ORIGINAL

Decision No. 91109 DEC 19 1979

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Investigation on the Commission's own motion into the electric resource plan and alternatives of Pacific Gas and Electric Company and the ratemaking implications and options relating to the various plans.	OII No. 26 (Filed September 6, 1978)

Malcolm H. Furbush, Robert Ohlbach, and Kermit R. Kubitz, Attorneys at Law, by Kermit R. Kubitz, for Pacific Gas and Electric Company, respondent.

Brobeck, Phleger & Harrison, by William H. Booth, James M. Addams, and Gordon E. Davis, Attorneys at Law, and Robert E. Burt, for California Manufacturers Association; Downey, Brand, Seymour & Rohwer, by Richard R. Gray and Philip A. Stohr, Attorneys at Law, for General Motors Corporation; Thomas S. Knox, Attorney at Law, for California Retailers Association; Graham & James, by Boris H. Lakusta, David J. Marchant, and Thomas J. MacBride, Jr., Attorneys at Law, for Western Mobilehome Association and California Hotel and Motel Association; Vincent Master, Attorney at Law, for San Diego Gas & Electric Company; Dennis G. Monge and Richard K. Durant, Attorneys at Law, and Earl R. Sample, for Southern California Edison Company; Allen B. Wagner, Attorney at Law, for The Regents of the University of California; David Roe, Attorney at Law, for Environmental Defense Fund; Thomas D. Clarke and David B. Follett, Attorneys at Law, by David B. Follett, for Southern California Gas Company; Jonathan Blees, Attorney at Law, for California Energy Commission; John C. Lakelanc, for Mass-Production Systems; and Robyn D. Boyer, for Assembly Subcommittee on Energy and Assemblyman Mel Levine, Chairman; interested parties.

Patrick J. Power and Steven Weissman, Attorneys at Law, for the Commission staff.

TABLE OF CONTENTS

I N T E R I M   O R D E R

I. Introduction

By Decision No. 89316 in Application Nos. 57284/5, this Commission ordered PG and E to:

1. Review all options for repowering existing facilities and to implement all cost-effective maintenance programs;

2. Review existing auxiliary power* sources and potential cogeneration* projects, and assess the related economics, institutional arrangements, maintenance and fuel requirements necessary to develop these resources;

3. Prepare and submit a twenty-year electric supply plan, reflecting conservation and alternative sources of supply.

It is the purpose of OII-26, as stated in the Order Instituting Investigation, to analyze these reports and to allow their long-term planning implications to be reviewed in a public forum.

A prehearing conference was held in this matter on February 9, 1979. By Administrative Law Judge's ruling, it was decided that auxiliary power and cogeneration** would be the first subjects to be addressed. PG and E's "Report on Co-generation and Auxiliary Power Sources" was filed timely and evidentiary hearings commenced on April 15, 1979. After 17 days of hearings, this matter was submitted upon the receipt of concurrent briefs on August 27, 1979.

* All asterisked terms are defined in the Glossary of this decision, Appendix B.

** This phase of the investigation has examined cogeneration and generation from biomass, refuse-derived fuels and wood waste (which may or may not include cogeneration). We intend for this order to include both types of generation. For convenience, the term "cogeneration" used herein includes both, unless expressly indicated.

II. Summary of the Record

A. PG and E's Showing

1. Introduction

PG and E offered four witnesses in support of its "Report on Co-generation and Auxiliary Power Sources" and related exhibits. These were Joseph G. Meyer, Supervising Engineer of the Co-generation and Solid Waste Unit of the Siting Department; Richard B. Myers, Engineer in the Mechanical and Nuclear Engineering Department; Samuel D. Wells, Senior Commercial Analyst in the Commercial Department; and William Gallavan, Vice President of Rates and Valuation. Meyer and Myers testified on cogeneration. Wells and Gallavan testified as to auxiliary power.

2. Cogeneration

Emphasis on cogeneration in this proceeding reflects not only the perception of many of the parties that cogeneration is a potentially major resource in PG and E's supply plan, but also the concern of several of the parties that PG and E has not acted to optimize the amount of cogeneration being developed.

Joe Meyer testified on policy and the status of various cogeneration projects under consideration. While cross-examination touched on all aspects of PG and E's cogeneration efforts, it focused on the purchased power price that PG and E pays cogenerators, as well as the way cogeneration development is reflected in PG and E's resource planning. Richard Myers testified regarding the general characteristics of cogeneration from an engineering design perspective, as well as some unique design challenges associated with individual projects. Although pricing principles of the utility, originally put forth by Joe Meyer, were the subject of extensive cross-examination, it would appear that they have been significantly modified by PG and E with the filing of the subsequent cogeneration pricing policy statement, Exhibit 43.

Testimony relating to cogeneration also was offered by Nolan H. Daines, Vice President of Planning and Research, appearing under subpoena by staff counsel. Mr. Daines testified at length as to how cogeneration planning is reflected in PG and E's resource planning.

3. Auxiliary Power

Mr. Gallavan testified as a policy witness in support of an experimental program intended to determine the availability of auxiliary power sources as resources for PG and E during times of peak demand. Mr. Wells testified regarding results of a survey of potential auxiliary power sources.

4. PG and E's Experimental Cogeneration Offer

By way of Exhibit 43 and the statements of counsel, PG and E amended its cogeneration showing to announce its willingness to base rates for purchased cogenerated power on marginal cost* (with specific limitations), rather than a negotiated price approach, as was proposed earlier. This offer was the subject of oral argument in anticipation of a possible interim Commission order addressing this limited proposal.

B. Staff's Showing

1. Introduction

Staff originally offered three witnesses in support of its report on "Cogeneration and Auxiliary Power." These witnesses were John Quinley, Supervising Utilities Engineer; Jeevan Ahuja, Research Specialist; and Ida Goalwin, Research Program Specialist. All three addressed some aspect of cogeneration. Mrs. Goalwin also testified on auxiliary power.

2. Cogeneration

Mrs. Goalwin addressed several major issues relating to cogeneration development, particularly, the effects of air quality regulation on cogeneration potential. Her testimony highlights the uncertainties that presently confront prospective cogenerators with respect to air pollution abatement requirements. This subject was subsequently addressed in greater detail by Gary Rubenstein of the Air Resources Board.

Mr. Ahuja's testimony provides background on the technical nature of cogeneration and the present status of its development. He supports a calculation of the potential for cogeneration in the PG and E service territory and recommends a goal for PG and E's use in resource planning. He also comments on PG and E's contract terms and price offerings, the steps PG and E might take to better assess its cogeneration potential, actions it might take in regard to oil field cogeneration projects, and the need to resolve wheeling issues.

John Quinley testified at length as to proposed "price guidelines" for the purchase of power from cogenerators. The basic theme of Mr. Quinley's proposal is "to maximize the development of a highly efficient means of electric generation while assuring that the utility ratepayers benefit through lower rates." The central feature of Mr. Quinley's price guidelines is that the benefits of cogeneration should be shared between the utility and the industrial entity, an undertaking which requires that the cogenerator's costs be known and that the proportions of the benefits to be shared be the subject of negotiation. Mr. Quinley offers principles for pricing firm and nonfirm power, as well as capacity payments. He addresses the applicable principles relative to the rates for standby capacity. He also sponsored the summary of staff recommendations relating to cogeneration and the general discussion of issues.

3. Auxiliary Power

Mrs. Goalwin reviewed PG and E's auxiliary power proposal and investigated the effect of air pollution regulations on the utilization of these sources. She concludes that the appropriate use of auxiliary power sources would be allowed under current air pollution requirements. Her testimony supports the basic premise of PG and E's proposal.

4. Further Staff Evidence Regarding Cogeneration

In the course of the proceedings, three additional staff members offered evidence: Julian Ajello, Senior Utilities Engineer; John Dutcher, Supervising Utilities Engineer; and Burton Mattson, Senior Economist. Each of these witnesses addresses some issue relating to cogeneration in his testimony.

Mr. Ajello testified regarding correspondence between PG and E, CP National, and a prospective cogenerator, concerning the possible purchase of power by CP National from a source other than PG and E. PG and E indicated its willingness to forgive fuel expenses, but not capacity charges. Apparently PG and E's offer and the resulting offer by CP National to the cogenerator were not adequate to induce the project to be built.

Mr. Dutcher testified as to a cogeneration incentive gas rate that would be applicable to purchases of natural gas by a cogenerating industrial customer. While this rate design recommendation was made previously to the Commission in Application No. 58470 (PG and E), staff did not propose that such a rate be adopted in this proceeding. This evidence was offered for demonstration purposes in order to allow comment by PG and E (PG and E having previously indicated a need to study this proposal further).

Mr. Mattson testified in support of a comprehensive proposal to apply policies and price rules to utility purchases of cogenerated, auxiliary and small production facility power. The proposal is premised on this market essentially being one of monopsony*. Specific limited action by the Commission is appropriate in monopsony markets just as it is necessary in monopoly* markets. He supports a series of policy statements and price rules that are intended to approximate the result that would occur in a competitive market. The central features of his proposal are that purchased cogenerated, auxiliary and small production facility power prices be based on marginal costs, that they be publicly stated and that the price be uniformly applied for all sources. He proposes that the same principles be applied, regardless of the form of ownership, and that the costs of the cogenerator need not be known.

C. Other Direct Showings

Various other parties appeared and offered direct evidence in the cogeneration phase of this proceeding.

Mr. Gary Rubenstein appeared as the Chief of the Energy Project Evaluation Branch of the Air Resources Board (ARB). His testimony addresses the application of the New Source Review rules to new cogeneration facilities, as well as the possible effect of Assembly Bill 524 discussed at page 30, infra. He emphasizes that the preferential allocation of natural gas to cogenerators is the single most effective means of resolving the air pollution concerns associated with siting cogeneration facilities. On cross-examination, he testified extensively regarding the effects of Kern County Rule 424 on oil field cogeneration potential.

Robert Weisenmiller and Donald Dier, Jr., appeared on behalf of the California Energy Commission (CEC). Their jointly-sponsored exhibit (Ex. 24) generally supports the PUC staff recommendations and emphasizes a utility administrative program for furthering cogeneration development. They expressly support the practice of wheeling, and criticize PG and E's reliability test and curtailment practices.

Harry Winters testified on behalf of the University of California regarding the University's cogeneration potential. His testimony addresses the advantages of cogeneration and specific incentives that might promote cogeneration development. He emphasizes the importance of standby rates, and the effect that the opportunity to wheel* would have on prospective cogenerators. He also supports special gas rates and priority classifications for cogeneration projects.

Albert J. Stoddart, President of Optimum Energy Systems, Inc., appeared as a prospective third party cogenerator who would build and own his facility selling electricity to the utility and heat to the industrial entity. Describing the efforts of his company to develop cogeneration potential in Kern County oil fields in his testimony, Mr. Stoddard estimates that this is a resource potential of greater than 3000 megawatts. He identifies three areas of constraints to this development - economic, environmental, and regulatory. He emphasizes the need for certainty in each of these areas, if large scale capital investments are to be made.

John Lakeland testified as the principal of Mass-Production Systems. His interest is primarily the smaller scale application of cogeneration technology - for residential and commercial uses, rather than industrial. He emphasizes the opportunity to greatly expand cogeneration potential, by way of mass-produced systems, to reduce costs to competitive levels. He shares Mr. Stoddart's concern with regulatory and economic uncertainties, and warns that manufacturers will not invest in mass production facilities under existing market conditions. He suggests that a Commission order requiring the utilities to purchase power from these sources may be needed as an incentive to mass production.

D. Contentions of Parties

Written argument was submitted on behalf of the following parties: PG and E, Staff, Environmental Defense Fund (EDF), General Motors (GM), University of California, California Energy Commission (CEC), California Manufacturers Association (CMA), and Mass-Production Systems (Mr. Lakeland). The major contentions of these parties are summarized below.

PG and E expresses its commitment to cogeneration and cites the role that cogeneration occupies vis a vis resource planning and staffing, the number of contractual offers for facilities, and cogeneration pricing, as tangible manifestations of such a commitment. It objects to the adoption of specific goals for cogeneration development and postulates that such goals, as proposed by Staff, are unrealistic and speculative and might be counterproductive. The utility claims that action by government agencies, to resolve ambiguity and uncertainty with respect to regulation, would enhance the development of cogeneration. PG and E supports as reasonable its experimental offer to purchase cogenerated electricity, and contends that wheeling would cease to be a major issue if the experimental approach were authorized.

Staff criticizes PG and E's cogeneration effort as inadequate and cites evidence in support of its contention that a rate of return penalty should be imposed. It suggests that the Commission authorize a pricing policy based on either "marginal cost" or case-by-case negotiations, but without the limitations proposed by PG and E. It recommends that PG and E's system power values (SPV)* be adopted as the test of marginal cost. Staff urges the Commission to work with the ARB to resolve air quality problems. The staff supports wheeling, and recommends further study of gas rate and priority incentives. Furthermore, it feels that a return increment should be allowed for cogeneration investment.

The EDF severely criticizes PG and E's cogeneration efforts, especially as they relate to resource planning. EDF emphasizes the relationship of resource planning to financial planning, and requests that the Commission order an adjustment of the supply plan to reflect additional cogeneration. It also recommends a rate of return penalty. It urges that marginal cost methodology be adopted and that particular emphasis be placed on large natural gas users and oil-field projects as prospective cogenerators. It suggests that system power values serve as the basis for marginal cost determinations.

GM supports cogeneration, but only under certain economic conditions. Warning that a marginal cost pricing methodology will result in subsidies to cogenerators, it supports, instead, a form of tax incentives. It argues that preferential gas rates or priorities would be unwise, and supports wheeling.

The University of California vigorously supports wheeling as a means of developing cogeneration, as well as marginal cost methodology for pricing. It asks that the Commission consider regulating the price of heat sold by the utility and contends that current standby rates are unreasonable. It supports incentive gas rates and priorities and recommends that the Commission investigate the reasons underlying the failure of any prospective cogeneration project.

The California Energy Commission strongly supports PG and E's marginal cost price offer, subject to the removal of the various limitations. It makes specific recommendations regarding wheeling and the need for additional factual information. It urges that PG and E work closely with prospective cogenerators and that it make its expertise available in order to assist cogenerators with air quality regulation problems and Fuel Use Act exemptions. It recommends adoption of PG and E's system power values as the measure of marginal cost for the purpose of this proceeding.

The California Manufacturers Association supports the development of cogeneration, but not when a subsidy results. It supports a pricing approach based on short run marginal cost principles and offers formulas for deriving such costs for energy and capacity. It also offers a basis for recognizing transmission costs and line losses in price. CMA supports a form of gas rate incentive. It rejects system power values as a basis for setting cogeneration prices.

Mr. Lakeland addresses the monopoly status of the utility company and conditions which might support a change in regulatory policy. He is interested particularly in the monopsony status of the utility, the only available purchaser of the cogenerator's output. He asks the Commission to pursue legislation to enable it to regulate such purchases. Without the assurance that would attach to such regulatory authority, he warns that potential manufacturers will not invest in the equipment that would mass produce cogeneration hardware so as to make small scale application of technology cost-effective.

III. Statement of Issues

The following are the major issues raised by the parties and addressed in the discussion herein:

A. What is the role of cogeneration in PG and E's resource planning?

1. What are the advantages of cogeneration as a resource option?
2. What is the significance of the amount of cogeneration in the supply plan?

B. What are the appropriate principles to apply to cogeneration development?

1. Should the Commission direct a pricing policy or approve guidelines?
2. What recognition should be given to proposed Federal Energy Regulatory Commission (FERC) regulations under the Public Utility Regulatory Policies Act (PURPA)?
3. Should prices be based on marginal cost or price negotiations on a case-by-case basis?
   a. What is the basis for pricing energy and capacity?
   b. What distinction should be made between firm and nonfirm power?
   c. What is the appropriate measure of marginal cost?
   d. Should PG and E's proposed limitations be allowed?
      i. Should the price be limited by size of the project or amount of cogeneration under contract?
      ii. Should the price apply to entire output, or only surplus?
      iii. Should there be a distinction between new and old cogeneration?
      iv. Should there be a difference in price depending on the form of ownership?
      v. Should load factors, reliability and transmission requirements affect price?

4. What is the appropriate basis for standby rates?
5. Should incentives be applied to enhance cogeneration development?
   a. Should incentive gas rates be authorized?
   b. Should an incentive gas priority be adopted?
   c. Should a rate of return increment be allowed on cogeneration investment?
6. Should wheeling and interconnection be required?
7. What is the appropriate ratemaking method for recognizing cogeneration expenditures?
8. How is this decision applicable to other energy alternates and other utilities?

C. What are the major constraints to cogeneration development?
   1. What is the best way to address air quality regulation issues?
   2. What limitations are imposed by the Fuel Use Act?

D. Have PG and E's efforts been adequate with respect to the development of cogeneration?
   1. Has PG and E been offering reasonable prices?
   2. Is its staff sufficient?
   3. Is its pace of development appropriate?

E. What is the appropriate Commission action in regard to auxiliary power?

IV. Discussion

A. Introduction

A review of the testimony and recommendations of parties in this proceeding shows that it is in the interest of the ratepayer for the Public Utilities Commission to encourage the development of cogeneration.[a/] This emphasis on the development of these sources of energy is consistent with both state and national energy policy.

Furthermore, evidence in this proceeding suggests that utility underpricing of energy from cogeneration has retarded its development. To eliminate this obstacle and promote development of this alternative generation, the Commission will authorize a pricing policy for the utilities to use in purchasing electricity from cogenerators.

B. Cogeneration in Resource Planning

1. Advantages of Cogeneration

Alternative generation sources, including cogeneration, can offer many benefits. First, cogeneration offers fuel efficiencies. The fuels that may be used in electric generation and industrial processes are consumed more efficiently when combined by cogeneration than they are under conventional technologies.

Second, alternative generating sources diversify the utility's resource plan. This necessarily minimizes dependence on any single source of generation; it increases the reliability of the system and minimizes the risk (financial and otherwise) associated with primary reliance on a single technology.

Third, alternative sources utilizing domestic fuels (such as biomass, woodwaste, and refuse) offer independence from foreign fuel sources. The use of domestic fuels is important for reasons of international economics and politics. The development of domestic sources of fuel is consistent with national goals expressed in the National Energy Act.

---

a/ Cogeneration as used in this discussion is defined on page 2 **.

Fourth, reserve margins* are often established such that spinning reserves* can replace an unplanned outage of the largest power plant online. The construction of large baseload* plants continues to require large reserve margins. The development of many small power plants requires smaller reserves, since it reduces the probability of a large outage, e.g., one-1000 MW plant failing versus many small plants failing simultaneously.

Fifth, the leadtime required for cogeneration is estimated to be several years less than that for large central station power plants, e.g., 3 to 5 years as opposed to 10 years. The development of the smaller cogeneration facilities introduces greater flexibility into resource planning, permitting further development of economic alternatives to large baseload facilities. Also, an indirect economic benefit to the ratepayer and a cash flow benefit to the utility of nonutility-owned cogeneration is that the utility does not have to raise the capital for construction of the cogeneration facility.

Finally, since the cogenerator's facility is not included in the utility's rate base and the cogenerator is only reimbursed for actual power and/or energy generated, the ratepayer does not have to bear the costs of any unscheduled outages of that facility.

2. Cogeneration and Resource Planning

Mr. Daines, PG and E Vice President of Planning and Research, established that the utility's supply plan is "the fundamental planning (document) for PG and E's expansion," and "represents management's best judgment of the plan that (the utility) will follow." It provides a basis for scheduling construction and capital expenditures, as well as a means of determing the type and timing of field investigations, studies and regulatory approvals that PG and E pursues. The supply plan "influences" budgeting for capital requirements, including the detailed budget (which covers a minimum of five years). In short, the supply plan is the blueprint that PG and E utilizes in deciding how to spend its money on new plant. While not unchangeable, as Mr. Daines repeatedly pointed out, it is the primary basis for financial commitments. Therefore, significant financial commitments would not be expected to be made for something which did not appear on the supply plan.

This Commission recognizes the crucial importance of supply planning, and the importance of modifying supply plans to include the most economic sources of energy before major capital commitments are made to improper and uneconomic choices. Since large, central station generating plants, such as baseload coal and nuclear, often require commitments of resources difficult to reverse, ten or more years in advance of going online, it is vital that supply plans be continually reevaluated during this time frame in order to avoid wasteful expenditures on uneconomic supply choices. Thus, it is not enough that PG and E pursue cogeneration development vigorously; it must also be properly reflected in the supply plan.

C. Economic and Price Considerations

1. Price Guidelines or Direction

An issue, at the outset, is whether the role of the Commission should be to direct that a pricing policy be applied or to announce price guidelines that may be followed by the utility in the exercise of managerial discretion. The latter is consistent with the tradition under which this Commission operates, i.e., allowing or disallowing utility expenditures, not directing management. Accordingly the Commission adopts that approach in this case.

2. Recognition of PURPA

Official notice is taken of recently proposed FERC regulations, which implement Section 210 of PURPA. (Federal Register, Vol. 44, No. 207, pp. 61190-61205.) The official summary is attached to this order as Appendix A.

The basic principles underlying the FERC proposal are that cogeneration prices be:

a. Just and reasonable to the electric consumers of the purchasing utility;

b. In the public interest;

c. Nondiscriminatory to qualifying facilities;

d. Not exceeding incremental costs of alternative electric energy (the costs of energy which, but for the purchase, the utility would generate from another source); and

e. Reflective of the cost that the purchasing utility can avoid as a result of obtaining energy and capacity from these resources versus conventional generation.

Further, it is observed that FERC's proposed regulations: (1) authorize the payment of the utility's avoided cost (supported by rebuttable presumption); (2) apply equally to small power producers as well as cogenerators; and (3) support a simultaneous purchase and sale provision for capacity and energy for new qualifying facilities. The Commission filed comments, dated November 30, 1979, with FERC basically in support of these proposed regulations and seeking additional flexibility in their implementation at the state level.

3. Marginal Cost or Negotiated Price?

Two pricing methodologies were presented by staff. One (Exhibit 17) argues that the price should be established through negotiations, and that the utility should pay up to the marginal cost (as defined by PG and E's system power values (SPV)) for cogeneration. To the extent that the cogenerator's costs would be lower than the marginal cost of the utility, this negotiated payment would be less than the utility's marginal cost.

While a negotiated price might provide some savings to the utility and the ratepayer in the short run, a second staff position (Exhibit 41) argues that it would encourage less than the economically optimal amount of cogeneration in the long run. It is argued that reliance on negotiations is untenable due to the monopsony position of the utility in the cogeneration market. Specifically, the utility is the sole buyer for cogenerated power and, therefore, exercises undue price control. This control is sufficient to keep economically justifiable cogeneration from being developed.

This market condition of monopsony requires that specific Commission action be taken (just as it is required in the monopoly market) to more nearly approximate the price/quantity solution of a competitive market and, therefore, to further the public interest. To simulate a market solution, price guidelines need to be established so that the utility can make a public offering to buy cogenerated eletricity, both firm and nonfirm, at published prices.

Since full development of cogeneration and generation from biomass and refuse-derived fuels is of the highest importance to ratepayers and society, it is reasonable to encourage development of these resources by authorizing the utility to pay its marginal costs for cogenerated electricity, i.e., approximate the competitive market solution. Consideration of the cogenerator's costs, as in negotiations, only serves to place the cogenerator at a disadvantage in obtaining an acceptable price and to delay action on projects. The nominal amounts of cogeneration online, in the face of much larger potential, attests, in part, to the inadequacy of previous negotiation attempts.

4. A Full Avoided Cost Standard

A proposal for paying less than the full avoided cost has been considered and rejected. The reason to pay only a portion of the full avoided cost would be to consciously retain a small cost savings for ratepayers. The other advantages of cogeneration, however, outweigh this benefit and favor the full avoided cost approach.

First, in paying less than full avoided cost, society is losing some electricity for which the ratepayer would have to pay 100% to the utility but the cogenerator could have generated at a lower cost but will not since only a portion is being paid. Thus, less cogeneration is developed than optimal and society is worse off for the underdevelopment.

Second, cogeneration is largely capital intensive and expensive. The distribution of costs against numbers of cogenerators is not a normal distribution but is skewed to the more costly. Thus, reducing the payment by increments of percentages from the full avoided cost will make uneconomic a disproportionate number of projects.

Third, more uncertainty directly translates into cogenerators requiring a higher rate of return on their investment than when uncertainty is minimized. Higher rates of return mean higher costs relative to costs under conditions of more certainty. High costs mean fewer projects will be cost-effective under the authorized payments. This undersirable result can be entirely offset by the Commission making clear policy decisions which minimize risks due to changes in regulatory policies.

Forth, cogeneration offers the opportunity to reduce our dependence on foreign sources of fuel. This pricing policy is a major opportunity to encourage development of technologies using renewable fuels, and at the same time reduce pollution. Also, it offers the potential for expanding our domestic economy.

Finally, the goal is to approximate the competitive market solution. This occurs at 100 percent of the avoided cost.

These reasons alone may argue for payment of more rather than less of the avoided cost. The proposed PURPA regulations, however, would restrict payment to the avoided ~~cost (i.e.,~~

cost (i.e., not above 100%). Therefore, authorization will be made at the maximum allowed rate of the full avoided cost, and the authorized maximum will not be restricted by this Commission to a lesser amount than the full (100%) avoided cost.

a. Measurement of Marginal Cost

PG and E's system power values (SPV) methodology will be the basis for determining prices to be paid for cogeneration capacity until such time as the Commission adopts its own methodology. The SPV methodology uses avoided cost* to determine values for capacity.* SPV data in this proceeding is based on the additional capital cost of a combined cycle* plant and such a plant's inherent fuel savings over current alternative plant options. Cogeneration provides fuel savings at least equal to a combined cycle plant as a result of comparable fuel efficiency. Savings also result from generation using biomass, since fossil fuels are not required.

b. Energy and Capacity

Energy payments should be based on the avoided cost to PG and E of purchasing energy from cogenerators, which it otherwise would have had to generate or provide itself. At present and for the near term future, PG and E's avoided cost for energy will be derived from oil-fired generation. Thus, as other electrical generation alternatives become available, PG and E will reduce oil-fired power production and oil purchases.

The rapid and successive increases in oil prices require that PG and E's actual avoided cost be reflected as accurately and rapidly as possible in its energy payments. Current volatility of oil prices makes forecasting difficult, and therefore undesirable. As current oil purchase prices are averaged into the inventory price, averaging introduces an unacceptable lag, making inventories too unresponsive as a price indicator of the utility's avoided costs. However, the utility's last quarter, average purchase price of oil is a reasonable and appropriate measure. Quarterly oil prices will be applied to the incremental heat rates provided by SPV (developed in the general rate case approximately every two years), along with appropriate other expenses, to establish the price offered to cogenerators of energy. This price will be offered on both a time-of-delivery and average monthly basis, the method of payment at the option of the cogenerator.

Capacity payments will be established by time-of-day and will include any appropriate related costs. A customer will be paid for capacity when it is delivered on a firm basis during the specified time period. For customers delivering during portions of two time periods, it will be necessary for PG and E to establish criteria for determining firm capacity deliveries during the customer's delivery periods. These criteria should view deliveries by cogenerators as comparable to those by the utility's own generating plant.

While exact prices to be offered should be developed through the combined efforts of staff and the utility, the figures below are from staff Exhibits and are based on future 1980 cost estimates made in 1978.

TABLE 1

AVOIDED COSTS

(EXHIBIT NOS. 17 AND 41)

Period or Capacity Factor	Energy (mils/kWh)	Capacity ($/kW/Mo.)
Summer		
On Peak	45	$2.30 b/
Mid Peak	44	3.49
Off Peak	38	1.88
Winter		
On Peak	43	1.33 b/
Mid Peak	41	2.70
Off Peak	37	1.49
Annual	37	6.71
75% (5 years beginning 1982)		5.25
100% (5 years beginning 1982)		5.67

b/ Capacity value at mid peak is higher than on peak because the mid peak period covers substantially more hours, which offsets a higher on peak hourly value; the on peak period is credited with a proportionately larger fuel savings than the mid or off peak periods.

Time-of-delivery capacity costs (Table 1) are based on the 1980 SPV for values to perpetuity.* These capacity costs are higher than those that would be derived for cogenerators from Exhibit 17 tables. Power delivery contracts for cogenerators will be for contract periods of various lengths. Given an initial year of delivery of 1982 and a 20-year contract term, the capacity value in constant 1980 dollars, at 100 percent load factor, would be 86 percent of the perpetuity value (Exhibit 17, Table A-1). There is not sufficient information in this record to restate capacity values for limited term contracts on a time-of-delivery basis, which is the adopted pricing approach. Therefore, PG and E may, in its price schedule, modify the capacity values in Table 1 to reflect different contract lengths.

Some cogenerators may prefer an average monthly price for energy and capacity. For very small projects, it would be appropriate for PG and E to develop such prices as part of its pricing schedule based on averaging time-of-delivery prices. For larger projects, average prices should be specific to the project's capacity factor and time-of-delivery characteristics. Such average monthly prices should be made available.

c. Firm and NonFirm

Nonfirm electricity should be purchased by the utility at a price equal to the utility's avoided energy cost. Firm electricity should be purchased at a price equal to the utility's avoided energy and capacity costs.

d. Simultaneous Purchase and Sale

This section addresses only energy, firm and nonfirm, which is contractually committed to the utility system by the cogenerator. The Commission recognizes that energy production for many potential cogenerators is only one of several competing economic considerations. It recognizes the right of the industrial entity to designate that portion of its output it wishes to commit to the utility.

As the cogenerator is both a producer and buyer of energy, a provision is made for the simultaneous purchase and sale of any portion of the facility's output. ~~This will make available more~~ KR

Where the utility's filed rates are less than the price that will be paid to the cogenerator or small power producer, a provision for simultaneous purchase from the utility and sale of all of the facilities output will further encourage development of these alternate resources. This provision will also make available more uniform treatment to cogenerators and small power producers in that their total output will be priced on the same basis irrespective of their own electrical requirements.

From the viewpoint of the utility and the utility ratepayer the providing of the total output, capacity and energy, to the electric system relieves the utility from constructing other resources to provide utility service.

The cogenerator or small power producer also has the option to provide all or a portion of its electric requirements from its own facilities and purchase supplementary capacity and energy from the utility. If the facility's output exceeds its requirements it can sell such excess capacity and energy to the utility and thereby reserve certain capacity exclusively for its own utilization. The cogenerator or small power producer can also subscribe for standby service from the utility.

Thus the two principal options available to the cogenerator or small power producer are: (1) simultaneous purchase of all of its electric requirements and sale of all of its capacity and energy to the utility or (2) purchase of supplementary requirements and standby from the utility and sale of only its excess output to the utility.

e. PG and E's Proposed Limitations

i. Introduction

PG and E (Exhibit 43) offers, on an experimental basis, to pay marginal cost for surplus electricity produced from cogeneration or solid waste fuels. The proposal is limited to individual facilities up to 30 MW and a program total of 500 MW. Furthermore, PG and E proposes to use different criteria for pricing the output of plants based on size (e.g., less than 10 MW, 10-30 MW, greater than 30 MW). While this approach is similar to that proposed in staff Exhibit 41 to the extent that it offers payment of the full marginal cost, it is impossible to compare the utility pricing proposal with those of Exhibits 17 and 41, as there is no specific illustration of the marginal cost-based prices proposed by PG and E.

ii. Size

Any pricing methodology applied by the utility should be uniform regardless of the size of the project or the form of ownership. Numerous other conditions attached by PG and E to their offer (Exhibit 43) are unnecessarily restrictive. Moreover, it should not be limited to 500 MW, or be subject to unnecessary reliability restrictions. In addition, it should not characterized as experimental. Attempts to place arbitrary restrictions on development of cogeneration may distort the market and result in less than optimal development.

iii. Surplus or Entire Output?

PG and E should buy all of a cogenerator's capacity and energy at the utility's avoided costs and sell power back to the cogenerator to meet his regular requirements based on regularly filed rates. To do otherwise would discourage the development of cost-effective cogeneration projects, particularly the more capital intensive refuse-derived fuel plants. On this basis, the potential cogenerator will invest only when it is at least as cost-effective to produce cogenerated electricity as to purchase it from the utility, provided that the total cost of producing cogenerated electricity does not exceed that of purchasing the same amount from the utility.

The potential cogenerator's decision to produce cogenerated electricity and the utility's decision to purchase it should be based on an analysis of the alternatives at the margin.

To the extent that the utility rates do not represent the marginal cost, neither current rates nor total bills will provide the correct economic data on which the cogenerator can base this decision. However, an avoided cost-based pricing approach does provide a more accurate signal. This approach underlies these price guidelines and will ensure that cost-effective investment decisions can be made. The cogenerator can make an economic decision to produce an amount which makes its total costs equal to the total payments for cogenerated power from the utility, so that the cost of producing its last unit is equal to the utility's.

iv. Old and New

The pricing approach to be adopted does not discriminate between existing ("old") and new cogenerators. Although some cogenerators have pioneered in this field, others have delayed, waiting for higher prices. To reward those who have delayed, but not those who have proceeded, would be inequitable. Further, no such distinction is made of other suppliers or customers of the utility. For example, one oil company does not get paid less because it has dealt with the utility previously and is, thus, an "old" supplier. Nor does an "old" customer pay a different rate than a "new" customer. Finally, it would cause distortions in investments and be administratively unacceptable to differentiate between old and new cogenerators. Cogenerators designated as old would have an incentive, by whatever means, to attempt to be redesignated as new. Particularly when additions or partial replacements are made to old facilities the designation process would become difficult.

For reasons of equity, consistency with the treatment of other suppliers and customers, and avoidance of market distortions and administrative problems, the output of all cogenerators (whether old or new) should be priced on the same basis. Contracts which are now in force will not be altered by this Order (unless enabling clauses have been inserted). At contract expiration, however, cogenerators and the utilities should be encouraged to negotiate new contracts under the guidelines.

v. Form of Ownership

Any utility price offering for cogenerated power should not be restricted to industrial or commercial customers. To do so results in the exclusion of the residential class and precludes third-party cogenerators, such as Mr. Lakeland (commercial) and Mr. Stoddart (industrial), from competing. Any adopted pricing policy should foster competition, not thwart it. Moreover, to fully develop cogeneration, the option must exist for joint venture arrangements or full utility ownership, leaving open the specific economic arrangements to be agreed upon between PG and E and the customer in specific cases.

Under utility ownership, PG and E would directly take the electric power from the project. Section 210 provisions of PURPA do not apply in the case of utility ownership. Economic terms of such an arrangement will be based, at least in part, on the price at which PG and E buys fuel from the customer, i.e., for oil field recovery or woodwaste facilities, and the price at which the utility sells process steam to the customer. Since these arrangement are, in essence, joint ventures between the utility and the customer, project benefits, where costs are less than the utility's avoided costs, should be shared with the customer. It is anticipated that PG and E will negotiate the price for cogenerated power when the project is partially or totally owned by the utility.

vi. Load Factors, Reliability, Transmission

PG and E proposes to base prices on conditions of reliability, load factors and transmission requirements. While no PG and E witness was offered to explain the rationale underlying these limitations or their implementation, they appear to be unnecessarily restrictive. Similar criteria have been roundly criticized by staff for impeding the development of cogeneration (Exhibit 17, p. 5-4 and Exhibit 41, p. 19).

The argument that customer-operated plants are of less value to

PG and E because of reduced dispatchability has been dealt with by time-basing capacity and energy payments. Staff does not feel that reliability should be a factor in prices offered cogenerators. Cogeneration projects are expected to be as reliable as utility-owned generation. Further, contracts for firm capacity will provide for legally enforceable guarantees of deliverability and reliability.

It is not necessary for the utility to file with the Commission specific contracts for purchased power from cogenerators; however, it will be necessary for staff to review contract terms to the extent required to determine compliance with appropriate regulations, including federal ones over which the state has implementing jurisdiction. This matter will be reviewed when considering final FERC regulations under Title II of PURPA.

PG and E should not be required to purchase energy from a cogenerator during the periods when such purchases will result in costs greater than those obtainable from other generation, including other purchases. These periods are understood to be at times of heavy stream flow to hydroelectric facilities and low load when acceptance of cogeneration would curtail lower cost hydro or geothermal generation. PG and E's current practice of limiting the maximum curtailment to 600 hours per year should be examined in the light of providing such energy to other California utilities when not required on its own system. It is felt that such curtailments are significant in years of high rainfall. Capacity payments, when applicable, will not be reduced by this provision for allowing the utility to forego cogenerated energy if and when lower cost energy is available.

4. Standby Rates

Any modification of standby rates for cogenerators should be cost-justified. A recent examination of these by PG and E, the staffs of the CPUC and CEC, and cogenerators (described in Exhibit 17), resulted in a 45 percent reduction of these rates, effective January 21, 1979.

Price guidelines authorized by this decision appear to obviate the need for changes in standby service since the cogenerator sells all of his generated power to the utility and purchases all his power requirements from the grid. Also, as no specific, cost-based stand-by rate revisions were presented in this proceeding, there is no apparent reason to modify existing standby rates at this time.

5. Should Incentives Be Adopted?

a. Gas Price Incentives

Staff proposed a gas price incentive for cogenerators. The Natural Gas Policy Act (NGPA) of 1978 (Section 206(c)(3) exempts cogeneration facilities from the incremental pricing provisions of the NGPA, allowing the Commission discretion in this regard.

With respect to the avoided cost of electric energy payments are to be made to the cogenerator based on PG and E's last quarter average oil prices. In establishing gas rates we consider the alternate price of fuel oil for interruptible customers and electric utilities. Consistent with this approach and our basis for determining electric utility avoided energy cost, we will in future gas rate proceedings consider establishing a gas rate for cogenerat~~ors~~ion based on the electric utility's gas rate. Kra

b. Gas Priority Incentives

It may be appropriate to establish a higher end-use gas priority for cogeneration. Currently, boiler fuel would be Priority 4 for boilers using in excess of 750,000 cubic feet of gas per day and Priority 3 for boilers using 100,000 to 750,000 cubic feet per day and for turbine fuel. Richard Myers, a PG and E design engineer, testified that natural gas is most desirable as a fuel as it lends itself to the designs of most cogeneration facilities. It is also the most favored fuel for air quality considerations. In addition, the Legislature recently mandated that the Commission staff, to the extent permitted by state and federal law, provide cogenerators with the highest possible priority for the purchase of natural gas as required by A.B. 524. In a concurrent proceeding (Case No. 9642), we will consider the feasibility of a higher end-use priority for cogeneration.

c. Rate of Return Bonus

A higher rate of return on cogeneration, biomass, or refuse projects may maximize the early development of such projects by PG and E. Section 454(a) of the Public Utilities Code allows an incremental rate of return of 1/2% to 1% to be added to the rate of return on utility investment provided that:

i. The utility makes a showing before the Commission and the Commission finds such an increase is justified; and

ii. The project generates or produces energy from renewable resources; and

iii. The project will result in a lower cost per unit of energy generated or produced over the life of the system than existing systems utilizing atomic energy, fossil fuels or natural gas; or

iv. The project is determined after public hearing to be experimental and to be reasonably designed to improve or perfect technology to generate energy from renewable resources, or to decrease environmental pollution, or to lower the unit cost of energy to utility customers.

The Commission encourages PG and E to consider all such projects that produce energy from renewable resources, reduce dependence on imported fuels, will improve technology, produce and use energy more efficiently, and/or lower costs to consumers. The Commission will accept from PG and E, staff and/or interested parties suggestions on methods of implementing the provisions in Section 454(a).

6. Wheeling and Interconnection

Wheeling is a major concern of some cogenerators, either for transmission of electricity to another utility, or the transmission of electricity to another site of a cogenerator. The primary argument for wheeling is to allow free market forces to operate. Wheeling allows the cogenerator to sell his product to the highest bidder or to use his power at another facility where the cost of purchasing power from the utility at that other facility exceeds the cost to the cogenerator of cogenerated and wheeled power.

Wheeling by the immediate utility to a second utility would appear to fall under FERC authority. (Sections 203 and 204 of PURPA add Sections 211 and 212 to the Federal Power Act.) FERC will issue regulations pertaining to wheeling under the authority granted by PURPA. We therefore believe that it is appropriate for us to delay any action on wheeling issues pending FERC rulemaking.

Furthermore, the Commission feels that the adopted pricing approach may substantially eliminate the importance of wheeling as an issue. Since a cogenerator will be receiving the maximum price from the utility for the entire output, he therefore would not need to wheel within one utility system from the cogenerator's generation source to any other point within that same system.

The proposed FERC regulations regarding the implementation of Section 210 of PURPA require that interconnection costs be borne by the cogenerator. With full avoided cost being paid for the cogenerator's electricity, any further incentives that would result from the utility absorbing interconnect costs would exceed the maximum allowable payment under PURPA.

FERC's proposed regulations define "interconnection costs" as the reasonable costs of connection, switching, metering, transmission safety provisions and other costs to an electric utility resulting from interconnected operation between an electric utility and a qualifying facility. They further state that each qualifying facility must reimburse any electric utility which purchases capacity or energy from the qualifying facility for any interconnection costs. These costs are limited to the net increased costs imposed on an electric utility, compared to those it would have incurred had it generated the energy itself or purchased an equivalent amount of energy or capacity from another source.

The proposed FERC regulations also provide that a qualifying facility must reimburse an electric utility which sells capacity or energy to the qualifying facility for interconnection costs resulting from such sale. This requirement is consistent with present utility procedures and filed tariffs.

7. Ratemaking Treatment

It has been proposed that cogenerators' payments be recovered in either the general rate case or the Energy Cost Adjustment Clause (ECAC) proceeding. ECAC now includes recovery of purchased power. All reasonable costs incurred using the price guidelines authorized herein for nonutility and nonjoint venture cogenerated power (firm and nonfirm) will be recoverable through ECAC, as are the costs of other purchased power. The reasonableness of these costs, however, will be subject to further staff review in the ECAC proceedings to determine compliance with Commission pricing guidelines.

General rate case proceedings will be utilized to recover costs other than fuel costs when the utility is part or full owner of a cogeneration or biomass-fueled plant, subject to potential increases in rates of return as provided for in Public Utilities Code Section 454(a). These proceedings are appropriate for the recovery of these costs, since they involve rate base and rate of return evidence.

It is well established that this Commission has authority to declare, ex post facto, that a utility contract is imprudent and to disallow any resulting excessive costs. The Commission also has authority to determine in a rate proceeding whether or not a utility has made sufficient progress in making advantageous purchases of energy. The only novel aspect of this proceeding is the attempt to develop standards to be applied prospectively. This decision merely prescribes in advance what sort of conduct would be acceptable and hence recognized as reasonable in a future rate case.

8. Applicability to Other Resources and Utilities

Of equal concern is the establishment of a pricing policy for the purchase of capacity and energy from other alternative generating sources, such as solar, low-head hydro and wind, and PG and E's efforts to encourage and develop these. These offer an alternative to oil-fired generation and should be encouraged. As they are included in the classification "Qualifying Small Power Production Facility" under Title II of PURPA, they will be the subject of regulations to be issued by FERC regarding purchase prices. Since the pricing principles in this decision would appear to apply equally to all small power production, PG and E also is authorized in the interim to buy power from these facilities.

Furthermore, the economic principles stated in this decision are in no way limited to PG and E. Other utilities subject to our jurisdiction are similarly expected to apply these principles in the exercise of their business judgment.

D. Constraints

1. Air Pollution

Air pollution regulation generally is perceived as a major potential barrier to cogeneration development, particularly in Kern County where the promise for cogeneration is great. This perception probably is related as much to uncertainty regarding the interpretation of existing and proposed regulations as to actual constraints.

#3

The Commission takes official notice of the passage of Assembly Bill No. 524, effective January 1, 1980. This bill changes Section 454.7 of the Public Utilities Code, Sections 39019.5, 39050.5, 41604, 42313 and Section 41515 of the Health and Safety Code.

This bill instructs local air pollution districts to issue permits to cogenerators and refuse-derived fuel projects (RDF) of up to 50 MW provided that such projects use best available control technology (BACT) and make every effort to provide necessary offsets, including abating any facilities owned by the applicant in the specific air basin. A RDF project, with no other sources in the air basin, may be expected to make every effort to purchase any available offsets.

The new law requires the Air Resources Board, in conjunction with the local air quality management districts and the California Public Utilities Commission to prepare an inventory by July 1, 1980, of feasible potential cogeneration projects which could be constructed before 1987. The Air Resources Board also must amend the State Implementation Plans by January 1, 1981 to provide mitigation of the air quality impacts of such cogeneration or RDF projects. In effect, this means that other stationary sources will have to be abated in order to maintain ambient air quality and to prevent significant deterioration of air quality.

The law does not specify who will pay for such mitigation, or which facilities will be abated. A subsequent air quality decision might require mitigation by the utility for pollution from cogeneration or RDF plants which are not entirely utility-owned, thus resulting in additional costs to the utility. If this occurs, the Commission should reexamine the level of capacity payments made to cogenerators and allow an adjustment of such payments to reflect PG and E's added costs. Since marginal cost methods include pollution abatement in plant costs, capacity payments effectively compensate cogenerators for similar costs. If PG and E, not the cogenerator, absorbs these costs, the marginal cost may have to be adjusted to reflect this change after the ARB and the local districts publish the mitigation regulations in June, 1981.

During this proceeding, the Air Resources Board witness, Mr. Rubenstein, testified at some length regarding ARB's interpretation of regulations intended to promote cogeneration. To further clarify the impact of air quality regulations on cogeneration development, the Commission should institutionalize the relationship between Commission and ARB staffs which was initiated during these proceedings at the direction of Commissioner Dedrick. Moreover, the Executive Director should assign staff to this function on a permanent basis. In this way, any required changes in air quality legislation or rules can be identified and vigorously pursued by the Commission. Such action is essential if the process of identifying cogeneration potential and establishing broad goals for its development is to be successful.

2. Fuel Use Act

Official notice is taken of the Power Plant and Industrial Fuel Use Act of 1978, P.L. 95-620 (42 U.S.C. Sections 8301 et seq.), hereinafter referred to as "FUA" or "the Fuel Use Act" and the implementing regulations proposed by the Economic Regulatory Administration (ERA). The Fuel Use Act and rules restrict the use of natural gas and oil as a primary energy source by powerplants and large industrial facilities known as "major fuel burning installations" (MFBI). The intent of the Act is to promote the use of coal and alternate fuels in order to conserve our natural gas supplies and reduce reliance on imported petroleum.

While the restrictions apply both to existing and new powerplants and MFBIs, they are most stringent with respect to new facilities and the use of natural gas. Facilities consisting of a boiler, gas turbine, combined cycle unit, or, additionally, in the case of an MFBI, internal combustion engine, are covered by FUA if each such individual unit consumes fuel at a heat input rate of at least 100 million BTUs per hour, or 250 million BTUs per hour, if the units are aggregated. The Fuel Use Act may have less impact on the Kern County oil fields, because the ERA has proposed to exclude steam generators used in enhanced oil recovery operations from coverage under the Act. (See 10 CFR Sections 500.2(a), definition of MFBI.) It is not clear from ERA's proposed rules, however, that the Act does not apply to cogeneration in the oil fields.

The statute and implementing rules provide for a permanent exemption for cogeneration facilities otherwise subject to these restrictions. (FUA Sections 212(c) and 312(c); 10 CFR Sections 503.37, 505.27, 504.35, and 506.35). It should be noted, however, that the exemption is discretionary with ERA, and the cogenerator must petition ERA and sustain a high evidentiary burden in order to obtain the exemption.

The statute requires the petitioner to show that economic and other benefits of cogeneration are not obtainable, unless natural gas or oil (or both) can be used in the facility. (FUA Sections 212(c) and 312(c).) The proposed regulations (10 CFR Sections 503.37 and 505.27, 44 Fed. Reg. 28950 at 28965-28966, 28994-28995, and 29014-29015, May 17, 1979) require the petitioner to demonstrate that the oil or gas to be consumed by the cogeneration facility will be less than would otherwise be consumed without the cogeneration facility, over and above the savings that FUA would achieve. The petitioner may include in these calculations displacement of oil or gas over a ten-year period which otherwise would be burned by the electric utility purchasing the cogenerated power. All of this information must be provided in a complex document known as a "Fuels Decision Report" submitted as part of the exemption petition.

If the petitioner cannot meet the burden of proof with respect to the oil or gas savings, an exemption still may be granted under a public interest test, based on such factors as the use of a technical innovation. Nevertheless, even if the petitioner meets the basic criteria for the exemption, ERA, in its discretion, can refuse to grant an exemption. In addition, exemptions, including the cogeneration exemption, generally are subject to other requirements, such as a showing that use of a mixture of natural gas or oil and coal or an alternate fuel, or the use of a fluidized bed combustion method for coal or an alternate fuel, is not economically or technically feasible. (FUA Sections 213 and 313.) ERA also can attach other terms and conditions to an exemption, including a cogeneration exemption, and has so provided in its regulations.

The Commission has filed comments with the ERA criticizing the restrictive treatment of the cogeneration exemption and urging that changes be made in the rules to promote cogeneration.

E. Inadequacy of Performance

1. Introduction

PG and E's development of cogeneration has been characterized by a minimal level of management support as evidenced by a low level of commitment of resources, inadequate pricing and insufficient staff. An examination of the process through which cogeneration development is reflected in the utility's resource plan (as described in the record of this proceeding) very clearly demonstrates management's view that cogeneration is a minor resource with minimal recognition in the resource planning process. While management has identified significant cogeneration potential as early as 1977 (Exhibit 11), there is no direct link between identification of this potential, its appearance in the Quarterly Report, and its ultimate consideration in the utility's resource plan, whereby funds can be budgeted for its development (TR/612-625).

The apparent rationale for this minimal level of support is PG and E's lack of experience with cogeneration development, according to Nolan Daines, PG and E Vice President of Planning and Research. He asserts that additional funds and staff would not at this time stimulate cogeneration development as much as would an increase in utility experience over time (TR/580-581).

PG and E's stated objective is to:

> ... develop available co-generation potential that is technically feasible, meets all environmental and regulatory constraints, is economically and technically competitive with non co-generation alternatives, for which an agreement can be reached with a willing customer. (Ex. 1, p. 3.)

Based on the record in this proceeding, it is clear that PG and E has not aggressively pursued this objective. Although lumber mills, oil fields, and large natural gas customers have been recognized for their cogeneration potential, there has been no prioritizing of development by class of customer (TR/571-572).

In assessing PG and E's commitment to cogeneration, the following have been considered:

1. Adequacy of pricing;
2. Commitment to wheeling to encourage cogeneration;
3. Identification of potential through data collection;
4. Contact with cogenerators to discuss pricing, exemption procedures, and options to encourage development;
5. Utilization of data on cogeneration in the planning process;
6. Adequacy of staffing;
7. Status of ownership of potential cogeneration facilities impacting development (e.g., whether utility-owned facilities are unduly favored).

2. Resource Planning

It is clear from the record that even the most promising cogeneration potential (e.g., a large natural gas user) may not find itself in the utility resource plan. This plan reflects management's philosophy of what may be undue caution in representing the generic technology, not individual projects (TR/566, 622-3, 681-2). Furthermore, an industrial cogenerator with significant internal requirements may not be regarded as an additional source of supply to the utility, but only as a reduction in load (TR/655) - providing little incentive to the potential cogenerator.

Mr. Daines indicated that cogeneration was first included in PG and E's resource plan in 1978 (TR/602). It was identified for the second time in the resource plan in January 1979. Although 1,000 MW of cogeneration are under consideration, only about half of these (497 MW) have been included in the resource plan for development by 1985. It does not appear that management's initial recognition of significant cogeneration potential (3,150 MW), as expressed by Mr. Shackleford in 1977 (Exhibit 11), was adequately pursued for consideration in the resource planning process (TR/614-617).

3. Pricing Practices

Staff has criticized PG and E's past practices with regard to prices offered existing and prospective cogenerators for energy and capacity. PG and E itself abandoned those earlier practices with the offer of its experimental price in this proceeding. While reflecting an apparent improvement in PG and E's attitude, this Commission recognizes that there is substantial evidence that PG and E has shown little vigor in this area.

The record reflects that PG and E has not treated cogeneration as a promising major resource. This management attitude is betrayed by the appearance of larger amounts of cogeneration in the resource plan revision prepared during this proceeding. One wonders what would be the status of cogeneration if more effort had been applied earlier.

The inadequacy of the price offering is confirmed in the record by the interest of the various parties in wheeling. The importance of wheeling as an alternative is inversely related to the utility's willingness to pay a reasonable price for purchased cogenerated electricity. Ironically, there is no evidence that PG and E has even been willing to wheel.

4. Staffing

The Commission shares staff's concern that PG and E's personnel commitment has been inadequate to reasonably determine the extent of the cogeneration resource, given the apparent complexity of cogeneration project development and design.

Staffing assignments reflect the company attitude that cogeneration is a minor supply option. This is shown by the testimony of Richard Myers that design for company-owned projects is performed by one full time engineer, two part time engineers, and perhaps another engineer with some support staff (TR/482).

Mr. Myers indicates that

> In all of the projects /he has/ evaluated to date, /he has/ found a minimum of similar characteristics. (Ex. 3, p. 4.)

The lack of similar characteristics would appear to require increased staff support. While this staffing level may have been adequate to handle the pace that PG and E has set for itself, based on its pricing practices, it is clear that additional support is required if the pace of project development is to be accelerated.

PG and E indicated that while their present staff is adequate for the 497 MW of cogeneration projected for development in their supply plan by 1985, it might not be adequate for the 1,000 MW being discussed - and that consultants might be required (TR/571).

5. Contact with Potential Cogenerators

PG and E has addressed the cogeneration potential of its large natural gas customers. The record is clear that natural gas is a premium fuel for cogeneration purposes. It allows for the most rapid design and implementation of cogeneration (TR/526). It is the most favored fuel for air quality considerations (TR/521). Given PG and E's own calculation of substantial potential in these customers, these facts and circumstances combine to suggest that natural gas-fired cogeneration should be pursued vigorously. However, the record shows that PG and E has approached natural gas fueled cogeneration projects very cautiously, as evidenced by the testimony of Mr. Meyer regarding the pace of development.

In 1977, PG and E's Senior Vice President in charge of electricity supply, Barton W. Shackelford, testified that PG and E was aware of 3,150 MW of cogeneration potential in its service area (TR/5259 in Appl. 55509/10). Mr. Shackelford based his testimony in part on two detailed PG and E documents, one showing eleven large "Cogeneration Potential Projects Where Discussions Have Taken Place" (Ex. 13 in this proceeding) and one showing 46 smaller "Natural Gas Users as Potential Cogeneration Projects" (Ex. 11 in this proceeding). The list of 46 potential cogenerators using natural gas was developed by PG and E in 1975 (TR/5218 of Appl. 55509/10). Both lists identified specific potential cogenerators. The fate of PG and E's list of 46 potential gas cogenerators is particularly revealing. After hurried review, Mr. Meyer admitted that four years later PG and E was studying only eight of the 46 potential cogenerators (TR/995-996).

Although the record shows 12 large natural gas customers already have cogenerated to some extent, there is still significant additional potential capacity (TR/942-51). The Commission agrees that these entities, already familiar with cogeneration, appear to be the most likely candidates for additional development. A quick calculation of the potential of the 12 indicates that from these sources alone, PG and E might be able to equal the 497 megawatts of cogeneration included in the resource plan by 1985. How has PG and E proceeded?

> We are taking a look at one of them, which is C & H Sugar. We are talking to three more, with regard to a possible exportation (sic) of cogeneration potential. (TR/953-54.)

It is clear that PG and E has had the opportunity for years to pursue cogeneration projects with large gas users and has failed to do so.

6. Reasonable Development Goals for Cogeneration

In 1977, Mr. Shackelford testified that PG and E was aware of 5,150 MW of cogeneration potential in its service area.

PG and E's stated corporate policy is that

> ... cogeneration will be an increasing and continuing resource that we will be developing and bringing into our resource planning, our resource programs. (TR/581, witness N. H. Daines)

In spite of recognized potential and a stated policy to pursue its development, there is a clear lack of utility effort to develop these resources. PG and E has not made reasonable efforts to pursue cogeneration potential and avail itself (and ultimately its ratepayers) of the obvious benefits of cogeneration. We have repeatedly put PG and E on notice that we expected it to pursue cogeneration vigorously. To the extent that it has not done so, it has slowed the pace of cogeneration development in its service territory. A rate of return penalty, as recommended by the staff and EDF, given the evidentiary record, is warranted despite PG and E's most recent efforts to change the record of poor performance.

The Commission expects PG and E to fully exploit the potential for the economic development of cogeneration as quickly as possible. Such action will reduce the nation's dependence on oil and, by modifying the utility's resources plan, reduce the need for new large utility generating plants.

Table 2 which follows is based on staff recommendations in Table 5-1 of Exhibit No. 17, modified to reflect the added stimulus which results from these price guidelines.

The number of contracts signed is to be used as a rough indicator of the encouragement of cogeneration development, giving recognition to the fact that two to three years may ensue before project construction is completed.

TABLE 2

EXPECTED MW OF NEW COGENERATION
TO BE IN OPERATION OR UNDER CONTRACT
FOR FUTURE OPERATION

Contracts Signed by End of Year	Megawatts
1980	600
1981	400 Additional
1985	1,000 Additional
1985	2,000 Total

Air pollution barriers may serve to reduce these expectations as could federal DOE regulations under the Fuel Use Act, as discussed above, which may limit the use of natural gas and petroleum fuels. However, this Commission is aware of extensive state and federal efforts to remove these barriers to cogeneration development to the extent possible and reasonable. PG and E will be required to report their success in meeting these expectations and, if unsuccessful, explain why projects have not reached the contract stage.

F. Auxiliary Power Sources

PG and E proposes to utilize the auxiliary power sources (APS) of its customers in a three-year experimental program. A customer will be paid $20/kW/year of available capacity plus the customer's out-of-pocket costs for replacing fuel used in a customer's APS, when operated at PG and E's request. PG and E will call for the operation of APS during periods when reserve margins are so critically low that, without the use of APS's and other emergency sources of load and load reduction, blackouts could occur.

The staff has recommended that PG and E be authorized to pursue its experimental program for the development of these sources. Unlike cogeneration, there is a valid "experimental" purpose to this program, since the degree of reliability of these sources for use as peak power is unknown.

PG and E should be authorized to pursue its program at the price incentive levels proposed. This should not be construed as a limitation on PG and E's discretion to take any other steps deemed necessary to the development of a valid study on APS. Specifically, PG and E should have the discretion to pay higher than the proposed prices, if its business judgment supports such a result. Additionally, it should expand the program to include more than the 100 MW goal if program results appear to warrant such an expansion.

Findings of Fact

1. Cogeneration technology can contribute significantly to fuel efficiency in the production of electricity and steam and heat.

2. Cogeneration can contribute significantly to meeting electricity needs in the PG and E service area in the near and foreseeable future and therefore has the potential to reduce significantly PG and E's need to construct generating plants.

3. Cogeneration offers many benefits to PG and E's ratepayers, including the resource planning advantages of diversification and reduced lead time resulting in earlier operational dates. Additionally, cogeneration results in fuel efficiency and reduced reliance on foreign fuels.

4. Electric generation from biomass and refuse-fueled power production is a state and national policy directive. Price guidelines for cogeneration, established by this order, should apply equally to small power production facilities using these fuels.

5. The use of marginal costs approximates the competitive marketplace. Such pricing will encourage the development of cogeneration, biomass, or refuse-fueled electricity.

6. PG and E's system power values are a representation of the utility's avoided costs and are an acceptable means of pricing capacity until such time as a marginal cost methodology is adopted by the Commission.

7. Capacity payments should be offered for any contract to sell firm electricity to the utility.

8. The value to the utility of electricity generated by cogeneration, as well as by biomass and refuse-derived fuels, varies with time of delivery and whether the power is firm or nonfirm. Prices should reflect these differences.

9. The limitations contained in PG and E's experimental cogeneration proposal (Exhibit 43) are not supported by evidence and are rejected. PG and E will develop price schedules as ordered in this decision, after review with our staff.

10. It is reasonable to purchase all of a cogenerator's power and then sell power back to the cogenerator at nondiscriminatory, filed tariff rates.

11. The limitation of the authorized, avoided cost-based prices to new installations may punish the prudent and reward those who have waited for additional benefits. As it is inconsistent with the treatment of other suppliers and customers, it invites distortions and administrative problems. Current contracts should be rewritten as they expire to conform with these pricing policies, or be renegotiated if the contract makes provision for this.

12. The price for cogenerated power should be negotiated on projects which are partially owned by the utility.

13. A modification of standby rates does not appear necessary at this time.

14. Reclassification of cogeneration facilities for gas priority purposes will be considered in the concurrent proceeding, Case No. 9642.

15. Since we have recommended the purchase of all cogenerated power at avoided cost price levels, there should not be any economic advantage in wheeling to one point to another within PG and E's service area.

16. Reasonable purchased power expenses incurred pursuant to cogeneration and auxiliary power programs are appropriately recovered in ECAC rates. Investment and expenses incurred when the utility is part or full owner of cogeneration or small power production operations are appropriately recovered in general rate proceedings, at which time the rate of return provisions of Section 454(a) can be considered.

17. The PUC staff should continue to work with the ARB staff to identify and resolve air pollution issues relating to cogeneration.

18. PG and E has not prioritized cogeneration candidates by type or class of customer based on their cogeneration potential.

19. PG and E's resource plans to date have not reflected the cogeneration potential it has recognized on prior occasions.

20. PG and E has not staffed itself to adequately pursue the cogeneration potential it recognized as existing in 1977 (3,150 MW), or minimum level of 2000-3000 MW which has been identified in this record as currently available, but rather has staffed itself to achieve only 497 MW of this potential cogeneration in its resource plan by 1985.

21. Large natural gas customers offer great potential as cogenerators.

22. Of the 46 largest natural gas customers having greatest cogeneration potential (so identified by PG and E in 1975), only eight have been approached by PG and E and seriously pursued regarding the possibility for cogeneration.

OII 26 Alt. - WJC/jy

23. PG and E can enter contracts for the amounts of future cogeneration capacity expressed in Table 2 herein. It is reasonable to expect that minimal level of performance for PG and E.

24. Auxiliary power sources are suitably the subject of an experimental program. The program should be pursued as proposed by PG and E.

25. There is justification for a gas rate incentive for cogeneration which is consistent with the avoided cost pricing approach.

Conclusions of Law

1. PG and E is authorized to pursue cogeneration based on authorized energy payments for purchased energy and authorized capacity payments for purchased capacity, each at the level of the utility's full avoided costs.

2. There is an urgent need to stimulate the pace at which cogeneration capacity is developed and to achieve that end most expeditiously, the following order should be effective the date of signature.

OII 26 Alt. - WJC/jy

INTERIM ORDER

IT IS ORDERED that:

1. Pacific Gas and Electric Company (PG and E) shall within 45 days publish and provide to all potential cogenerators a schedule of its full avoided capacity costs as defined by system power values and appropriate related costs.

2. PG and E shall within 45 days and each quarter thereafter publish and provide to all potential cogenerators a schedule of its full avoided energy costs, based on the prior quarter's average purchase price of oil to PG and E plus appropriate related costs.

3. PG and E is authorized to offer to purchase at the above rates all power produced and delivered on firm contracts to the bus bar by cogenerators. Nonfirm purchases shall be authorized at the avoided cost of energy to PG and E at the time of delivery, i.e., on-peak, mid-peak or off-peak. Capacity and energy payments will be authorized on a time basis, whenever feasible. An equivalent, average monthly rate also is to be available.

4. PG and E shall file a schedule of prices to be paid to cogenerators including proposed contract terms and provisions for purchased cogenerated electricity.

5. PG and E shall mail copies of their shcedules of full avoided costs for energy and capacity and proposed contract terms to all existing and identified potential cogenerators within 45 days.

6. Sales to cogenerators for all their internal needs will be at filed rates.

7. Cogenerators who elect not to sell power to PG and E on firm contract and who supply power for all their internal needs shall remain on filed standby rate schedules.

8. Current contracts for purchased power by PG and E will not be affected by this pricing policy unless so provided for in the contract. Except for contracts in force, no distinction shall be made between old and new sources.

9. PG and E will hire a consultant to estimate cogeneration potential to 1990, and to develop identification and an ongoing tracking system for use by PG and E, regulators and interested parties. Alternatively, PG and E may within 45 days present a plan whereby the above can be accomplished by their own staff or with minimal outside assistance.

10. PG and E will maintain a list of all known projects not yet part of the Quarterly Project Status Report and expand its status report to include small power producers.

11. PG and E will establish a special task force to identify, pursue, and report on oil field recovery projects.

12. PG and E shall assist cogenerators in obtaining current knowledge of pollution control and environmental regulations. PG and E shall assist cogenerators in obtaining cost-justified pollution control tradeoffs as appropriate. PG and E shall within 45 days prepare a financial analysis program for the confidential use of cogenerators in their cost/benefit analyses or, alternatively, within 45 days present a plan for completing such a program.

13. PG and E is directed to file a proposed gas rate incentive tariff to be reviewed in the next gas proceeding for cogeneration consistent with the avoided cost principal developed in this proceeding.

~~14. An incremental rate of return is provided in Section 454(a) of the Public Utilities Code for several types of investments by the utility. Utilities should present proposals for implementation of this section.~~

14 ~~15~~. OII No. 26 shall remain open.

The effective date of this order is the date hereof.

Dated DEC 19 1979, San Francisco, California.

We dissent in part. See attached.

John E. Bryson

Richard D. Gravelle

John E. Bryson

Vernon L. Sturgeon

Richard D. Gravelle

Claire T. Dedrick

Leonard M. Grimes

Appendix A

Highlights of Proposed FERC Rulemaking

on

Small Power Production and Cogeneration Facilities

(Docket RM79-55)

The proposed rulemaking regarding the Implementation of PURPA, Section 210(a) was issued October 18, 1979 and comments are to be filed by December 1, 1979:

"SUMMARY

"The proposed rules provide that electric utilities must purchase electric energy and capacity made available by qualifying cogenerators and small power producers at a rate reflecting the cost that the purchasing utility can avoid as a result of obtaining energy and capacity from these sources, rather than generating an equivalent amount of energy itself on purchasing the energy from other suppliers. To enable potential cogenerators and small power producers to be able to estimate these avoided costs, the rules require electric utilities to furnish data with regard to present and future costs of energy and capacity on their systems.

"These rules also provide that electric utilities must furnish electric energy to qualifying facilities on a nondiscriminatory basis, at a rate that is just and reasonable and in the public interest, and must provide certain types of service which may be requested by qualifying facilities to supplement or back up those facilities' own generation.

"The rule exempts all qualifying cogeneration facilities and certain qualifying small power production facilities from rate and certain other regulations under the Federal Power Act, from the provisions of the Public Utility Holding Company Act of 1935 related to electric utilities, and from State laws regulating electric utility rates and financial organization.

"The implementation of these rules is reserved to the State regulatory authorities and nonregulated electric utilities. Within one year of the issuance of the Commission's rules, each State regulatory authority or nonregulated utility must implement these rules. That implementation may be accomplished by the issuance of regulations, on a case-by-case basis, or any other means reasonably designed to give effect to the Commission's rules.

"The Commission observes that this rulemaking represents an effort to evolve concepts in a newly developing area within rigid statutory constraints. The Commission is attempting to afford broad discretion to the State regulatory authorities and nonregulated electric utilities in recognition of the variety of institutional, economic, and local circumstances which may be affected by this proposed rulemaking. In this regard, the Commission seeks the fullest range of comments on the legal authority of proposed Commission action, and on the technical and practical aspects of the proposals set forth in this rule-making."

Appendix B
Glossary

Auxiliary Power Sources (APS) - Electric generating facilities located on nonutility company sites, designed to be used in the event of an outage on the local utility grid.

Average Cost Pricing - The pricing of electric service designed to recover the total costs on a system in order to make total revenues (including rate of return) equal to total costs. Total costs are based on cost as recorded in books of account and forecasted to be recorded in such accounts.

Avoided Costs - Avoided costs are those which a utility would incur, but for the purchase from another source of energy or capacity or both. It can include both the fixed and/or running costs on the utility system which can be avoided by such a purchase.

Baseload - The minimum continuous load on a power system over a given period of time.

Biomas Conversion - The process of conversion of plant materials such as wood waste, rice hulls, walnut shells, etc., into electricity or energy.

Capacity - Maximum power output expressed in kilowatts or megawatts.

Capacity Factor - The ratio of average load on a generating resource to its capacity rating during a specified period of time expressed in percent.

Cogeneration - The sequential production of electricity and heat, steam or useful work from the same fuel source.

Combined Cycle - Waste heat from a gas turbine topping cycle is utilized for the generation of electricity in a steam turbine/generator system, thereby increasing the efficiency of heat utilization.

Firm Power - Power available at all times during the period covered by the commitment, except for forced outages and scheduled maintenance. Firm power is provided with sufficient legally enforceable guarantees of deliverability to permit the purchasing electric utility to avoid the need to construct a generating unit, to build a smaller and less expensive plant, or to purchase less firm power from another utility.

Kilowatt (KW) - An electrical unit of power which equals 1,000 watts.

Kilowatt-hour (KWHR) - A basis unit of electrical energy equal to the use of 1 kilowatt for a period of one hour.

Load - The amount of electric power delivered to a given point on a system, or total amount of demand on the system.

Load Factor - The ratio of average load to the a specified period of time, expressed in percent.

Marginal Cost Pricing - The pricing of electric service designed to equate the rates for electric service with the marginal costs of that electric service.

Marginal Cost - The change in total cost caused by a change in output. Marginal cost can also be understood as the additional cost to produce an additional unit of output, or the savings from producing one unit less of output (i.e., avoided cost).

Monopoly - A market structure in which there are many buyers but only one seller.

Monopsony - A market structure in which there are many sellers but only one buyer.

Nonfirm Power - Electric power available as surplus only, which is supplied by the power producer at his/her option and can be interrupted by the power producer (or large) at will.

Peak Load - The maximum electric load consumed or produced in a stated period of time. It may also be characterized as the minimum instantaneous load within a designated interval of a stated period of time

Refuse-Derived Fuels - Fuels derived from municipal waste used as fuel for electric energy production or low BTU gases from sewage treatment plants for use in turbines.

Reserve Margins - Extra capacity available to: 1) meet anticipated demands for power; 2) serve load in the event of a loss of generation resulting from an unscheduled outage. Reserve margin is the ratio of excess capacity to antitipated peak load expressed as a percent.

Spinning Reserves - Reserves that are operated at less than the rated capacity so as to provide immediately available capacity to relieve imbalance on the system.

System Power Values (SPV) - PG and E's model of the marginal costs of additional capacity and energy, based in this case on a combined cycle plant as the marginal plant.

Values to Perpetuity - The costs (values) to own and operate a generating plant for an infinite number of years, assuming plant replacement at the end of its useful life. Values are then levelized to the initial year.

Wheeling - The use of transmission facilities of one utility system to transmit power to another system or between customer facilities within a single utility system.

OII No. 26

Commissioners John E. Bryson and Richard D. Gravelle, dissenting in part:

By our signing the principal decision in this matter today, we have indicated our agreement with other members of the Commission as to the great importance of cogeneration as an alternative energy source, as to the general principles which should guide Pacific Gas and Electric Company (PG&E) and other utilities in negotiating contracts with potential cogenerators, and as to the PG&E's disappointing performance to date in tapping the potential of cogeneration. There is, however, one significant point on which we differ with other members of the Commission.

We believe that the principal benefit which can accrue to the public utilities and the ratepaying public from full exploitation of the potential for cogeneration is a reduction in the utilities' own generating capacity requirements. As the principal decision in this proceeding makes clear, cogenerators will be encouraged to make available to the utility quantities either of energy or of both energy and capacity. It will be much simpler for the cogenerator to commit only its excess energy output to the utility, without committing to any fixed level of energy production for the utility's use. In this event, of course, the cogenerator will not be entitled to capacity payments, but only to compensation for quantities of energy provided. Even so we believe that many potential cogenerators will hesitate to commit their capacity to the utility's disposal when they can qualify for energy payments under the simultaneous purchase and sale provisions of today's decision <u>without</u> such a commitment of capacity.

It can be argued that the commitment of many cogenerators to the production of energy for their own use, with the excess to be provided to the utility, amounts in practical terms to the provision of added generating capacity to the utility system, with a corresponding decrease in the utility's need to construct new capacity of its own. This is surely true to an extent, but that extent is uncertain. Marginal generating capacity is needed to meet emergency situations. We cannot predict how much energy cogenerators, whose capacity is not committed to the utility, will be able or willing to provide for the utility's use in the event of an emergency energy shortage.

The principal decision in this case provides for simultaneous purchase of all the cogenerator's electric requirements from the utility and sale of all its electrical output to the utility, whether or not the cogenerator is also selling its capacity, i.e. committing its output, to the utility. We believe the principle of simultaneous purchase and sale is appropriately applied only to cogenerators who have committed their capacity to the utility system. This commitment properly entitles them to compensation, at the utility's full avoided cost, for all energy which they generate, even for their own use. In contrast, the cogenerator who is unwilling to commit his generating capacity to the utility's disposal should be entitled to payment at the level of full avoided cost only for the energy which it actually provides to the utility - its excess output.

Implementation of the simultaneous purchase and sale concept in this limited manner would provide greater incentive to potential cogenerators to commit firm capacity to the public utility system, thus more clearly obviating the need to construct more central power plants at ratepayer expense.

/s/ John E. Bryson
John E. Bryson, President

/s/ Richard D. Gravelle
Richard D. Gravelle, Commissioner

San Francisco, California
December 19, 1979