, 1988.

2. PG&E's current ECAC proceeding marks the beginning of the regular revision in its ECAC case of key components in the calculation of prices paid for power sold to the utility by QFs.

3. It is the Commission's goal to develop both a utility's rates and QF prices on a consistent basis.

4. DRA's economic forecast reflects recent economic projections.

5. The June 1 snow survey was the most recent information on potential hydroelectric generation available at the time of the hearing.

6. When PG&E's method underforecasted recent recorded sales, DRA developed independent methods that provided reasonable results.

7. The basis for TURN's recommended adjustment to agricultural sales for drought effects was unclear.

8. The drought will tend to increase sales to MID/TID, and no party challenged the assumptions underlying TURN's recommended adjustment.

9. SMUD's estimate of its sales to its customers should be the best estimate of expected sales.

10. DRA developed a reliable method for estimating lost and unaccounted for power.

11. Some of the Geysers geothermal units have been curtailed because of insufficient steam in recent months.

12. In their brief operating histories, the Diablo Canyon nuclear units have had higher operating capacity factors and longer refueling outages than comparable plants.

13. A 12-week target refueling outage for nuclear plants allows two weeks for contingencies.

14. The average second-cycle refueling outage in the nuclear industry is just under 12 weeks.

15. When a plant is restarted after refueling, power is gradually increased to full power over a period of two weeks.

16. Extensive modifications to and scrutiny of the Rancho Seco plant should result in a higher capacity factor than experienced in the past.

17. Under the terms of an initiative adopted by SMUD voters in June, if the monthly capacity factor of Rancho Seco falls below 50% for four consecutive months, it will be shut down.

18. Shortages may cause shortfalls in PG&E's ability to obtain gas from the El Paso system during cold periods.

19. Shortfalls in deliveries on the El Paso system last year averaged around 103 MMcf/d.

20. Up to 170 gWh is available during off-peak periods from the Western Systems Power Pool and other Southwest sources at 15 mills/kWh. These purchases may be backed down. Up to 200 gWh may be purchased from the CPP, and these purchases should be made whenever PG&E's incremental heat rate reaches 11,500 Btu/kWh. Sales to CPP are forecasted at 60 gWh at 24.4 mills/kWh.

21. Emergency power may be purchased from the CPP at 26.75 mills/kWh.

22. The price and amount of purchases from Sierra Pacific and the Lewiston Powerhouse are undisputed.

23. Both PG&E's service territory and the Pacific Northwest have received less rainfall than normal in recent years.

24. Low precipitation in the Northwest will limit the availability of PG&E's economy energy purchases from the Northwest in 1988.

25. The drought has reduced the supply of, and increased the demand for, low-cost economy energy. As a result, prices of economy energy from the Northwest will be higher than normal in 1988.

26. The average price of PG&E's purchases from the Northwest was 19.75 mills/kWh in June, 21.01 mills/kWh in July, and 21.47 mills/kWh through August 17, 1988.

27. In July, BPA made a preliminary offer to sell PG&E between 288 gWh and 298 gWh per month from September to December 1988 at 22 mills/kWh.

28. BC Hydro's territory has received normal rainfall in recent years. BC Hydro has regularly sold power to PG&E.

29. PG&E's entitlement on the Pacific Intertie will increase from 1639 MW to 1775 MW on April 1, 1989.

30. The chief resources displaced by purchases of Northwest economy energy are PG&E's fossil-fired steam generation units.

31. WAPA estimates that its Northwest purchases during the forecast period, delivered to the Tracy pumping plant, to be 1,998.1 gWh.

32. In recent years, SMUD has made use of any capacity on the AC line that NCPA and CSC did not use to purchase power from the Northwest.

33. Transmission constraints, reliability requirements, contractual requirements, load following requirements, and other limitations can cause PG&E's fossil-fueled generation units to be dispatched at times when they would not be dispatched on an economic basis.

34. PG&E has identified area reliability constraints in its East Bay, Humboldt Bay, and San Francisco areas. In addition, required protection of striped bass requires some units to be dispatched out of economic order.

35. PG&E has the contractual rights to back down purchases from some other utilities and QFs, to limit other utilities' purchases from the Northwest, and to limit generation by some other utilities.

36. PG&E currently operates its system in a way that meets the area reliability constraints.

37. PROMOD's default allocation of minimum generation overallocates generation to night and weekend periods.

38. ELFIN derates a unit's capacity before committing it to account for the plant's historical forced outage rate.

39. Accepting economy energy neither increases nor decreases PG&E's spinning reserve requirement.

40. Transmission over the AC and DC lines incurs line losses of 4.5%, and transmission over the DC line incurs an additional conversion loss of 4.5%.

41. Variable O&M costs are not related to changes in the cost of the marginal fuel but are related to variation in the generation by the swing units.

42. Some O&M costs that the generation by QFs allows PG&E to avoid vary over more than one year.

43. When modelers use the same assumptions and consistent modeling conventions, PROMOD, ELFIN 1.6, and PROSYM yield nearly the same results, within the range of variables pertinent to this case.

Conclusions of Law

1. The Commission should adopt load forecasts for the forecast year as follows: total PG&E sales of 67,236 gWh, total area load of 91,606 gWh, and total planning load of 91,803 gWh.

2. A reasonable estimate of hydroelectric generation for the forecast year is 21,007 gWh, including hydroelectric QFs. Reasonable costs are $3,767,000 for PG&E's facilities and $47,065,000 for the irrigations districts' generation.

3. It is reasonable for forecast purposes to assume the curtailments of the Geysers geothermal units because of insufficient steam will continue during the forecast period at about the same rate as was experienced in the first five months of this year.

4. Geothermal generation of 9734.8 gWh, based on a capacity factor of 81.4%, should be adopted as a reasonable forecast for PG&E's units. Reasonable estimates of the capacity of SMUD's units and NCPA/CCPA's units are 100% and 96.1%, before scheduled maintenance.

5. Use of a full cycle capacity factor for nuclear plants is a fair way to balance maintenance done during refueling outages against reduced outages for scheduled maintenance.

6. For the Diablo Canyon nuclear units, a full cycle capacity factor of 67% and a 12-week refueling outage for Unit 2 should be adopted. For a typical 18-month cycle, this cycle capacity factor converts to an operating capacity factor of 79.1%. With a two-week ramp-up for Unit 2, generation of 13,088 gWh is a reasonable forecast.

7. PG&E's method for calculating nuclear fuel costs should be adopted.

8. A 65% capacity factor for the Rancho Seco nuclear plant during power ascension and during operation should be adopted for the forecast.

9. PG&E's approaches to estimating expected generation from wind QFs and hydroelectric QFs are reasonable.

10. PG&E's estimates of generation by large geothermal, solar, and small QFs are reasonable, as is the Santa Fe-PG&E stipulation of the proportions of fixed- and variably priced small QFs.

11. PG&E's estimate of generation by thermal QFs, after certain corrections proposed by DRA, is reasonable.

12. A forecast of total generation by QFs of 11,679.6 gWh, as shown in Table 3, should be adopted.

13. No purchases from DWR should be forecasted for 1988. In 1989, the price of purchases from DWR should be assumed to be at the same price as purchases from the Pacific Northwest.

14. The Solano County wind turbine's generation of 3.3 gWh should be included in the resource mix, but its cost should not be included in the revenue requirement in this case.

15. The capacity price paid to QFs for as-available capacity should remain at $42/kW/yr, until further order of the Commission. This figure should also be used in forecasting PG&E's revenue requirement.

16. The DRA-PG&E stipulation of gas prices, as shown in Table 4, should be adopted.

17. A reasonable fuel oil inventory is 5.6 million barrels.

18. Reasonable estimates of the price of Northwest economy energy in 1988 are 23 mills/kWh on peak and 21 mills/kWh off peak.

19. It is reasonable to assume that enough Northwest economy energy will be available to fill 100% of PG&E's entitlement on the

Pacific Intertie during on-peak periods and 50% of the entitlement during off-peak periods in 1988.

20. It is reasonable to assume that Northwest economy energy will be available up to 90% of PG&E's entitlement on the Pacific Intertie at all times in 1989.

21. It is reasonable to assume that the average price of economy energy from the Northwest in 1989 will be 90% of PG&E's average incremental fossil-fired steam generation cost.

22. A reasonable estimate of the maximum purchases of Northwest power by WAPA is 2,088 gWh.

23. It is reasonable to assume that SMUD, NCPA, and CSC, in combination, will fully use their allotted 200 MW of capacity on the AC line to import Northwest power, except when minimum load conditions or the operation of Rancho Seco requires SMUD to back down its purchases.

24. A reasonable estimate of the cost of distillate oil is $23.53 per barrel and a reasonable distillate oil inventory for combustion turbine use is 100,000 barrels.

25. A reasonable estimate of the amount of generation available from the Helms pumped storage plant because of upstream runoff and normal water management is 34.5 gWh.

26. To be useful in this type of proceeding, a model must accurately reflect the actual operation of the utility's system.

27. Models should reflect the minimum generation requirements associated with the area reliability requirements identified by PG&E. Minimum generation should not be allocated by default by PROMOD for the East Bay, Coastal, or San Francisco areas, but should be allocated 62% to day time, 12% to nighttime, and 28% to weekends.

28. The backdown order listed in Ex. 48 is reasonable and should be followed in the models. In addition, if minimum load is sufficiently low, Rancho Seco and NCPA geothermal should be backed down.

29. Modelers should correct for ELFIN's derating of capacity for forced outages in committing units to meet commitment targets.

30. In attempting to meet a commitment target, ELFIN modelers should check to see that the model does not commit more than the needed resources and if necessary should choose a different target and repeat the process.

31. The Helms pumped storage plant should be 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.

32. Line and conversion losses associated with transmission over the AC and DC lines should be taken into account when determining whether purchases from the Northwest are economic, but no adjustments should be made for these losses in the determination of the IER or for the calculation of the revenue requirement other than the LUAF amount.

33. Northwest purchases by NCPA/CSC should not vary between the QFs-in and QFs-out simulations, but modelers should allow for reductions of Northwest purchases by SMUD and WAPA during minimum load periods, which may vary between the QFs-in and QFs-out runs.

34. The annual average UEG rate should be used throughout the calculation of the IER.

35. The avoided O&M payment should be removed from the calculation of the IER and added as a separate payment to the base energy rates paid to QFs.

36. A reasonable base estimate of the variable O&M cost that the contribution of QFs allows PG&E to avoid is 1.82 mills/kWh. This base figure should be adjusted to reflect the proportion of conventional fossil generation in PG&E's resource mix. Parties should calculate the O&M adder by determining the amount of conventional fossil generation added between the QFs-in and QFs-out runs. This amount should be multiplied by 1.82 mill/kWh. The

3. PG&E shall present a study of the operations and maintenance costs avoided by QFs' generation in its test year 1990 general rate case.

This order is effective today.

Dated __________________, at San Francisco, California.

product should be divided by the total generation of variably priced QFs (the generation removed in the QFs-out run).

37. PG&E should present a study of the O&M costs avoided by QFs' generation in its test year 1990 general rate case.

38. Standby units that can be restarted in a short time should be modeled to be available during the entire forecast period and may be dispatched in the QFs-out run. Substitute units--newly constructed plants or new contracts for purchases--should not be assumed to be in existence or available in the QFs-out run.

39. Parties should be permitted to calculate an IER that assumes no generation from Rancho Seco. If Rancho Seco is shut down during the forecast period, this alternate IER should be used in revising the energy payments to QFs.

40. The models should be rerun to reflect the determinations of this decision.

ORDER

IT IS ORDERED that:

1. The temporary suspension of PG&E's Annual Energy Rate (AER) authorized in D.88-09-036 shall be lifted, and PG&E's AER shall be reinstated at the time that the rates resulting from this decision become effective.

2. The capacity price paid to qualifying facilities (QFs) for as-available capacity should remain at $42/kW/yr until further order of the Commission.

APPENDIX A
Page 1

List of Appearances

Applicant: Roger J. Peters, Robert B. McLennan, and Mark R. Huffman, Attorneys at Law, for Pacific Gas and Electric Company.

Interested Parties: Messrs. Lindsay, Hart, Neil & Weigler, by Michael Peter Alcantar, Attorney at Law, for Cogenerators of Southern California and its individual members; C. Hayden Ames, Attorney at Law, for Chickering & Gregory; John K. Van de Kamp, Attorney General, by Andrea Sheridan Ordin, Michael J. Strumwasser, Mark J. Urban, Peter H. Kaufman, and Peter Van der Naillen, Deputy Attorneys General, for the Attorney General's Office, State of California; Messrs. Morrison & Foerster, by Jerry R. Bloom, Attorney at Law, for California Cogeneration Council; Messrs. Jackson, Tufts, Cole & Black, by William H. Booth and Allan J. Thompson, Attorneys at Law, for California Large Energy Consumers Association; David R. Branchcomb, for Henwood Energy Services, Inc.; Messrs. McCracken, Byers & Martin, by David J. Byers, Attorney at Law, and Reed V. Schmidt, for California City County Street Light Association; Thomas P. Corr, Attorney at Law, for Independent Power Corporation; Messrs. Brobeck, Phleger & Harrison, by Gordon E. Davis, Attorney at Law, for California Manufacturers Association; Messrs. Biddle & Hamilton, by Richard L. Hamilton and Terri A. De Mitchell, Attorneys at Law, for Western Mobilehome Association; Lawrence E. De Simone, for Energy Management Associates, Inc.; Michel Peter Florio, Attorney at Law, for Toward Utility Rate Normalization (TURN); Norman J. Furuta, Attorney at Law, Thomas Vargo, and Sam De Frawi, for the Department of the Navy; Steven Geringer and Karen Mills, Attorneys at Law, for California Farm Bureau Federation; Michael Golden, Attorney at Law, for Redwood Alliance; Jerry W. Green, for Resource Management International, Inc.; Law Office of Dian M. Grueneich, by Dian M. Grueneich, Barry H. Epstein, and Matthew V. Brady, Attorneys at Law, for California Department of General Services; Messrs. Hanna & Morton, by Douglas K. Kerner, Attorney at Law, for Santa Fe Geothermal, Inc., Union Oil Company of California, Freeport-McMoRan Resource Partners; John D. Quinley, for Cogeneration Service Bureau; Messrs. Armour, St. John, Wilcox, Goodin & Schlotz, by James D. Squeri, Attorney at Law, for UNOCAL; Messrs. Downey, Brand, Seymour & Rohwer, by Philip A. Stohr and Deborah K. Teltier, Attorneys at Law, for Industrial Users; Messrs. Barakat, Howard & Chamberlin, Inc., by Nancy C. Thompson, for Barakat, Howard & Chamberlin; John Vickland, Attorney at Law, for BART; Robert B. Weisenmiller, for Morse, Richard, Weisenmiller & Associates,

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Inc.; Sara Hoffman, Deputy County Administrator, for Contra Costa County; William B. Marcus and Jeffrey A. Nahagian, for JBS Energy, Inc. and TURN; Jan Smutny-Jones, Attorney at Law, for Independent Energy Producers and California Cogeneration Council; Randolph L. Wu, Attorney at Law, for El Paso Natural Gas Company; Messrs. Lindsay, Hart, Neil & Weigler, by Frederick J. Dorey, Attorney at Law, for Midset Cogeneration Company, et al.; A. Kirk McKenzie, Attorney at Law, for California Energy Commission; David R. Clark, Attorney at Law, and Lynn G. Van Wagenen, for San Diego Gas & Electric Company; Graham & James, by Michael P. Hurst and Martin A. Mattes, Attorneys at Law, for Amerada Hess Corporation; and Karen Edson and Joseph G. Meyer, for themselves.

Division of Ratepayer Advocates: Catherine A. Johnson, Attorney at Law, Meg S. Gottstein, and James H. Barnes.

(END OF APPENDIX A)

estimate is a reasonable forecast of the generation that the Diablo units will produce during the forecast year.

When we apply this operating capacity factor to the ratings of the Diablo Canyon units and take into account the 12-week refueling outage we have adopted, the resulting predicted generation for the forecast period is 7,435 gWh for Unit 1 and 5,799 gWh for Unit 2, for a total of 13,234 gWh.

However, a slight adjustment must be made to these figures. PG&E testified without challenge that after refueling, the generation of a restarted unit is increased to full power gradually over two weeks. This ramp-up reduces the total generation slightly, by approximately 146 gWh (Tr. 15:1529; Ex.50). Although the full cycle capacity factors we have relied on would ordinarily take this ramp-up into account, the first cycle is measured from commercial operation date and begins with the capability to operate at full power. Because of our reliance on the full cycle capacity factors from the first cycles, it is appropriate to account for the ramp-up in the generation expected from Unit 2, which will be refueled during the forecast period. Accordingly we will subtract 146 gWh from the expected generation of Unit 2, for a total of 5,653 gWh from Unit 2 and 13,088 gWh from both units.

We note that the actual generation during the reasonableness period of February 1, 1987 through January 31, 1988, which included the first refueling of Unit 2, totaled 8,607 gWh for Unit 1 and 5,755 gWh for Unit 2, a total of 14,362 gWh (Tr. 12:1197-1198). Even after taking into account the extraordinary operating capacity factor achieved by Unit 1 during 1987, we believe that our adopted forecast of generation is reasonable.

The 67% full cycle capacity factor that underlies our estimates is considerably higher than the capacity factor of about 58% that is the basis for the settlement in the Diablo Canyon case (A.84-06-014, A.85-08-025). However, the capacity factor used in this case is the forecasted performance for only one year. The Diablo Canyon settlement covers the full life of the plant, roughly 30 years. In addition, the particular year covered by our forecast occurs early in the plant's life, when higher capacity factors are typical and expected. Thus, we see no contradiction between our forecast in this case and the settlement in the Diablo Canyon case.

b. Nuclear Fuel Cost

PG&E's method for calculating the nuclear fuel revenue requirement was uncontested and will be adopted. The estimates in the record suggest that the nuclear fuel revenue requirement associated with our adopted level of generation from the Diablo Canyon plant will be about $100 million. (See Ex. 1, p. 5-13, Ex. 62.)

2. Rancho Seco

SMUD voters on June 7, 1988, approved a ballot measure that permits Rancho Seco to operate for an 18-month fuel cycle. PG&E's original estimate was adopted with certain modifications proposed by Santa Fe in the August 5 ALJ ruling, and most parties now support that estimate.

We believe that the estimate of generation from the August 5 ruling is reasonable. That estimate assumes that the plant will operate at a 65% operating capacity factor during power ascension and after full power is achieved. Full power is assumed to be reached in November 1988. The 65% operating capacity factor converts to a cycle capacity factor of 53.6%, which approximates the historic cycle capacity factor of 52.8% for nuclear plants of similar design (Ex. 8).

CCC continues to argue for a 41% capacity factor based on historical performance of the plant. However, the plant has undergone extensive modifications under intensive scrutiny by the Nuclear Regulatory Commission since that historic record was established, and better performance may reasonably be expected as a permit greater levels of economic dispatch by the models. We have no way of telling whether the way PG&E operates its system is in fact the most efficient way, although we hope we have created incentives to promote efficiency. The lack of information also prevents PG&E from receiving the benefit of the instructional aspects of at least some of the models; with better information, some of the models may be able to suggest alternative, more efficient ways to maneuver around the area limitations.

For these reasons, we will direct PG&E in its next ECAC application to include a detailed description of the reasons for the area reliability requirements and a detailed justification for the minimum generation requirements associated with these constraints.

Having concluded that the models should satisfy the area reliability requirements, we are not persuaded that PG&E's approach is the only way to meet those requirements. As we have stated, PG&E has presented little information on the specific requirements that require special provision in the models. Since the minimum generation requirements seem to subsume the must-run designations, it is not clear that models must necessarily include both limitations to meet the constraints successfully. In light of the hazy record in this area, we will not require modelers to specify the must-run units in the manner proposed by PG&E. For the Coastal, East Bay, and San Francisco areas, modelers will have the option of satisfying the area reliability requirements in another way, and may use other features of their models to satisfy these requirements. The reliability requirements for the striped bass run and for the Humboldt Bay area have been justified, and modelers should reflect these constraints in their runs.

Unfortunately, the record leaves us with little basis for determining whether the models have satisfied the area reliability requirements. We will allow modelers to meet the area reliability requirements by meeting the minimum generation requirements, which