ALJ/MSW/dk

Mailed

OCT 25 1990

Decision 90-10-062 October 24, 1990

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of PACIFIC GAS AND ELECTRIC COMPANY for Authority to Adjust its Electric Rates Effective November 1, 1990; and for Commission Order Finding that PG&E's Gas and Electric Operations during the Reasonableness Review Period from January 1, 1989, to December 31, 1989, were Prudent. (U 39 M)	Application 90-04-003 (Filed April 2, 1990)

(See Appendix A for appearances.)

I N D E X

O P I N I O N

I. Summary of Decision

By this decision we approve for Pacific Gas and Electric Company (PG&E) an increase in its overall revenue requirement of $480,912,000 for the 12-month period beginning November 1, 1990. This increase is composed of an increase of $542.8 million under PG&E's Energy Cost Adjustment Clause (ECAC), an increase of $24.5 million under its Annual Energy Rate mechanism (AER),[1] a decrease of $63.7 million under its Electric Revenue Adjustment Mechanism (ERAM), and a decrease of $22.7 million under its Low Income Rate Assistance (LIRA) program.

These revenue requirement adjustments, which reflect a joint recommendation of parties who were active in the current phase of the proceeding, will be consolidated with the adjustments resulting from PG&E's 1991 attrition adjustment filing (authorized by Decision (D.) 89-12-057 in PG&E's last general rate case), its 1991 cost of capital proceeding (Application (A.) 90-05-011), and other pending proceedings.

This order adopts the forecast resource mix, energy prices, payment factors for purchases from variably priced qualifying facilities (QFs), and the revenue requirement adjustments noted above. Revenue allocation issues will be considered in a separate phase of this proceeding. The consolidated revenue requirement changes will be combined with the

---

1 By order instituting investigation I.90-08-006 dated August 8, 1990, the Commission ordered suspension of the AER for California's major electric utilities until further order. By Advice Letter No. 1313-E dated August 9, 1990, PG&E implemented this order with a rule which retains the AER mechanism in its tariff but which also provides for transferring differences between the AER revenues and the AER-related expenses to the ECAC balancing account.

revenue allocation factors adopted in that phase, and will be implemented through rate adjustments effective January 1, 1991. Reasonableness review issues relative to PG&E's operations during the period January 1, 1989 to December 31, 1989 will be considered in a subsequent phase (or phases) of this proceeding.

II. Summary of the Application

PG&E filed this application on April 2, 1990, requesting an increase of $544.5 million in its electric revenues on an annualized basis effective November 1, 1990. The requested increase, which represents approximately 8.4% of PG&E's electric revenues based on rates in effect on January 1, 1990, is composed of the following revenue requirements changes:

1. An increase of $614.6 million under PG&E's ECAC;
2. An increase of $33.5 million under PG&E's AER;
3. A decrease of $81.7 million under PG&E's ERAM; and
4. A decrease of $21.9 million under PG&E's LIRA account.

PG&E states that the revenue requirement increases are due primarily to forecast increases in energy and capacity payments to QFs; a forecast price increase for Diablo Canyon generation as authorized by D.88-12-083; a forecast gas price increase; and undercollections in the ECAC balancing account due to higher costs for QFs, higher Diablo Canyon generation, higher gas prices, and lower hydroelectric generation than previously forecast and reflected in current rates.

PG&E requests that the revenue changes be consolidated with its 1991 attrition adjustment and cost of capital filings, with a single set of rate changes effective January 1, 1991. Unlike the ECAC, ERAM, and LIRA mechanisms, the AER is not normally accorded balancing account treatment. Under PG&E's proposal, the November 1 AER revenue requirement increase would be recovered in the ECAC balancing account until the rate changes become effective the following January 1.

In addition to the revenue requirement adjustments, PG&E proposes to establish the Incremental Energy Rates (IERs) and the Energy Reliability Index (ERI) used to determine energy and capacity payments for certain QFs during the forecast period. PG&E also proposes a new Diablo Canyon Incremental Energy Rate (DIER) which, in accordance with the Diablo Canyon settlement agreement as adopted by D.88-12-083, is used to adjust the AER for differences between forecast and actual generation. Finally, PG&E requests an order finding its gas and electric operations during the period January 1, 1989 through December 31, 1989 to be reasonable.

In compliance with Commission directives in earlier proceedings, PG&E included with this year's filing reports on: a study of the Dispatcher Risk Aversion modeling convention; a study of fossil steam plant outages in 1986 and 1989; implementation of time-of-use programs; problems affecting the Geysers geothermal plants, including a verifiable method for determining the likely forecast-period yield; and a study of issues related to variable operations and maintenance (O&M) costs included in variably priced QF energy payments.

III. Background

A. Electric Utility Offset Proceedings

The ECAC process enables the electric utilities' rates to reflect changes in its fuel and purchase power expenses on an annual basis outside of the three-year general rate case cycle. This ECAC filing is made in accordance with the rate case plan (RCP) for processing energy cost offset proceedings that was most recently modified by D.89-01-040. Under the RCP, staggered forecast periods are designated for the major electric utilities. PG&E's forecast period is the 12-month period which begins on November 1 of each year, and rates reflecting ECAC, AER, and ERAM revenue requirements are adjusted as of the November 1 revision date. The RCP provides for automatic suspension of the AER mechanism when the forecast period upon which the then-current AER was calculated ends and a new AER has not yet been adopted.

By D.89-07-062 and D.89-09-044, which completed implementation of the baseline reform legislation known as SB 987 (Ch. 212, Stats. 1988), the Commission ordered energy utilities to give qualifying low-income ratepayers a 15% discount on their energy bills. The costs of this LIRA program are collected through a surcharge which is accorded balancing account treatment. The Commission determined that for PG&E's electric rates, the LIRA surcharge would be updated in the company's ECAC proceedings.

B. QF Payments

Consistent with previous PG&E ECAC proceedings, this application combines consideration of ECAC issues with an updating of key components of the calculation of prices paid for power sold to the utility by QFs. The QF calculation issues relate to the prices to be paid to QFs that do not have contracts specifying fixed prices. Variable QF prices are the sum of three basic components: a payment for capacity, a payment for the O&M costs that PG&E avoids because of its purchases from variably priced QFs, and a variable payment for energy.

Critical to the determination of these payments are the utility's ERI and 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. An ERI of less than 1.0 indicates that the utility is in an excess capacity situation in that it has more than enough resources to maintain reliability. The IER, which reflects the utility system's incremental efficiency in converting heat energy to electricity, is combined with an estimate of avoided O&M costs to form an equivalent IER which is multiplied by the utility's incremental fuel cost to produce the price the utility pays for the variably priced QFs' energy.

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

C. Production Cost Models

Computerized production cost models designed to simulate the manner in which utility resources meet system loads are used to forecast energy costs which underlie ECAC revenue requirement calculations as well as ERI and IER values. The simulations are driven by resource and load assumptions which are inputs to the model and which in many cases represent the resolutions of conventional ECAC issues that constitute the heart of an ECAC proceeding.

The use of these 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.

The Commission directed that workshops be held in ECAC filings to determine resource and load data and other data that the utility used to calculate its IER. (D.87-12-066, at p. 205.) The workshop is also to serve as a forun for the parties to agree, to the extent possible, on the assumptions to be used and the appropriate source of those assumptions. The requirement for a common data set modeling workshop was integrated into the RCP by D.89-01-040, with a provision that the workshop should occur early in the proceeding. Accordingly, a production cost modeling workshop was held on May 2, 1990, with Ali Miremadi of the Commission Advisory and Compliance Division (CACD) serving as arbitrator. The workshop report required under the RCP was received as Exhibit 21.

PG&E uses Energy Management Associates' production simulation model PROMOD III, Version 29.1 (PROMOD). For this proceeding the Commission's Division of Ratepayer Advocates (DRA) and the California Cogeneration Council (CCC) also used PROMOD.[2] The Geothermal Resources Association (GRA) and the Independent Energy Producers Association (IEP) used the PROSYM model for the initial common data set runs described above but did not make separate PROSYM runs to support their testimony. By D.89-12-015 in last year's PG&E ECAC proceeding, we reinstituted a requirement

2 Energy Management Associates, Inc. provided DRA with a free license which allowed it to use PROMOD for the duration of this year's ECAC proceeding. DRA has used the ELFIN model in previous ECAC proceedings and indicates it may again use it in future proceedings due to cost and availability considerations.

that PG&E's application be supported by an ELFIN run regardless of the model it wishes to use for its preferred case. PG&E submitted the required ELFIN run.

D. <u>Procedural History</u>

The rate case plan (RCP) provides that reasonableness reviews will be considered separately from forecast period issues in ECAC proceedings. Accordingly, the Administrative Law Judge (ALJ) ruled that PG&E's request for a finding that its 1989 operations were reasonable would be considered in a separate phase of A.90-04-003. At the first prehearing conference held on April 23, 1990, several parties stated that their interest in this year's PG&E ECAC proceeding was limited to revenue allocation issues, and requested that such issues be considered separately. There was no objection to the request, and the ALJ ruled that the forecast phase would be subdivided into a "Resource and Revenue Requirements" phase and a "Revenue Allocation" phase.

The RCP established staggered ECAC revision dates for the various electric utilities in order to balance the Commission's workload over the course of the year and to ease the burden of issuing year-end decisions. There are no major energy utility general rate cases before the Commission requiring year-end decision in 1990, and it is possible to adjust the schedule for PG&E for this year's proceeding by adopting revenue requirements and QF payment factors to become effective on the November 1 revision date, while deferring implementation of rate adjustments until January 1, 1991. This will allow PG&E to implement a single set of rate revisions on January 1 which reflect ECAC revenue requirements as well as adjustments resulting from other proceedings, instead of two sets of revisions occurring two months apart.[3]

The resource and revenue requirements phase encompassed issues relating to the forecasts of sales, resource mix, fuel and purchase power costs, and variable payments to QFs. This opinion decides only these first phase issues. Revenue allocation issues will be considered in a separate decision.

Hearings were held on four days between June 28 and July 18, 1990 in San Francisco, California. The active parties in this phase were PG&E, DRA, CCC, GRA, IEP, the Cogenerators of Southern California (CSC), the Independent Power Corporation (IPC), and Toward Utility Rate Normalization (TURN). This phase was submitted on August 29, 1990 with the receipt of late-filed Exhibits 37, 38, and 39.

Comments on the ALJ's proposed decision were filed by PG&E and DRA. DRA filed reply comments. Our order incorporates minor revisions for clarification.

IV. Summary of the Parties' Positions

Besides PG&E, DRA was the only party to present comprehensive testimony encompassing the full range of ECAC proceeding issues. CCC, GRA, IEP, CSC, and IPC (the QF parties) presented testimony addressing issues which arise in determining QF

---

3 This is the second PG&E ECAC proceeding to be processed since the RCP was revised by D.89-01-040. In last year's proceeding (A.89-04-001) the ECAC/AER/ERAM revenue changes were consolidated with the 1989 general rate case revisions (A.88-12-005), with a single set of rate changes effective January 1, 1990.

Even though circumstances have allowed us to depart from the RCP's provision for both November 1 (ECAC/AER/ERAM) and January 1 (attrition/cost-of-capital/general rate case) rate revisions in both of these ECAC proceedings, such departures may sometimes interfere with the overall functioning of the RCP for all energy utilities. In the future it may be necessary to deny such requests for departures. If PG&E intends to regularly request such deferral and consolidation of ECAC-related rate revisions, it should seek modification of the RCP itself.

payments, including modeling issues affecting calculation of the IER, the ERI, and the O&M adder.

A. PG&E

PG&E's application is summarized above. Without formally changing its rate request, the company revised many of its forecast assumptions in update testimony submitted on June 26, 1990. This update includes a revised revenue requirement increase request of $470,945,000, consisting of an ECAC increase of $543.7 million, an AER increase of $23.3 million, an ERAM decrease of $72.9 million, and a LIRA decrease of $23.1 million.

The forecast data that PG&E submitted with the application reflected the results of a February 1, 1990 snowpack survey. By D.89-12-015 in last year's ECAC proceeding, the Commission provided that for future ECAC proceedings PG&E should present updated hydroelectric forecast information based on its June snow survey. PG&E's updated showing incorporated the June snow survey.

The decrease in PG&E's forecast ECAC revenue requirement from the original filing (from $614.6 million to $543.7 million) is due primarily to lower gas prices than were originally forecast. The forecast cost of gas was updated by PG&E to incorporate costs adopted in D.90-04-021 dated April 11, 1990 in PG&E's Annual Cost Allocation Proceeding (ACAP).

B. DRA

DRA served its showing on June 8, 1990, recommending an overall revenue requirement increase of $482,727,000. DRA stated that pending the results of the June snowpack survey, its June forecast and recommendations were preliminary in nature. DRA agreed with PG&E's initial estimates of sales and several of its resource assumptions, including Diablo Canyon generation and prices, hydroelectric generation (subject to the June snow survey), and geothermal and QF generation.

DRA disagreed with the company's forecasts of gas and oil generation, geothermal prices, purchased power, QF energy payments. DRA projected a total cost of $589.4 million for gas generation, or $61.4 million less than PG&E's forecast of $650.8 million. Other areas where DRA disagreed with PG&E's initial showing included the cost of geothermal generation, with DRA forecasting steam costs to be $3.4 million less than PG&E's estimate of $118.5 million; purchased power, with DRA forecasting total costs to be $3.2 million less than the company's estimate of $199.2 million; and QF purchases, with DRA forecasting energy payments to be $20.9 million less than the company's forecast of $1,081.3 million.

DRA indicated that these differences were primarily attributable to different gas price forecasts developed by PG&E and DRA. PG&E's initial proposal yielded an average UEG rate of $3.55/Dth., compared to DRA's estimate of $3.24/Dth. (PG&E's June update yielded an average rate of $3.26/Dth.) DRA recommended that the gas price forecast be updated to reflect the new Canadian price which was then being negotiated.

DRA agreed with all of PG&E's modeling conventions with the exception of the weekend spinning reserve margins of 9% (October to April) and 11.5% (May to September) proposed by PG&E. DRA used a margin of 7% as being consistent with earlier Commission decisions and with the requirements of the California Power Pool. Modeling higher spinning reserve margins will generally result in a shift from nonfirm to firm generation sources and increased output from higher cost resources.

For determining QF energy payments, DRA calculated an ERI of 1.0 based on the methodology set forth in D.89-06-048 and D.89-12-015. The calculation is based on assumptions of dry-year hydroelectric conditions and firm intertie capacity which includes only intertie entitlements which are backed by firm contracts. DRA disagrees with PG&E's alternate proposal for an ERI of 0.4 because, it asserts, the proposal is based on arguments that were rejected in the last ECAC proceeding. DRA also believes that such changes in methodology should be addressed in Biennial Resources Plan Update proceedings (BRPU).

Based on the preliminary forecast, DRA calculated a QF IER of 10,537 Btu/kWh, a DIER of 8443 Btu/kWh, and an O&M adder of 2.56 mills/kWh. DRA disagrees with PG&E's proposal for a reduced O&M adder (0.84 mills/kWh less than the otherwise applicable adder of 2.55 mills/kWh proposed by PG&E) for QFs with Standard Offer 2 and Standard Offer 4 contracts.

On July 5, 1990 DRA submitted revisions to its June forecast report, updating its forecast to reflect PG&E's June update. DRA's update includes a revised revenue requirement increase recommendation of $470,929,000, consisting of an ECAC increase of $543.8 million, an AER increase of $23.2 million, an ERAM decrease of $72.9 million, and a LIRA decrease of $23.1 million. DRA accepts as reasonable PG&E's updated gas price forecast. Table 13-1 in DRA's updated forecast report shows an effective average gas price of $3.27072/Dth. DRA states that it agrees with PG&E's updated forecasts of sales, nuclear generation and expenses, hydroelectric generation and expenses (except for a $906,000 difference over purchased water expense), gas and oil generation and expense, and geothermal generation and expense. DRA's purchased power forecast reflects a higher expense than that forecast by PG&E ($184.9 million v. $177.4 million) primarily because of the modeling convention differences and a revision to PG&E's showing to reflect a purchase of $4,283,000 from the Department of Energy's Western Area Power Administration.

In its update DRA calculates and recommends adoption of an annual QF IER of 9,902 Btu/kWh, a DIER of 7849 Btu/kWh, and an O&M adder of 2.35 mills/kWh. The ERI calculation yields a recommendation for an ERI of 1.0.

While it disagrees with PG&E's proposal to defer and consolidate rate changes, DRA recommends that if the changes, including the AER, are implemented on January 1, 1991, such implementation be accomplished in a way that prevents suspension of the AER. DRA recommends that a memorandum account be established to track the AER revenues and expenses as if the AER had been in effect November 1 and until the January 1 changes. DRA opposes PG&E's proposed balancing account approach, maintaining that PG&E is not entitled to interest on AER revenues for November and December.

For PG&E's next ECAC proceeding, DRA recommends that PG&E again include information reflecting a specific study of problems affecting the Geysers geothermal plants, including a verifiable method for determining the likely yield from the Geysers during the next forecast period. DRA also recommends that PG&E make a good faith effort to redesign its QF Payments Model prior to the 1991 ECAC filing or report on the status of the effort if it is not completed. According to DRA, the model used by PG&E is not arranged to allow quick sensitivity analyses based on alternative assumptions. Finally, DRA requests that the Commission direct that the required ELFIN base case model run be submitted by PG&E in a more complete fashion which allows comparisons with PG&E's PROMOD runs.

C. QF Parties

Each of the QF parties with the exception of IPC addressed PG&E's alternative proposal to adopt an ERI of 0.4. PG&E made this calculation using average year hydroelectric conditions and assuming that all Pacific Northwest power, up to available intertie capacity, should be used in the ERI calculations. Echoing DRA's concern, the QFs point out that this proposal was considered and rejected in last year's ECAC decision (D.89-12-015). They recommend adoption of an ERI of 1.0.

The QFs' proposals for the O&M adder, as well as those of PG&E and DRA, are shown in the following table:

TABLE 1

Proposed O&M Adder

Party	(Mills/kWh)
CCC	3.84
GRA/IEP	3.84
CSC	3.00
IPC	3.80
PG&E	
Application	
SO-2/SO-4	1.71
SO-1/SO-3	2.55
June update	
SO-2/SO-4	1.56
SO-1/SO-3	2.34
DRA	
June	2.56
July update	2.35

In general, the QFs recommend that the O&M adder be calculated using the methodology adopted in D.89-09-093, and that major departures from that methodology be considered in future BRPU proceedings rather than ECAC proceedings. They oppose PG&E's proposal to adjust the O&M adder according to the QF's capacity designation. Additionally, they disagree (as does DRA) with PG&E's calculations which incorporate variable O&M costs filed by PG&E in the California Energy Commission's Eighth Common Forecasting Methodology proceeding (CFM-8). They assert there is no basis for using CFM-8 data which includes variable O&M costs which are significantly less than those filed in CFM-7.

The parties' differences in the calculation of the O&M adder are due to different estimates of the O&M costs of operating plants which are avoided by variably priced QFs. CCC, GRA/IEP, and IPC calculated the operating plant component of the adder by using CFM-7 avoided O&M costs escalated to 1991 dollars. The QFs assert that this yields the most reliable estimate and is the only method which does not represent a significant departure from the methodology approved by the Commission in D.89-09-093, and that PG&E's and DRA's recommendations should therefore be rejected.

CSC notes that estimates of operating plant avoided O&M costs are dependent on subjective allocations of costs between fixed and variable components. CSC's calculation of 3.0 mills/kWh is based on allocations which use a method published by the Electric Power Research Institute in its Technical Assessments Guide.

CCC disagrees with the assumptions used by PG&E and DRA for Diablo Canyon generation, stating they are based on a different methodology than was adopted in the last two PG&E ECAC proceedings. PG&E used only the last two refueling outage cycles for each unit. CCC notes that the two units have each just completed their best cycles to date, and that the PG&E method gives more weight to the most recent cycle. CCC recommends a 12-week refueling outage and an 85.6% operating capacity factor for each unit. PG&E's forecast results in a 13-week refueling outage and an 88.9% operating capacity factor.

D. TURN

TURN did not present testimony in this phase but did participate through cross examination of PG&E's gas price witness. TURN did not elect to further litigate gas price issues because of the small effect on revenue requirements that would occur even if it were to prevail.

E. Joint Recommendation

At the first prehearing conference active parties were asked to develop a consensus document allowing for a comparison of the positions taken by various parties on each of the contested issues. In reviewing a draft of the comparison document which reflected the updated showings of PG&E and DRA, the parties found that their positions were close on most issues. After the evidentiary hearings were under way, PG&E, DRA, and the QF parties engaged in a series of discussions with a view to reaching agreement on the few remaining contested issues. TURN was apprised of these discussions but did not actively participate in them.

As a result of these discussions the parties agreed on a series of recommendations for revenue requirements, QF payment factors, and deferred implementation of the ECAC rate changes to allow consolidation with those of other proceedings. The joint recommendation dated July 18, 1990 was received as Exhibit 10 and is attached as Appendix B.

By the terms of the joint recommendation, the parties agreed to an update in the recommended revenue requirements to reflect the latest available recorded data for balancing account balances and an updated estimate of revenues at present rates. PG&E submitted late-filed Exhibit 37 (with supporting workpapers which were received as Exhibits 38 and 39) in accordance with this agreement. The update incorporates July 31, 1990 ECAC, ERAM, and LIRA balancing account balances in lieu of the May 31 balances reflected in the joint recommendation. The ERAM base revenue amount was also adjusted to reflect Resolution E-3188 dated June 20, 1990, which authorized an increase in PG&E's electric revenues for 1989 Research, Development and Demonstration expenditures. The update also makes minor revisions correcting and updating estimates of revenues at present rates.

V. Discussion

The joint recommendation was sponsored by all active parties in the resource and revenue requirements phase of this proceeding except TURN, and it represents the only final proposal before us. It reflects the parties' proposals for resolution of all contested issues. Although TURN addressed the gas price forecast through cross examination of one of PG&E's witnesses, it neither offered an alternate proposal nor elected to brief the issue. TURN concluded that the effect on ratepayers of any different gas price that might result from pursuing the issue was so small as to not warrant additional time. The basic issue before us then is whether adoption of the joint recommendation is reasonable and in the public interest. For the reasons discussed below we conclude that it is.

In reviewing the process which led to the joint recommendation, it is instructive to consider the revenue requirements changes proposed by PG&E and DRA in their initial and updated showings.

TABLE 2

Summary of Recommended Revenue Changes
November 1990 through October 1991
(M$)

	PG&E Proposed Apr 02	DRA Proposed Jun 08	PG&E Proposed Jun 26	DRA Proposed Jul 05	Joint Recomm. Jul 18	Joint Recomm. Aug 24
ECAC	$614,650	$542,846	$543,735	$543,775	$552,372	$542,845
AER	33,457	24,977	23,260	23,204	24,114	24,551
ERAM	(81,654)	(62,413)	(72,905)	(72,904)	(72,905)	(63,658)
LIRA	(21,908)	(22,683)	(23,145)	(23,145)	(23,145)	(22,746)
Total	544,545	482,727	470,945	470,929	480,437	480,992

(Red Figure)

Table 2 shows that their initial forecasts were nearly $62 million apart, while the updated forecasts incorporating the June snowpack survey, adopted gas prices from PG&E's ACAP decision (D.90-04-021), and updated balancing account balances, were nearly identical. It is clear from the evidence in this proceeding and from Table 2 that the initial differences over forecast revenue requirements can be largely attributed to the different dates on which the forecasts were made rather than to fundamental disagreements over resource assumptions, modeling conventions or other methodological differences. Since these independent analyses yielded such similar results, we believe it was appropriate for the parties to meet and consider combining their proposals in a process which allowed all parties to participate.

In addition to DRA's gas price recommendations, the joint recommendation incorporates DRA's testimony on the IER and the DIER, including the annual average IER of 9,902 Btu/kWh and the DIER of 7,849 Btu/kWh. It adopts a spinning reserve requirement of 7% as recommended by DRA as well as GRA/IEP. The recommended fuel oil inventory cost reflects DRA's price forecast of $22.76/Bbl. for low sulfur fuel oil and an average inventory of 8,000,000 Bbl., which is somewhat higher than DRA's original forecast of 7,598,000 Bbl. but below PG&E's forecast of 9,648,000 Bbl. Also, the joint recommendation proposes adoption of an ERI of 1.0 as proposed by DRA and all of the QFs instead of PG&E's alternate proposal of 0.4. DRA and PG&E have agreed on ratemaking treatment of sales to the Northern California Power Agency. We find the proposed resolution of these issues to be reasonable; no further discussion of them is necessary.

PG&E's purchased water expense includes payments to various entities for water used in the hydroelectric plants, costs associated with PG&E's weather modification activities, and several other costs related to water rights and headwater improvements. PG&E's forecast expense is $4,591,000. DRA points out that PG&E's forecast is 28.3% higher than the 1989 recorded amount and 21% higher than the six-year average recorded amount from 1984 through 1989. DRA believes that while water system maintenance and improvement by water districts will vary from year to year, their fixed costs of bond debt will remain constant. DRA's forecast of $3,685,000 is based on 1989 recorded expenses, with fixed expenses held constant and operation and maintenance costs escalated by 5% for 1990 and 1991. It is apparent that this expense can be expected to vary considerably from year to year. In view of the differences in methodology used by DRA and PG&E, and uncertainty over the result that would have been reached if they had litigated the issue, we agree with the position stated in the joint recommendation that $4,240,000 is a reasonable estimate for purchased water expense.

The recommendation for an O&M adder of 2.8 mills/kWh for both the 1990 and 1991 ECAC proceedings is another issue on which the parties have forged a reasonable compromise. In D.89-09-093 we adopted a methodology for calculating PG&E's O&M adder, and provided that subject to minor refinements the basic methods adopted would be used in PG&E's 1990 ECAC proceeding. Using that methodology and incorporating CFM 7 data, the QFs have calculated adders of 3.80 or 3.84 mills/kWh. CSC calculated an adder of 3.00 mills/kWh using alternative allocation factors for operating plant O&M expenses. As noted by CSC, these estimates are dependent on subjective judgements for allocation of costs between fixed and variable components. The QFs assert that PG&E and DRA departed from the D.89-09-093 methodology in developing their substantially lower proposals.

Although the joint recommendation provides for use of the O&M adder of 2.8 mills/kWh in next year's proceeding as well as this one, it also allows for changes in the adder in the BRPU or other appropriate proceedings. With this provision for changes, we find that the proposal for using the same adder for two years is reasonable.

One of DRA's principal concerns with PG&E's proposal to defer implementation of rate changes from November 1, 1990 to January 1, 1991 was the possible impact on the AER revenues in the event they were granted balancing account treatment during that interim period. As previously noted, the Commission took action to suspend the AER of all electric utilities on August 8, 1990. Although the parties went to considerable effort to develop an agreeable solution to their differences, this action renders DRA's concern over the AER moot. We do not anticipate lifting the suspension of the AER prior to January 1, 1991. While the AER is effectively suspended, PG&E's tariffs retain the AER mechanism along with a new rule which transfers AER shortfalls and surpluses to the ECAC balancing account. It is not necessary to adopt the joint recommendation for treatment of November and December recorded AER sales.

The parties agree that PG&E will update its study of steam depletion at the Geysers plant for the 1991 ECAC proceeding. They also agree that PG&E will include an ELFIN model run with its 1991 filing, and PG&E agrees with DRA's recommendations for improving access to the QF spreadsheet model. We will incorporate these agreements in the order which follows.

Exhibit 37 includes a forecast increase in ECAC revenues of $542,845,000 and an AER increase of $24,551,000. Based on our review of the arithmetical calculations in Exhibit 37, we find the ECAC increase should be $542,844,000, a difference of $1,000. The AER revenue requirement calculated in the exhibit does not include an adjustment for franchise fees and uncollectibles related to designated sales to resale customers. Correcting this reduces the revenue requirement by $79,000. We find that these corrections are necessary to reflect the intent of the parties in their joint recommendation. The adopted revenue requirements increases in Appendix C incorporate these corrections.

PG&E notes that the LIRA shortfall revenues estimated in Exhibit 37 will be subject to change as a result of revenue allocation factors to be adopted in the next phase of this proceeding. In adopting the revenue requirements set forth in Appendix C, we note that the LIRA revenue requirement will require a final update, with a corresponding change in the ERAM base revenue.

<u>Findings of Fact</u>

1. PG&E filed this application on April 2, 1990, requesting an increase of $544.5 million to its electric rates on an annualized basis effective November 1, 1990, and proposing to establish the IER, ERI, and O&M adders which are the basis of payments to variably priced QFs.

2. The parties in this year's proceeding developed their resource mix and revenue requirements forecasts by using the PROMOD production cost model.

3. PG&E submitted an ELFIN base case model run in accordance with D.89-12-015.

4. PG&E's ELFIN run did not account for certain operating constraints and therefore was not comparable to PG&E's preferred PROMOD filing.

5. The joint recommendation attached as Appendix B was sponsored by all active parties in the resource and revenue requirements phase of this proceeding except TURN, and it represents the only final proposal before us.

6. The joint recommendation reflects the parties' proposals for resolution of all contested issues.

7. TURN does not oppose the joint recommendation.

8. The overall revenue requirements forecasts of PG&E and DRA were initially nearly $62 million apart, but updated forecasts, which incorporated the June snowpack survey, adopted gas prices from PG&E's ACAP decision (D.90-04-021), and updated balancing account balances, were nearly identical.

9. The initial differences over forecast revenue requirements are largely attributable to the different dates on which the forecasts were made rather than to fundamental disagreements among the parties over resource assumptions, modeling conventions or other methodological differences.

10. The joint recommendation incorporates DRA's updated testimony on gas prices, the IER and the DIER, including DRA's recommendations for an effective annual gas price for generation of $3.27072/Dth, an annual average IER of 9,902 Btu/kWh and a DIER of 7,849 Btu/kWh.

11. The joint recommendation adopts a spinning reserve requirement of 7% as recommended by DRA and GRA/IEP.

12. The recommended fuel oil inventory cost reflects DRA's price forecast of $22.76/Bbl. for low sulfur fuel oil and an average inventory of 8,000,000 Bbl., which is somewhat higher than DRA's original forecast of 7,598,000 Bbl. but below PG&E's forecast of 9,648,000 Bbl.

13. The joint recommendation adopts an ERI of 1.0 as proposed by DRA and all of the QFs.

14. DRA and PG&E have agreed on ratemaking treatment of sales to the Northern California Power Agency.

15. PG&E's purchased water expense can be expected to vary considerably from year to year.

16. The joint recommendation for purchased water expense of $4,240,000 is a reasonable estimate.

17. Estimates of avoided O&M expenses for operating plants are dependent on subjective judgements for allocation of costs between fixed and variable components.

18. In D.89-09-093 we adopted a methodology for calculating PG&E's O&M adder, and provided that subject to minor refinements the basic methods adopted would be used in PG&E's 1990 ECAC proceeding.

19. Using the adopted O&M methodology, the QFs have calculated adders of 3.80 or 3.84 mills/kWh.

20. CSC calculated an adder of 3.00 mills/kWh using alternative allocation factors for operating plant O&M expenses.

21. The QFs asserted that PG&E and DRA departed from the D.89-09-093 methodology in developing their substantially lower proposals for the O&M adder.

22. The joint recommendation for an O&M adder of 2.8 mills/kWh for both the 1990 and 1991 ECAC proceedings is a reasonable compromise.

23. Since the joint recommendation provides for changes in the O&M adder in BRPU or other appropriate proceedings, adopting the same adder for this proceeding and next year's ECAC proceeding is reasonable.

24. DRA's concern over the possible impact on the AER revenues in the event they were granted balancing account treatment for November and December 1990 is moot due to suspension of the AER of all electric utilities on August 8, 1990 in I.90-08-006.

25. While the AER is effectively suspended, PG&E's tariffs retain the AER mechanism with a rule which transfers AER shortfalls and surpluses to the ECAC balancing account.

26. The joint recommendation provides that PG&E will update its study of steam depletion at the Geysers plant and include an ELFIN model run with its 1991 filing.

27. PG&E agrees with DRA's recommendations for improving access to the QF spreadsheet model.

28. Correcting an arithmetical calculation in Exhibit 37 results in an ECAC increase of $542,844,000, a difference of $1,000.

29. Correcting the AER revenue requirement in Exhibit 37 to include an adjustment for franchise fees and uncollectibles related to designated sales to resale customers reduces the AER revenue requirement by $79,000.

30. The corrections to Exhibit 37 described in the previous findings are necessary to reflect the intent of the parties in their joint recommendation.

31. The LIRA shortfall revenues estimated in Exhibit 37 will be subject to change as a result of revenue allocation factors to be adopted in the next phase of this proceeding.

32. The joint recommendation represents a reasonable settlement of contested issues.

33. Adoption of the joint recommendation, with the updates proposed in Exhibit 37 and the corrections to calculate ECAC and AER revenue requirements increases which are reflected in Appendix C, is in the public interest.

34. The revenue requirements changes set forth in Appendix C are reasonable, and the increases are justified.

Conclusions of Law

1. The joint recommendation set forth in Appendix B should be adopted with the update proposed by PG&E in Exhibit 37 and with the corrections in the ECAC and AER revenue requirements described in the findings.

2. PG&E should be ordered to adjust its revenue requirements as set forth in Appendix C for the ECAC forecast period November 1, 1990 to October 31, 1991.

3. The final recommendations found in Appendix B for the IER, the time-differentiated IERs, UEG volumes, the DIER, and ERI, as well as the underlying resource assumptions and modeling conventions listed in Appendix B, should be adopted for the ECAC forecast period November 1, 1990 to October 31, 1991.

4. The recommended O&M adder of 2.80 mills/kWh should be adopted for PG&E's 1990 and 1991 ECAC proceedings subject to change as provided in Appendix B.

5. In accordance with the joint recommendation, PG&E should be ordered to update its study of steam depletion at the Geysers plant for the 1991 ECAC proceeding.

6. PG&E should be ordered to include a complete ELFIN model run which allows meaningful comparisons with its preferred model with its 1991 filing.

7. DRA's recommendations for improving access to PG&E's QF spreadsheet model should be adopted.

8. The joint recommendation for treatment of November and December recorded AER sales is moot since AER undercollections and overcollections are recorded in PG&E's ECAC balancing account pursuant to the Commission's order in I.90-08-006.

9. The LIRA revenue requirement Appendix C may require a final update in the revenue allocation phase of this proceeding, with a corresponding change in the ERAM base revenue.

O R D E R

IT IS ORDERED that:

1. Effective November 1, 1990, Pacific Gas and Electric Company (PG&E) is authorized and directed to record in the respective balancing accounts an increase in its Energy Cost Adjustment Clause revenue requirement of $542,844,000; an increase in its Annual Energy Rate revenue requirement of $24,472,000; a decrease in its Electric Revenue Adjustment Mechanism revenue requirement of $63,658,000; and a decrease in its Low Income Rate Assistance revenue requirement of $22,746,000.

2. The rate adjustments related to the revenue requirements adjustments adopted in Ordering Paragraph 1, which are to be adopted in the Revenue Allocation phase of this proceeding, may be consolidated with rate adjustments resulting from PG&E's 1990 Cost of Capital proceeding, its 1990 Attrition Rate Adjustment filing, and other pending proceedings, with an effective date of January 1, 1991.

3. The incremental energy rate (IER), time-differentiated IERs, gas (UEG) volumes, Diablo Canyon IER, and energy reliability index set forth in Appendix B are adopted for the ECAC forecast period November 1, 1990 to October 31, 1991.

4. The O&M adder of 2.80 mills/kWh is adopted for the ECAC forecast period November 1, 1990 to October 31, 1991 and for PG&E's 1991 ECAC proceeding, subject to change as provided in Appendix B.

5. In its next ECAC application, PG&E shall provide an update to its study of steam depletion at the Geysers plant.

6. PG&E shall include a complete ELFIN model run with its 1991 filing which allows meaningful comparisons with its preferred model filing.

7. Prior to its 1991 ECAC filing, PG&E shall make a good faith effort to improve its QF payments spreadsheet model in

accordance with the discussion of objectives and recommendations set forth in Appendix B to Chapter 8 of Exhibit 6 and in Exhibit 7.

8. The LIRA revenue requirement set forth in Appendix C may be adjusted in the Revenue Allocation phase of this proceeding, with a corresponding change in the ERAM base revenue.

This order is effective today.

Dated October 24, 1990, at San Francisco, California.

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

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

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

NEAL J. SHULMAN, Executive Director

List of Appearances

Applicant: Roger J. Peters, Michelle L. Wilson, and Robert B. McLennan, Attorneys at Law, for Pacific Gas and Electric Company.

Interested Parties: Messrs. Lindsay, Hart, Neil & Weigler, by Michael P. Alcantar, for Cogenerators of Southern California; C. Hayden Ames, Attorney at Law, for Chickering & Gregory; Barkovich & Yap, by Barbara Barkovich, and Messrs. Jackson, Tufts, Cole & Black, by William H. Booth, Joseph S. Faber, and Evelyn K. Elsesser, Attorneys at Law, for California Large Energy Consumers Association; Messrs. Morrison & Foerster, by Jerry R. Bloom and Lynn M. Haug, Attorneys at Law, and Morse, Richard, Weisenmiller & Associates, Inc., by Mark Younger and Robert Weisenmiller, for California Cogeneration Council; David R. Branchcomb, for Henwood Energy Services, Inc.; Maurice Brubaker, for Drazen-Brubaker & Associates; Messrs. McCracken, Byers & Martin, by David J. Byers, Attorney at Law, for California City-County Street Light Association (CAL/SLA); Thomas Corr, Attorney at Law, for Independent Power Corporation; Messrs. Brobeck, Phleger & Harrison, by Gordon E. Davis, Attorney at Law, for California Manufacturers Association; Grueneich and Ellison, by Barry H. Epstein, Attorney at Law, for California Department of General Services; Norman Furuta, Attorney at Law for Federal Executive Agencies; Steven A. Geringer, Attorney at Law, for California Farm Bureau Federation; Martin A. Katz, for Sierra Energy and Risk Assessment, Inc.; Richard K. Durant, Frank J. Cooley, and James M. Lehrer, Attorneys at Law, and David R. Hinman, for Southern California Edison Company; Loretta Mabinton, Attorney at Law, for Union Oil Company of California; Joseph G. Meyer, for Joseph Meyer Associates; Ken Meyer, for Energy Consulting Group; Jeff Nahigian, for JBS Energy; John D. Quinley, for Cogeneration Service Bureau; Bartle Wells Associates, by Reed V. Schmidt, for City of Fresno and County of Marin; Dennis Shigeno, for Unocal Corporation; Michel Peter Florio and Joel R. Singer, Attorneys at Law, for Toward Utility Rate Normalization (TURN); Messrs. Downey, Brand, Seymour & Rohwer, by Philip A. Stohr and Ronald Liebert, Attorneys at Law, for Industrial Users; Melissa Metzler for Barakat & Chamberlin, Inc.; Thomas A. Tribble, for University of California; Randolph L. Wu, Attorney at Law, by Phyllis Huckabee, for El Paso Natural Gas Company; Messrs. Jackson, Tufts, Cole & Black, by William H. Booth, Joseph S. Faber, and Evelyn K. Elsesser, Attorneys at Law, for California Large Energy Consumers Association; David R. Clark, Attorney at Law, for San Diego Gas & Electric Company; Messrs. Ater, Wynne, Hewitt, Dodson, and Skerritt, by Paul J. Kaufman, Attorney at Law, for Kern River Cogeneration; Patrick J. Power, for Bonus Gas Processors; RCS, Inc., by Donald W. Schoenbeck, for Regulatory and Cogeneration Services; Messrs. Roberts & Kerner, by Douglas K. Kerner, Attorney at Law, for Geothermal Resources Association and Independent Energy Producers Association; David G. Salow, for Association of California Water Agencies; and Nancy I. Day, Attorney at Law, for Southern California Gas Company.

Division of Ratepayer Advocates: Catherine A. Johnson, Attorney at Law, and David H. Weiss.

(END OF APPENDIX A)

Application No. 90-04-003

Exhibit No. 10

Date: July 18, 1990

JOINT RECOMMENDATION OF THE
DIVISION OF RATEPAYER ADVOCATES,
PACIFIC GAS & ELECTRIC COMPANY,
CALIFORNIA COGENERATION COUNCIL,
COGENERATORS OF SOUTHERN CALIFORNIA,
GEOTHERMAL RESOURCES ASSOCIATION,
INDEPENDENT ENERGY PRODUCERS ASSOCIATION,
AND INDEPENDENT POWER CORPORATION

JOINT RECOMMENDATION OF THE
DIVISION OF RATEPAYER ADVOCATES,
PACIFIC GAS & ELECTRIC COMPANY,
CALIFORNIA COGENERATION COUNCIL,
COGENERATORS OF SOUTHERN CALIFORNIA,
GEOTHERMAL RESOURCES ASSOCIATION,
INDEPENDENT ENERGY PRODUCERS ASSOCIATION,
AND INDEPENDENT POWER CORPORATION

The parties to the recommendations contained in this document, including appendices, ("Joint Recommendation") are the Division of Ratepayer Advocates ("DRA"), Pacific Gas and Electric Company ("PG&E"), the California Cogeneration Council ("CCC"), the Cogenerators of Southern California ("CSC"), the Geothermal Resource Association ("GRA"), the Independent Energy Producers Association ("IEP"), and the Independent Power Corporation ("IPC"). DRA, PG&E, CSC, CCC, GRA, IEP, and IPC are collectively referred to herein as the "Parties," and individually referred to as a "Party."

The Parties jointly recommend that the Commission adopt the following recommendations in this proceeding:

A. Total Revenue Requirement

The Parties jointly recommend that a revenue requirement increase of $480,437,000 be adopted, as contained in Appendix A.[1/]

1/ The Parties jointly recommend that this amount be updated for the latest available recorded data in the ERAM, ECAC, and LIRA accounts as of August ~~21~~, 24 1990. The Parties jointly recommend that the revenues at present rates also be adjusted at that time to reflect the adopted sales forecast and updated FERC resale and other rates.

B. Annual Average Incremental Energy Rate (IER) 9,902 btu/kWh

Based upon the annual average IER of 9,902 btu/kWh reflected by this Joint Recommendation, the Parties agree that the time differentiated IERs will be as follows:

	Peak	Partial Peak	Off	Super Off-Peak
Summer	9,654	9,353	8,808	8,078
Winter		11,233	10,808	10,130

With the exception of the spinning reserve requirement and the Diablo Canyon capacity factor and refueling duration, the underlying resource assumptions and modelling conventions used in the development of the IER were uncontested and are listed in Appendix B.[2/]

The IER is based upon DRA's July 5, 1990 revised testimony and production cost model simulations of the operation of PG&E's system for the forecast period November 1, 1990 through October 31, 1991, as shown in Appendix C. The PROMOD energy balance contained in Appendix D and the UEG volumes and average UEG rate contained in Appendix E are the basis of the 9,902 btu/kWh IER. The Parties jointly recommend that the UEG volumes, contained in

---

2/ Appendix B reflects the position of the Parties as of July 9, 1990. Because hearings were continued on that date in order for the Parties to participate in informal discussions on the issues described herein, these positions were taken without participation in the hearing and briefing process, and do not necessarily reflect the final positions of the Parties had the issues been fully litigated.

Appendix E, be adopted for use in the calculation of QF payments.

1. Diablo Canyon Capacity Factor

The Parties jointly recommend that the Commission adopt a Diablo Canyon capacity factor of 88.9% with a 13-week refueling duration. The Parties recommend that the DIER be 7,849 btu/kWh, as contained in Appendix F.

2. Spinning Reserve Requirement

The Parties jointly recommend that the Commission adopt a spinning reserve requirement of 7% for PROMOD modelling.

C. Energy Reliability Index (ERI)

The Parties jointly recommend that an ERI of 1.0 be adopted.

D. Operations and Maintenance (O&M) Adder

The Parties jointly recommend that an O&M Adder for all variable-priced qualifying facilities ("QFs") be fixed for the 1990 and 1991 ECAC proceedings. Specifically, the Parties recommend that the O&M Adder be set at 2.8 mills/kWh for a two-year period which, consistent with Decision No. 88-03-026, will commence with the first quarter in which QF energy prices may be affected by a decision in this proceeding. The Parties agree, however, that the O&M Adder may be subject to change should the Commission in the Biennial Resource Plan Update proceeding, or such other proceeding as the Commission may direct, during the two-year period, adopt and implement a methodology for calculating the O&M Adder for use by PG&E.

E. Fuel Oil Inventory

DRA and PG&E jointly recommend that the Commission adopt an average low sulfur fuel oil inventory of 8,000,000 barrels. DRA and PG&E jointly recommend that the price be $22.76 per barrel for low sulfur fuel oil.

F. Water For Power Related Expenses

DRA and PG&E agree that $4,240,000 is a reasonable estimate of water for power related expenses.

G. Ratemaking Treatment of NCPA Sale

DRA agrees that the ratemaking treatment accorded to PG&E's sales to NCPA for the purposes of the 1990 ECAC is reasonable. PG&E intends to provide DRA with a cost benefit study in the 1991 ECAC for prospective review of the continued ratemaking treatment of this sale until PG&E's 1993 General Rate Case.

H. Study Requirements

The Parties agree that in its showing in this proceeding PG&E has complied with the study requirements for the dispatcher's risk aversion feature in PROMOD, fossil steam plant outages and a verifiable method for determining the likely yield from the Geysers during the forecast period. The Parties agree that these studies meet the requirements set forth by Decision No. 89-12-015. PG&E will update its study of the steam depletion at the Geysers in its 1991 ECAC application. The Parties agree that PG&E

filed an ELFIN base case submittal in compliance with Decision No. 89-12-015. PG&E will provide an ELFIN base case run with its 1991 ECAC application. PG&E accepts the recommendations of DRA with respect to the QF spreadsheet model as set forth in Exhibit 7.

I. Treatment of AER Revenues from November 1 to December 31, 1990

PG&E proposed to consolidate the ECAC/AER/ERAM/LIRA rate changes with the January 1, 1991 Attrition Rate Adjustment and Cost of Capital rate changes. The ALJ ruling on May 16, 1990, assumes consolidated rates.

For purposes of the 1990 AER rate change only, DRA and PG&E agree that PG&E shall be authorized to record in the ECAC balancing account the difference between current AER revenues and adopted AER revenues for the months of November and December 1990.

These amounts shall be calculated based on recorded November and December sales. The adjustment amounts shall be recorded in the ECAC balancing account at the close of each month (i.e., November and December, respectively). However, interest shall not be recorded in the ECAC balancing account for the month of November on the adjustment amount pertaining to November. Otherwise, these amounts shall remain part of the ECAC balance, accruing interest at the 3 month commercial paper rate, until such time as the ECAC balancing account is amortized.

Specifically, the difference in AER revenue for the months of November and December, 1990 shall be calculated using a proxy rate determined as described in Exhibit 22 (Update Testimony of L. L. Wong, chapter 6), pages 4-5.

This recommendation assumes a November 1, 1990 effective date for the ECAC/AER revenue requirement and a January 1, 1991 effective date for consolidated rates. If the ECAC/AER revenue requirement effective decision date is delayed beyond November 1, 1990, the otherwise applicable provisions of Decision No. 89-01-040 shall apply. If the consolidated rate change is delayed beyond January 1, 1991, the AER revenue treatment described above shall apply until consolidated rates become effective.

J. General Terms

The testimony of the Parties supports a range of revenue requirements, IER, O&M Adder and ERI calculations. Based upon that testimony and informal discussion thereof, held with the Administrative Law Judge's assent, the Parties believe that adoption of this compromise position represents a reasonable recommendation based upon the positions advocated by the Parties in this proceeding.

The Parties jointly recommend that the Commission adopt this Joint Recommendation without any further modelling simulations because this result is within a reasonable bandwidth of the expected values for PG&E's

revenue requirements, (see footnote 1) IER, O&M Adder, and ERI calculation.

No Party to this Joint Recommendation will contest in this proceeding or in any other forum, or in any other manner before this Commission, the recommendations contained in the Joint Recommendation. However, this shall not be construed to be an acceptance or endorsement of the principles, assumptions or methodologies underlying these recommendations.

The Parties agree that the principles, assumptions, or methodologies underlying the specific items addressed in this Joint Recommendation are recommended for purposes of this proceeding only and are not to be deemed by the Commission or any other entity as precedent in any proceeding or litigation except as necessary to implement the recommendations contained herein in this proceeding. Except as provided in footnote 1 to this Joint Recommendation, the Parties expressly reserve the right to advocate in other proceedings principles, assumptions or methodologies different from those which may underlie, or appear to be implied by, this Joint Recommendation.

The Parties intend and agree that this Joint Recommendation is subject to each and every condition set forth herein, including its acceptance by the Commission in its entirety and without change or condition. Unless the Commission accepts the Parties' recommendations contained herein in their entirety, without change or condition, this

Joint Recommendation shall be null and void, unless otherwise agreed upon by the Parties.

The Parties agree to extend their best efforts to ensure the adoption of this Joint Recommendation.

Jointly submitted by counsel of record for the following parties:

Division of Ratepayer Advocates

/s/ CATHERINE A. JOHNSON
CATHERINE A. JOHNSON

Pacific Gas and Electric Company

/s/ MICHELLE L. WILSON
MICHELLE L. WILSON

California Cogeneration Council

/s/ JERRY R. BLOOM
JERRY R. BLOOM

Cogenerators of Southern California

/s/ PAUL K. KAUFMAN
PAUL K. KAUFMAN

Geothermal Resources Association/
Independent Energy Producers Association

/s/ DOUGLAS K. KERNER
DOUGLAS K. KERNER

Independent Power Corporation

/s/ THOMAS P. CORR
THOMAS P. CORR

Dated: July 18, 1990

TABLE 6-1

PACIFIC GAS AND ELECTRIC COMPANY
SUMMARY OF CHANGES IN REVENUE REQUIREMENTS

$(000)

	Joint Recommendation Test Year Beginning November 1, 1990
ECAC	$552,372
AER	$24,114
ERAM	($72,905)
LIRA	($23,145)
TOTAL	$480,437

TABLE 6-1A

PACIFIC GAS AND ELECTRIC COMPANY
SUMMARY OF TOTAL REVENUE REQUIREMENTS
AND REVENUE CHANGES

LINE	REVENUE ELEMENT	PRESENT RATE REVENUE ($000'S) (a)	PG&E PROPOSED REVENUE ($000'S) (b)	Joint Recommendation REVENUE CHANGE ($000'S) (c)
1	Base Energy Rate (ERAM)	$3,099,638	$3,026,734	($72,905)
2	Annual Energy Rate (AER)	$194,773	$218,887	$24,114
3	Conservation Financing Adjustment (CFA)	$1,391	$1,391	$0
4	Energy Cost Adjustment Clause (ECAC)	$3,177,837	$3,730,209	$552,372
5	Low Income Rate Assistance (LIRA)	$34,248	$11,103	($23,145)
6	CPUC Fees	$8,352	$8,352	$0
7	*Subtotal*	$6,516,239	$6,996,675	$480,437
8	Other Revenues	$46,394	$46,394	$0
9	Total	$6,562,633	$7,043,069	$480,437

TABLE 6-2
PACIFIC GAS AND ELECTRIC COMPANY
ECAC/AER/ERAM/LIRA
CALCULATION OF CHANGE IN REVENUE REQUIREMENT

Line No.	Revision Date: November 1, 1990 Forecast Period: Twelve Months Beginning November 1, 1990	(a) Quantity MDth or GWh	(b) Price $/Dth or KWh	Joint Recommendation (c) Total Costs $(000)
	Fossil Fuel			
1	G-PC	187,855	$2.38636	$448,290
2	G-UEG			$166,131
3	*Subtotal Gas*	187,855	$3.27072	$614,421
4	Residual Oil	3,156	$3.40304	$10,740
5	Distillate Oil	362	$4.45304	$1,612
6	*Subtotal Fossil Fuel*	191,373	$3.27514	626,773
7	Geothermal Steam	6,823	$0.01699	$115,933
	Purchased Power			
8	Irrigation Disticts	4,837	$0.01030	$49,801
9	CVP	(2,146)	$0.01428	($30,649)
10	Variably Priced QF Energy	8,972	$0.03545	$318,044
11	Other QF Including Capacity Pmts	10,713	$0.10951	$1,173,131
12	Total QF	19,685	$0.07575	$1,491,175
13	Northwest	8,252	$0.01988	$164,034
14	Southwest(Including Sales)	147	$0.01087	$1,598
15	CDWR	0		$0
16	Other	6	$0.05583	$335
17	*Subtotal Purchased Power*	30,781	$0.05446	$1,676,294
18	Water for Power	12,263	$0.00035	$4,240
19	Oil Inventory Carrying Cost			$11,560
20	Variable Wheeling			$1,531
21	Losses(Gains) on Fuel Oil Sales			$0
22	*Subtotal Energy Expense*			$2,436,431
23	Less: 9% of Energy Expense			$219,279
24	*Subtotal*			$2,217,152
25	DC Settlement Revenues *	13,685	$0.07890	$1,283,442
26	Excess Oil Inventory Carrying Cost			$0
27	*Subtotal*			$3,500,594
28	Allocation to CPUC Jurisdiction @ 0.9898			$3,464,888
29	Less: DC Basic Revenue Requirement			$204,347
30	*Subtotal*			$3,260,542

* The average rate excludes the basic revenue requirement and FF&U expenses and includes the Safety Committee Fee.

TABLE 6-2
PACIFIC GAS AND ELECTRIC COMPANY
ECAC/AER/ERAM/LIRA
CALCULATION OF CHANGE IN REVENUE REQUIREMENT

Line No.	Revision Date: November 1, 1990 / Forecast Period: Twelve Months Beginning November 1, 1990	Joint Recommendation $(000)
	ECAC REVENUE REQUIREMENT(cont.)	
31	*Subtotal (from page 1)*	$3,250,542
32	Estimated ECAA Balance on October 31, 1990	$531,144
33	DC Safety Committee Fee	$608
34	Less: Designated Sales Transactions to Resale Customers	$93,525
35	*Subtotal*	$3,698,769
36	Franchise Fees & Uncollectible Accounts Expense @ .85%	$31,440
37	TOTAL ECAC REVENUE REQUIREMENT	$3,730,209
38	Less: ECAC Revenue at Present Rates of 5/11/90	$3,177,837
39	CHANGE IN ECAC REVENUE REQUIREMENT	$552,372
	AER REVENUE REQUIREMENT	
40	9% of Energy Expense (Line 23)	$219,279
41	Allocation to CPUC Juris. @ 0.9898	$217,042
42	Franchise Fees & Uncollectible Accounts Expense @ .85%	$1,845
43	TOTAL AER REVENUE REQUIREMENT	$218,88[illegible]
44	Less: AER Revenue at Present Rates of 5/11/90	$194,773
45	CHANGE IN AER REVENUE REQUIREMENT	$24,114
	ERAM REVENUE REQUIREMENT	
46	Base Revenue Amount	$3,315,225
47	Estimated ERAM Balance on October 31, 1990	($209,604)
48	Less: LIRA Shortfall	$25,495
49	Less: Designated Sales Transactions to Resale Customers	$53,392
50	TOTAL ERAM REVENUE REQUIREMENT	$3,026,734
51	Less: ERAM Revenue at Present Rates of 5/11/90	$3,099,639
52	CHANGE IN ERAM REVENUE REQUIREMENT	($72,905)
	LIRA REVENUE REQUIREMENT	
53	LIRA Shortfall	$25,495
54	Estimated LIRAA Balance on October 31, 1990	($16,367)
55	Adminstrative Costs	$1,975
56	TOTAL LIRA REVENUE REQUIREMENT	$11,10[illegible]
57	Less: LIRA Revenue at Present Rates of 5/11/90	$34,248
58	CHANGE IN LIRA REVENUE REQUIREMENT	($23,145)

PACIFIC GAS AND ELECTRIC COMPANY
1990 ECAC/AER/ERAM/LIRA FILING

SUMMARY OF UNCONTESTED RESOURCE ASSUMPTIONS

1. Area Load Forecast - June update
   ECAC test year Nov. 1990 - Oct. 1991 — 97,193.9 Gwh

2. Hydroelectric Generation - June update

a.	PG&E owned Hydro w/o Helms	12,324.3 Gwh
b.	Irrigation Districts	4,839.5 Gwh
c.	USBR (WAPA) Hydro	2,676.0 Gwh
d.	NCPA	503.5 Gwh
e.	SMUD	1,670.0 Gwh
f.	CCSF	1,451.5 Gwh

3. Helms Pumped Storage
   Three units with a combined generating capacity of 1212 MW and pumping capacity of 966 MW. Inflows and water management operations modeled thru PROMOD EXCH records.

4. Northwest firm purchases by PG&E from PP&L - 250.3 Gwh, priced at 27.0 mills/kwh
   Firm peaking purchase from PP&L based on contract.

5. Northwest purchases by CSC - 91.2 Gwh
   On-peak firm takes over 25 MW share of DC line capacity.

6. Southwest Miscellaneous purchases by PG&E - 240.0 Gwh, priced at 16.8 mills/kwh
   Fixed off-peak purchases based on historical quantities.

7. California Power Pool Sales - 120.0 Gwh
   Fixed unscheduled energy sale transaction based on historical quantities, priced at rates similar to CPP Purchases.

8. California Power Pool Purchases
   Economic energy purchases assumed at an incremental heat rate of 11,000 Btu/kwh, priced at dispatch cost of gas.

9. Sierra Pacific Purchases - 3.6 Gwh at a cost of $299,000
   Around the clock deliveries to serve PG&E customers in the Echo Summit Area

10. Miscellaneous purchases for others - 43.8 Gwh
    5 MW around the clock purchases by others in the area, based on historical quantities.

11. NCPA Resources
    a. NCPA Geothermal - 1295.4 Gwh
       Unit with cycling operations - 238 MW on-peak and 90 MW off-peak.
    b. NCPA COG - 34.2 Gwh
       Fixed firm unscheduled transaction based on historical quantities.
    c. NCPA CT - 18.0 Gwh
       Fixed non-firm peaking transaction based on historical quantities.

PACIFIC GAS AND ELECTRIC COMPANY
1990 ECAC/AER/ERAM/LIRA FILING

SUMMARY OF UNCONTESTED RESOURCE ASSUMPTIONS

12. SMUD Resources
   a. NW for SMUD - 1750.2 Gwh
      Assumes full utilization of 200 MW AC line entitlement
   b. SMUD PV, SMUD CT - 5.1 Gwh
      Fixed peaking transaction based on historical quantities.
   c. SMUD Geothermal - 559.6 Gwh
      Unit availability based on two year average historical outage statistics.
   d. SCE sales to SMUD - 351.9 Gwh
      SMUD elected 300 MW contract capacity. Takes are based on contract, availability of other resources and SMUD's loads. SMUD's deficit energy supplies by 85-15 split between PG&E and SCE. Modeled as a hydro unit with 25% minimum take and scheduled 150 MW weekday takes in most months except summer when SMUD needs more capacity. No takes in April and May due to lower demand.

13. CCPA Geothermal - 273.7 Gwh
   One 37.2 MW unit available based on actual operations. Energy split 83% and 17% to SMUD and NCPA based on owernership.

14. QF Generation - 19,686.0 Gwh, including hydro QFs.
   Includes 8,971.3 Gwh of variably priced QF generation.
   a. Firm capacity contracts modeled at their firm capacity ratings. Remaining QF's reflect average megawatts.
   b. Gilroy Foods operates at a SO4.
   c. BAF is shut down January through April, curtailed 6 hours per day May through September, Curtailed 10 hours per day Monday through Saturday and all day Sunday October through December. 20% fixed and 80% variable.
   d. No minimum load based curtailments (600 hour or SO4 curtailment option B) are forecasted to occur. However, non-standard curtailment provisions not tied to minimum load conditions are forecast.
   e. Hydro capacity factor for 1990 is adjusted to reflect June hydro conditions.

15. Sales to Southern Cities - 213.5 Gwh
   Firm 39 MW peak sale at 62.5% capacity factor.

16. Sales to Redding - 66.8 Gwh, June update
   Firm energy transaction based on forecasts of sales to Redding and Shasta Dam.

17. Geysers Units - 6,822.5 Gwh
   Unit availability based on two years average historical forced outage statistics. Steam supply limitations modeled as capacity derations. Forecast period capacity factor 59.8%. 1990 steam price is 16.34 mills/kwh. 1991 steam price is 17.13 mills/kwh.

PACIFIC GAS AND ELECTRIC COMPANY
1990 ECAC/AER/ERAM/LIRA FILING

SUMMARY OF UNCONTESTED RESOURCE ASSUMPTIONS

18. Northwest for WAPA - 2995.3 Gwh
Forecast reflects both firm and non-firm energy takes by WAPA from the Northwest. Assumes WAPA will fully utilize their line entitlement through February 1991, take 300 average MW at Tracy from March 1991 on. WAPA has 151 MW firm contract capacity available November through July and 177 MW firm contract capacity August through October. Remaining imports considered non-firm. Resource may be backed down during minimum loads. Wapa's excess/shortfall energy and /or capacity is banked with PG&E at contractual rates.

19. Northwest for PG&E
a. Energy availability up to the line entitlement, 1150 MW on the AC line and 722 MW on the DC line, reflecting DC scheduled maintenance of 45 days during October and November and AC loop flow causing 10% line limitations from April through June. 50% of WAPA's unused NW line entitlement available to PG&E.
b. Transmission losses are 6% on the AC line and 7.5 % on the DC line.
c. NW energy is priced at 95% of of system incremental costs in January, February and October through December, 90% of system incremental costs in March, April, July through September, 75% of system incremental costs in May and June.
d. 150 MW long-term contract with WWP for firm capacity with 217 Gwh of energy June through September 1991, with a return provision starting in November 1991. Exchange agreement has no monetary component.

20. Conventional Thermal Plants
Unit availability based on five years' average historical forced outage statistics. Heat rate performance factor of 3.5%. The average dispatch price for the ECAC period is $2.41/Dth. The average core-elect G-PC for the ECAC period is $2.38/Dth.

21. Combustion Turbine Units
Unit availability based on five year average historical forced outage statistics. The average cost of distillate oil burns is $4.51/Dth.

22. Unserved energy
Emergency purchases are made from the California Power Pool and priced at 115% of dispatch cost of gas.

23. Diablo Canyon units
Unit 1 scheduled for refueling beginning mid-February 1991, unit 2 scheduled for refueling beginning mid-September 1991. Two-week ramp-up period assumed at the end of a refueling period.

PACIFIC GAS AND ELECTRIC COMPANY
1990 ECAC/AER/ERAM/LIRA FILING

SUMMARY OF UNCONTESTED MODELING CONVENTIONS

1. Dispatchers Risk Aversion feature
   100% of weekends with a MW adjustment, zero weeknights and weekdays.

2. Minimum Thermal Generation
   Use in PROMOD the minimum fuel burn feature to assure at least 565 Gwh / month generation from the conventional thermal generating plants.

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

4. Minimum Load Conditions
   Backdown order according to economic and contractual rules as shown on pages 3-26 and 3-27 of PG&E's Forecast Report. In PROMOD, FRPL records are used to mimic the order.

5. Minimum Downtime
   72 hours for 750 MW and 330 MW class units. 48 hours for the smaller classes of units.

Pacific Gas and Electric Company
Application No. 90-04-003

Total Equivalent IER Calculation
Joint Recommendation

Line No.			Line No.
1	Total G-PCG-UEG Cost - $/mmbtu	3.26458	1
2	Total QF in Cost - Thousand $	1,504,485	2
3	Total QF out Cost - Thousand $	1,394,490	3
4	Change in Total Cost - Thousand $	290,005	4
5	Variable QFs - gwh	5971.3	5
6	Marginal Energy Cost - mills/kwh (excl. O&M adder)	32.33	6
7	IER - Btu/kwh	9,902	7
8	Variable O&M adder - mills/kwh	2.50	8
9	Geothermal adder - mills/kwh	0.4519	9
10	Cash Working Capital - mills/kwh	0.1237	10
11	Total Marginal Energy Cost - mills/kwh	35.70	11
12	Equivalent IER - Btu/kwh	10,936	12

Notes:

(1) Variable O&M Adder from joint recommendation in App. No. 90-04-003
(2) Geothermal Adder from Supplemental Advice Letter 1282-E-A, April 10, 1990.
(3) Cash WOrking Capital Adder from TY1990 PG&E GRC.

ICRA ECAC UPDATE DATA SET 7-01-90 *** QF-IN FINAL RUN ***
PG&E ASSUMPTIONS, SPINNING RESERVE AT 7%
FRI, JUN 29 1990 8:44 P.M.

VERSION 13.0 PAGE 1
PROMOD RUN DATE 06/2[illegible]

P R O M O D I I I

0

D I V I S I O N O F R A T E P A Y E R A D V O C A T E S

R E S O U R C E S , P L A N N I N G L O A D , A N D F O S S I L F U E L R E Q U I R E M E N T S

G I G A W A T T H O U R S

01991	YEAR	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT
0													
PG&E HYDRO W/O HELMS	12324.3	561.0	798.5	932.4	895.2	1057.4	1090.4	1285.7	1235.8	1265.2	1151.0	1100.4	951.3
IRRIG DISTRICT	4839.5	187.1	210.6	404.5	297.0	372.6	433.9	427.6	497.4	570.6	531.2	499.7	407.3
USBR	2676.0	41.0	0.0	0.0	0.0	67.6	156.9	509.5	451.8	531.5	422.4	289.3	256.0
SMUD HYDRO	1670.0	66.0	115.0	167.7	113.8	136.9	168.3	192.3	162.5	163.9	172.9	150.1	50.5
NCPA HYDRO	508.5	9.0	21.2	41.9	45.8	56.2	95.4	106.0	44.7	26.9	29.2	22.5	9.7
SAN FRANCISCO	1451.5	80.0	80.0	80.0	80.0	80.0	120.0	170.5	173.1	153.7	145.7	141.7	143.5
HYDRO QF	523.0	10.7	10.4	17.7	27.7	59.5	73.7	64.9	71.3	73.5	53.2	33.4	27.2
	-------	-----	------	------	------	------	------	------	------	------	------	------	------
SUBTOTAL AREA HYDRO	23992.9	954.8	1235.7	1644.2	1459.5	1830.2	2138.6	2756.5	2636.6	2785.3	2508.6	2237.1	1505.7
HELMS GENERATION	426.6	13.4	7.6	8.7	5.8	6.9	7.2	87.5	80.4	40.3	65.6	81.0	22.1
HELMS PUMPING	-488.2	-17.4	-9.6	-11.1	-7.3	-8.7	-110.2	-117.5	-82.7	-49.6	-39.9	-11.4	-22.9
	----	---	---	---	---	---	-----	----	---	---	----	----	---
SUBTOTAL HELMS	-61.6	-3.9	-2.0	-2.4	-1.5	-1.8	-102.9	-30.0	-2.3	-9.2	25.7	69.6	-0.8
N/W													
FIRM	212.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	52.2	54.0	54.1	52.3	[illegible]
NON-FIRM	7788.9	506.8	521.5	399.4	571.4	816.8	927.8	694.8	713.9	605.1	744.5	556.3	[illegible]
COT PROJECT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	------	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
SUBTOTAL N/W - PG&E	8001.6	506.8	521.5	399.4	571.4	816.8	927.8	694.8	766.1	659.2	798.6	938.7	430.5
PPBL 115KV	250.3	23.6	23.6	23.6	23.6	23.6	18.9	18.9	18.9	18.9	18.9	18.9	18.9
N/W - USBR	2988.1	287.7	297.3	297.3	268.5	233.4	225.9	233.0	220.0	232.4	233.4	225.9	233.4
N/W - SMUD	1750.2	143.9	148.7	148.7	134.3	148.7	143.9	148.7	143.9	148.7	148.7	143.9	148.7
N/W - NCPA/COT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N/W - CSC	91.2	7.5	7.7	7.7	7.0	7.7	7.5	7.7	7.5	7.7	7.7	7.5	7.7
TOTAL N/W	13081.4	969.4	998.8	876.7	1004.8	1230.2	1323.9	1103.1	1156.3	1066.9	1207.3	1334.8	[illegible]
S/W MISC PURCHASES	240.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
CP & EMERG PURCHASE	27.4	11.3	0.7	0.1	2.5	0.5	3.9	0.7	0.2	0.6	0.1	0.2	6.2
SIERRA PACIFIC	3.6	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
COUR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MISC PUR FOR OTHERS	43.8	3.6	3.7	3.7	3.4	3.7	3.6	3.7	3.6	3.7	3.7	3.6	3.7
NCPA RESOURCES	1394.1	114.1	117.9	117.9	106.6	117.9	114.1	117.9	116.1	119.9	119.9	114.1	117.9
SMUD GEOTHERMAL	816.8	70.1	72.4	72.4	65.4	72.4	34.1	72.4	70.1	72.4	72.4	70.1	72.4
SMUD NUCLEAR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SMUD OTHER RESOURCES	5.1	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
SMUD FROM SCE	351.9	36.7	37.5	31.5	25.8	26.2	0.0	0.0	37.4	49.5	43.5	34.6	29.2

1990 ECAC UPDATE DATA SET 7-01-90 *** QF-IN FINAL RUN ***
PG&E ASSUMPTIONS, SPINNING RESERVE AT 7%
FRI, JUN 29 1990 8:44 P.M.

VERSION 13.0 PAGE 2
PROMOD RUN DATE 06/29/90

P R O M O D I I I

0

D I V I S I O N O F R A T E P A Y E R A D V O C A T E S

R E S O U R C E S , P L A N N I N G L O A D , A N D F O S S I L F U E L R E Q U I R E M E N T S

G I G A W A T T H O U R S

01991	YEAR	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT
QF THERMAL	15603.8	1097.5	1139.6	1238.1	1186.2	1266.5	1169.6	1342.3	1368.5	1413.1	1418.2	1480.9	1483.3
QF THERMAL PEAK	248.2	14.3	14.7	14.7	13.3	14.7	14.3	27.3	26.4	27.3	27.3	26.4	27.3
QF WIND & SOLAR	1168.0	26.4	23.6	20.6	29.9	53.0	89.8	158.4	194.6	223.9	165.0	106.9	75.9
QF UNDER 1 MW	111.9	4.3	5.2	6.6	10.0	9.6	11.4	14.0	10.7	11.8	8.8	10.7	8.5
SANTA FE GEOTHERMAL	700.8	57.6	59.5	59.5	53.8	59.5	57.6	59.5	57.6	59.5	59.5	57.6	59.5
GILROY FOODS	929.3	76.4	78.9	78.9	71.3	78.9	76.4	78.9	76.4	78.9	78.9	76.4	78.9
BASIC AMER FOODS	401.2	37.4	38.7	0.0	0.0	0.0	0.0	58.0	56.2	58.0	58.0	56.2	38.7
	-------	------	------	------	------	------	------	------	------	------	------	------	------
TOTAL HYDRO,PURCHASE, NCPA,SMUD,COGEN	59058.4	3490.7	3845.6	[illegible]83.5	4051.6	4782.3	4954.9	5783.6	5829.1	5982.5	5817.8	5699.9	4637.0
DIABLO CANYON 1	6227.0	694.5	717.7	717.7	324.1	0.0	0.0	230.9	694.5	717.7	717.7	694.5	717.7
DIABLO CANYON 2	7458.7	703.6	727.0	727.0	656.7	727.0	703.6	727.0	703.6	727.0	727.0	329.0	0.0
PG&E GEOTHERMAL	6822.6	586.8	599.7	575.4	535.0	583.9	560.9	574.4	552.6	566.3	564.7	543.6	557.3
COMBUSTION TURBINES	27.7	6.8	1.7	0.3	1.2	0.3	3.3	0.0	0.1	0.1	0.1	0.4	13.4
	-------	------	------	------	------	------	------	------	------	------	------	------	------
TOTAL DC, GEO, REF, CT, HYDRO	20536.0	1991.7	2046.1	2249.5	1517.0	1311.3	1267.7	1532.4	1950.8	2013.1	2009.6	1567.5	1288.3
TOTAL NON-CONV THERM	79594.4	5482.4	5891.7	6226.0	5568.5	6093.6	6222.7	7316.0	7779.9	7995.6	7827.4	7267.4	5925.3
PLANNING LOAD	97199.0	7642.0	8003.0	7973.0	7527.0	7569.0	7725.0	7876.0	8343.0	9046.0	8909.0	8619.0	7967.0
CP POOL SALES	120.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
REDDING SALES	66.8	0.0	0.2	1.1	3.3	0.0	0.0	0.0	10.4	26.2	19.1	6.5	0.0
SO CALIF CITY SALES	213.5	17.5	18.1	18.1	16.4	18.1	17.5	18.1	17.5	18.1	18.1	17.5	18.1
W/W RETURN	103.6	103.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PLAN LOAD+SALES OUT	97703.0	7773.2	8031.3	8002.2	7556.7	7597.1	7752.6	7904.1	8381.0	9100.3	8956.2	8653.1	7995.1
REQUIRED CONV THERM	18108.6	2290.8	2139.6	1776.2	1988.1	1503.6	1529.9	588.2	601.1	1104.7	1128.8	1385.7	2269.8
UNSERVED ENERGY	0.3	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
NON-CONV COST($K)	1077810	81878	82826	83917	81107	86470	86470	90928	96985	101545	101255	98684	85745
CONV THERM COST($K)	465287	57059	53937	47460	51700	38512	38186	17655	17447	28556	29343	35351	50081
TOTAL COST($K)	1543097	138937	136763	131377	132806	124983	124655	108583	114432	130101	130598	134035	135826
VOM COST ($K)	0	0	0	0	0	0	0	0	0	0	0	0	0

IDRA ECAC UPDATE DATA SET 7-01-90 *** QF-IN FINAL RUN ***
PG&E ASSUMPTIONS, SPINNING RESERVE AT 7%
FRI, JUN 29 1990 8:44 P.M.

VERSION 13.0 PAGE 3
PROMOD RUN DATE 06/29/90

FUEL REQUIREMENT (THOUSANDS OF EB, OIL BASIS)

REQUIRED FUEL													
EOBBLS(INC START-UP)	29010.0	3578.6	3307.3	2762.5	3039.7	2366.3	2452.7	1136.9	1150.9	1878.7	1890.3	2249.5	3246.9
START-UP BBLS	220.8	15.8	18.2	18.0	15.2	15.5	16.6	22.6	17.2	19.8	18.8	18.3	24.9
DISTILLATE(BBLS)	62.1	15.3	3.8	0.8	2.7	0.7	7.6	0.1	0.2	0.1	0.3	0.9	29.9
AVERAGE HEAT RATE	10573.2	10309.7	10201.7	10253.3	10090.8	10386.9	10365.5	12756.6	12636.4	11223.7	11052.0	10714.5	10353.3
KWH / BBL	624.2	640.2	647.0	643.7	654.1	635.4	636.7	517.4	522.3	588.0	597.2	616.0	637.5

Appendix E

Table 13-10: NATURAL GAS--Forecast Period
November 1990 thru October 1991

		NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL	SOURCE
Natural Gas															
Conv Thermal	(MEB)	3575	3304	2759	3038	2362	2398	1133	1148	1875	1887	2244	3242	28967	Table 13-8
Residual Oil	(MEB)	42	42	42	42	42	42	42	42	42	42	42	42	504	SJF/05/08/90
Gas Burn	(MEB)	3533	3262	2717	2996	2320	2356	1091	1106	1833	1845	2202	3200	28463	Calculation
Natural Gas	(MDth)	23316	21529	17935	19773	15315	15552	7204	7301	12096	12176	14536	21122	187856	Calculation
Natural Gas Prices															
Commodity G-PC	($/Dth)	2.4	2.4	2.5	2.5	2.4	2.4	2.3	2.3	2.3	2.3	2.4	2.3	2.386	DBC/07/02/90
Tier I	($/Dth)	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	DBC/05/09/90
Tier II	($/Dth)	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	DBC/05/09/90
Customer Charge	(M$)	96	96	96	96	96	96	96	96	96	96	96	96	1154	DBC/05/09/90
Demand Charge	(M$)	9216	7484	7539	8338	8321	10328	7698	7925	9816	9786	9783	8741	104974	DBC/05/09/90
UEG w/o CustCh	($/Dth)	3.1	3.1	3.2	3.2	3.3	3.3	3.8	3.8	3.5	3.5	3.4	3.1	3.3	Calculation
Natural Gas Cost															
Commodity G-PC	(M$)	55161	51586	44422	49574	37005	36794	16825	16904	28008	28438	34243	49332	448292	Calculation
Tier I Volume	(MDth)	2018	2018	2018	2018	2018	2018	2018	2018	2018	2018	2018	2018	24216	DBC/05/09/90
Tier I Cost	(M$)	1288	1288	1288	1288	1288	1288	1288	1288	1288	1288	1288	1288	15460	Calculation
Tier II Cost	(M$)	5797	5311	4333	4833	3619	3684	1412	1438	2743	2765	3407	5200	44543	Calculation
Subtotal UEG	(M$)	7086	6599	5621	6121	4908	4972	2700	2726	4032	4053	4696	6488	60004	Calculation
Demand Cost	(M$)	9312	7580	7635	8434	8417	10424	7794	8021	9912	9882	9879	8837	106128	Calculation
Total UEG	(M$)	16397	14179	13257	14556	13324	15397	10494	10748	13944	13935	14575	15325	166131	Calculation
Total	(M$)	71558	65765	57679	64129	50330	52190	27319	27652	41952	42374	48817	64657	614424	Calculation

Average Rate excluding
customer charge $3.2646/mmbtu

05-Jul-90

Line No.	DIER Calculation	DC Capacity Factor 99.9 (a)	79.9 (b)	Difference (c)		Line No.
1	DC costs ($000 000)	136371	109069			1
2	Thermal Costs ($000 000)	503180	646243			2
3	Other Costs ($000 000)	940047	875000			3
4						4
5	Total ($000 000)	1579598	1630312			5
6	Total excl DC ($000 000)	1443227	1521243	78016		6
7						7
8	DC Generation (GWh)	15208.1	12163.4	3044.7		8
9						9
10	Average Rate (mills/kWh)		25.62			10
11	(Ln 5(c) ÷ Ln 8(c))					11
12						12
13	Total G-PC/G-UEG rate ($/MMBtu)		3.26458			13
14						14
15	DIER (btu/kWh)			7849		15
16	((Ln 10(b) ÷ Ln 13) * 1000)					16
17						17
18						18
19	Diablo Unit	DC Capacity Factor				19
20	Generation	99.9	79.9			20
21						21
22	Unit 1	6919.7	5534.4			22
23	Unit 2	8288.4	6629.0			23
24	Total:	15208.1	12163.4			24
25						25
26						26
27		DC Capacity Factor		Difference		27
28	Replacement Energy	99.9	79.9	GWh	%	28
29						29
30	Thermal	17447.4	18797.9	1350.5	0.44	30
31	Northwest - PG&E	7166.3	8811.8	1645.5	0.54	31
32	Calif Pwr Pool & emerg	13.7	44.6	30.9	0.01	32
33	Combustion Turbines	20.7	34.9	14.2	0.00	33
34	Helms P.S.	-60.8	-66.9	-6.1	0.00	34
35						35
36	Total	24587.3	27622.3	3035		36

(END OF APPENDIX B)

APPENDIX C
TABLE 1

PACIFIC GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
ADOPTED ENERGY COSTS
ECAC Forecast period: November 1, 1990 through October 31, 1991

TYPE OF ENERGY	PURCHASES/ GENERATION (GWh)	%	AVERAGE COSTS ($/KWh)	TOTAL COSTS ($000's)	TOTAL CPUC Costs 1/ ($000's)	ECAC COSTS 2/ ($000's)	AER COSTS 3/ ($000's)	
Fossil Fuel								
Gas - PC	17,802	21.79%	$0.0252	$448,290	$443,717	$403,783	$39,935	4/
Gas - UEG				166,131	164,436	149,637	14,799	
Oil - Residual	309	0.38	0.0348	10,740	10,630	9,674	957	5/
Oil - Distillate	28	0.03	0.0576	1,612	1,595	1,452	144	6/
Subtotal Fossil Fuel	18,139	22.20	0.0346	626,773	620,380	$564,546	$55,834	
Geothermal Steam	6,823	8.35	0.0170	115,933	114,750	104,423	10,328	
Purchased Power								
Irrigation Districts	4,837	5.92	0.0103	49,801	49,293	44,857	4,436	
CVP	(2,146)	(2.63)	0.0143	(30,649)	(30,336)	(27,606)	(2,730)	
Variably Priced QF Energy	8,972	10.98	0.0354	318,044	314,800	286,468	28,332	7/
Other QF	10,713	13.11	0.1095	1,173,131	1,161,165	1,056,660	104,505	
Northwest	8,252	10.10	0.0199	164,034	162,361	147,748	14,612	
Southwest(Including Sales	147	0.18	0.0109	1,598	1,582	1,439	142	
Other	6	0.01	0.0558	335	332	302	30	
Subtotal Purchased Power	30,781	37.68	0.0545	1,676,294	1,659,196	1,509,868	149,328	
Water for Power	12,263	15.01	0.0003	4,240	4,197	3,819	378	
Oil Inventory Carrying Cost				11,560	11,442	10,412	1,030	
Variable Wheeling				1,631	1,614	1,469	145	
Subtotal Engergy Expense	68,006	0.83	0.0358	2,436,431	2,411,579	2,194,537	217,042	
DC Settlement Revenues	13,685	16.75	0.0938	1,283,442	1,270,351	1,270,351	0	
DC Basic Revenue Requirement			(0.0149)	(204,347)	(204,347)	(204,347)	0	8/
DC Safety Committee Fee			0.0000	608	608	608	0	8/
TOTALS	81,691	100.00%	$0.0430	$3,516,134	$3,478,191	$3,261,149	$217,042	

1/ = Jurisdictionalized at 98.98%.
2/ = ECAC costs are 91% of CPUC total costs, unless otherwise specified.
3/ = AER costs are 9% of CPUC total costs, unless otherwise specified.
4/ = Equivalent to 187,855 billion BTU at an average heat rate of 10,552 BTU/Kwh.
5/ = Equivalent to 3,156 billion BTU at an average heat rate of 10,214 BTU/Kwh.
6/ = Equivalent to 362 billion BTU at an average heat rate of 12,929 BTU/Kwh.
7/ = Associated capacity payments included on the next line under the title "Other QF".
8/ = Average costs computed on the basis of 13,685 GWh generation.

APPENDIX C
TABLE 2

PACIFIC GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
Summary of Revenue Changes
ECAC Forecast period: November 1, 1990 through October 31, 1991

REVENUE ELEMENT	PRESENT RATE REVENUE 1/ ($000's)	REVENUE CHANGE ($000's)	ADOPTED REVENUE REQUIREMENT ($000's)	ADOPTED AVERAGE RATE 2/ (cents/kwh)
Energy Cost Adjustment Clause (ECAC)				
Adopted ECAC Costs	3,271,320	(10,171)	$3,261,149	
Estimated ECAC account balance as of 10/31/90	0	521,656	521,656	
Designated Sales Transactions to Resale Customers	(93,525)	0	(93,525)	
Subtotal	3,177,795	511,485	3,689,280	
Franchise Fees & Uncollectible Accounts Expense @ 0.85%	0	31,359	31,359	
Total ECAC Retail Revenues	3,177,795	542,844	3,720,639	5.364
Annual Energy Rate (AER)				
Adopted AER Costs	194,336	22,706	$217,042	
Designated Sales Transactions to Resale Customers	(9,250)	0	(9,250)	
Subtotal	185,086	22,706	207,792	
Franchise Fees & Uncollectible Accounts Expense @ 0.85%	0	1,766	1,766	
Total AER Retail Revenues	185,086	24,472	209,558	0.302
Base Energy Rate (ERAM)				
Authorized Base Revenue Amount	$3,148,473	174,379	$3,322,852	
Estimated ERAM account balance as of 10/31/90	0	(211,921)	(211,921)	
LIRA Shortfall	0	(26,116)	(26,116)	
Designated Sales Transaction to Resale Customers	(53,392)	0	(53,392)	
Total ERAM Retail Revenues	3,095,081	(63,658)	3,031,423	4.371
Low Income Rate Assistance (LIRA)				
LIRA Shortfall	34,170	(8,054)	$26,116	
Estimated LIRA account balance as of 10/31/90	0	(16,667)	(16,667)	
Administrative Costs	0	1,975	1,975	
Total LIRA Revenues	34,170	(22,746)	11,424	0.016
Conservation Financing Adjustment (CFA)	1,388	0	1,388	
California Public Utilities Commission Fees	8,331	0	8,331	
TOTAL RETAIL REVENUES	$6,501,851	$480,912	$6,982,763	10.067
PERCENTAGE INCREASE		7.40%		

1/ = Based on rates effective 7/6/90.
2/ = Average Rates based on the forecasted retail sales of 69,360 GWh.

(End of Appendix C)