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ORIGINAL

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

An Investigation before the Public Utilities Commission and the California Energy Commission into electric utility system reliability.	OII 89 (Filed April 21, 1981)

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O P I N I O N

In Order Instituting Investigation 89 (OII 89) and CEC Docket No. 81-ESR-1, the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) instituted a joint investigation to assess the adequacy and reliability of the State's electric system for the period 1982 through 1985. All electric utilities within the jurisdiction of the CPUC were made respondents. By Decision (D.) 93323 dated July 22, 1981, Pacific Power and Light Company, Sierra Pacific Power Company, and CP National Corporation were deleted as respondents.

During 1981 the staffs of the two Commissions conducted five workshops to study questions raised about uncertain schedules of new generating capacity due to come on line, the load carrying capability of new generating capacity during initial years of operation, high forced outage rates at some existing plants, and the adequacy of the transmission and distribution system. In addition to the staffs, the utilities, members of the public, and representatives of user groups participated in the workshops.

In November 1981, a draft report prepared by the staffs of the CPUC and CEC was issued and served on all parties. The report, entitled "Joint CEC/CPUC Staff Draft: Staff Response to Committee Order for Hearings on Assessment of Adequacy of Electric Utility Systems 1982-1985" was intended to provide the focus for discussion and for definition of issues in subsequent hearings.

To determine the level of participation and identify the issues, a prehearing conference was held December 4, 1981, in Sacramento before Russell L. Schweickart, Chairman of the CEC, Commissioner Victor Calvo of the CPUC, and Administrative Law Judge (ALJ) Burt E. Banks of the CPUC. At the prehearing conference it was determined that Phase I of the proceeding would be quasi-legislative with hearings to begin in January 1982.[1/] A Prehearing Conference Report and Order dated December 14, 1981, were forwarded to all respondents and interested parties who were requested to address various topics contained in the joint staff draft report at the quasi-legislative hearing.

Hearings were held January 11, 12, and 14, 1982 in San Francisco. Participating were Southern California Edison, Pacific Gas and Electric Company, San Diego Gas and Electric Company, Los Angeles Department of Water and Power, Sacramento Municipal Utilities District, California Department of Water Resources, Santa Clara Manufacturing Group, Sierra Club, the Cities of Anaheim, Riverside, and Colton, and the CPUC and CEC staffs.

On January 19, 1982, a hearing report was issued giving the parties until February 8, 1982 to comment on the material presented during the Phase I hearings.

Based on all the studies, data, and presentations offered by the CPUC and CEC staffs, electric utilities, and interested parties, the Committee of Victor Calvo and Russell L. Schweickart prepared a report entitled "Joint Investigation into the Reliability of California's Electric Power System." (Hereafter, the "Committee Report.") We hereby adopt the Committee Report, attached as Appendix A.

The Committee Report concludes that, under all reasonably foreseeable contingencies during the 1982 to 1985 period, adequate capacity is anticipated to meet projected peak demand without undertaking extraordinary action. In reaching this conclusion, the report separately discusses the adequacy of the transmission and distribution system, and the generation system.

1/ If further hearings proved necessary, these would be quasi-judicial and designated as Phase II.

The Committee Report begins by defining reliability criteria to assess the adequacy of the transmission and distribution system and the generation system. Although most of the discussion in this proceeding focused on the reliability of the generation system as the most important factor affecting overall system reliability, the report emphasizes that a comprehensive analysis of reliability of electric service must evaluate the entire system. It was determined that about 90 percent of all electric outages experienced in California in the past have been due to distribution-related problems, with all the remaining outages due to transmission system failures.

The lack of focus on transmission and distribution reliability was largely due to the absence of sophisticated measures of assessing such reliability. The Committee Report recommends that improved measures be developed for assessing, first, reliability of the transmission and distribution system and, second, the effects of the transmission and distribution system on overall system reliability. Based on the available information, the transmission and distribution system appears to be adequate both in terms of having sufficient capacity to deliver power to augment supply, and in terms of withstanding single-contingency transmission line outages without causing electric service interruptions. The transmission and distribution system in California appears to be among the best in the nation.

One of the major issues in this proceeding centered on the appropriate reserve margin criteria to use in assessing the adequacy of the generation system. The Committee Report specifically identifies the methods used to define reserve margin criteria in order to prevent any confusion regarding the basis of the report's conclusions. This report uses a short-range reserve margin based on generating capacity after reductions for units on scheduled maintenance and the amount of generating capacity expected to be forced out of service due to equipment failures. Importantly, the report uses a statewide reserve margin criterion as the relevant indicator of generation reliability. Because the California electric utilities are interconnected with each other and with utilities out of state, a capacity-deficient utility has the ability to purchase power from a capacity-rich utility when needed. Thus, shortfalls in reserve within a particular utility generally are not a matter of overriding concern. The critical issue is whether, on a statewide basis, the reserve margin falls below minimum targets. Furthermore, to obtain meaningful statewide reserve margins, additional resources not ordinarily included in utilities' resource plans must be considered.

From the peak demand forecasts and resource plans submitted by the utilities, a base case scenario of most likely occurrences during the 1982 to 1985 period was defined. The base case presented in the Committee Report was modified from the one in the staff report to include more recent information about current conditions as the 1982 summer approaches. The modifications present a base case scenario that is somewhat conservative, or less optimistic, than staff originally assumed.

Utility witnesses testified that the utilities routinely rely on substantial amounts of short-term purchases of power, both within and out of state, to provide additional capacity when needed; that they are confident of the availability of sufficient quantities of such power; and that this practice is more economic for the ratepayer than committing to long-term contracts. A Southern California Edison (SCE) witness testified that SCE has recently refused offers by other utilities to sell firm capacity, preferring to wait until the power is needed.

Based on the utility testimony and other information presented in this proceeding, the Committee Report concludes that this practice of reliance on short-term purchases is reasonable. Since these purchases are not covered by long-term contracts, they do not appear in utilities' resource plans and reserve margin calculations. Studies which assess adequacy of supply based solely on utility resource plans without considering the availability of short-term purchased power significantly understate the adequacy of supply.

Other sources identified in the Committee Report which could yield additional supplies include cogeneration and small power production where investment or contract commitments have not yet been made, and load management beyond that included in utility resource plans. While some of these sources are less certain than others, they are important because, in the aggregate, they provide assurance that additional supplies will be available.

Several adverse contingencies which could potentially occur in the four year period were also examined. These contingencies include delays in scheduled plant additions, adverse hydro conditions, and higher than projected forced outage rates for both existing and new plants.

After analyzing the base case scenario, the availability of additional resources not in utilities' resource plans, and potential contingencies which may occur during the four year period, the Committee Report concludes that even under worst case conditions, sufficient resources should be available to California utilities to adequately meet projected demand. The report further concludes that while 1982 is the critical year in which contingencies could have the most adverse effect on system reliability, sufficient resources are available to meet demand without taking extraordinary action.

Two contingencies are singled out for detailed discussion in the Committee Report: high forced outage rates at existing plants and lower than expected availability of new immature plants. The utilities indicated that maintenance practices for existing plants have improved. However, all parties agreed that since actual maintenance expenses have consistently exceeded projected expenses, maintenance practices and the methodologies used to project maintenance expenses should be re-examined. The Committee Report makes such a recommendation. SCE took exception to staff's recommendations that scheduled maintenance be deferred past the summer peak. However, in more recent California Power Pool reports, SCE does not show any maintenance scheduled during the summer peak of 1982.

Continuance of power plant performance incentives on a unit-specific basis to increase reliability is recommended by the Committee Report, notwithstanding certain utilities' objections. Insufficient information supporting other methods was presented to lead to a different recommendation.

The final chapter of the report discusses the reliability needs of end-users. The report adopts the suggestion by the California Manufacturers Association representative that since transmission and distribution outages account for all outages that end-users have experienced, more analysis of transmission and distribution reliability should be made. The report also recommends that utilities explore methods for expanding customer options for different levels of reliability.

The report concludes with recommendations to examine several issues in further actions.

Findings of Fact

1. The purpose of the joint investigation initiated by the California Energy Commission and this Commission was to assess the adequacy and reliability of the State's electric system for the period 1982 through 1985.

2. Factors most likely to reduce electric system reliability in the 1982 through 1985 period are delays in scheduled operation for major generation projects, high forced outage rates of new immature units and greater than projected forced outages of existing thermal capacity.

3. A comprehensive study of electric system reliability assesses the adequacy of both the generation system and the transmission and distribution system.

4. Most studies of electric system reliability focus on the ability of the generation system, rather than the transmission and distribution system, to provide adequate service, partly because of the absence of sophisticated measures to assess the latter.

5. In evaluating the adequacy of the generation system, reserve margin criteria are often used.

6. Short-range reserve margins as defined in the Committee Report are appropriate for evaluating generation reliability in the 1982 to 1985 period.

7. Statewide rather than individual utility reserve margin criteria are the relevant criteria for assessing generation system reliability.

8. To obtain meaningful statewide reserve margins, resources contained within utilities' resource plans and additional resources not ordinarily included in resource plans must be considered.

9. Substantial amounts of out of state power are routinely relied upon by California utilities to provide capacity when needed during peak demand periods.

10. Other sources which, in the aggregate, could yield additional supplies beyond that included in utilities' resource plans include cogeneration, small power production, and load management.

11. Sufficient resources should be available to California utilities to adequately meet projected demand even under worst case conditions.

12. Transmission and distribution system outages account for all outages that end-users have experienced.

13. Forced outage rates of existing plant for some utilities have been increasing in recent years.

Conclusions of Law

1. Under all reasonably foreseeable contingencies during the 1982 to 1985 period, adequate capacity is anticipated to meet projected peak demand without undertaking extraordinary action.

2. Based on available information, California's transmission and distribution system appears adequate both in terms of having sufficient capacity to deliver power to augment supply, and in terms of withstanding single-contingency transmission line outages without causing electric service interruption.

3. No further hearings in this proceeding are necessary.

ORDER

IT IS ORDERED that the Committee Report issued this date attached as Appendix A is adopted.

This order is effective today.

Dated JUN 2 1982, at San Francisco, California.

JOHN E. BRYSON
President
RICHARD D. GRAVELLE
LEONARD M. GRIMES, JR.
VICTOR CALVO
PRISCILLA C. GREW
Commissioners

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

Joseph E. Bodovitz, Executive Director

(APPENDIX A)

COMMITTEE REPORT

COMMITTEE REPORT

JOINT INVESTIGATION INTO THE RELIABILITY OF CALIFORNIA'S ELECTRIC POWER SYSTEM

California Public Utilities Commission

California Energy Commission

June 2, 1982

Committee:

Victor Calvo, Commissioner, California Public Utilities Commission
Russell L. Schweickart, Chairman, California Energy Commission

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EXECUTIVE SUMMARY

- Even under worst case conditions, sufficient resources should be available to the utilities to adequately meet demand in the 1982 to 1985 period.

- In the 1982 to 1985 period, 1982 is the year in which contingencies analyzed by the two Commissions in the course of this investigation could have the most adverse effect on system reliability. However, sufficient additional resources are likely to be available to meet demand without taking extraordinary measures.

- Substantial amounts of out-of-state power are routinely relied upon by California utilities to provide capacity when needed during peak demand periods. However, since these purchases are not covered by purchase contracts, they do not appear in utility resource plans and reserve margin calculations.

- In light of the present and projected availability of such purchased power, utilities' current practices of making short term power purchases on an as-needed basis are reasonable and economically beneficial to ratepayers.

- Transmission and distribution system outages have accounted forall outages that California end-users have experienced to date. Nevertheless, transmission and distribution reliability in California appears to be above the national average.

- Of all electric system interruptions, about 90 percent have been the result of distribution system outages and 10 percent have been the result of transmission system outages.

- Residential, commercial, and industrial customers have varying perceptions of their need for reliable electric service. Therefore, different levels of electric service at different prices may be appropriate to meet these varying needs.

- The utilities have initiated improvements in their preventive maintenance plans and practices.

- Immaturity of major new baseload facilities scheduled to come into service during the 1982 through 1985 period may increase system-wide forced outage rates.

- Powerplant performance can be improved by developing incentives to operate individual units more reliably.

Recommendations

- To assure realistic assessments of supply adequacy, future assessments should explicitly consider the potential availability of purchased power to augment existing utility resources.
- The potential for additional cost-effective load management should continue to be examined by the utilities, the CEC, and the CPUC.
- Utilities should continue to study means of reducing the unusually high forced outage rates experienced in recent years.
- Utilities should improve methods for analyzing the reliability of transmission and distribution systems.
- The Commission's staffs should assess the adequacy of in-state transmission ties among the California utilities.
- Utilities should improve their ability to compare generation, transmission and distribution reliability in order to guide utility investments in increased reliability.
- Utilities should re-examine their methods of forecasting maintenance expenses in order to predict actual expenditures more closely.
- The CPUC should continue to consider incentives for major baseload power plant performance on a unit-specific basis.

- Utilities should explore methods for expanding customers' options for different levels of reliability.
- The Commissions' staffs should continue to assess the ability of the utilities' systems to provide adequate service on an ongoing basis and inform the Commissions as appropriate.

INTRODUCTION

On April 21, 1981, the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) initiated a joint investigation to assess the reliability of the electric utility system in California for the period 1982 through 1985. The investigation was prompted by concerns that electric system reliability might prove to be inadequate during this four-year period. Factors which could adversely affect system reliability include delays in operation of new generating capacity; poor performance of new generating capacity once on line; high forced outage rates at existing plants; and possible inadequacy of transmission and distribution systems.

Californians have enjoyed extremely reliable electric service. This is true of all customer classes: residential, commercial, industrial, and agricultural. In response to the concerns over the continued vitality of California's historically reliable power system, this study was undertaken to examine all aspects of electric service from generation, transmission, and distribution, to the needs of consumers for various levels of dependable electric service.

Every two years, the California Energy Commission, in its Biennial Report process, assesses electric system reliability for the next 12 years. In its 1981 Biennial Report, the CEC projected that long-term reliability of service will be assured through the addition of new generating resources (both conventional baseload plants and small-scale alternative sources) and increasingly efficient use of energy. However, the CEC recognized at that time that certain contingencies might pose challenges in the near-term period through about 1985, particularly if large planned additions do not come on line when scheduled or if a significant portion of existing facilities is unavailable during times of peak demand.

Each spring, the CPUC has assessed the adequacy of the electric generation system to meet the expected peak demand during the following summer. Since this assessment is made just a few months before the summer peak, only very short-term remedies, such as emergency power purchases, are available to meet a projected capacity shortfall. The CPUC has established voluntary conservation and mandatory curtailment schedules for electric customers in the event of shortages of supply, though implementation of these emergency measures has never been required.

Because the two Commissions have focused on either immediate short-term or fairly long-term system reliability, and because of the concerns which have been raised, it became obvious that an intermediate term analysis was desirable. A four-year study period was selected in order to allow a reasonable period for the Commissions and California utilities to respond to prevent potential energy shortages. These shortages could be remedied by measures which require more lead time than emergency measures but substantially less time than long-range solutions. Intermediate measures include securing short-term purchases from other utilities before those utilities commit their capacity; developing generation projects with short lead times, such as cogeneration and small hydro; accelerating cost-effective conservation and load management; and improving maintenance practices to reduce forced outages of generation, transmission, and distribution systems.

Following adoption of the orders initiating this proceeding in April 1981, the Commissions issued a data request seeking information from utilities covered by the order. These included:

Pacific Gas and Electric Company (PG&E)
Southern California Edison Company (SCE)
San Diego Gas and Electric Company (SDG&E)
Los Angeles Department of Water and Power (LADWP)
Sacramento Municipal Utility District (SMUD)
California Department of Water Resources (DWR)

Other California utilities were invited to participate in the proceeding. The Commissions also urged other parties such as concerned business and manufacturing organizations to take part in the investigation.

A committee consisting of Commissioner Victor Calvo of the Public Utilities Commission and Commissioner Russell Schweickart, Chairman of the California Energy Commission was established to preside over the investigation. The Committee was assisted by CPUC Administrative Law Judge Burt Banks.

The Committee decided to limit the initial stage of this reliability proceeding to informal investigation of a broad range of issues. Because this proceeding was conducted informally, without sworn testimony or cross-examination, no specific actions or directives to utilities will result. However, recommendations of actions which could be implemented formally through other regulatory proceedings before the Energy Commission or the Public Utilities Commission are made.

The joint staff conducted a series of informal, exploratory workshops with the utilities and other parties in September and October of 1981. Following these workshops, the joint staff issued a report[1/] in November 1981, which addressed a wide range of reliability issues and made certain recommendations. The staff report, which was commented on extensively by the utilities, framed the issues for a series of Committee hearings conducted in San Francisco in January 1982. This joint Committee report summarizes the information gathered in this proceeding, and contains conclusions and recommendations. It has been prepared for submission to both the CPUC and the CEC for formal adoption by each Commission.

1/ "Joint CEC/CPUC Staff Draft: Staff Response to Committee Order for Hearings on Assessment of Adequacy of Electric Utility Systems 1982-1985," November 1981.

The Committee report is divided into several chapters. The first chapter develops planning criteria for assessing the adequacy of the utilities' systems. Chapter 2 then assesses the transmission and distribution systems. In Chapter 3, the ability of current planned resource additions to meet projected demand is evaluated. Resources not included in utility resource plans but potentially available to augment supply are also considered. A "Base Case" scenario and several contingencies that could reasonably occur in the four-year period are presented and assessed to determine their impact on system reliability. Potential contingencies include delays in scheduled commercial operation of various plants, higher than anticipated forced outage rates for existing plants, and less than expected availability of new, immature plants. In Chapter 4 the problem of growing forced outage rates of existing plants and immature units is discussed along with methods for projecting maintenance expenses. Performance incentives for increasing power plant reliability are also discussed. Chapter 5 looks at perceptions of reliability by the end-user, how these perceptions correspond to objective criteria, and ways in which varying reliability needs of different end users may be accommodated. Lastly, the Conclusion recommends several courses of action for the two Commissions to pursue.

CHAPTER I

RELIABILITY CRITERIA

At the starting point for any discussion of electric system reliability lies the question of what one means by the term. A general definition of "reliability" refers to whether electrical energy will be available, whenever needed, for whatever purpose. By that measure, California utilities have provided outstanding levels of service, compared with other utilities in the nation. At no time in California history has there been a bulk power outage caused by inadequate generating resources. Although some large outages have been caused by transmission line failures or problems with the distribution system, there has never been a prolonged, widespread outage in this state comparable to the notorious "blackout" of the Northeast in 1966 or the disruptive New York City power failure in 1977.

For system evaluation and planning purposes, a variety of reliability criteria have been developed. Each criterion provides some measure of the reliability of a segment or segments of the utility system. However, a comprehensive analysis of the reliability of electric service must evaluate the system as a sum of its parts.

Public attention has tended to focus on the adequacy of a utility's generation system. Yet, adequacy of the generation system is not by itself an accurate indication of overall reliability, since it does not address the reliability of the transmission and distribution grid. As an illustration, a utility could make major investments in new power plants and still provide unreliable service due to a substandard transmission and distribution system.

It became apparent in this proceeding that there is no analytical tool which provides an overall standard to measure reliability, or to guide investments in improved reliability. The utilities could not explain how they invest to improve overall reliability. For example, should the next dollar of investment go toward new generation resources, additional bulk transmission facilities, or more distribution feeder lines? Thus, this study has been limited by the necessity to evaluate separately the reliability of each part of the utilities' electric systems.

Generation System Reliability Criteria

Utilities evaluate the adequacy of their bulk power supply from two perspectives: that of the system generation planner (long-range) and that of the system operator (short-range). The system generation planner is concerned with the timing and characteristics of new power plant additions required to maintain a specified long-run reliability standard. The system operator's perspective is of a much shorter time period, generally called the operating year. During this period, the emphasis is on ensuring that after accounting for scheduled maintenance and expected hydro conditions, there will be sufficient generating capacity to cover the system's random equipment failures and still serve the expected load. As a result of these differing perspectives, the system planner and the system operator have different criteria for evaluating system reliability.

For long-range planning purposes, and as a basis for decisions to invest in new generating resources, utilities use probabilistic reliability planning criteria. The industry standard which is used by all electric utilities in California is to maintain a "one day in ten years" loss of load probability.

The debate over electric system reliability has tended to view "reserve margins" as a seemingly straightforward measure of reliability. This measure is easier to calculate than loss of load probabilities, and target reserve margins are often derived by determining what reserve margin results from application of the desired loss of load probability criterion to a particular utility system.

Reserve margins can be calculated and used in several ways. This can lead to confusion, as was seen initially in this proceeding, unless the specific assumptions are made clear.

Planning reserve margins that result from long-range loss of load probability calculations are usually in the 15 to 20 percent range, and are based on system generating capacity without deducting scheduled maintenance and projected forced outages. A different measure of reserve margins is used to describe the amount of reserve required during the actual operating year. These operating reserve margins are usually based on generating capacity after reductions for units on scheduled maintenance and the amount of generating capacity expected to be forced out of service due to equipment failures. Operating year reserve margins generally would be in the range of 5 to 12 percent.

The analysis of utility generation reliability in this proceeding is based on use of short-term reserve margin criteria. To avoid confusion the following definitions will be used in this report:

Load Forecast -- A forecast of the maximum monthly peak demand of utility customers.

Planning Load -- The load forecast adjusted for loads not included in the forecast models, such as contracts to sell power to other utilities.

RM-1 -- The reserve margin that is calculated as the difference between the electric utility system capacity and the planning load.

$$\text{RM-1 in percent} = \frac{\text{RM-1} \times 100}{\text{Planning Load}}$$

RM-2 -- The reserve margin that is calculated by deducting the planning load, estimated forced outages, scheduled maintenance, and known restrictions from the electric utility system capacity. RM-2

$$\text{in percent} = \frac{\text{RM-2} \times 100}{\text{Planning Load}}$$

PG&E, SCE and SDG&E classify years beyond the current operating year within their long-range planning period and therefore assess the adequacy of reserve margins during the 1983 to 1985 period based on long-range planning criteria. Long-range planning consists of scheduling projects with long lead times of five years or more. These projects therefore could not be implemented in the 1982 to 1985 period. Long-range planning, by the utilities' definition, does not include options such as reducing forced outage rates, implementing additional load management and conservation, or accelerating short lead-time projects such as cogeneration.

Consequently, for the purpose of evaluating the 1982 to 1985 period, this report uses a short-range reserve margin target. The adequacy of statewide reserve margins for the 1982 through 1985 period is assessed in the following manner:

(a) The utilities' system generating capability, including firm purchases, is calculated.

(b) All scheduled maintenance or known restrictions and the forced outages projected by the utilities are subtracted from the system generating capacity for each year in the 1982 to 1985 period (i.e., the reserve margin is determined on an RM-2 basis).

(c) If the resulting statewide reserve margin is 5 percent or more, the conclusion is reached that the utilities have a reasonable expectation of meeting loads during peak demand periods without relying on further actions.[1/] If the statewide reserve margin falls below 5 percent, then the availability of power from sources not now in the utility resource plans is examined.

The above criteria are applied to the statewide system and also on a service area-by-service area basis to determine any projected deficiency within the state. Normally, when one utility's reserve margin falls below acceptable levels, another utility will supplement the deficient utility. This arrangement is by agreement under the terms of the California Power Pool. Thus, shortfalls in

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1/ The 5 percent reserve margin is tied to curtailment plans submitted by utilities and approved by the CPUC to respond to potential shortfalls during peak demand. Under CPUC guidelines, a utility whose reserve margin has fallen to 5 percent enters a Stage I alert and seeks voluntary load curtailment from its customers (via radio advertisements and direct communication with large customers). If demand continues to rise and reserves fall to 3 percent, a Stage II alert would be declared involving interruption of large, low priority customers. A Stage III alert triggered at 1.5 percent reserve margins would involve rotating outages for some period of time. It is expected that Stage I and II alerts would result in loads dropping by 2145 MW, thus increasing reserve margins by 5 percent based on utilities' projections. (Exhibit 234 dated April 7, 1981, in Case 9884.)

reserve within a particular utility generally are not a matter of overriding concern. The critical issue is the level of the statewide reserve margin.

Transmission and Distribution Reliability Criteria

For planning purposes, virtually all California utilities use deterministic planning criteria to evaluate the reliability of the high-voltage bulk transmission system; that is, the effects of various failures are analyzed, without explicit consideration of the likelihood that those events might occur. A single contingency criterion is usually used, i.e., the failure of a single line, transformer, or capacitor should not result in loss of power to any customers. Only a double contingency, triggered by a larger or more widespread cause or by simultaneous but independent causes, can result in a disruption of electric service. The staff report characterizes current transmission planning criteria as "based on subjective and intuitive planning and engineering judgments which have evolved from planning and operating experience and not by precise analytical methods" (Staff report, p. 99). There have been recent attempts to develop more sophisticated probabilistic measures of transmission system reliability, which could encompass the effects of transmission limitations on generation capacity as well.

Distribution lines are lower voltage than transmission lines, and are used to carry electricity from the bulk transmission system to the utility customer. Reliability criteria for planning distribution systems are even less sophisticated than those for transmission systems.

California utilities employ radial distribution systems to serve many customers. As a result, outage of a single distribution line will likely result in loss of service to some customers. In high-density urban areas, interconnection of distribution lines often provides multiple paths for electricity to reach the customer and thus the likelihood of an outage resulting from a single line failure is reduced.

The utilities indicated in this proceeding that distribution planning criteria provide for higher levels of reliability for larger customers, in terms of redundancy in distribution lines serving those loads. However, this appears to be based on broad, general principles, rather than on any detailed quantified reliability measurements.

As is discussed elsewhere, all electric outages in California to date have resulted from transmission and distribution-related problems. Given this and the increasing reliance on transmission links to provide access to remote generating capacity and to lower cost energy purchases, it is clear that more sophisticated analytical tools should be developed for assessing reliability of transmission and distribution facilities and their impacts on overall system reliability.

CHAPTER II

RELIABILITY OF THE TRANSMISSION AND DISTRIBUTION SYSTEMS

The transmission and distribution network is a critical part of California's electric system. Of the electricity outages that have occurred in California within the last five years, approximately 90 percent have been the result of disruptions in the low-voltage distribution system, with the remaining outages resulting from interruptions in the large high-voltage transmission system. Given this experience and the growing reliance of utilities on generation plants built out-of-state and on purchases of economical surplus capacity and energy from distant sources, reliability of the transmission and distribution system warrants careful attention.

Utilities collect outage data on their systems to characterize the adequacy of their service, to identify reliability trends, and to assist in performing cost/benefit analyses. Utilities have not standardized their data collection system for transmission and distribution as they have done with their generation system. For this reason, it is difficult to compare transmission and distribution system performance among utilities.

From the data collected, the utilities develop reliability indices. Two indices typically reported or used in assessing historic reliability of the electric service system are duration and frequency of outages. These indices can be further refined to show interruption duration (minutes per customer) and interruption frequency (interruptions per customer). Outage data for five California utilities is shown in Table II-1.

As can be seen from this table, both the interruption duration and interruption frequency are relatively low. The rather large difference between PG&E and the other California utilities is presumed to be due to differences in the type of geographical area served by PG&E. The PG&E service area is spread out over much of California and therefore has extensive mileage of both transmission and distribution radial feeds.

While comparisons with other utilities in the United States are difficult, California utilities appear to have some of the highest overall levels of reliability in transmission and distribution service anywhere. The outages that occur on the distribution system are caused largely by forces beyond the control of the utilities -- storms, fires, automobile collisions with power poles, etc. A major reason for the low overall outage rates is the mild climate in this state. Storm-caused outages, which regularly afflict utilities in the East and Midwest, are not as common in California.

California utilities are linked to one another and to utilities in other western states through an extensive system of transmission facilities. Three major lines connect utilities with power supplies in the Pacific Northwest (PNW). Two 500 kV alternating current (AC) lines terminate in northern and southern California.

An 800 kV direct current (DC) line from Oregon terminates at Sylmar in southern California. These three lines have a net capacity during summer periods of about 4,050 MW. This capacity is planned to increase to 4,450 MW in 1985 when the voltage on the DC line is increased to 1,000 kV.

Table II-1

Electric Service Reliability

	Interruption Duration 1/ Minutes/Customer/Year	Interruption Frequency 1/ Interruption/Customer/Year
PG&E	135.70	1.68
SCE	57.26	2.08
LADWP	41.93	1.38
SDG&E	90.36	1.64
SMUD	65.16	2.87

1/ 5-year average

The CEC in particular has expressed strong interest in the addition of another line to the PNW to take advantage of large amounts of surplus hydroelectric energy and capacity which, at present, is wasted through spillage. This addition is part of PG&E's resource plan but is not anticipated until late in this decade. While the schedule for this line could probably be advanced, it will not be available in any case during the period through 1985.

Southern California utilities are interconnected with utilities in other Pacific Southwestern states (PSW) through several transmission lines, including four 500 kV lines to the Hoover Dam area in southern Nevada. The staff report describes in some detail existing and planned transmission facilities, the out-of-state capacity, owned by California utilities, and the purchase contracts between California and other Southwestern electric utilities. The current capacity of major transmission facilities from California to the PSW will approach 5,800 MW after the new Devers-Palo Verde line is fully energized this year. (In early May, this line was being tested at low levels.) In the summer of 1984 the transfer capability from the PSW is planned to increase to 6,820 MW with the completion of the 500 kV Eastern Interconnection between Palo Verde and San Diego.

Limitations on transmission capacity result from a phenomenon known as "loop flow." Loop flow is the difference between scheduled and actual power flows on transmission lines. Loop flow is caused by configuration of the bulk power transmission system in the western states and the loads and resources operating at a particular time. The shape of the Western Bulk Power System is characterized as a "doughnut" with weak interconnections in the center. The western side of the doughnut has lower impedance (resistance) than the eastern side of the doughnut. Power tends to flow around the loop, with the flow being clockwise or counterclockwise depending on system conditions (e.g., power from the Northwest may reach southern California by way of Montana and Colorado).

Loss of available transmission capacity due to space on the lines being used by loop flow has been measured as high as 1,000 MW. Utilities in the western United States have been trying to solve loop flow problems since the early 1970s but have been largely unsuccessful. SCE had to curtail the generation of about 350 MW of firm power from its Four Corners coal plant at times during 1980 and 1981, in order to accommodate high clockwise loop flows. If the Palo Verde to Devers 500 kV line is not available during peak summer conditions in 1982, utilities might be required to curtail electric power imports from the PSW again this summer due to loop flow problems.

The amount of power which California can import from the PNW during the summer months is currently reduced by the amount of loop flow occurring and will continue to be restricted for this reason between 1982 and 1985.

This proceeding did not focus on ways in which the reliability of transmission and distribution systems could be improved. Similarly, the utilities do not seem to place much emphasis on improving current methods of evaluating reliability of these systems, nor on expenditures to improve transmission and distribution reliability. Some end-users who participated in this proceeding did not appear concerned about transmission and distribution outages. Some parties characterized outages caused by transmission and distribution failures as "random and unpredictable", while those caused by generation inadequacy were termed "preventable by proper planning".[1] This argument is not persuasive, since the reliability of transmission and distribution systems can also be upgraded through proper planning and prudent investment. The effect of an outage on a customer is the same regardless of its cause. However, there is little evidence that the reliability of the present transmission and distribution is inadequate for the general customer. The topic of the needs of different end-user classes for different levels of electric supply reliability is discussed in detail in Chapter 5.

Another topic that did not receive sufficient attention in this proceeding is the adequacy of in-state transmission ties among the California utilities to permit optimal flow of power. If the ties are not adequate, this would reduce the ability of California utilities to fully coordinate operations of their resources

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1/ Transcript, p. 381.

and also their abilities to receive any out-of-state power which might require transportation through another in-state system. Closely connected is the question of current utility practices which may discourage power "wheeling" and power pooling among utilities. For example, PG&E stated that it had a difficult time arranging firm transmission from the Southwest through the SCE or LADWP system.2/ Questions were also raised about whether the Southern California Power Pool Association has firm transmission capacity for its Palo Verde nuclear power plant entitlement through the SCE system. These issues are of great importance and should receive further scrutiny from the Commissions.

2/ Transcript, pps. 154 and 155.

CHAPTER III

RELIABILITY OF THE ELECTRIC GENERATION SYSTEM

This chapter examines the adequacy of the utility generation resource plans to meet projected demand, based on likely occurrences during the 1982 to 1985 period. For this analysis, the short run (RM-2) reserve margin criterion has been applied to current utility demand forecasts and resource plans. A "Base Case" scenario dependent upon assumptions of most likely occurrences is analyzed. The "Base Case" is compared with several contingencies for each year of the study period to determine the effect of less likely occurrences on system reliability. Additional resources likely to be available to supplement the utilities' resource plans are also considered. Significantly, under most contingencies, the statewide reserve margin based on resource plans alone will equal or exceed the 5 percent reserve margin criterion. Even if reserve margins fall below this level, it appears that there will be more than enough power available from sources not in utility resource plans to preclude any significant possibility of customer curtailments.

Peak Demand Forecasts

The utilities' forecasts submitted in this proceeding are used for this study. These forecasts were selected rather than the CEC adopted forecasts because they are available on a monthly basis and because in most cases they have been developed with a specific short-term methodology. The submitted forecasts were modified after workshops and additional inputs from the utilities, primarily to account properly for load management programs and purchase contracts. The modified forecasts used in the analysis are shown in Table III-1.

Table III-1

Modified Forecasts of Peak Demand
(Megawatts)

	1982	1983	1984	1985
Pacific Gas & Electric	15,627	15,791	16,154	16,765
Southern California Edison	13,618	13,860	14,264	14,698
San Diego Gas & Electric	2,064	2,066	2,138	2,239
Los Angeles Department of Water & Power	4,455	4,387	4,461	4,536
Burbank	215	222	228	235
Glendale	215	220	225	230
Pasadena	209	215	221	228
Statewide Total 1/	36,403	36,761	37,691	38,932

1/ Non-coincident total of peak demand.

Due to statewide climate variations, peak demands in different parts of the state often occur at different times. Thus, there is a potential for exchanges of capacity between northern and southern California during one area's peak demand period. The differences in statewide coincident and non-coincident peak demands for 1972 through 1980 are shown in Table III-2 with the difference ranging from a low of 102 MW in 1976 to a high of 1,553 MW in 1975.

Table III-2

Statewide Historical Coincident and Non-Coincident Peak Demand

(Megawatts)

	STATEWIDE PEAK DEMAND			
	Coincident 1/		Non-Coincident 2/	Difference
Year	MW	Date	MW	MW
1972	25,295	7/28	26,784	1,489
1973	27,299	6/21	27,643	344
1974	27,740	7/25	27,935	195
1975	26,948	7/25	28,501	1,553
1976	30,436	6/28	30,538	102
1977	29,862	9/7	30,586	724
1978	31,689	8/7	33,071	1,382
1979	32,352	9/12	33,638	1,286
1980	33,658	7/29	34,068	410

1/ Includes PG&E, SCE, LADWP, SDG&E and SMUD. Coincident peak is the maximum combined peak demand for different systems that occurred at any one hour of the year for all utilities.

2/ Non-coincident peak is the sum of the maximum peak demand for electricity in each utility system regardless of the time.

Staff has estimated that the statewide coincident peak demand will average about 880 MW less than the total of the non-coincident peak demands of the individual utilities shown in Table III-1. Since this statewide reduction is so unpredictable, it has not been included explicitly in the analyses in this report. This additional margin of safety does not appear in the reserve margins in this report or in utility analyses.

Utility Generation Resources

The utilities' resource plans submitted in this proceeding were also used in this analysis. A Base Case scenario was developed which depends primarily on the utilities' assumptions of likely occurrences in the 1982 to 1985 period. However, several modifications have been made, mainly to reflect actual 1982 conditions as the summer season approaches.[1/] These modifications include:

-- Diablo Canyon 1 -- The first unit (1084 MW) of PG&E's Diablo Canyon nuclear project was included in PG&E's resource plan beginning in January 1982, but is not included in the Base Case until 1983.

1/ Average hydro conditions were assumed for all years, including 1982, notwithstanding the fact that 1982 is a better than average hydro year. Therefore, the analyses for 1982 and 1983 are more conservative than if actual 1982 hydro data had been used.

-- Scheduled Maintenance -- All maintenance scheduled by SCE at the time of its system peak, except for San Onofre 1 in 1983, is deferred to off-peak periods. This is consistent with later SCE submittals to the California Power Pool.2/

-- Helms Pumped Storage -- The first unit (374 MW) of PG&E's Helms pumped storage project was scheduled for initial operation in July 1982. Since PG&E now projects that Unit 1 will not be in service until after the summer, it is not included in the Base Case for 1982.

-- San Onofre 1 -- The first unit (436 MW) of the San Onofre Nuclear Generating Station (SONGS), which has been operating since 1968, may not be on-line this summer. It has been closed for technical and safety evaluations, and, on May 20, 1982, the NRC staff recommended that it remain closed until modifications are made to correct seismic safety deficiencies which have been found. For this reason, the facility is assumed not operational for the summer of 1982.

2/ "1982 Power Supply: A Special Report to the Board of Control of the California Power Pool," California Power Pool, February 22, 1982; and "1982 Power Supply, April 1982 Report", California Power Pool, May 13, 1982.

- San Onofre 2 -- The second unit (1100 MW) of SONGS was scheduled for initial commercial operation in June 1982. This unit is now expected to be undergoing low-power testing during the 1982 summer, with commercial operation occurring later in 1982. No reliable capacity is included in the Base Case for the 1982 summer.

- Rancho Seco -- The Sacramento Municipal Utility District (SMUD) nuclear project (875 MW) is included in PG&E's resource plan. Although PG&E assumed that it would be shut down for maintenance until September 1982, it is now expected to resume operation on August 1, 1982. Rancho Seco is not included in the Base Case for 1982. Peak period reserve margins would be increased by up to 875 MW in 1982 if it is operating during that time.

The system capacities for the Base Case scenario for the California utilities are shown in Table III-3 for the years 1982 through 1985. The resource plans are shown broken down by resource type in Appendix A.

Table III-3

Modified Forecasts of Generation Capacity 1/
Average Hydro
(Megawatts)

	1982	1983	1984	1985
Pacific Gas & Electric	16,416	20,188	20,607	20,760
Southern California Edison	15,138	17,238	18,012	17,998
San Diego Gas & Electric	2,522	2,813	2,937	2,926
Los Angeles Department of Water & Power	6,215	6,315	6,289	6,351
Burbank	267	270	253	253
Glendale	336	339	342	342
Pasadena	314	316	274	274
Statewide Total	41,208	47,479	48,714	48,904

1/ Known restrictions and forced outages, and scheduled maintenance not included.

Additional Resources Potentially Available

Electricity will be available from a number of other sources not traditionally included in the utilities' resource plans. As discussed in a later section, utilities routinely rely on substantial amounts of purchased power from a variety of sources which do not appear in their resource plans. The plethora of options discussed in this section which will likely be available between 1982 and 1985 gives a high degree of confidence that dependable service will be maintained.

In its near-term resource plan, a utility includes only those supplies which it owns or for which it has already signed "firm" purchase contracts (as compared to "non-firm" contracts which only provide for purchases when and if the power is available). There are three main categories of resources which could yield additional supplies within the 1982 to 1985 period: purchases or exchanges on either a firm or a non-firm basis with other utilities within California or out-of-state; development of cogeneration and other short lead-time small power sources in-state beyond that now under contract; and further implementation of utility load management programs beyond that included in current resource plans.

These potential sources hold varying degrees of promise. Nonetheless, even some of the more uncertain resources discussed in this chapter are important because they provide, in the aggregate, assurance that additional supplies will be available beyond those which are certain enough to be included in the resource plans.

a. The Pacific Northwest

One of the most reliable resources available to supplement capacity is purchased power from the Pacific Northwest (PNW). Northwest utilities are winter peaking, mainly to meet electric resistance heating loads, and have a substantial amount of surplus power available for sale to California during the summer. Earlier projections of diminishing Northwest surpluses have given way to a more promising picture of long term availability of this resource. California utilities have existing contracts to exchange or purchase power with the utilities in the PNW which appear in their resource plans. In 1982 these contracts amount to over 2,400 MW. DWR's Canadian entitlement will terminate in 1983; this will reduce the total amount of capacity under firm contract by 150 MW in 1983 and beyond.

A review of loads and resources in the PNW, as presented in the Western System Coordinating Council's (WSCC) "Coordinating Bulk Power Supply Program, 1980 - 1990" report, dated April 1, 1981, reveals that considerable excess capacity could be available during the summer months in the early eighties. From information in this report, the following estimates have been made of yearly amounts which could be available:

1982	7,553 MW
1983	5,936 MW
1984	9,587 MW
1985	8,312 MW

These estimates allow for forced and scheduled outages and are based on adverse hydro conditions. With normal or above normal hydro conditions the excess capacity could be even larger. However, the actual imports which can be received from the PNW will be limited by the availability of transmission capacity, as discussed in Chapter 2.

From 1982 to 1984, after allowing for firm purchases and for summer-time loop flow estimated to be 500 MW in a counterclockwise direction, 1,100 MW of PNW transmission capability will not be loaded. Thus, California utilities could use this capability to purchase short-term firm power or interruptible non-firm energy from PNW utilities. In 1985 the available transmission capability to carry short-term firm purchases and interruptible energy will increase to over 1,650 MW.

Addition of another transmission line to the PNW should be considered seriously as a planning option. This line could not be built within the 1982 to 1985 period, but, when built, would substantially increase the amount of purchases from the PNW possible for California utilities.

b. The Pacific Southwest

California utilities also purchase power from utilities in the Pacific Southwest (PSW). In addition to purchases, the California utilities own some capacity in the Hoover area, Arizona, and New Mexico. The capacity owned or under contract for firm purchase by California utilities totals over 4,500 MW in 1982 and is expected to increase to 5,500 MW by 1985.

Information in the WSCC report cited previously has been used to estimate the following amounts of excess capacity in the PSW that could be available for purchase by California utilities:

1982	489 MW
1983	369 MW
1984	641 MW
1985	422 MW

These estimates allow for forced and scheduled outages. As discussed in Chapter 2, transmission capability is not likely to limit the ability of California utilities to import these levels of excess capacity unless planned transmission additions are substantially delayed. In 1982, after allowing for firm purchases and an anticipated 400 MW of clockwise loop flow, there will be 860 MW of transmission capability between California and the PSW not loaded. Thus, up to 860 MW of power could be transmitted, if available. By 1985, there will be 1,130 MW of transmission capacity to carry such purchases.

c. Cogeneration, Small Hydro, Wind, and Geothermal

Included in each utility's data submittal are estimates of the generation additions it expects on a yearly basis from cogenerators and small power producers. These sources include biomass, solid waste, wind, solar, and small hydroelectric projects less than 50 MW. The utility estimates include only those projects for which a contract or investment commitment has been made. Projects under negotiation, even if they have a reasonable likelihood of reaching commitment in the next few months, are not included. Thus, the supply additions from these sources will likely be higher than the utility predictions, assuming that the market and related conditions for the sale of electricity to utilities in California stabilize in a favorable manner.3/

3/ Indications are that uncertainties surrounding the prices and contract terms under which utilities must buy power from cogeneration and small power producers, in conformance with guidelines established by the CPUC, are currently hindering some development. These uncertainties should be resolved soon, as the new purchase offers ordered by the CPUC are implemented.

The CPUC staff has identified several potential projects which are in early planning stages but whose lead times are short enough so they could be available in the early eighties. The staff estimate of the amount of cogeneration, wind, geothermal, and small hydroelectric capacity in addition to that shown in the utility submittals totals 627 MW by 1985, based on its judgment of the likelihood that each project known to be under negotiation with the utilities will proceed and come on line.

d. Department of Water Resources

The California Department of Water Resources (DWR) is projected to have excess capacity during peak periods which could be available to California utilities between 1982 and 1985.

DWR's resources, forecasted demand, and contract obligations were compared to calculate excess capacity which may be available during peak periods for 1982 to 1985. DWR may have 182 MW of excess capacity in 1982 and between 270 and 500 MW in 1983, 190 and 410 MW in 1984, and 90 and 310 MW in 1985, depending on the availability of the Reid Gardner coal plant, for which DWR has an interruptible contract, and less any forced outages. Further, DWR has historically reduced pumping loads during statewide peak demands to supply extra capacity to California utilities if needed. DWR staff indicate that DWR can reduce its load up to 300 MW on a short-term basis for this purpose.

DWR's resources are not included in the utilities' resource plans but provide another source of capacity which is potentially available to augment supply.

e. Additional Load Management

Load management can provide another source of additional capacity by shifting non-essential energy usage away from peak demand periods. Load management can effectively reduce load during high demand periods which occur only a few hours each year. For example, in 1981 PG&E's peak demand was 15,576 MW, but PG&E only exceeded 15,000 MW on three days that summer. SCE's system demand came within 600 MW of its peak in 1981 on only two days. SDG&E and LADWP had similar experiences on a smaller scale.

PG&E has included all load management programs it considers potentially cost effective in its resource plan. In contrast, SCE and SDG&E include only existing programs at current funding levels in their resource plans. LADWP has not explicitly accounted for the impacts from any of its conservation programs in its resource plan. However, it claims that some of its programs' impacts on forecasted peak are captured through variables such as energy and price which are inputs to the forecast model.

In their submittals, SCE and SDG&E identified some additional load management measures that they plan to implement if additional funds are made available. The potential load reduction of SCE and SDG&E's planned programs and LADWP's load-reducing swimming pool pump program are 327 MW in 1983 and 353 MW in 1985.

Based on the results of utility programs which comply with the Residential Load Management Standard established by CEC, CEC staff has determined that residential cycling is cost-effective. The CEC staff has analyzed utilities' program plans for residential cycling and has determined the maximum demand reduction attainable from the CEC standard by 1985. The pace set by the three investor-owned utilities between now and 1983 approaches these levels, but could be accelerated somewhat if needed.

A number of non-residential programs also merit consideration for implementation in the 1982 to 1985 time frame, since preliminary analyses by the CEC staff show that they are cost-effective. Furthermore, these programs lend themselves to the short lead time required in the event that contingencies develop. CEC staff has estimated that, by accelerating cost-effective load management programs, augmenting existing programs with incentives, and expanding into new programs, utilities could reduce statewide peak demand by an additional 756 MW by 1983 and 1,196 MW by 1985. Adequate data was not available in this proceeding to determine the cost-effectiveness and desirability of specific programs. The potential for additional cost-effective load management should continue to be examined by the utilities, the CEC, and the CPUC.

f. Other Sources

Palo Verde ownership by small municipalities totalling 142 Mw by 1984 has not been reflected in the statewide analysis of available capacity. Moreover, various other sources of capacity are potentially available if needed during peak demand periods. Actual system operation often provides additional capacity. For example, the actual capacity delivered to Sierra Pacific Power Company (SPPC) by PG&E during the time of PG&E's peak demand in recent years has been considerably less than the 108 MW contract commitment because of SPPC's reduced demand. Another source of capacity is potentially available from the Metropolitan Water District (MWD) in southern California. MWD has reported that it could provide up to 80 MW of emergency capacity by reducing its pumping load.

Enhanced power pooling between utilities is another source of capacity. LADWP and, to a lesser extent, SDG&E enjoy large reserves of peaking power to meet summer load. For example, LADWP's Castaic hydroelectric pumped-storage power plant has a total installed generating capacity of 1,247 MW. The operation of this facility is dependent upon the amount of thermal energy available from LADWP's own system and from purchases in the Pacific Northwest. During adverse hydro years, the energy LADWP has available for pumping Castaic will only produce 621 MW, leaving

626 MW of surplus capacity that can be used by other utilities if they have the energy to pump the water back at off-peak periods. LADWP sold over 600 MW to other utilities during the summers of 1980 and 1981. In its current resource plan, LADWP includes only 621 MW; thus another 626 MW should be available if needed.

Although LADWP says that it does not anticipate reducing its own demand simply to make additional surplus power available to other utilities, such a policy could very well be in the public interest. This policy, of course, would include appropriate pricing of capacity and adequate compensation to the utility selling the power.

Reliance on Short-term Purchases During Peak Periods

Some of the resources described in the previous section, most notably short-term purchases from other utilities, are routinely relied upon by California utilities to provide capacity when needed. However, since the purchases are not covered by existing purchase contracts, they do not appear in the utility resource plans. As a result, an analysis of reserve margins based solely on the resource plans would understate the actual reserve margins which can be expected. For this reason, the conclusions and recommendations emerging from this proceeding do not rest on reserve margin criteria based strictly on utility resource plans.

In this proceeding, PG&E and SCE have recognized the importance of these short-term resources, and have detailed their reliance upon them. In the hearings in this proceeding, PG&E witness William Flowers discussed PG&E's policy:

> "We attempt to make advance purchases of capacity where needed to give us a 10 percent margin. That is a 10 percent margin after taking into effect known limitations on our system, but leaving the 10 percent margin available to take care of forced outages.4/ And we expect to make these advance purchases and we make them ... pretty much on a monthly basis. ...
>
> "On a daily basis, the California Power Pool has a requirement for an operating margin ... of 7 percent reserve each day. And it is our operating practice and that of other utilities to attempt ... to provide this 7 percent margin. ..."5/

Mr. Flowers indicated that purchases are arranged if needed at the end of each day to provide a 7 percent reserve margin the next day, based on expectations of the day's load demands. Further, during the operating day additional purchases are made on an hourly basis to maintain reserves of at least 5 percent. He concludes:

> "... as long as we still maintain our 5 percent ... we feel as though the operating reserve is adequate. ...

4/ Since the RM-2 reserve margin in this report is calculated after projected forced outages have been subtracted, PG&E's 10 percent reserve margin implies an RM-2 reserve margin, as calculated in the Base Case, of 5.8 percent for 1982.

5/ Transcript, pps. 141 and 142.

"Now, that differs a bit from the philosophy which we think that the Energy Commission and the Utilities Commission have prepared, ... that we should make long-term purchases to assure the 5 percent margin every day. If we actually in fact did do this, why, we would be buying capacity which was unneeded on the system for many, many days, ... would be uneconomical, would be unnecessary, and certainly would be costs that would have to be borne by someone on the PG&E system."6/

Consistent with this stated planning philosophy, PG&E lists capacity amounts expected to be available for monthly purchase from outside the PG&E's area in the February 22, 1982 California Power Pool Report, which are as follow:

	June	July	August	September
	(Megawatts)			
Puget Sound Power & Light	Up to 114 MW			
Los Angeles DW&P	Up to 600 MW			
San Diego Gas & Electric	350	350	300	75
Sierra Pacific Power Company	110	110	110	110
Southern California Edison	Unknown			
WAPA-CVP (via the Northwest)	400	400	400	400
Maximum Available	1,574	1,574	1,524	1,299

The purchase of the capacity listed which is not already included in the statewide resources shown in Table III-3 would increase statewide reserve margins by over 3 percent.

6/ Transcript, pps.142 and 143.

SCE concurs with PG&E's position regarding short-term purchases.

In this proceeding, SCE witness Glenn Bjorklund stated:

> "For us to make purchases in excess of that which we would expect to be needed would unduly burden the ratepayer with us having firm contracts for purchases of capacity and energy that we may not need. ...
>
> "We know where there is space capacity and we know what reasonably ... would be available to use, and we know where we have capacity on our lines.
>
> "So, we have a high degree of confidence that should the occasion arise, that we can go out and make those spot purchases, and they are very, very willing, quite frankly, to sell capacity and energy to California because of the good price that is brought by that." 7/

Bjorklund further added:

> "One thing else that would be of interest for the degree of confidence that we have and for the decision process that goes on: Hardly a week or two goes by that I don't get a letter ... offering to sell us 100, 200, 300 megawatts with related energy for any period of time should we be interested.
>
> "And our response to them is no. We have adequate reserve margins now and we don't have a need for the capacity because we feel that for us to purchase something that is in excess of our needs is a commitment that is not proper to make again for the ratepayers."8/

7/ Transcript, pps. 48 and 49.
8/ Transcript, p. 56.

The statements of these two utilities and independent data detailed in the preceeding section combine to present a convincing argument that the current utility practice of relying upon short-term power purchases in providing reliable electric service at a minimum cost to California ratepayers is appropriate and prudent.

Potential Contingency Conditions

In addition to the Base Case, which includes expected conditions, the effects on system reliability of contingencies which may occur between 1982 and 1985 are examined. The factors most likely to reduce electric system reliability in these four years are delays in scheduled commercial operation dates for major generation projects,9/ high forced outage rates of immature generating units, and greater than projected forced outages of the existing thermal capacity.

Of the 7,519 MW planned capacity additions for the 1982 to 1985 period, 6,163 MW are in four major projects: Diablo Canyon (2,190 MW), San Onofre (2,200 MW), and Palo Verde (653 MW) nuclear

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9/ The delays in licensing the Diablo Canyon Nuclear Plant are a case in point. PG&E estimated in its February 1976 resource plan that Diablo Canyon would be available for the 1976 summer peak. In the January 1982 hearings in this proceeding, PG&E similarly estimated that Diablo Canyon would be available for 1982 summer peak. Diablo Canyon, however, will not be available this summer, and may not be available to meet the 1983 summer peak. It is precisely this kind of "rolling delay" which is most likely to affect new generating resources. The most difficult aspects of a "rolling delay" are the lack of warning time available to the utility and the unknown duration of the delay. These aspects hinder utility management's ability to plan alternate resources to meet demand in the interim.

projects, and the Helms pumped storage project (1,120 MW). Any delays in the scheduled commercial operation date of these projects or availability below that projected as the result of their being immature units could have a significant effect on reserve margins in this period.

The effect of high forced outage rates at existing plants was also examined. For the 1982 to 1985 period the utilities are projecting the following forced outages each year for the existing system:

PG&E	1,527 MW	LADWP	723 MW
SCE	1,600 MW	SDG&E	141 MW

However, both PG&E and SCE have been experiencing increasing forced outages. In 1981, the amounts of capacity on forced outages at the time of the system peak were:

PG&E	3,152 MW	LADWP	309 MW
SCE	2,036 MW	SDG&E	12 MW

Forced outage rates may be increased with the addition of immature plants to the utility system. Large power plants experience a maturing period in which, for the first few years, design and operational bugs are worked out. This is a time when forced outage rates are higher than the projected long-run average forced outage rates. Due to their more complicated design and operational and safety requirements, the forced outage rate of immature nuclear plants in particular can be significantly higher than the expected forced outage rates of mature plants. By the summer of 1983 the major California utilities are expected to have four new in-state nuclear reactors (4,390 MW) in operation and should be receiving 361 MW from Palo Verde 1, which is expected to be in its first year of operation in 1983. The estimated forced outages provided by the utilities do not include the effect of new plant additions.

For analysis purposes, several contingency conditions which, individually, have a reasonable likelihood of occurring were hypothesized, and a "Worse Case" scenario was constructed combining all the contingencies. The following contingency events were included:

(a) Adverse Hydro Conditions in All Years Except 1982. This is pessimistic since it is already known that 1983 will have better than adverse hydro conditions.

(b) Forced Outage Rates--Existing Systems
The forced outages each year for the 1982 through 1985 period would be equal to those occurring in 1981. This is 1,518 MW more than is projected by the utilities for each of those years.

(c) Delays in Scheduled Capacity Additions

1983:	Diablo Canyon 1 and 2	-- not available
	SONGS 3	-- not available

(d) Forced Outage Rates of Immature Units

In addition to high forced outage rates for the existing system, it was assumed that unit immaturity would result in the following additional forced outages:

1984: One Diablo Canyon unit and either SONGS 2 or SONGS 3 would be on forced outage at the time of the system peak.

1985: 1,500 MW of new nuclear capacity would be forced out at the time of the system peak.

Assessment of Adequacy of Generation Resources

In the preceding sections, information has been compiled regarding demand forecasts, resources in the utility resource plans, power sources not included in the resource plans, and potential contingency conditions. In this section, this information is drawn together to obtain an assessment of the adequacy of the current utility plans. The calculations are summarized in Table III-4 through Table III-7 for the years 1982 to 1985.

Table III-4

Assessment of Generation Resources
1982
(Megawatts)

	PG&E	SCE	LADWP	SDG&E	BGP 1/	Statewide
Peak Demand	15,627	13,618	4,455	2,064	639	36,403 2/
Base Case:						
Base Case Resources 3/	16,416	15,138	6,215	2,522	917	41,208
Projected Forced Outages 4/	652	1,251	723	54	0	2,680
RM-2 Reserve Margin (MW)	137	269	1,037	404	278	2,125
RM-2 Reserve Margin (%)	0.9	2.0	23.3	19.6	43.5	5.8
Potential Additional Resources:						
Pacific Northwest						1,100
Pacific Southwest						489
Cogeneration, etc. 5/						up to 71
DWR						300+
Load Management 6/						0
Castaic						626
Other 7/						130
Total Additional Resources						up to 2,716
Potential Contingencies:						
High Forced Outages 8/						-1,518
Worst Case Total						-1,518
MW of Additional Resources Needed for 5% R.M. 9/						1,213
MW of Additional Resources Needed for 7% R.M. 9/						1,941

1. Burbank, Glendale, and Pasadena.
2. Non-coincident total; could be 880 MW less in average coincident conditions.
3. Reduced by known restrictions and forced outages.
4. Does not include known forced outages.
5. Staff report, p. 74.
6. CEC staff estimated 676 MW; however none is included due to insufficient lead time.
7. Sierra Pacific Power Co. (PG&E) 50 MW
   MWD Load Interruption 80
   130 MW
8. 1981 forced outages, less projected forced outages.
9. Under worst-case contingency conditions.

Table III-5

Assessment of Generation Resources
1983
(Megawatts)

	PG&E	SCE	LADWP	SDG&E	BGP 1/	Statewide
Peak Demand	15,791	13,860	4,387	2,066	655	36,761 2/
Base Case:						
Base Case Resources 3/	20,188	17,238	6,315	2,813	925	47,479
Projected Forced Outages	1,527	1,600	723	141	0	3,991
RM-2 Reserve Margin (MW)	2,870	1,778	1,205	606	270	6,727
RM-2 Reserve Margin (%)	18.2	12.8	27.5	29.3	41.2	18.3
Potential Additional Resources:						
Pacific Northwest						1,100
Pacific Southwest						369
Cogeneration, etc. 4/						up to 274
DWR						300+
Load Management 5/						up to 1,083
Castaic						626
Other 6/						201
Total Additional Resources						up to 3,953
Potential Contingencies:						
High Forced Outages 7/						-1,518
Adverse Hydro						-1,120
Diablo Canyon 1 & 2 Out						-2,190
SONGS 3 Out						-1,100
Worst Case Total						-5,928
MW of Additional Resources Needed for 5% R.M. 8/						1,039
MW of Additional Resources Needed for 7% R.M. 8/						1,774

1. Burbank, Glendale, and Pasadena.
2. Non-coincident total; could be 880 MW less in average coincident conditions.
3. Does not include San Onofre Nuclear Generating Station 1 (436 MW) which is scheduled for maintenance during the summer of 1983.
4. Staff report, p. 74.
5. Staff report, pp. 56 & 61.
6. Palo Verde ownership by municipalities 71 MW
   Sierra Pacific Power Co. (PG&E) 50
   MWD Load Interruption 80
   201 MW
7. 1981 forced outages, less projected forced outages.
8. Under worst-case contingency conditions.

Table III-6

Assessment of Generation Resources
1984
(Megawatts)

	PG&E	SCE	LADWP	SDG&E	BGP 1/	Statewide
Peak Demand	16,154	14,264	4,461	2,138	674	37,691 2/
Base Case:						
Base Case Resources	20,607	18,012	6,289	2,937	869	48,714
Projected Forced Outages	1,527	1,600	723	141	0	3,991
RM-2 Reserve Margin (MW)	2,926	2,148	1,105	658	195	7,032
RM-2 Reserve Margin (%)	18.1	15.1	24.8	30.8	28.9	18.7
Potential Additional Resources:						
Pacific Northwest						1,100
Pacific Southwest						641
Cogeneration, etc. 3/						up to 488
DWR						300+
Load Management 4/						up to 1,321
Castaic						626
Other 5/						272
Total Additional Resources						up to 4,748
Potential Contingencies:						
High Forced Outages 6/						-1,518
Adverse Hydro						-1,120
Diablo Canyon Unit Out						-1,045
SONGS Unit Out						-1,100
Worst Case Total						-4,783
MW of Additional Resources Needed for 5% R.M. 7/						0
MW of Additional Resources Needed for 7% R.M. 7/						389

1. Burbank, Glendale, and Pasadena.
2. Non-coincident total; could be 880 MW less in average coincident conditions.
3. Staff report, p. 74.
4. Staff report, pp. 56 & 61.
5. Palo Verde ownership by municipalities 142 MW
   Sierra Pacific Power Co. (PG&E) 50
   MWD Load Interruption 80
   272 MW
6. 1981 forced outages, less projected forced outages.
7. Under worst-case contingency conditions.

Table III-7

Assessment of Generation Resources
1985
(Megawatts)

	PG&E	SCE	LADWP	SDG&E	BGP 1/	Statewide
Peak Demand	16,765	14,698	4,536	2,239	693	38,931 2/
Base Case:						
Base Case Resources	20,760	17,998	6,351	2,926	869	48,904
Projected Forced Outages	1,527	1,600	723	141	0	3,991
RM-2 Reserve Margin (MW)	2,468	1,700	1,092	546	176	5,982
RM-2 Reserve Margin (%)	14.7	11.6	24.1	24.4	25.4	15.4
Potential Additional Resources:						
Pacific Northwest						1,650
Pacific Southwest						422
Cogeneration, etc. 3/						up to 4627
DWR						300+
Load Management 4/						up to 1,549
Castaic						626
Other 5/						272
Total Additional Resources						up to 5,446
Potential Contingencies:						
High Forced Outages 6/						-1,518
Adverse Hydro						-1,120
Nuclear Capacity Out						-1,500
Worst Case Total						-4,138
MW of Additional Resources Needed for 5% R.M. 7/						103
MW of Additional Resources Needed for 7% R.M. 7/						881

1. Burbank, Glendale, and Pasadena.
2. Non-coincident total; could be 880 MW less in average coincident conditions.
3. Staff report, p. 74.
4. Staff report, pp. 56 & 61.
5. Palo Verde ownership by municipalities 142 MW
   Sierra Pacific Power Co. (PG&E) 50
   MWD Load Interruption 80
   272 MW
6. 1981 forced outages, less projected forced outages.
7. Under worst-case contingency conditions.

For 1982, a statewide RM-2 reserve margin of 5.8 percent is obtained if only the Base Case resources are considered. Over 2,700 MW of additional resources have been identified which could be utilized if needed. Since system conditions for this summer are fairly well known, the only contingency examined for 1982 was the occurrence of very high forced outage rates. This would reduce reserve margins by over 1,500 MW. About 1,200 MW of additional resources would be required under this situation to maintain a 5 percent statewide reserve margin. However, over twice this amount of additional sources has been identified which will likely be available this summer. Thus, electric reliability this summer should not be jeopardized.[10/]

Similar results are found for 1983 through 1985. While the statewide reserve margin based on utility resource plans could reach very low levels under severe contingency conditions, the potential purchases and other resources not included in these resource plans appear to be more than adequate to assure reliable levels of service.

10/ The conclusion that adequate supplies exist this summer contrasts with the more pessimistic view of the May 13, 1982 California Power Pool report. Importantly, that report does not consider supplies not in the utility resource plans. Due to different reporting procedures, it is difficult to pinpoint all the differences between this analysis and the CPP report. The CPP report does not include the loads and resources of Burbank, Glendale, and Pasadena, which accounts for almost half the difference between the 3.9 percent reserve margin found by CPP and the 5.8 percent reserve margin based on utility resource plans shown in Table III-4.

The worst case scenario analyzed presents an unlikely combination of contingencies occurring together in a given year. For each year of the study period, certain contingencies are more likely to happen than others. In 1983, for example, the most likely contingencies are the delays in Diablo Canyon 1 and 2 and SONGS 3. Based on 1982 hydro conditions, an adverse hydro year for 1983 is highly unlikely. The major contingencies for 1984 and 1985 are increased forced outages due to the addition of immature nuclear units, and an adverse hydro year. For these more likely contingencies, there appear to be ample resources both within and out of state to provide substantial capacity beyond that needed to meet projected peak demands.

It is always possible that unanticipated catastrophic changes could render even larger portions of the electric generation unavailable. For example, a major accident at a nuclear plant, whether in California or out-of-state, could result in a shutdown order and a licensing delay encompassing all nuclear plants. This would affect 1,200 MW of existing capacity and over 5,000 MW of new nuclear capacity owned by California utilities. Such far-reaching events would also have major impacts on the availability of out-of-state power purchases, and present analytical problems beyond the scope of this proceeding.

CHAPTER IV

FORCED OUTAGE AND MAINTENANCE OF UTILITY PLANTS

An addition of 7,500 MW of new generating capacity over the next four years will strengthen electric system reliability in California. At the same time, reserve margins and system reliability in general would be markedly improved if existing and new generating resources were kept available during peak periods. Adequate maintenance of existing resources is an area that deserves attention.

During the 1981 summer peak season, California utilities had a record amount of generating resources that were unavailable to meet peak load requirements. PG&E had 3,152 MW on forced outage at time of systems peak, representing about 32 percent of its thermal capacity. SCE had more than 2,000 MW or 16 percent of its thermal capacity on forced outage during the same period.

These high (and increasing) forced outage rates are attributable to several factors. These include (1) generic problems with design, manufacturing, and construction of plant components; (2) utility specifications in the procurement process that sometimes minimize plant cost at the expense of plant reliability; (3) problems with operating and maintenance procedures; (4) deteriorating fuel quality; (5) plant modifications to meet environmental requirements; (6) poor weather; (7) management and organization problems; (8) the lack of interchangeability of parts, (9) long lead-time for deliveries and undependable deliveries; (10) actual maintenance costs exceeding projected allowances under current forecasting methods; (11) small windows for maintenance during the off-peak season, and (12) potential operational problems such as turbine generator failure, steam generator tube failure, and thermal shock. These factors are discussed in detail in the staff report.

In addition to the factors cited above, immaturity of new large baseload facilities scheduled to come into service may significantly increase forced outages. These large new units may undergo a substantial period of "shakedown" testing and operation before they reach commercial operating levels. While utilities project lifetime capacity factors of approximately 65 percent for the four major nuclear units, they will likely operate at lower capacity levels during early operating years.

Another problem with the newer units is that they will cause more "lumpy" outage levels. Utilities will have to prepare for losses of 1000 MW at a time if large plants go off line. Maintenance expenses for complex new plants during this period of immaturity could divert funds away from normal maintenance for the older plants. Thus, it becomes critical that utilities carefully and realistically assess their maintenance costs during this transition period.

In response to the high forced outage rates experienced in recent years, all major California utilities have implemented improved preventive maintenance programs. Each utility's program appears adequate to meet the objectives for which it was designed when it is fully implemented.

An improved maintenance program will not necessarily result in an increase in the yearly plant availability or capacity factor because in order to perform maintenance in most (if not all) cases the unit will have to be taken out of service. Under the program, a larger portion of the outage hours will be scheduled and thus will occur at a predetermined time. With more scheduled maintenance, forced outages theoretically should be reduced. How effective this strategy will be in reducing the forced outages during the maximum peak demand is difficult to predict.

An issue which generated controversy during the proceeding concerns utility scheduling of preventive maintenance during peak periods. It appears that only SCE currently schedules routine maintenance during peak periods. SCE argued that it was necessary to do so for a variety of reasons, ranging from productivity of work crews to conflicts in scheduling a large amount of maintenance during the off-peak season. Notably, in later California Power Pool reports, SCE does not show any scheduled maintenance during the 1982 summer peak. It therefore appears that in actual practice, SCE has deferred scheduled maintenance beyond the peak demand period this year.

Forecasting Maintenance Expenses

It became evident from the workshops and hearings that some utilities have consistently underestimated the level of maintenance expenditures required. Approved funding levels based on utilities' estimates have fallen substantially below actual expenditure levels.

Forecasting a reasonable cost of maintenance in future test years is difficult. Future maintenance expenses have generally been forecasted by both the CPUC staff and the utilities based on trend analyses using a detailed evaluation of recorded and forecasted maintenance expenditures. Briefly a trend analysis:

(1) Eliminates unusual expenses from historical costs;

(2) Normalizes recorded expenses to a base year;

(3) Applies a regression analysis to develop future maintenance expense estimates; and

(4) Escalates these expenses by appropriate inflation factors.

The trended estimates are then supplemented with specific adjustments to incorporate unusual expenses forecasted to occur in future test years. Because actual maintenance costs have consistently exceeded test year allowances for maintenance, the current methods of forecasting maintenance and reliability expense may need revision.

In this proceeding, several alternative methods were identified which could be used for projecting utility maintenance expenses including (1) indexing, (2) balancing accounts, (3) cost-benefit analysis, (4) improved trending, and (5) contingency funds. However, the general consensus was that this complex topic would require more thorough examination before changes in the current methods could be recommended. Given the importance of an adequate maintenance program, this topic should receive further consideration. The most appropriate forum would be in each utility's general rate case before the CPUC.

Performance Incentives for Increasing Power Plant Reliability

Power plant performance can be improved by developing incentives which induce the utilities to operate and maintain their plant more efficiently. Improvement in performance equates to higher availability of supply and thus, greater reliability of service.

The CPUC has already implemented an incentive program for the operation of SCE's baseload coal plants. Under this program, the company is forced to bear a greater portion of the operating risks of these plants and thus is given an incentive to operate these plants efficiently. The CPUC is currently considering performance incentives for the SONGS 2 facility. A similar program should be considered for the new Diablo Canyon and SONGS 3 facilities when they come on line.

During the course of this proceeding, several utilities urged that should an incentive program be adopted, it be based on each utility's average system performance rather than performance by individual unit. This approach is rejected because it can either overstate or understate efficiency by combining poorly operating units with better performing ones. The CPUC staff has made an extensive analysis of programs to improve power plant performance existing in other states. This analysis is detailed in Appendix E.1 of the staff report.

This report recommends continuation at this time of the unit-by-unit approach already adopted by the CPUC. While a significant amount of information regarding potential changes in this approach was obtained in this proceeding, it was inadequate to support adoption of a new approach. Further consideration of this topic should be given in future rate cases, or in rate base offset proceedings for new facilities.

CHAPTER V

RELIABILITY NEEDS OF END-USERS

The previous chapters in this report have established and relied on systemwide criteria in concluding that reliability for the 1982-1985 period is adequate. Another perspective in evaluating reliability is from the perception of the end user, who may demand a higher level of reliability or accept a lower level based on other criteria. The CPUC and the CEC began this proceeding, at least in part, because of concern expressed by commercial and industrial customers over possible interruption of service. Many companies were represented in the proceeding, either directly or through associations.

For certain customers, disruption of any kind could lead to serious economic, health, or safety concerns. Most hospitals, for example, have emergency electric generators. Other customers have paid for specially dedicated dual service lines to tap power from a wider service area and reduce the possibilities of disruption. However, other customers may be willing to accept a lower level of reliability[1/] in return for lower rates.

1/ Parties generally accepted the idea that the customer who demands a higher level of reliability than systemwide criteria indicate should pay for it. Conversely, the customers who accepts less reliable service should pay less for it. This concept was only briefly explored in this proceeding and should be analyzed more fully in future proceedings.

Utilities must make a sufficient investment in the electric system to ensure resilience in the face of failures at any given point. However, there is a level of redundancy beyond which it is no longer economic, or even feasible, to expend ratepayer money for the benefit of a small class of customers. Finding this balance is difficult.

As stated earlier in this report, the utilities' general planning criteria provide for higher levels of reliability for larger customers, in terms of redundancy in transmission and distribution systems serving those loads. This appeared to be based on broad, general principles, rather than detailed planning criteria. Utilities often may serve more than one class of customers on a single distribution system. While they may make subjective judgments as to the needs of each customer class, there seems to be a paucity of data on this point.

As previously indicated in this report, in the last five years approximately 90 percent of customer interruptions were caused by distribution line outages, and the remainder were caused by transmission line outages. The data collected by utilities quantifies the frequency and duration of failures on circuits which connect various classes of customers. However, it does not detail which particular classes of customers experienced transmission and distribution failures, or how often and how long they experienced them. This report therefore recommends that the utilities collect data to determine which classes of customer are adversely affected by transmission and distribution outages, and the frequency and duration of the outages for each class. From this data, further studies can be undertaken to determine whether reliability for a particular customer class should be enhanced, and how that may be achieved.

As indicated by the data, power outages historically have been caused by transmission and distribution failures and not generating failure. While a great deal of attention by the utilities and certain customers has been focused on the adequacy of generation, equal attention should be given to the reliability of the transmission and distribution system.[2] Reliability issues encompass a broad range of subjects covering all aspects of the system, and should be analyzed completely.

2/ Robert Burt of the California Manufacturers Association summed up this view well:

> "...there seems to be a passionate utility interest in generation reliability indicated by exhaustive study, reams of data, substantial dollar investment. There seems to be little utility interest in T&D reliability. There seems to be little study, little data available on it, and any expenditure to improve it tends to be incidental to other utility action." (Transcript, p. 383).

The information in this study should give confidence to end users in California that overall reliability of service is high. The combination of adequate generating plants, interconnections with other utilities in-state and out-of-state, and mild climates contribute to high levels of dependable electric service for customers.

CONCLUSION

This study has analyzed electric utility system reliability during the period 1982 to 1985 and concludes that under all reasonably foreseeable contingencies, adequate capacity is anticipated without undertaking extraordinary actions. In most of the contingency situations, the utilities' current resource plans are adequate to maintain minimum reserve margins. Information presented in this proceeding indicates that substantial amounts of purchased power within California and from out of state will be available to supplement supply. While these increases are not always included in current studies assessing supply adequacy, they should be in order to realistically assess reliability. These purchases, together with capacity additions from small power generation, conservation, and load management will more than adequately ensure sufficient capacity for the next four years. It should be emphasized that systemwide reliability is not measured solely by the adequacy of the generating system. The adequacy of transmission and distribution capacity is another very important factor in evaluating reliability.

The study has served several useful purposes. In assessing intermediate term reliability, a number of issues arising in other proceedings have been brought together and placed into the context of systemwide electric reliability. The interrelationships of resource planning and reserve margins, maintenance funding and power plant performance, and available resources and transmission capacity have been analyzed as a whole in assessing statewide reliability.

The study has also identified areas which deserve further analysis. Significantly, there is a need to develop sophisticated methods for analyzing reliability of transmission and distribution systems. This study focused primarily on the adequacy of the generation system because of the dearth of comparable information on the transmission and distribution system.

Moreover, there is a need to develop criteria which indicate how a utility should invest its dollars to improve reliability. Other areas which deserve further study include the adequacy of current maintenance funding methodologies; the continuation of unit-by-unit incentives to improve baseload power plant performance; and the impact of transmission and distribution failures on specific classes of customers. In addition, this report recommends further analysis of expanding customers' options for levels of reliability of electric service.

The usefulness of a four-year horizon has been clearly demonstrated in this proceeding. Not only does a four-year study focus attention on utility planning for adequate capacity, it also allows utilities sufficient opportunity to take appropriate action, if necessary, to supplement capacity. It is therefore recommended that assessment of electric system reliability be continuously updated on an ongoing yearly basis.

APPENDIX A

Utility Generation Resources

Table A-1

Utility Resources
At Time of Peak Demand
Average Hydro
1982

(Megawatts)

Fuel Type	PG&E	SCE	LADWP	SDG&E 1/	BURBANK	GLENDALE	PASADENA	STATEWIDE
Oil/Gas	7193	8939	3141	1943	148	117	206	21687
Combined Cycle		1012				98		1110
Combustion Turbine	403	587	76	273	74	53	52	1518
Coal		1631	1076					2707
Nuclear	0	0		0				0
Hydroelectric	6263	934	1499 2/					8696
Geothermal	908							908
Cogeneration	235	47		63				345
Wind	1	3						4
Solar								
Purchases	1413	1985	423	243	45	68	56	4233
TOTAL	16416	15138	6215	2522	267	336	314	41208

1/ Source of data: General Order 131-B, October 1981.
2/ Does not include 626 MW of Castaic pumped storage plant, which would be available to other utilities.

Table A-2

Utility Resources
At Time of Peak Demand
Average Hydro
1983

(Megawatts)

Fuel Type	PG&E	SCE	LADWP	SDG&E	BURBANK	GLENDALE	PASADENA	STATEWIDE
Oil/Gas	7193	8939	3141	1743	148	117	206	21487
Combined Cycle		1012				98		1110
Combustion Turbine	403	587	76	273	74	53	52	1518
Coal		1624	1006					2630
Nuclear 1/	3065	1962	116	440	3	3	2	5591
Hydroelectric	7030	944	1503 2/					9477
Geothermal	1234	41						1275
Cogeneration	262	72	50	63				447
Wind	1	9						10
Solar								
Purchases	1000	2048	423	294	45	68	56	3934
TOTAL	20188	17238	6315	2813	270	339	316	47479

1/ Includes 15 MW SCPPA purchase by SCE resale customers; does not include SONGS 1 which is scheduled to be out for maintenance.

2/ Does not include 626 MW of Castaic pumped storage plant.

Table A-3

Utility Resources
At Time of Peak Demand
Average Hydro
1984

(Megawatts)

Fuel Type	PG&E	SCE	LADWP	SDG&E	BURBANK	GLENDALE	PASADENA	STATEWIDE
Oil/Gas	7193	8939	3141	1643	128	117	161	21322
Combined Cycle		1012				98		1110
Combustion Turbine	403	587	76	273	74	53	52	1518
Coal		1624	936					2560
Nuclear 1/	3065	2513	232	527	6	6	5	6354
Hydroelectric	7152	954	1504 2/					9610
Geothermal	1349	111						1460
Cogeneration	444	72	50	63				629
Wind	1	16						17
Solar								
Purchases	1000	2184	350	431	45	68	56	4134
TOTAL	20607	18012	6289	2937	253	342	274	48714

1/ Includes 30 MW SCPPA purchase by SCE resale customers.
2/ Does not include 626 MW of Castaic pumped storage plant.

Table A-4

Utility Resources
At Time of Peak Demand
Average Hydro
1985

(Megawatts)

Fuel Type	PG&E	SCE	LADWP	SDG&E	BURBANK	GLENDALE	PASADENA	STATEWIDE
Oil/Gas	7193	8579	3141	1443	128	117	161	20762
Combined Cycle		1012				98		1110
Combustion Turbine	403	587	76	273	74	53	52	1518
Coal		1612	894					2506
Nuclear 1/	3065	2513	232	527	6	6	5	6354
Hydroelectric	7193	984	1528 2/					9695
Geothermal	1459	111						1570
Cogeneration	444	72	130	63				709
Wind	3	28						31
Solar		10						10
Purchases	1000	2500	350	620	45	68	56	4639
TOTAL	20760	17998	6351	2926	253	342	274	48904

1/ Includes 30 MW SCPPA purchase by SCE resale customers.
2/ Does not include 626 MW of Castaic pumped storage plant.

ALJ/km/vdl

H5/6.2

Decision 82 06 020 JUN 2 - 1982

ORIGINAL

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

An Investigation before the Public Utilities Commission and the California Energy Commission into electric utility system reliability.	OII 89 (Filed April 21, 1981)

Daniel G. Lubbock and Daniel E. Gibson, Attorneys at Law, for Pacific Gas and Electric Company; John R. Bury, David N. Barry, Frank J. Cooley, James M. Lehrer, and Richard K. Durant, Attorneys at Law, for Southern California Edison Company; John R. Asmus, Attorney at Law, for San Diego Gas & Electric Company; David L. Nye, Attorney at Law, for Los Angeles Department of Water and Power; and Dean H. Park, for Sacramento Municipal Utilities District, respondents.

Robert W. Schempp, for the Metropolitan Water District of Southern California; Michael Paparian, for Sierra Club; Robert Burt, for California Manufacturers Association; and Rourke & Woodruff, by Everett C. Ross and Lydia S. Levin, Attorneys at Law, for the Cities of Anaheim, Riverside, and Colton; interested parties.

Gary Fay, Attorney at Law, and Viju Patel, for the California Energy Commission staff.

Vincent MacKenzie, Attorney at Law, and William Stalder, for the Public Utilities Commission staff.

OPINION

In Order Instituting Investigation 89 (OII 89) and CEC Docket No. 81-ESR-1, the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) instituted a joint investigation to assess the adequacy and reliability of the State's electric system for the period 1982 through 1985. All electric utilities within the jurisdiction of the CPUC were made respondents. By Decision (D.) 93323 dated July 22, 1981, Pacific Power and Light Company, Sierra Pacific Power Company, and CP National Corporation were deleted as respondents.

During 1981 the staffs of the two Commissions conducted five workshops to study questions raised about uncertain schedules of new generating capacity due to come on line, the load carrying capability of new generating capacity during initial years of operation, high forced outage rates at some existing plants, and the adequacy of the transmission and distribution system. In addition to the staffs, the utilities, members of the public, and representatives of user groups participated in the workshops.

In November 1981, a draft report prepared by the staffs of the CPUC and CEC was issued and served on all parties. The report, entitled "Joint CEC/CPUC Staff Draft: Staff Response to Committee Order for Hearings on Assessment of Adequacy of Electric Utility Systems 1982-1985" was intended to provide the focus for discussion and for definition of issues in subsequent hearings.

To determine the level of participation and identify the issues, a prehearing conference was held December 4, 1981, in Sacramento before Russell L. Schweickart, Chairman of the CEC, Commissioner Victor Calvo of the CPUC, and Administrative Law Judge (ALJ) Burt E. Banks of the CPUC. At the prehearing conference it was determined that Phase I of the proceeding would be quasi-legislative with hearings to begin in January 1982.[1] A Prehearing Conference Report and Order dated December 14, 1981, were forwarded to all respondents and interested parties who were requested to address various topics contained in the joint staff draft report at the quasi-legislative hearing.

Hearings were held January 11, 12, and 14, 1982 in San Francisco. Participating were Southern California Edison, Pacific Gas and Electric Company, San Diego Gas and Electric Company, Los Angeles Department of Water and Power, Sacramento Municipal Utilities District, California Department of Water Resources, Santa Clara Manufacturing Group, Sierra Club, the Cities of Anaheim, Riverside, and Colton, and the CPUC and CEC staffs.

On January 19, 1982, a hearing report was issued giving the parties until February 8, 1982 to comment on the material presented during the Phase I hearings.

Based on all the studies, data, and presentations offered by the CPUC and CEC staffs, electric utilities, and interested parties, the Committee of Victor Calvo and Russell L. Schweickart prepared a report entitled "Joint Investigation into the Reliability of California's Electric Power System." (Hereafter, the "Committee Report.") We hereby adopt the Committee Report, attached as Appendix A.

The Committee Report concludes that, under all reasonably foreseeable contingencies during the 1982 to 1985 period, adequate capacity is anticipated to meet projected peak demand without undertaking extraordinary action. In reaching this conclusion, the report separately discusses the adequacy of the transmission and distribution system, and the generation system.

1/ If further hearings proved necessary, these would be quasi-judicial and designated as Phase II.

The Committee Report begins by defining reliability criteria to assess the adequacy of the transmission and distribution system and the generation system. Although most of the discussion in this proceeding focused on the reliability of the generation system as the most important factor affecting overall system reliability, the report emphasizes that a comprehensive analysis of reliability of electric service must evaluate the entire system. It was determined that about 90 percent of all electric outages experienced in California in the past have been due to distribution-related problems, with all the remaining outages due to transmission system failures.

The lack of focus on transmission and distribution reliability was largely due to the absence of sophisticated measures of assessing such reliability. The Committee Report recommends that improved measures be developed for assessing, first, reliability of the transmission and distribution system and, second, the effects of the transmission and distribution system on overall system reliability. Based on the available information, the transmission and distribution system appears to be adequate both in terms of having sufficient capacity to deliver power to augment supply, and in terms of withstanding single-contingency transmission line outages without causing electric service interruptions. The transmission and distribution system in California appears to be among the best in the nation.

One of the major issues in this proceeding centered on the appropriate reserve margin criteria to use in assessing the adequacy of the generation system. The Committee Report specifically identifies the methods used to define reserve margin criteria in order to prevent any confusion regarding the basis of the report's conclusions. This report uses a short-range reserve margin based on generating capacity after reductions for units on scheduled maintenance and the amount of generating capacity expected to be forced out of service due to equipment failures. Importantly, the report uses a statewide reserve margin criterion as the relevant indicator of generation reliability. Because the California electric utilities are interconnected with each other and with utilities out of state, a capacity-deficient utility has the ability to purchase power from a capacity-rich utility when needed. Thus, shortfalls in reserve within a particular utility generally are not a matter of overriding concern. The critical issue is whether, on a statewide basis, the reserve margin falls below minimum targets. Furthermore, to obtain meaningful statewide reserve margins, additional resources not ordinarily included in utilities' resource plans must be considered.

From the peak demand forecasts and resource plans submitted by the utilities, a base case scenario of most likely occurrences during the 1982 to 1985 period was defined. The base case presented in the Committee Report was modified from the one in the staff report to include more recent information about current conditions as the 1982 summer approaches. The modifications present a base case scenario that is somewhat conservative, or less optimistic, than staff originally assumed.

Utility witnesses testified that the utilities routinely rely on substantial amounts of short-term purchases of power, both within and out of state, to provide additional capacity when needed; that they are confident of the availability of sufficient quantities of such power; and that this practice is more economic for the ratepayer than committing to long-term contracts. A Southern California Edison (SCE) witness testified that SCE has recently refused offers by other utilities to sell firm capacity, preferring to wait until the power is needed.

Based on the utility testimony and other information presented in this proceeding, the Committee Report concludes that this practice of reliance on short-term purchases is reasonable. Since these purchases are not covered by long-term contracts, they do not appear in utilities' resource plans and reserve margin calculations. Studies which assess adequacy of supply based solely on utility resource plans without considering the availability of short-term purchased power significantly understate the adequacy of supply.

Other sources identified in the Committee Report which could yield additional supplies include cogeneration and small power production where investment or contract commitments have not yet been made, and load management beyond that included in utility resource plans. While some of these sources are less certain than others, they are important because, in the aggregate, they provide assurance that additional supplies will be available.

Several adverse contingencies which could potentially occur in the four year period were also examined. These contingencies include delays in scheduled plant additions, adverse hydro conditions, and higher than projected forced outage rates for both existing and new plants.

After analyzing the base case scenario, the availability of additional resources not in utilities' resource plans, and potential contingencies which may occur during the four year period, the Committee Report concludes that even under worst case conditions, sufficient resources should be available to California utilities to adequately meet projected demand. The report further concludes that while 1982 is the critical year in which contingencies could have the most adverse effect on system reliability, sufficient resources are available to meet demand without taking extraordinary action.

Two contingencies are singled out for detailed discussion in the Committee Report: high forced outage rates at existing plants and lower than expected availability of new immature plants. The utilities indicated that maintenance practices for existing plants have improved. However, all parties agreed that since actual maintenance expenses have consistently exceeded projected expenses, maintenance practices and the methodologies used to project maintenance expenses should be re-examined. The Committee Report makes such a recommendation. SCE took exception to staff's recommendations that scheduled maintenance be deferred past the summer peak. However, in more recent California Power Pool reports, SCE does not show any maintenance scheduled during the summer peak of 1982.

Continuance of power plant performance incentives on a unit-specific basis to increase reliability is recommended by the Committee Report, notwithstanding certain utilities' objections. Insufficient information supporting other methods was presented to lead to a different recommendation.

The final chapter of the report discusses the reliability needs of end-users. The report adopts the suggestion by the California Manufacturers Association representative that since transmission and distribution outages account for all outages that end-users have experienced, more analysis of transmission and distribution reliability should be made. The report also recommends that utilities explore methods for expanding customer options for different levels of reliability. KL

The report concludes with recommendations to examine several issues in further actions.

Findings of Fact

1. The purpose of the joint investigation initiated by the California Energy Commission and this Commission was to assess the adequacy and reliability of the State's electric system for the period 1982 through 1985.

2. Factors most likely to reduce electric system reliability in the 1982 through 1985 period are delays in scheduled operation for major generation projects, high forced outage rates of new immature units and greater than projected forced outages of existing thermal capacity.

3. A comprehensive study of electric system reliability assesses the adequacy of both the generation system and the transmission and distribution system.

4. Most studies of electric system reliability focus on the ability of the generation system, rather than the transmission and distribution system, to provide adequate service, partly because of the absence of sophisticated measures to assess the latter.

5. In evaluating the adequacy of the generation system, reserve margin criteria are often used.

6. Short-range reserve margins as defined in the Committee Report are appropriate for evaluating generation reliability in the 1982 to 1985 period.

7. Statewide rather than individual utility reserve margin criteria are the relevant criteria for assessing generation system reliability.

8. To obtain meaningful statewide reserve margins, resources contained within utilities' resource plans and additional resources not ordinarily included in resource plans must be considered.

9. Substantial amounts of out of state power are routinely relied upon by California utilities to provide capacity when needed during peak demand periods.

10. Other sources which, in the aggregate, could yield additional supplies beyond that included in utilities' resource plans include cogeneration, small power production, and load management.

11. Sufficient resources should be available to California utilities to adequately meet projected demand even under worst case conditions.

12. Transmission and distribution system outages account for all outages that end-users have experienced.

13. Forced outage rates of existing plant for some utilities have been increasing in recent years.

Conclusions of Law

1. Under all reasonably foreseeable contingencies during the 1982 to 1985 period, adequate capacity is anticipated to meet projected peak demand without undertaking extraordinary action.

2. Based on available information, California's transmission and distribution system appears adequate both in terms of having sufficient capacity to deliver power to augment supply, and in terms of withstanding single-contingency transmission line outages without causing electric service interruption.

3. No further hearings in this proceeding are necessary.

O R D E R

IT IS ORDERED that the Committee Report issued this date attached as Appendix A is adopted.

This order is effective today.

Dated JUN 2 1982, at San Francisco, California.

JOHN E. BRYSON
President
RICHARD D. GRAVELLE
LEONARD M. GRIMES, JR.
VICTOR CALVO
PRISCILLA C. GREW
Commissioners

(APPENDIX A)

COMMITTEE REPORT