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Effects of the Drought on California Electricity Supply and Demand

Peter Benenson, Barbara Greene, Edward Kahn, Betsy Krieg, Ike Lasater, Ron Ritschard, Henry Ruderman, Jayant Sathaye, Richard Sextro, William Siri and Lauran Vincent

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Lawrence Berkeley Laboratory University of California/Berkeley

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EFFECTS OF THE DROUGHT ON CALIFORNIA ELECTRICITY SUPPLY AND DEMAND

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Energy Research and Development Administration.

Table of Contents

I. INTRODUCTION 1
Acknowledgments 3
II. SUMMARY
Electricity Demand 4
Electricity Supply 9
Measures to Alleviate Adverse Impacts 12
III. ELECTRICITY DEMAND 15
Demand for Electricity and Power 19
Peak Demand 19
ELECTRICITY REQUIREMENTS FOR AGRICULTURE WATER DEMAND
Introduction 29
Water Supply and Demand in 1977 29
Unit Energy Use for Ground and Surface Water 32
Unit Water Use by Crop 33
Unit Energy Use by Crop 33
Estimated Crop Acreage in the Central Valley 35
Energy Demand for Agricultural Pumping in the Central Valley 38
Potential Energy Conservation Strategies in Agriculture During 1977 43
ENERGY REQUIREMENTS FOR RESIDENTIAL AND INDUSTRIAL WATER USE
Objectives 45
Description of Approach 45
Residenital 46
Industrial 49
Results 53
Conclusions 58
IV. ELECTRICITY SUPPLY 61
Hydroelectric Energy Supply 64
Thermal-Electric Energy Supply 68
LOSS OF LOAD PROBABILITY FOR PG&E, SUMMER 1977 73
ENVIRONMENTAL EFFECTS 87
REFERENCES 91

Table of Contents (Continued)

Appendix A - Summaries of May 1977 Responses by the Four Major Utilities to the California Energy Resources Conservation and Development Commission 93

Appendix B - California Reservoir Storage Projections, June through December 1977 107

List of Figures

Figure 1 Monthly electricity supply and sales for California 20

Figure 2 Hydrologic Basin Planning Areas 31

Figure 3 Monthly load and resources for PG&E with a comparison to previous years 62

Figure 4 Capacity resources available for California by month, summer 1977 65

Figure 5 Risk at peak as function of load for PG&E with 600 MWe support 84

List of Tables

Table A Comparison of Present Water Conditions to Average Water Year Conditions 5
Table 1 California Electricity Sales 16
Table 2 Electricity Demand by Major Utility Service Area . . . 18
Table 3 Projected Peak Demand for 1977 22
Table 4 Historical Peak Demand by Utility Service Area 23
Table 5 Weather-Sensitive Coefficients and Maximum Temperatures 25
Table 6 Statewide Energy Conservation Potential 26
Table 7 Estimated Agricultural Water Supply and Demand in the Central Valley - 1977 30
Table 8 Estimated Groundwater Well Depth in the Central Valley 30
Table 9 Energy Use Per Acre-Foot in the Central Valley 30
Table 10 Water Requirements Per Acre in the Central Valley . . . 34
Table 11 Energy Use Per Acre for Crops in the Central Valley . . 36
Table 12 Estimated Major Crop Acreage in the Central Valley . . 37
Table 13 Percentage of Acreage in Surface and Sprinkler Systems in the Central Valley 39
Table 14 Total Energy Use for Selected Crops in the Central Valley by Water Source and Irrigation Method 40
Table 15 Total Estimated Energy Requirements for Agricultural Irrigation in the Central Valley - 1977 41
Table 16 Residential Interior Water Use 47
Table 17 Energy Requirements for Water Use 48
Table 18 Residential Water Conservation by End-Use Category . . 50
Table 19 Water Conservation Measures Applicable to Industry . . 52
Table 20 Water and Associated Energy Consumption by HSA 54
Table 21 Energy Requirements for Total Water Delivery During 1977 55
Table 22 Residential Water and Associated Energy Consumption by End-Use 56
Table 23 Industrial Water and Associated Energy Use by Sector 57

List of Tables (Continued)

Table 24 Hydroelectric Supply in California 63

Table 25 Fuel Oil and Natural Gas Use by Electric Utilities . . 71

Table 26 System Parameters for Two Alternative Cases 76

Table 27 Parameters Used in Loss-of-Load Probability Calculations 79

Table 28 Results of Loss-of-Load Probability Calculations . . . 81

Table 29 Monthly Emissions in South Coast and South Central Coast Air Basins 88

Glossary of Abbreviations

While we have endeavored to spell out at least once the names of concepts and institutions referred to in this report we rely heavily on the use of initials as abbreviations for these longer names. We therefore provide this guide to our shorthand notations.

AF	-	Acre-foot - volume equal to an area of one acre filled to a depth of one foot
BPA	-	Bonneville Power Administration
(C)ARB	-	California Air Resources Board
(C)DWR	-	California Department of Water Resources
CEP	-	Canadian Entitlement Power
CERCDC	-	California Energy Resources Conservation and Development Commission
(C)PUC	-	California Public Utilities Commission
CVP	-	Central Valley Project (USBR)
EBMUD	-	East Bay Municipal Utility District
ERDA	-	Energy Research and Development Administration
FEA	-	Federal Energy Administration
GWe	-	10^9 watts of electrical generating capacity
GWh	-	10^9 watt-hours or 10^6 kilowatt-hours (kwh)
HBPA	-	Hydrological Basin Planning Area
HSA	-	Hydrological Study Area
LADWP	-	Los Angeles Department of Water and Power
LOLP	-	Loss-of-load Probability
MWe	-	10^6 watts of electrical generating capacity
MMWD	-	Marin Municipal Water District
PGE	-	Portland General Electric
PG&E	-	Pacific Gas & Electric Company
SCE	-	Southern California Edison Company
SDG&E	-	San Diego Gas & Electric Company
SWP	-	State Water Project (CDWR)
Therm	-	10^5 BTU
USBR	-	Unites States Bureau of Reclamation

EFFECTS OF THE DROUGHT ON CALIFORNIA ELECTRICITY SUPPLY AND DEMAND

I. INTRODUCTION

Much of the western United States lies in the grip of a severe drought with total precipitation for the past year ranging from 30 to 50 percent of normal in the affected states. In California, where the drought has now passed its second year, the 1977 weather year (July 1, 1976 - June 30, 1977) was the driest on record. In May 1977, water storage in California reservoirs, which supply a significant fraction of California's electricity demand, stood at only 50 percent of normal for the season. Hydroelectric generation along with consumptive use of water is consequently experiencing severe curtailment and could affect the balance in electricity supply and demand within California.

How will the drought affect the consumption of electricity in California? With hydroelectric reserves reduced by half, can alternative generating capacity and energy sources meet the demand this summer and early fall, and at what cost and level of reliability? What, if any measures have been or could on short notice be implemented to ensure reliable service, particularly during the summer peak loads? What are the probable consequences of these measures?

These questions and some of their implications have been examined in this study conducted by the Lawrence Berkeley Laboratory (LBL) in cooperation with the San Francisco Operations Office of the Energy Research and Development Administration (ERDA) and Region IX of the Federal Energy Administration (FEA). The purposes of the study were to:

- assess the impacts of the drought on California electricity supply and demand,
- evaluate remedial measures and
- develop methodology for such assessments

This report presents a preliminary analysis focusing on the near-term impacts and only those remedial measures that could be put into effect with little or no lead time. A summary of the results of the study is presented in Section II along with actions that would aid in alleviating

both potential imbalances in electricity supply and demand associated with the drought and energy-related impacts. Some of the measures related to supply have already been instituted by the California electric utility industry; conservation measures to reduce electricity demand could be put into effect by consumers at slight inconvenience and with some gain in economic and environmental benefits as well as better assurance of reliable service.

The major end uses of electricity—lighting, air conditioning, appliances, and industrial machinery—appear little affected directly by the water shortage. Those demands affected directly by the drought are associated largely with water, such as supply (pumping), treatment and heating. To assess these impacts a procedure was developed (Section III) to determine the effect on electricity demand of changes in water supply and use in the major sectors by geographic region of the state. The method involves detailed analysis of electricity requirements for irrigated agriculture and for residential and industrial water use.

The capacity of the four major electric utility companies to meet anticipated summer peak loads and total electricity demands in their service areas is affected unevenly by the drought. In a normal water year, hydroelectric generation supplies nearly a quarter of the state's electricity, but three-fourths of it is produced and consumed in the Pacific Gas & Electric Company's (PG&E) service area. With hydroelectricity severely curtailed by depleted water storage, PG&E will need support from the southern California utilities whose ample reserves in thermal-electric capacity remain unaffected by the drought.

These electricity supply issues are discussed in Section IV, including an assessment of the present hydro- and thermal-electric generating resources available for the summer. An analysis of the reliability of electrical energy supply has been done for the resources expected to be utilized, using an analytical method for estimating "loss-of-load probability." We also discuss the possibility of power pooling among California utilities, and the resultant effects of increased generation in southern California on oil and gas use and power plant emissions.

While power pooling enables PG&E to meet projected demands for both power and energy with acceptable reliability, it is not without added cost

to the consumer and increased air pollution in southern California air basins. In this preliminary report only the gross additional cost and increased power plant emissions were estimated, based on the quantity of oil consumed to compensate for the reduction in hydroelectricity.

Although the impacts of the drought on electricity supply thus far are moderate and appear manageable with little disruption, a third consecutive year of the drought could create potentially serious consequences which need to be examined with care. Effective remedial actions may require institutional changes, economic adjustments and capital expenditures that will have long lead times. They should be clearly characterized and initiated long in advance of the potential need.

Acknowledgments

We would like to thank all the individuals and organizations who provided us with data and information and insight into the various aspects of the relationship between California electricity and water supply and demand. In particular we would like to thank the following:

Martin Domagala and Dennis Wong of the San Francisco Operations Office of the Energy Research and Development Administration and Gene Standley of the Region IX Office of the Federal Energy Administration, who helped with various administrative and technical facets of this study; Bob Ham and his staff of the Emergency Planning Office of the California Energy Resources Conservation and Development Commission, who helped supply utility data and whose advice was invaluable; staff members of the Pacific Gas & Electric Company, the Southern California Edison Company; the California Air Resources Board; the California Public Utilities Commission, the California Department of Water Resources; the United States Bureau of Reclamation; and local water agencies throughout the state.

II. SUMMARY

At the end of the driest weather year on record (see Table A), California faces water shortages whose impacts will be felt with progressive severity through the summer and fall of 1977. Electric power is not entirely exempt from these impacts and could, if severely affected, compound the direct distresses of the drought. Each of the major California electric utility companies has forecasted the short-term effects on electricity supply and demand in its service area. The study reported here undertook an independent analysis to provide a statewide assessment of impacts and remedial actions and to develop additional analytical tools and data for these purposes. The study examined various aspects of the drought as it relates to electricity supply and demand, reliability of supply to meet summer peak loads, the efficacy of conservation measures, and probable increases in power plant emissions and cost of generating electricity.

The results of the study, based in part on the 1977 electricity supply and demand projections submitted by the four utilities to the California Energy Resources Conservation and Development Commission (CERCDC), support the utilities' conclusions that the three southern California utilities have sufficient reserve capacity and fuel to meet their own needs and to assist PG&E in meeting its load demand with little loss of reliability. However, to achieve this the utilities in their submissions have had to assume: 1) full coordination among the utilities; and 2) no air pollution limitations on electricity generation in the South Coast Air Basin.

Electricity Demand

The drought will not have a major direct impact on statewide total consumption of electricity although electricity requirements for water supply and use in agricultural, residential, and industrial sectors will be affected. Our estimates indicate that the expected increase in consumption for agricultural groundwater pumping will partially offset the decrease in water-related electricity demand in the residential and industrial sectors due to their reduced water consumption.

Peak demands determine the generating capacity for which utilities must plan and the risk of power outage if this capacity is unavailable.

Table A

Comparison of Present Water Conditions[a] to Average Water Year Conditions

Hydrologic Area	Annual Runoff		Reservoir Storage - May 1	
	Average Year[b] (10^6 acre-ft)	Present & Forecast[c] (%)	Average Year[a] (10^6 acre-ft)	Present, 1977 (%)
North Coastal	27.2	20	2.55	50
San Francisco Bay	3.0	20	0.52	60
Central Coastal	2.5	20	0.73	60
South Coastal	1.2	25	1.23	75
Sacramento Valley	22.4	25	13.56	45
San Joaquin Valley	11.2	15	6.69	55
Lahontan	3.1	20	0.28	60
Colorado Desert	0.2	--	--	--
Statewide	70.8	20	25.56	50

[a] Source: California Department of Water Resources, "Water Conditions in California," Bulletin 120-77, Report 4, May 1, 1977.

[b] Source: California Department of Water Resources, "The California Water Plan: Outlook in 1974," Bulletin 160-74, November 1974.

[c] Actual data from October 1, 1976 to May 1, 1977, plus forecast by DWR of runoff for June through September.

While the drought is not expected to affect peak loads significantly, it has narrowed the supply margin because of the loss in hydroelectric reserves; hence, reliability of service is made more sensitive to uncertainties in peak demands. During the past four years, statewide electricity demand has peaked during the summer months. With the rapidly expanding use of airconditioning, peak loads are becoming increasingly temperature-sensitive. Variations from projected summer temperatures could lead to uncertainties in the utilities' estimated peak demands amounting to as much as four percent statewide.

Energy conservation programs would enable the utilities to meet these loads with larger reserve margins. Numerous recommendations have been made by the CPUC, some of which can easily be implemented this summer. Among the more effective means for better management of energy consumption are adjusting thermostats, better maintenance of appliances and buildings, and reduction of lighting in offices and other commercial buildings. These measures alone could save as much as 300 million kwh per month, assuming they could be implemented in 25 percent of the commercial sector.

Many loads, especially in the residential and industrial sectors, can be deferred to off-peak hours. Some load management which can be implemented with little economic penalty, will shift loads to off-peak hours and onto more efficient generating capacity, thereby saving fuel as well as reducing peak demand and improving service reliability. Some voluntary peak load reduction by large customers is also possible, potentially reducing power demand by as much as 350 MWe in PG&E's service area for short durations. PG&E is the only major utility in the state with an interruptible customer service. If fully exercised, a total of 87 MWe could be shed at peak load, although it appears unlikely, barring unusual events, that service interruptions will be required.

Energy conservation would have immediate benefits in addition to the obvious savings in cost to the customer. First, it would reduce the amount of oil burned, which could prove to be a critical air pollution issue in the South Coast Air Basin. Second, it would increase reliability of service within each utility service area thereby lessening the need for interconnection support and risk of power interruptions.

Historically the agricultural sector, whose energy use is dominated by groundwater and other irrigation water pumping, has accounted for approxi-

mately four percent of electricity consumption. The increased groundwater pumping caused by the drought last year led to a 20 percent increase in electricity consumption from the previous year. Approximately 75 percent of electricity sales in this sector occur in the PG&E service area; PG&E will bear the main burden of any increase in pumping.

We have estimated the total energy demand for agricultural pumping in the Central Valley (90 percent of PG&E's agricultural service area) to be 5.9 billion kwh, based on the following factors: 1) expected water deliveries to agriculture during 1977 from both surface and ground sources; 2) energy requirements of surface and sprinkler irrigation methods; 3) estimated planted acreage for the major crops in the Valley, and 4) water requirements by crop. The increase in peak demand attributed to agricultural pumping was also calculated. Our estimate of 187 million kwh for August is equivalent to about 400 MWe of electrical capacity, which is about 90 MWe (on-peak) higher than PG&E's estimate. This additional power however should not cause a severe drain on the electric reserve capacity during the maximum peaking period.

Several water conservation strategies can be employed during a drought to aid in stretching agricultural water allocations and reduce energy requirements for pumping: 1) switching to shorter season crops; 2) eliminating double crops; 3) substituting low water demand crops for high demand crops; 4) mulching; and 5) reducing the leaching requirements. In addition, it has been suggested that switching to night irrigation where practicable could reduce water demands and help to reshape the load curve to reduce peak loads.

Long-term conservation strategies are more numerous and are more likely to make substantial savings in energy demand. These would include better irrigation management, improving pumping efficiency, and better irrigation system design. Such long-term measures require investments of time and capital that preclude their use in 1977. Moreover, there is no single solution with universal application. Factors such as soil, climate and economic conditions would dictate the form and extent of long-term conservation programs.

The drought will generally reduce energy requirements for water supply and use in the residential and industrial sectors. In the residential sector, electricity consumption for household appliances such as dishwashers

and washing machines, for outdoor watering and for hot water heaters will decrease during the drought. Pumping requirements for delivering and distributing surface water supplies will also decrease as will the energy re-requirements for waste water treatment.

This year, without conservation, electricity requirements for these residential and industrial activities would be roughly 6.5 billion kwh or about four percent of total sales. Of the 6.5 billion kwh approximately 2.7 billion kwh would originate in the PG&E service area. This year water conservation measures will reduce this electricity demand to an estimated 1.8 billion kwh.

Residential water conservation measures implementable this year could result in savings to the extent of 40 percent of electricity and natural gas associated with water use. At present this degree of savings is being achieved in only a few areas in northern California. The water conservation measures, in decreasing order of energy savings are: 1) installing flow control restrictors and taking shorter showers; 2) operating clothes and dishwashers with full loads and on the shortest cycles; and 3) reducing exterior water use by the measures outlined in Section III. Water conservation measures in the San Francisco, South Coastal and Tulare Basin Hydrologic Study Areas will result in the largest energy savings because of the high energy requirements for surface water delivery and groundwater pumping.

The electricity requirements for the delivery and distribution of water in the industrial sector can be reduced at least 12 percent through water conservation. The water conservation measures for the industrial sector that can be implemented immediately include housekeeping procedures, reduced use of cooling water by filter installation and blowdown reduction, and process water reuse where extensive retrofitting is not required. The highest energy cost for industrial water delivery occurs in the San Francisco and South Coastal HSA's, which are also the largest industrial centers. Accordingly, water conservation in these areas will have a relatively large impact on electricity consumption for water supply. The paper and petroleum sectors appear to have large water conservation potential, as does the food processing sector.

Electricity Supply

Steam-electric generating capacity accounts for roughly 23,300 MWe of a total California electric capacity of 32,800 MWe. Most of the power plants which account for this capacity are located along the coast and use sea water for once-through cooling. Freshwater requirements for inland power plants are small, and adequate freshwater supplies are available this year. The drought is therefore not expected to affect steam-electric generation in California.

The principal effect of the drought on electricity supply will be the reduced hydroelectric generation in California, which in a normal water year supplies 20 to 25 percent of the total electricity consumed. Electricity generation from hydroelectric sources depends on the quantity of water released from the state's reservoirs. Since reservoir storage levels and water releases are well below normal this year, hydroelectric energy production is expected to be only half of that for 1975. Hydroelectric power capacity however will not be as severely affected since the hydraulic head in many California hydroelectric plants is affected only slightly by changes in storage reservoir level.

Among the four major utilities, PG&E, whose service area covers most of northern California, is the most seriously affected by the drought, since in a normal water year approximately 35 percent of its electricity is derived from hydroelectric sources. To meet its summer loads, PG&E will therefore have to buy additional energy from the southern California utilities (Southern California Edison, Los Angeles Department of Water and Power and San Diego Gas & Electric), in addition to operating its steam power plants at maximum possible capacity. It will also have to draw upon energy that it has banked with Pacific Northwest utilities.

PG&E has entered into agreements with the three southern California utilities for the transfer of electrical power and energy during this summer. Although LADWP and SDG&E have no direct ties with PG&E, these two utilities are interconnected with SCE which can transfer power to PG&E. The existing transmission equipment between PG&E and SCE appears adequate for the expected energy transfers.

This year the total statewide decrease in hydroelectric generation from a normal year will amount to approximately 18 billion kwh. Approximately 29 million barrels of oil will be required to make up for this decreased generation at an expected cost of $375 million. To a first approximation this will be the added cost of electricity to the consumer. According to studies by FEA supplies of 0.5 percent and 0.25 percent sulfur fuel oil appear to be adequate to meet California demand this year.

However, the additional use of oil in the South Coast Basin to supply supplemental energy for SCE, LADWP and PG&E will increase the pollutant emissions in that Basin. During 1975-76 this Basin experienced 100 days with first-stage oxidant episodes, 46 days with first-stage sulfate-oxidant episodes and seven days with second-stage oxidant episodes. The South Coast Air Quality Maintenance District has estimated that the increased fuel oil use could lead to as many as 9 additional sulfate-oxidant episode days.

Testimony at hearings held by the CPUC has indicated that additional natural gas combustion would completely offset pollutant emissions and reduce the air quality episodes resulting from supplying energy to PG&E. Present CPUC regulations assign a low priority (P-5) for natural gas use in power plants. Any additional natural gas combustion by the southern California utilities to generate energy for PG&E would require the transfer of part of PG&E's P-5 gas to southern California. A mechanism for this gas transfer has yet to be worked out; however, the CPUC is considering such a mechanism and a decision regarding such a gas transfer is expected soon.

Estimates of the risk of outages for PG&E have been calculated under two sets of supply assumptions. The main areas of uncertainty in these calculations are the hydroelectric capacity during the summer, the availability of Rancho Seco, and the expected load. The May 11 submissions by the utilities to CERCDC differ from the March 9 submissions in these areas. The May 11 hydroelectric data did not include the full impact of recent precipitation, and may therefore be considered a worst case. The March 9 data with the largest contribution from hydroelectricity can be considered as a best case. For both cases we calculated the probability that PG&E will

require support beyond its planning level of 600 MWe. In its March 9 submission (the best case), PG&E estimates a 2.7 percent chance of support requirements greater than 600 MWe for August and a 1.7 percent chance for July.

Our estimates based on the May 11 data (the worst case) show a 9.5 percent probability for August and a 8.4 percent for July. The change is due to lower hydroelectric capacity estimates and a shift in expected peak from August to July. In all cases the southern California utilities can provide the additional support. The May 11 data show a statewide reserve margin in August of 13.1 percent, the lowest value for the year. This value, which corresponds to 4200 MWe statewide, is still adequate to carry the coincident load reliably, although it is less than the 15 percent or more reserve margin utilities seek to maintain for planning purposes.

Measures to Alleviate Adverse Impacts

Several near- and long-term measures to alleviate potential adverse impacts of the drought on electricity supply and demand have been identified in our analysis of California electricity supply and demand. In this section we have emphasized some of the short-term measures which could easily be implemented this summer. These include: 1) water and energy conservation measures to reduce energy demand; 2) load management measures to shift on-peak demand to off-peak hours; 3) rescheduling the refueling of Rancho Seco power plant to aid in meeting summer peak loads; and 4) use of natural gas as boiler fuel to reduce air pollutants. Some of the measures in item 1) are currently being implemented, while implementation of some of the measures in items 2) and 4) is at present being discussed by the concerned agencies. The specific measures and their expected impacts on electricity supply and demand are discussed below.

Water conservation measures implemented by consumers have already resulted in some water and energy savings. The water saved by these measures would help in meeting the water and energy demands over the next year. Based on our analysis we have identified a potential for more extensive implementation of some of the measures currently in use. In the residential sector the largest water-related energy consuming activities are bathing, laundering, dishwashing and exterior water use. Our analysis indicates that conservation measures currently in use, such as installing flow control devices, shorter showers, using short cycles and full loads for washing machines and dishwashers, and reducing water consumption for exterior use could be more extensively implemented with little financial outlays to further reduce water and energy consumption this year. Similarly, in the industrial sector, water and energy consumption could futher be reduced by better housekeeping, decreased blowdown from cooling towers and increased reuse of process water where feasible.

Agricultural pumping in the Central Valley is expected to increase substantially this year. This would add to the on-peak pumping energy load. Implementation of night irrigation where feasible (especially in areas with a large amount of groundwater pumping) would shift this load to off-peak hours, thus reducing the peak load.

The CPUC has identified several conservation measures in its Rule 14.1, "Prohibitions and Curtailment Provisions." This rule includes provisions limiting the use of electrical energy for the purposes of 1) outdoor advertising and decorative lighting, 2) functional outdoor lighting, 3) comfort heating and cooling, 4) outdoor public gatherings, and 5) indoor business lighting. Conservation measures such as delamping of commercial and retail floor space, higher thermostat settings for air conditioners, and off-peak use of discretionary residential appliances would also alleviate peak load demands. While there may be some overlap in these categories, a reasonably effective implementation program can result in important reductions in both energy and capacity requirements during the critical summer months. Statewide, these monthly savings could amount to about 4 percent (∿600-800 GWH) in energy and up to 10 percent (∿3000 MWe) in power demand.

The Rancho Seco nuclear power plant is scheduled to shut down on August 19 for refueling. In light of the uncertainty as to when the summer peak might occur, this plant could be operated, albeit less economically, beyond August 19 at gradually reduced power levels. The delayed refueling of Rancho Seco would have to mesh with the maintenance schedules of other power plants in the PG&E service area.

A major impact of the drought would be the increased quantity of air pollutants from power plants burning oil in the South Coast Air Basin. These power plants would operate at a higher than normal capacity factor to make up for the decrease in hydroelectric generation. Since the use of natural gas instead of fuel oil would reduce the quantity of air pollutants, the following measures to burn gas could be implemented:

1. Use of natural gas to offset increased emissions caused by energy supply to PG&E.

2. Use of Scattergood Unit #3, which is equipped to burn natural gas, for generation of energy to be transferred to PG&E.

3. Use of natural gas as a boiler fuel for selected steam plants on anticipated air pollution episode days.

Since the present CPUC regulations assign a low priority to gas for use as a boiler fuel, any additional gas used for this purpose in

southern California would require transfer of gas from PG&E to the southern California utilities or assignment of a higher priority to the southern California gas for use on episode days. In either case, the CPUC would need to institute changes in its regulations. Transfer of gas to southern California would require PG&E to burn the equivalent in fuel oil.

On the long-term side, better coordination between the concerned agencies is essential. The responsible agencies such as CERCDC, CPUC and the CARB could establish an integrated real-time monitoring program for air quality in the critical air basins (including episode predictions), for fuel availabilities and for energy use within these areas. Especially important would be a predictive capability for determining the likelihood that peak loads will exceed forecasts, and a prearranged program of public information to ensure rapid institution of voluntary load-shifting measures based on these predictions.

This report has concentrated on a study of the effects of the drought during the summer of 1977. However, preliminary indications are that a continuation of the drought into its third year in 1978, a not unlikely event considering that periods of three or more consecutive years of less than average rainfall have occurred in the past, would have severe impacts on energy and water supply. Long time periods are involved in implementing alternative supply options and in implementing programs for reducing water and energy consumption. Hence an early assessment of these options and the resulting impacts is essential before the beginning of the next water year in order that utilities and concerned agencies can formulate plans for coping with an extended drought.

III. ELECTRICITY DEMAND

During 1976 electricity sales in California amounted to 152 billion kwh. Residential, commercial and industrial sectors accounted for 30 percent, 28 percent, and 27 percent, respectively, of the total sales (see Table 1). Agricultural sales accounted for only 4 percent of the total. Household appliances, space conditioning (heating and cooling) and lighting are the largest residential end uses. The decrease in water supplies due to the drought and the consequent decrease in water consumption will result in reduced energy requirements for some household appliances such as dishwashers and washing machines. Other major components of the residential sector will not be affected directly by the drought.

Electricity use in the commercial sector is dominated by lighting and space conditioning and in the industrial sector by manufacturing and raw materials processing. The energy demand in the commercial sector is not likely to be affected directly by the drought, but the industrial sector may show decreases in energy requirements related to water use. Use in this sector is extremely diversified and difficult to estimate. We have estimated the decreased electricity requirements only for delivering and distributing water to the majority of the large water consuming industries. Electricity requirements for residential waste water treatment have also been computed. Overall, the electricity requirements to supply and utilize water in these sectors are approximately 6×10^9 kwh, or about four percent of total sales.

Agricultural electricity uses are dominated by groundwater and other irrigation water pumping. The increased pumping caused by the drought will have a major impact on electricity requirements in this sector. Although this sector accounted for only 4 percent of total sales in 1976 it showed a growth of 20 percent from 1975 as pumping loads increased to supply water in the first year of the drought. Translated into increase in agricultural electricity sales, this amounts to 1.1 billion kwh out of a total increase in sales of 7.1 billion kwh. Since 75 percent of the electricity sales in this sector occur in the PG&E service area, any increase in demand will affect PG&E more than any other utility. This year the effect will be

Table 1

California Electricity Sales*
(10^9 kwh)

Sector	1975	1976	Percent Change 1975-1976
Residential	43.52	45.04	3.5
Commercial	40.92	43.13	5.4
Industrial	39.34	41.30	5.0
Agricultural	5.44	6.53	20.1
(PG&E)	(4.09)	(4.97)	(21.0)
Other	16.01	16.38	2.3
TOTAL	145.23	152.39	4.9

*Source: Quarterly Fuel and Energy Summary, Vol. 2, No. 4, Fourth Quarter 1976, CERCDC.

more pronounced because of a further decrease in PG&E's hydroelectric supply capabilities. A careful evaluation of increases in agricultural electricity demand is therefore necessary. We have estimated the agricultural electricity demand in the Central Valley which accounts for over 90 percent of PG&E's agricultural demand.

Overall, the decreased water availability will result in reduced energy requirements for water pumping in both the federal Central Valley Project (CVP) and the California State Water Project (SWP). In a normal year the CVP would require about 1.6 billion kwh for water deliveries to agricultural users in the San Joaquin Valley. This year the U.S. Bureau of Reclamation, operator of the CVP, estimates they will use only 700 million kwh.[31] DWR staff had projected increases in the volume of water delivered by the SWP for the next several years; hence they expected energy use in any one of these years to exceed the last. Under the assumption that 1977 would be a normal water year, DWR had projected a total energy use of about 5.3 billion kwh.[32] This year with reductions in both agricultural, municipal and industrial deliveries, including cessation of water deliveries to the Metropolitan Water District (MWD) after the first of March, the estimated energy use for SWP pumping is 1.7 billion kwh (this includes additional MWD pumping from the Colorado River). These combined reductions total 4.5 billion kwh, or nearly three percent of the total statewide electricity demand. This reduction has been accounted for in the utilities' submittals, and the total for 1977 is shown in Table 2 below.

In the following sections we analyze the utilities' projections of total electricity demand by service area and the effect of changed water supply and consumption on agricultural, residential and industrial electricity demand. We also discuss the uncertainties in these demand forecasts, including the effect of the variation in temperature on peak load. Conservation measures and their potential for reducing electricity requirements are also outlined.

Table 2

Electricity Demand by Major Utility Service Area
(10^9 kwh)

	1975[a]	1976[a]	Percent Change 1975-76	Projected[b] 1977	Percent Change 1976-77	CERCDC Adopted Forecast 1975-85 Percent Change[c]
PG&E[d]	70.77	74.44	5.2	76.12	2.2	3.7
SCE[d]	57.18	61.43	7.4	64.35	4.6	4.7
DWP[d]	20.60	21.41	3.9	20.67	-3.5	3.6
SDG&E	8.78	8.99	2.4	10.04	11.0	5.9
TOTAL	157.34	166.26	5.5	171.17	2.9	

[a]Source: Quarterly Fuel and Energy Summary, Vol. 2, No. 4, Fourth Quarter 1976, CERCDC.

[b]Source: "Combined Response of California Electric Utilities," Docket No. EA-1, May 11, 1977, CERCDC.

[c]Source: CERCDC, California Energy Trends & Choices, Vol. 2, "Electricity Forecasting and Planning," 1977 Biennial Report.

[d]The loads and resources in the utility service areas include many local municipal utility and irrigation districts. Notable among them are Sacramento Municipal Utility District (SMUD) in the PG&E area, and Municipal Water District (MWD) in the SCE area. A complete set of these is given in Ref. a above.

Demand for Electricity and Power

In response to the three heatings held by the CERCDC during the spring under their contingency planning authority,* the four major electric utilities in California produced a set of three month-by-month resource plans for 1977, showing the peak power and energy loads for each service area, the expected indigenous resources available and the expected intra- and interstate energy transfers.[1] The latest responses (May 11) are reproduced in Appendix A. These projections are made by service area, but are not disaggregated further. The estimated overall growth rate for electrical energy appears to be consistent with recent trends, albeit somewhat less than the growth rate between 1975 and 1976. These values are shown in Table 2. It should be noted that the values for 1975 and 1976 are from a different source than that for the 1977 estimates. The accounting bases may not be the same. One should therefore use these comparisons with caution.

A month-by-month comparison of electrical energy supply and sales for 1975 and expected supply for 1977 is shown in Fig. 1. The trends in supply are similar with a peak in July in the first case, and an expected peak in August for the latter year. Details for the major end-use sectors for 1975 are also shown in Fig. 1. Agriculture shows the largest annual variation. One should also note that the monthly sales curves for the residential, commercial, and industrial sectors are all very similar. None of these three sectors shows a marked summertime peak.

Peak Demand

Based upon the utility submissions, the total statewide peak demand is anticipated to increase 5.5 percent over last year, with a range of 3.0 to 6.6 percent by individual service area. The projected and historical peak demands, coincidence factors, and the growth rates are shown in Tables

*California Public Resources Code, Division 15, Sec. 25700 to 25705.

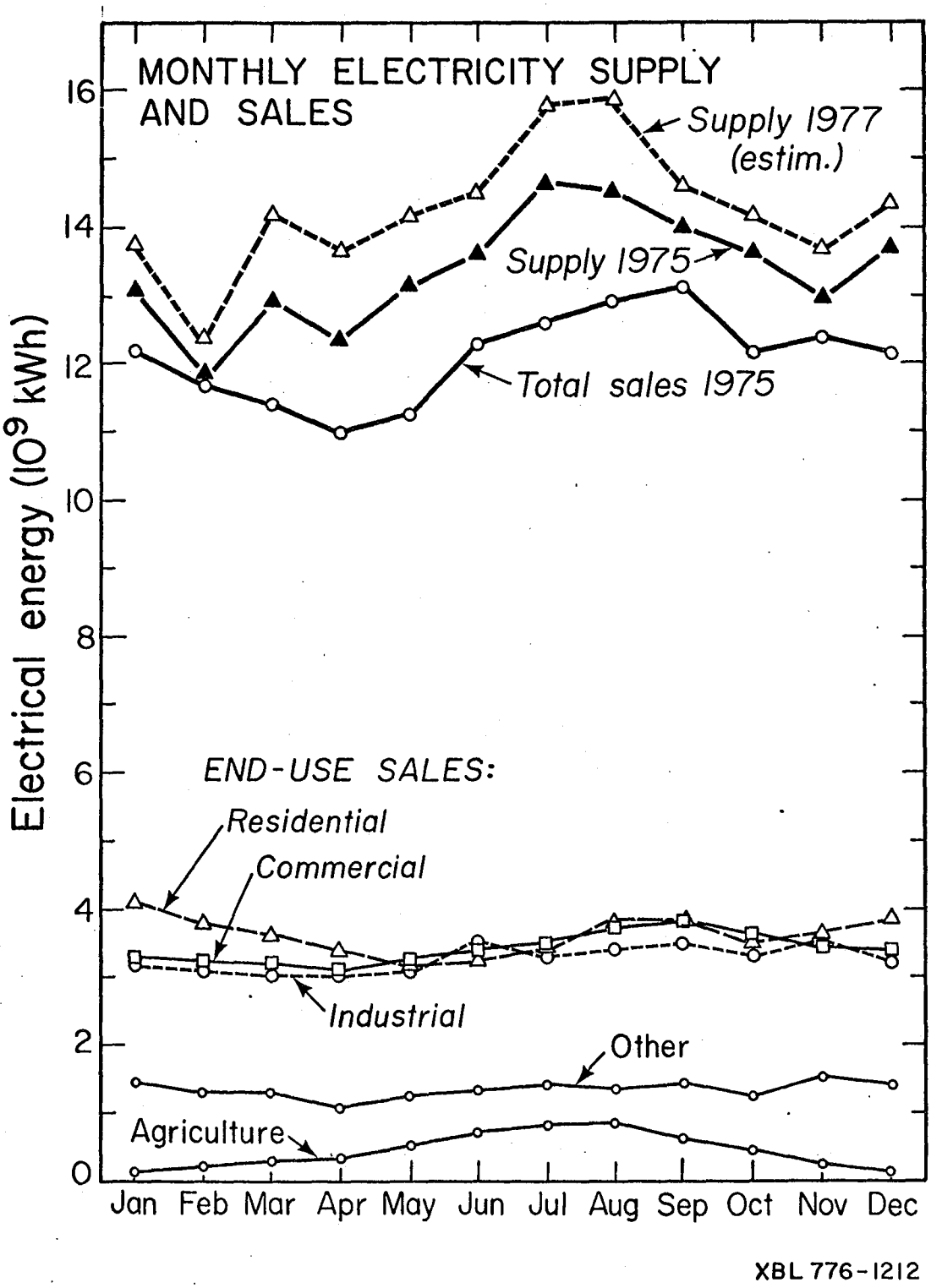

Fig. 1 Monthly electricity supply and sales for California

3 and 4. Since 1970 the yearly growth rates in peak demand have shown large fluctuations for all four major utility service areas. The projected growth rates for SCE and SDG&E appear to be consistent with a general trend toward declining rates of growth in peak demand, while the projections for PG&E and LADWP both anticipate increases in growth rates.

For comparison, growth rates for each service area recently adopted by CERCDC have been used to project utility service area peak demand. As can be seen from Table 3, these estimated peaks are lower than those projected by PG&E and LADWP and somewhat higher for SCE and SDG&E, although the largest difference is only 400 MWe (for PG&E).

Another aspect to be considered is the likelihood that the daily peak loads on each utility system will occur simultaneously. As noted from the latest submission (Ref. 1) the three southern California utilities have used August as the month with highest peak demand, while PG&E has selected July. PG&E, with the largest amount of agricultural demand in its service area, apparently expects the earlier peak based on anticipated shorter crop cycles, and a demand for agricultural water pumping earlier in the season.

We have analyzed the historical peak loads in California for the past seven years, and have calculated a coincidence factor for each utility system peak. This factor is the ratio of the simultaneous peak demands on a given day (the peak day for the utility of interest) to the sum of the highest peaks recorded by each utility that year. For example, PG&E's highest daily peak of 9813 MWe for 1970 occurred on August 10. The peak loads that day for the other utilities were 1028 MWe for SDG&E, 2941 MWe for LADWP and 8023 MWe for SCE.[2] The maximum peaks recorded for these utilities were 1143 MWe for SDG&E (on Sept. 28), 3107 MWe for LADWP (on Aug. 17) and 8274 MWe for SCE (on Aug. 7).[2] The sum of the maximum peak loads (regardless of when they occurred in 1970) yields the coincidence factor for PG&E of 0.98.

Historically, the utilities have shown daily coincidence factors ranging from 0.86 to 1.0 (see Table 4). The hourly peak load data were unavailable to us; however, it should be noted that the summer peaks generally occur between 2 and 4 PM for all four service areas, and these are fairly broad, with ∿98 percent of the peak magnitude occurring within ±2 hours of the recorded peak time. Because these peaks are broad, one

Table 3

Projected Peak Demand for 1977

		Utilities Projections[a]		CERCDC Adopted Forecast[b]	
	1976 MWe	Percent Growth 1976-77	MWe	Annual Growth Rate 1975-85	MWe
PG&E	13772	6.6	14713	3.8	14305
SCE	11081	4.2	11554	4.5	11591
LADWP	3809	6.1	4050	3.4	3941
SDG&E	1716	3.0	1769	6.4	1829

[a]Source: "Combined Response of California Electric Utilities," Docket No. 77-EA-1, May 11, 1977, CERCDC.

[b]Source: CERCDC, California Energy Trends & Choices, Vol. 2, "Electricity Forecasting and Planning," 1977 Biennial Report.

Table 4

Historical Peak Demand by Utility Service Area[a]

Year	PG&E Peak[b] (MWe)	PG&E c.f.[c]	PG&E Annual Growth Rate (%)	SCE Peak (MWe)	SCE c.f.	SCE Annual Growth Rate (%)	LADWP Peak (MWe)	LADWP c.f.	LADWP Annual Growth Rate (%)	SDG&E Peak (MWe)	SDG&E c.f.	SDG&E Annual Growth Rate (%)
1970	9813	0.98	---	8274	0.96	---	3107	0.96	---	1143	0.92	---
1971	10730	0.92	8.9	9350	0.94	12.2	3439	0.93	10.2	1211	0.86	5.8
1972	11660	0.93	8.3	9815	0.95	4.9	3630	0.95	5.4	1367	0.95	12.1
1973	12090	0.95	3.6	10253	1.00	4.4	3665	0.98	1.0	1431	0.88	4.6
1974	12610	1.00	4.2	9997	1.00	-2.5	3500	0.99	-4.6	1451	1.00	1.4
1975	12983	0.97	2.9	10193	0.95	1.9	3594	0.95	2.7	1619	0.93	11.0
1976	13772	1.00	5.9	11081	1.00	8.4	3809	1.00	5.8	1716	1.00	5.8

[a]Data from David Morse, Forecasting Office, CERCDC, and from R. Logan and D. Morse, "Technical Documentation of Staff Procedures for Estimating Peak Demand," CERCDC, Oct. 1976.

[b]PG&E peaks are for service area, including SMUD.

[c]The coincidence factor for utility i is defined as the statewide demand on the day utility i has its peak demand divided by the sum of annual utility peak demands. Thus if the utility and statewide peaks occur on the same day, the coincidence factor is one.

0 0 0 0 4 7 8 0 3 6 1 2 4

can use the daily peaks instead of hourly peaks to calculate coincidence factors. Statewide coincident peaks have occurred twice in the past seven years; in 1974 (on July 25) and 1976 (on June 28). Though there are not enough data to define a clear trend, it appears that a statewide coincidence factor above 0.98 is likely. As air conditioning saturation increases in each service area, the peak demand becomes increasingly sensitive to temperature. Thus a uniform statewide summertime temperature pattern could produce simultaneous utility peaks.

The peak forecast by each utility for 1977 apparently relies to some extent upon analysis of weather-sensitive demand. The uncertainties associated with the magnitude of each peak load forecast can therefore be estimated based upon the variation in maximum temperatures associated with the historical peaks. Weather-sensitive demand has been analyzed by the CERCDC for each utility, and peak demands and coincident temperatures have been reported.[2] Temperatures related to the peak demand are recorded at several reporting stations within each service area. Hence the reported coincident temperature is an average. The weather-sensitive coefficients for each service area for 1975 are taken from this analysis and are shown in Table 5. Using these values, and variation in temperature about the average maximum, the uncertainties in our estimates of the peak load forecasts are shown in the last column of Table 5. This temperature-related uncertainty appears to be a significant part of any error associated with the peak demand estimates. We will discuss the effect of temperature changes on reliability in Section IV.

Finally, in considering the issue of demand, the potential for energy conservation should not be overlooked. As we shall discuss in Section IV, reduction of demand for both energy and capacity can have beneficial effects with regard to supply system reliability, fuel consumption and environmental effects. However, no adequate investigation of energy conservation programs for the summer of 1977 has been done.

The CPUC staff at the intial set of hearings held by CERCDC[3] cited significant conservation potential—as much as 3000 MWe at peak—however, no detailed end-use analysis was presented except for suggesting enforcement of the existing CPUC Rule 14.1.[29] These recommendations have been listed in Table 6 along with CPUC estimates of the energy and capacity savings. We have not verified these estimates.

Since little time remains before summer for the analysis and implementation of conservation programs, we have identified two programs that have

Table 5

Weather-Sensitive Coefficients and Maximum Temperatures

Utility	Coefficient[a] MWe/°F (1975)	$\bar{T} \pm \Delta T$[a] (°F)	ΔMWe
PG&E	118	105.8±2.6	311
SCE	96	99.5±5.3	511
LADWP	31	106.2±7.0	218
SDG&E	15 (Summer)	88.8±11.1	167
			1207

[a]Source: R. Logan and D. Morse, "Technical Documentation of Staff Procedures for Estimating Peak Demand," CERCDC, Oct. 1976.

Table 6

State Energy Conservation Potential

Action	Statewide[a]	
	Energy Savings (GWh/Time)	Peak Savings (MWe)
1. Enforcement of existing CPUC regulation 14.1, advocating commercial/industrial thermostat setback; outdoor lighting reduction; reducing nighttime indoor lighting of unoccupied office and other commercial buildings	600/year	?
2. Voluntary conservation - all customers	7.2/day	1200
3. Voluntary load reduction by large customers as requested by utilities	5.4/day	900
4. Voluntary load reduction by all customers (general appeal via mass media)	7.2/day	1200
Statewide monthly average, Items 1 & 2	265/month	1200+
Items 1 through 4	640/month	3300+

Source: Amaroli, G.A. "The Impact of an Expanded Voluntary Conservation Effort During the 1977 California Drought," CPUC. Presented before CERCDC, March 9, 1977, under Docket No. 77-EA-1.

[a] Effect for PG&E territory is approximately 1/2 for both energy and peak power demand.

significant potential savings. We concentrated on energy management programs that do not involve the purchase or installation of new equipment. However, the practice of better energy management can be instituted quickly in many parts of the commercial sector where we believe the largest short-term payoff exists.

The estimated savings that accrue through a combination of lower heating thermostat settings and higher cooling thermostat settings, equipment maintenance, and reduced operation of some equipment are nearly 15 percent for commercial buildings.[4] Referring to Table 1, the impact of better energy management translates into nearly 6.5 billion kwh, a monthly average of almost 550 million kwh (note from Fig. 1 that the commercial electricity sales curve is nearly flat). Assuming that these practices could be effectively applied in 25 percent of the commercial sector by August, this is a savings of 135 million kwh per month. A substantial portion of energy use in the commerical sector is for air conditioning, which has potential for energy and capacity savings. We have not estimated the total capacity savings due to these energy management programs.

Significant savings can also be obtained from another energy management program, the reduction of lighting in commercial buildings. Based on our earlier work,[5] the savings in energy and capacity from a delamping program in California can be quantified. We estimate that, with some effort, about 25 percent of the statewide delamping potential could be achieved by August. We believe this is a reasonable estimate providing that the program focuses on removal of tubes or switching off fixtures without the use of Phantom™ tubes or rewiring. These savings could amount to 160 million kwh/month, or about 600 MWe (on peak).

These two programs have the potential of saving almost 300 million kwh per month, which (as we discuss later) can have a significant impact on the energy and capacity situation this summer. Further energy conservation measures are discussed in the sections dealing with agricultural and residential and industrial water demand.

Our analysis based on the utiltties' submissions to the CERCDC shows sufficient capacity available to PG&E to meet its expected loads. However in the event of an unexpected peak load emergency, customers could

be asked to reduce their electric power consumption. This could be achieved by either shifting electricity consumption to off-peak hours or by limiting the electricity consumption. Of the four major utilities, PG&E is the only utility with interruptible customers.[1a] These five interruptible customers have a combined maximum demand of approximately 87 MWe. This load is interruptible for periods not to exceed 2190 hours or approximately three months each year. In addition, large customers of PG&E, LADWP and SDG&E, responding to different surveys, have indicated that they would voluntarily reduce their loads for short durations in the event peak load were to exceed available capacity. PG&E's load, for example, could be reduced by about 450 MWe for short durations.[1a] In addition, the Energy Research and Development Administration has indicated that it could decrease its load in Northern California from 72 MWe to 61 MWe by voluntary load reduction.

ELECTRICITY REQUIREMENTS FOR AGRICULTURAL WATER DEMAND

Introduction

Electrical energy is an essential input to the present form of agriculture in California. About 98 percent of the irrigation pumping units in California are electric.[6,7] Higher than normal demand from the agriculture sector for electric power could cause a severe drain on the electrical reserve capacity. The increased demand would result from pumping groundwater in areas where the surface water supply has fallen below normal as a result of drought conditions.

Energy required for irrigation varies widely across the state as a function of the water source, the method of irrigation and the water requirements of the crops. The objective of this part of the study is to determine the energy requirement for agricultural pumping during the 1977 season. Since nearly 80 percent of the estimated water use in agriculture and 75 percent of the energy requirement occur in four of the 16 hydrologic basins (5A, 5B, 5C, 5D) established by the State Water Resources Control Board (Fig. 2), these basins were used as the basic geographic area for all energy calculations. The major part of the area represented by these basins lies within the Pacific Gas and Electric Company's service area.

This section estimates energy use by crop and irrigation method in the four hydrologic basin planning areas of the Central Valley. The basic approach used to determine energy requirements for agricultural pumping in the Central Valley follows the procedure used in a recent report.[7] Energy requirements are calculated for 1) on-farm wells incorporating the best available data on average well depths in the Central Valley; 2) pumping energy required for moving water within the state and federal water projects; 3) energy required by irrigation districts for pumping water. The latter two energy values are taken from recently published and unpublished reports (Refs. 8 and 9). The energy calculations are based on average values within each hydrologic basin for factors such as well depths, water requirements, planted acreage, and irrigation systems.

Water Supply and Demand in 1977

Table 7 summarizes the estimated agricultural water supply in the Central Valley for 1977. The data represent estimates by the staff at the Department of Water Resources. The total water available to agriculture

Table 7

Estimated Agricultural Water
Supply & Demand in the Central Valley - 1977
(10^6 acre-feet)[a]

Water Source	5A	5B	5C	5D	Valley Totals
Surface Water	4.01	1.56	2.06	1.71	9.34
Groundwater	2.43	1.12	2.73	8.46	14.74
TOTAL WATER SUPPLY[b]	6.44	2.68	4.79	10.16	24.08
Percent Surface Water	62.3	58.3	43.0	16.7	
Percent Groundwater	37.7	41.7	57.0	83.2	
WATER DEMAND[c]	6.30	2.56	5.61	11.13	25.60

[a]An acre-foot = 325,851 gallons.

[b]Data from Department of Water Resources, 1977

[c]Estimated total applied water demand.

Table 8

Estimated Groundwater Well Depth in the Central Valley

Hydrologic Planning Basin	Pumping Depth (feet) 1972 Data[a]	Average Drop in Groundwater Level (1972-77)-feet[b]	Estimated Pumping Depth in 1977 (feet)
5A	53	8	61
5B	89	8	97
5C	123	4	127
5D	181	7	188

[a]Knutson, et al., 1977.

[b]Data from Department of Water Resources, 1977.

Table 9

Energy Use Per Acre-Foot in the Central Valley
(kwh/AF)

Irrigation Method	5A	5B	5C	5D
Surface Irrigation From:				
Groundwater	113	180	236	350
Surface Water	18	43	204	258
Sprinkler Irrigation From:				
Groundwater	347	414	470	584
Surface Water	252	277	438	492

[a]From Roberts and Hagan, 1975; Hagan and Roberts, 1976.

Fig. 2 Hydrologic Basin Planning Areas

from surface and groundwater sources has been apportioned to the appropriate hydrologic planning areas being studied.

The assumption is made that surface water deficits in the Central Valley during the drought period will be offset by increased groundwater pumping. DWR's estimates of water availability in the Central Valley include an increased amount of groundwater pumping over previous years. The total water available to agriculture in the Central Valley is reported to be 24.08 million acre-feet.

The projected applied water demands,which are the quantities of water delivered to the point of use for agriculture, were taken from a DWR bulletin.[10] Alternative II as outlined in the bulletin was used, and interpolations were made between the appropriate years. The estimated applied water needs for 1977 exceed the available water resources in the San Joaquin and Tulare Basins.

Unit Energy Use for Ground and Surface Water

In order to calculate the energy requirements for groundwater the average pumping depth for wells in each hydrologic planning basin was estimated. Average pumping depths were taken from the estimates for 1972 by determining the average static water level for each basin and adding the average draw down (21 feet) and average surface irrigation pressure head (4 feet). Since the water table has been generally declining throughout the state, it was necessary to update the data presented by Knutson.[7] Information on the average drop in groundwater levels was obtained from the various districts of DWR which represent the Central Valley. The estimated groundwater well depths are presented in Table 8. These values, which are basin averages, are used to determine the energy required to pump groundwater to the surface.

An average overall pumping plant efficiency of 55 percent was used. Although this is a more conservative figure than the percentage used in other studies,[6,7] it is probably more representative of the overall picture in the Central Valley. By combining the average pumping efficiency with the pumping depth,the energy used to pump groundwater was determined by the following formula:

$$\text{Unit Energy Use (kwh/AF)} = 1.024 \times \frac{D}{E} \qquad (1)$$

where: kwh/AF = kilowatt-hour per acre-foot

1.024 = number of kilowatt-hours to lift one acre-foot of water one foot in height at 100 percent efficiency

D = pumping depth (feet)

E = overall pumping plant efficiency (55 percent)

Table 9 presents the energy required to pump groundwater in the Central Valley. The groundwater numbers were calculated according to Eq.1. The surface water numbers represent the average energy per acre-foot required for moving irrigation water by state and federal water projects and pumping water by irrigation districts. They were determined in recent studies.[6,8,9] Sprinkler irrigation requires energy equivalent to an additional 126 foot lift.

Unit Water Use By Crop

Data in Table 10 on the expected water requirements for various crops within each Central Valley hydrologic basin were taken from two reports.[7,11] These average values for the amount of water applied per acre were given in Knutson's paper for different methods of application. Comparisons were made between surface and sprinkler methods which are used on the majority of the irrigated acreage in California.

The amount of water applied per acre is affected by the application efficiency of the different methods of irrigation. Since little data are available on the relative application efficiencies of the different irrigation methods, average water application efficiencies of 65 percent for surface irrigation and 81 percent for sprinklers were used. The details of the calculations are given in another report.[7]

Unit Energy Use by Crop

The energy use per acre for various crops in the Central Valley was calculated by a method used previously.[7] The procedure consisted of combining the energy required to pump one acre-foot of water (kwh/AF) from either surface or groundwater sources with the water used per acre of crop (AF/acre). The following formulae were used:

Table 10

Water Requirements per Acre in the Central Valley*
(Acre-foot/Acre)

HBPA**	Irrigation Method	Alfalfa	Corn	Cotton	Grain	Rice	Sugar Beets	Fruit/ Nuts	Vines	Vege-tables
5A	Surface	3.9	2.5	--	1.0	8.2	3.1	3.2	3.0	2.7
5A	Sprinkler	3.1	--	--	0.8	--	2.5	2.5	2.4	2.2
5B	Surface	3.5	2.2	--	1.0	8.2	3.0	3.2	2.5	2.7
5B	Sprinkler	2.8	--	--	0.8	--	2.4	2.5	2.0	2.3
5C	Surface	5.2	3.2	4.0	1.0	6.7	3.7	4.1	3.6	2.3
5C	Sprinkler	4.1	--	3.2	0.8	--	2.9	3.2	2.8	1.8
5D	Surface	5.6	3.4	4.2	1.2	6.7	3.8	4.0	4.0	2.2
5D	Sprinkler	4.5	--	3.3	1.0	--	3.0	3.2	3.2	1.8
VALLEY AVERAGE		4.5	2.8	3.9	1.1	7.5	3.3	3.5	3.2	2.3

*Knutson, et al., 1977.

**Hydrologic Basin Planning Areas

Surface Irrigation: (kwh/AF) X (AF/Acre) for each crop

Sprinkler Irrigation: [(kwh/AF) + additional energy for sprinkler pressure head] X (AF/Acre) for each crop

The energy use per acre of crop (kwh/Acre) for the hydrologic basins of the Central Valley is tabulated in Table 11. Energy requirements are presented for both surface and sprinkler irrigation methods using either ground or surface water.

Estimated Crop Acreage in the Central Valley

In order to complete an energy analysis of agricultural pumping it was necessary to estimate the acreage planted for each crop in the various hydrologic basins of the Valley. This task proved to be the most difficult because of a lack of definitive data on expected cropping patterns for the 1977 growing season.

The procedure used the April 1977 report on farmers' intentions to plant various crops in California. This information was available on a statewide basis. Information obtained through various conversations with the staff members of the State Department of Food and Agriculture was used to separate the Central Valley crop intentions from the state totals. Finally the estimated planted acreages were apportioned to the hydrologic basins according to historical cropping patterns.[7,12] Since the statistical data in these studies on planted acreage pertained to the year 1972, a comparison was made to 1974-75 information on production and yield. The percentages of total statewide acreage estimated in each hydrologic basin within the Central Valley did not change significantly during this time period, and so 1972 data on the percentage of each crop planted in the four hydrologic planning basins were used to estimate 1977 acreage.

The estimated planted acreage in the Central Valley by crop for 1977 is presented in Table 12. These crop estimates are apportioned to the appropriate hydrologic basin by the method described above. It is important to note that the figures are only approximations and may differ significantly from actual plantings.

Table 11

Energy Use per Acre for Crops in the Central Valley

(kwh/acre)

HPBA*	Irrigation Method/ Water Source	Alfalfa	Corn	Cotton	Grain	Rice	Sugar Beets	Fruit/ Nuts	Vines	Vegetables
5A	Surface Irrigation									
	Groundwater	441	283	--	113	927	350	362	339	305
	Surface water	70	45	--	18	148	56	58	54	49
5A	Sprinkler Irrigation									
	Groundwater	1076	--	--	278	--	868	868	833	763
	Surface water	781	--	--	202	--	630	630	605	554
5B	Surface Irrigation									
	Groundwater	630	396	--	180	1476	540	576	450	486
	Surface water	151	95	--	43	353	129	138	108	116
5B	Sprinkler Irrigation									
	Groundwater	1159	--	--	331	--	994	1035	828	952
	Surface water	776	--	--	222	--	665	693	554	637
5C	Surface Irrigation									
	Groundwater	1227	755	944	236	1581	873	968	850	543
	Surface water	1061	653	816	204	1367	755	836	734	469
5C	Sprinkler Irrigation									
	Groundwater	1927	--	1504	376	--	1363	1504	1316	846
	Surface water	1796	--	1402	350	--	1270	1402	1226	788
5D	Surface Irrigation									
	Groundwater	1960	1190	1470	420	2345	1330	1400	1400	770
	Surface water	1445	877	1084	310	1729	980	1032	1032	568
5D	Sprinkler Irrigation									
	Groundwater	2628	--	1927	584	--	1752	1869	1869	1051
	Surface water	2214	--	1624	492	--	1476	1574	1574	886

*Hydrologic Planning Basin Areas

Table 12

Estimated Major Crop Acreage in the Central Valley - 1977

CROPS	Estimated Statewide Acreage (10^3A)	5A		5B		5C		5D	
		% State Acreage	Estimated Acres - 1977 (10^3A)	% State Acreage	Estimated Acres - 1977 (10^3A)	% State Acreage	Estimated Acres - 1977 (10^3A)	% State Acreage	Estimated Acres - 1977 (10^3A)
Alfalfa	1680	15.2	255.4	9.8	164.6	22.6	379.7	25.4	426.7
Corn	450	18.2	81.9	21.8	98.1	27.1	122.0	30.6	137.7
Cotton	1400	--	--	--	--	9.1	127.4	71.9	1006.6
Grain	1250	8.3	103.8	8.6	107.5	4.7	58.8	48.6	607.5
Rice	320	89.2	285.4	2.1	6.7	7.4	23.7	1.4	3.8
Sugar Beets	210	35.4	74.3	27.1	56.9	12.9	27.1	21.9	46.0
Fruits/Nuts	1335	32.7	436.5	17.2	229.6	19.9	265.7	25.0	333.8
Vineyards	647	6.7	43.3	9.1	58.9	20.0	129.4	48.1	311.2
Vegetables	900	38.6	347.4	29.7	267.3	15.5	139.5	16.2	145.8

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Energy Demand for Agricultural Pumping in the Central Valley

To determine the total energy demand for agricultural pumping, which is the objective of this section of the report, the energy use per acre was multiplied by the estimated acreage in the Central Valley water basins. These computations were made for surface and sprinkler irrigation methods using water from either ground or surface sources.

Certain assumptions related to irrigation systems and water sources were made in order to obtain the appropriate acreages. First, it was assumed that the irrigation patterns reported previously had not changed significantly.[7,12] The percentages of acreage used for surface and sprinkler irrigation system, as shown in Table 13 were taken from the 1972 data, and were apportioned to the estimated planted acres in 1977.

The second assumption is that the proportion of acreage using surface and sprinkler systems for a given hydrologic basin applied equally to water from ground and surface sources, i.e., that groundwater and surface water were used in the same ratio in sprinkler irrigation as they were in surface irrigation. Therefore the acreage employing surface and sprinkler irrigation methods was applied to the ratio of ground and surface water available within each hydrologic basin for 1977 as shown in Table 7. The results of such calculations are the estimated planted acreage by water source and irrigation method.

The estimated planted acreages were then multiplied by the appropriate energy use per acre value as presented in Table 11 to give the total energy use for the various crops in each hydrologic basin. Table 14 contains the total energy use for selected crops according to the water source and irrigation method. The data are summarized in Table 15 as the estimated total energy requirements for agricultural pumping in the Central Valley.

The total energy requirements for agricultural pumping in the Central Valley during 1977 were calculated to be 5.91 million kwh. This energy value is slightly greater than the estimate suggested by the staff of PG&E. The difference in total energy needs is probably due to the application of different overall average pumping efficiencies. We assumed an overall average efficiency of 55 percent while other estimates have utilized greater efficiencies. The method employed in this study also considered the estimated acreage planted for selected crops in the Central Valley. Although these cropping patterns represented historical trends, the resultant energy

Table 13

Percentage of Acreage in Surface and Sprinkler Systems in the Central Valley (1972)

Crops	5A			5B			5C			5D		
	Estimated acres (10^3A)	% Surface	% Sprinkler	Estimated acres (10^3A)	% Surface	% Sprinkler	Estimated acres (10^3A)	% Surface	% Sprinkler	Estimated acres (10^3A)	% Surface	% Sprinkler
Alfalfa	255.4	91.9	8.1	164.6	97.6	2.4	379.7	93.3	6.7	426.7	90.1	9.9
Corn	81.9	100	--	98.1	100	--	122.0	100	--	137.7	100	--
Cotton	--	--	--	--	--	--	127.4	70.0	30.0	1006.6	79.6	20.4
Grain	103.8	93.2	6.8	107.5	99.8	0.2	58.8	94.7	5.3	607.5	95.0	5.0
Rice	285.7	100	--	6.7	100	--	23.7	100	--	3.8	100	--
Sugar Beets	74.3	80.9	19.1	56.9	93.6	6.4	27.1	92.9	7.1	46.0	85.7	14.3
Fruit/Nuts	436.5	44.8	55.2	229.6	54.3	45.7	265.7	80.6	19.4	333.8	74.1	25.9
Vineyards	43.3	95.0	5.0	58.9	95.0	5.0	129.4	91.5	8.5	311.2	93.0	7.0
Vegetables	347.4	81.9	18.1	267.3	96.2	3.8	139.5	99.9	0.1	145.8	57.8	42.2

Table 14

Total Energy Use for Selected Crops in the Central Valley by Water Source and Irrigation Method*
(10^6 kwh)

HPBA**	Irrigation Method/ Water Source	Alfalfa	Corn	Cotton	Grain	Rice	Sugar Beets	Fruit/ Nuts	Vines	Vegetables
5A	Surface Irrigation									
	Groundwater	36.64	8.20	--	3.87	93.76	7.45	25.06	4.94	30.72
	Surface Water	10.61	2.38	--	1.13	27.31	2.17	7.33	1.43	9.01
	Sprinkler Irrigation									
	Groundwater	7.88	--	--	0.70	--	4.36	74.04	0.64	16.98
	Surface Water	10.43	--	--	0.92	--	5.78	98.06	0.85	22.50
		65.56	10.58	--	6.62	121.07	19.76	204.49	7.86	79.21
5B	Surface Irrigation									
	Groundwater	42.20	16.20	--	8.05	4.12	11.99	29.95	10.50	52.11
	Surface Water	14.14	5.43	--	2.69	1.38	4.01	10.03	3.52	17.39
	Sprinkler Irrigation									
	Groundwater	1.91	--	--	0.03	--	1.51	45.29	1.02	4.04
	Surface Water	1.78	--	--	0.03	--	1.41	42.39	0.95	3.77
		60.03	21.63	--	10.80	5.50	18.92	127.66	15.99	77.31
5C	Surface Irrigation									
	Groundwater	247.77	52.50	47.98	7.49	21.36	12.53	118.16	57.37	43.14
	Surface Water	161.62	34.26	31.29	4.88	13.93	8.18	76.99	37.37	28.10
	Sprinkler Irrigation									
	Groundwater	27.94	--	32.76	0.67	--	1.49	44.19	8.25	0.07
	Surface Water	19.65	--	23.05	0.47	--	1.05	31.07	5.80	0.05
		456.98	86.76	135.08	13.51	35.29	23.25	270.41	108.79	71.36
5D	Surface Irrigation									
	Groundwater	626.95	136.34	979.96	201.67	7.41	43.62	288.11	337.11	53.98
	Surface Water	93.33	20.29	145.92	30.06	1.11	6.49	42.88	50.19	8.04
	Sprinkler Irrigation									
	Groundwater	92.35	--	329.23	14.76	--	9.58	134.44	33.87	53.80
	Surface Water	15.72	--	56.03	3.51	--	1.64	22.87	5.76	9.16
		828.35	156.63	1511.14	249.00	8.52	61.33	488.30	426.93	124.98

*Assumes 0.55 efficiency.

**Hydrologic Planning Basin Areas

Table 15

Total Estimated Energy Requirements for Agricultural Irrigation in Central Valley - 1977
(10^6 kwh)

HPBA	Alfalfa	Corn	Cotton	Grain	Rice	Sugar Beets	Fruit/ Nuts	Vineyards	Vegetables	Basin Totals
5A	65.56	10.58	--	6.62	121.07	19.76	204.49	7.86	74.21	515.15
5B	60.03	21.63	--	10.80	5.50	18.92	127.66	15.99	77.31	337.84
5C	456.98	86.76	135.08	13.51	35.29	23.25	270.41	108.74	71.36	1201.43
5D	828.35	156.63	1511.14	249.0	8.52	61.33	488.3	426.93	124.98	3855.18
TOTAL ENERGY REQUIRED:										5909.60

demands that were calculated probably describe the actual situation in more detail. Furthermore, the total energy demands reported in this section include the additional energy required to move irrigation water within state and federal water projects and irrigation districts.

In PG&E's submission to the California Energy Resources Conservation and Development Commission in March 1977[1] information on increased energy demands for agricultural pumping was given. In Table 3 of that submission it was estimated that the yearly total agricultural demand would increase by 1.013 billion kwh. Our results suggest a somewhat greater increase of 1.3 billion kwh.

PG&E has projected that its maximum peak electric load of 14,650 MWe will occur in August. This estimate includes about 315 MWe from increased agricultural pumping during that month. In order to determine this projected addition (called the peak load adder), it was necessary first to calculate a monthly increase in agricultural energy requirements (10^6 kwh) and then combine this figure with an estimated monthly load factor, which finally resulted in the peak load adder in megawatts of capacity.

We were unable to specify energy requirements for agricultural pumping on a monthly basis. We therefore had no direct method to translate the total energy needs that were calculated into peak load generating capacity. In order to estimate the increase in agricultural load due to dry year conditions, we assumed a proportional relationship between PG&E's projections and those reported in this section.

Using PG&E's estimates of total and monthly additions in energy demand (1013 million kwh and 146 million kwh respectively), and the total agcultural requirement mentioned above (1300 million kwh), an increase of 187 million kwh is calculated for August. When this figure is applied to the estimated load factor (.648) for August used in the PG&E report, an additional 401 MWe on peak are required. This value is 88 MWe greater than the peak load addition projected by PG&E.

Since PG&E predicts an even larger increase in agricultural load in September (328 MWe), similar calculations were made for that month. Using the procedure mentioned above, it was found that 419 MWe were added to the average peak load. Because of the different monthly load factor (.663) for September the difference between PG&E's projections and our estimates amount

to an additional 91 MWe on peak load. This increased energy requirement if considered along with other loads will probably not cause a severe drain on the electrical reserve capacity.

In a more recent response to the State Energy Commission PG&E has shifted the predicted maximum peak load from August to July. Furthermore, the maximum peak capacity is increased by 62 MWe (14651 to 14712 MWe). The response does not however mention specific changes in the agricultural sector. Therefore it is unclear if any changes are made in PG&E's projections of increased agricultural demands under dry year conditions.

Potential Energy Conservation Stategies in Agriculture During 1977

In California about 85 percent of water demand derives from the agricultural sector, while only 13 percent originates from urban sources including residential, nine percent, commercial, two percent, and industrial two percent. A 75 percent savings in residential use of water would cause about a seven percent decline in total water usage, while a mere eight percent savings in agricultural use can yield the same results. Concomitant with these decreases in water use are certain reductions in energy demands. In seems appropriate therefore to address the topic of potential energy conservation strategies associated with agricultural water use in California.

In general, California farmers can be credited with using effective irrigation practices. Even though irrigation efficiencies are generally higher in California than in other western states, various water and energy conservation methods offer potential on-farm savings. The conservation strategies can be classified as short-term methods which require minor adjustment in current practices, and long-term methods involving an investment of time and capital by the irrigation districts and the individual farmers.

The practice most likely to occur during the drought year such as 1977 involves a switch to short season crops. This minimizes the water loss by evapo-transpiration and subsequently the amount of water applied (AF/acre). In the case of annual crops, farmers do have some flexibility in shifting to shorter cycle crops or eliminating a second crop in a dry year. Furthermore, there is the possibility of substituting crops with low-water demand for high-water demand crops. The latter situation seems to be representative of this growing season since there is expected to be a statewide decrease in rice and sugar beets, which are high-water use crops, and a record

increase of cotton, which is a relatively drought-resistant crop.

Another potential near-term approach involves the leaching requirement, which is a measure of the net salt flow in the root zone of the plant. Within certain hydrologic basins there is the possibility of allowing salts to concentrate for one season by limiting the amount of water that is applied for leaching. Substantial quantities of water and energy can be conserved by limiting deep percolation of water.

The largest water loss is by mature plants through evapo-transpiration. There are some promising measures for retaining water on the land to reduce pumping costs. An example of such a measure is mulching the surface of the soil to reduce evaporative losses. In addition, procedures are available and used to retard transpiration in mature plants. Since some of the chemicals used in this process also reduce the crop yield by interfering with the oxygen transport system, they are to be employed with some caution.

A final strategy of energy and water conservation related to the control of water losses is to use night irrigation systems where practicable. Not only would the amount of evaporation be reduced substantially, but some of the irrigation pumping would be shifted from on-peak to off-peak hours. This shift would help to reshape the load curve.

ENERGY REQUIREMENTS FOR RESIDENTIAL AND INDUSTRIAL WATER USE*

Objectives

This section focuses on residential and industrial water demand and the energy associated with water use. These two sectors account for nine and two percent of the 1972 California water demand, respectively;[11] agriculture accounts for 85 percent.[10] Taken together, the study accounts for 96 percent of the state's water use. The electricity requirements for this water use are comparatively small when viewed in the context of total California electricity consumption. For example, the annual residential and industrial electricity consumption associated with water use is estimated to be about 6.5 billion kwh; for agriculture the annual energy consumption is about 4 billion kwh. These requirements are 4.5 percent and 3 percent respectively, of total electrical energy consumption. Although these are small fractions of total use, they may be affected by the drought and, if significantly altered, could impact both capacity reserve margins and fuel use associated with electricity generation.

The objectives of this section are to:

1. Determine present water use in major geographic regions of California by industrial sectors and residential end uses;
2. Estimate the energy associated with this water use;
3. Determine the impact of present and potenital water conservation efforts for reducing energy and peak power demand in addition to water consumption;
4. Pinpoint the water conservation strategies that are likely to have the largest impacts on energy and water demand.

Description of Approach

To accomplish these objectives, a scenario for water consumption and the associated energy use is constructed for the residential and industrial

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*Condensed from a forthcoming study on water and related energy use in the residential and industrial sectors.

sectors. The scenario is disaggregated by residential end use, industrial sector, and hydrologic study area (HSA). The sectoral and end-use disaggregations are used to determine the potential for energy and water reductions from specific water conservation measures. The geographic disaggregation is used to reflect the variability in energy requirements for water delivery across the state. Generally, the major sources of water in California are not located near the major points of use. Water is conveyed from northern California to southern California, from the Sierra to the Central Valley and San Francisco, from the Owens Valley to Los Angeles, and from the Colorado River to San Diego and Los Angeles.[13] There are also regional differences in the energy required for groundwater pumping. The disaggregation by HSA's helps to capture the different energy requirements for water delivery.

Residential

The calculations for the residential sector begin with an estimation of interior and exterior water use. Interior use is broken down into detailed end uses such as toilet flushing, bathing, etc. (shown in Table 16). The energy use associated with this water use is then calculated. Estimates are made for groundwater pumping, surface water conveyance, distribution, heating, and waste water treatment for each hydrologic study area (Table 17). Both energy and water use are extrapolated to 1977, based on the historical per capita consumption and the average annual population growth rate.[14] From this point, two alternative calculations are made.

1. Expected water and energy consumption by HSA for the summer of 1977 are estimated based on anticipated water conservation efforts in each region. The data for this calculation are derived from a survey of water consumption by HSA in April 1977.

2. Potential water and energy use from implementation of water conservation measures for each end use are estimated. This calculation is based on an investigation of the water conservation measures applicable to each residential end use and on estimates of the savings potential for each measure. The latter serves as the factor by which average per capita water and accompanying energy consumption are reduced. Thus water conservation can be viewed as a strategy for reducing peak power and energy demand as

Table 16

Residential Interior Water Use

End Use	Temperature °F	Gallons/ Person Year	Comments
Toilet	60	9125	5 gallon toilet flushed 5 times per day
Bathing	105	7300	5 showers per person per week, 5 gallons per minute, 5-6 minutes per shower
Laundry	130	3194	62 gallons per person per week
Dishwashing	105-140	1369	
Cooking,Drinking	60	1095	
Bathroom Sink	105	730	
Utility Sink	105	456	
TOTAL		23,269	

Sources:

1. Clear, Robert,"Technical Aspect of Energy Conservation in Residential Hot Water Heaters,"unpublished LBL report.
2. Institute for Research on Land and Water Resources, Pennsylvania State University, Proceedings, Conference on Water Conservation and Sewage Flow Reduction and Water Saving Devices, Information Report No. 74, July 1975.
3. Mutch, James J.,"Residential Water Heating, Fuel Conservation Economics and Public Policy," Rand Corporation Report No. R-1498.
4. Quinn, Jr., Richard S., "The Effects of Increased Capital Expenditure as a Method of Reducing Electricity Demand for Hot Water Generation in New Homes," M.Sc. Thesis, University of Tennessee, Knoxville, TN, August 1972.

Table 17

Energy Requirements for Water Use[a]

HSA	Delivery[b] kwh/gallon X 10^{-3}	Distribution[c] kwh/gallon X 10^{-3}	Waste Water[d] Treatment kwh/gallon X 10^{-3}
North Coastal	0.22	--	1.149
San Francisco	0.73	0.8	0.140
Central Coastal	0.54	--	1.149
Southern Coastal	1.123	0.3	0.946
Sacramento Basin	0.23	--	1.149
Delta Central Sierra	0.57	--	0.140
San Joaquin	0.66	--	0.214
Tulare Basin	1.05	--	0.214
North Lahontan	0.29	--	1.149
South Lahontan	0.96	--	1.189
Colorado Desert	0.66	--	1.149

[a]Energy requirements for water heating are assumed constant across HSA's. They are 196 X 10^{-3} kwh/gallon and 9.53 X 10^{-3} therms/gallon. They are derived by assuming a 70 percent efficiency for gas hot water heaters, a 99.5 percent efficiency for electric hot water heaters and 666 BTU/gallon to heat hot water from 60°F to 140°F.

[b]1) Department of Water Resources, State of California, Sacramento.
(i) Bulletin 132-75. The California State Water Project, 1975.
(ii) Bulletin 166-2. Urban Water Use in California, 1975.
2) U.S. Bureau of Reclamation, "Central Valley Operations: Report of Operations," Central Valley Operation Coordination Office, Sacramento, CA, December 1976.

[c]Personal communication with staff members of EBMUD, LADWP, Sacramento City Water, San Diego Water Department, and San Francisco Water Department.

[d]Hagan, Robert M. and Roberts, Edwin B., "Energy Requirements of Alternatives in Water Supply and Waste Water Treatment," National Water Supply Improvement Journal, January 1977.

well as water consumption. The residential water conservation measures and potential savings are given in Table 18. These measures can be implemented immediately. Also, they require little additional equipment, so there will be minimal cost to the consumer.

Industrial

The calculation for the industrial sector begins with the identification of the largest industrial water users. They are, in decreasing order of water use: 1) Food and Kindred Products; 2) Lumber and Wood Products; 3) Paper and Allied Products; 4) Chemical and Allied Products; 5) Petroleum and Coal Products; 6) Stone, Clay and Glass Products; and 7) Primary Metals. These sectors account for 86 percent of the industrial water use in California (see Ref. 15, Table 6). The rest of the industries are aggregated into a category called Other Industries. Fresh and brackish water use for each industry are estimated, as are the energy requirements for water delivery by HSA. Energy requirements for water distribution have been included for the two largest industrial areas, the San Francisco and South Coastal HSA's. Energy and water use per employee are calculated and then total water and associated energy use for 1977 are estimated based on an extrapolation of employment in each industry.[16,17] From this point the same two calculations made for the residential sector (expected water and energy consumption and potential water and energy consumption with full conservation implementation) are repeated for the industrial sector.

The water conservation measures for the industrial sectors are broken down by industry, and subsequently by three generic categories—housekeeping, cooling, and effluent reduction for reuse. This categorization corresponds to the three ways that water used in industry can be conserved; either it is wasted, in which case housekeeping measures apply; its temperature is increased, in which case it can be cooled for reuse; or its quality is decreased, in which case it can be used in processes that require lower quality water, or it can be purified and reused. The applicability of these three general types of water conserving measures to the seven largest water consuming industries is summarized in Table 19. This table also shows the estimated water conservation potential in each industry. The

Table 18

Residential Water Conservation by End Use

End Use	Overall Savings from Water Conservation	Derivation and Sources
Toilet	28%	Two quart plastic bottles in 5 gallon tank - 10% Reduce number of flushes per day from 5 to 4 - 20%
Bathing[a]	57%	Flow control restrictors - 40% Reduce showering time from 5.6 to 4.6 minutes - 18%
Laundry[b,c]	14%	Existing stock: Wash full loads; Check for leaks; Save and reuse cleanest rinse water - 5% savings assumed Wash on shortest cycle - eliminate prewash --10% New machines: Buy most water-efficient appliance
Dishwashing[b,d]	41%	Existing stock: By machine: plug leaks; wash only full loads - 5% savings assumed By hand: aerators - 50%, plug leaks, shut off water when not in use, 5% savings assumed Dishwasher saturation assumed to be 24%
	50%	New stock: Buy most water-efficient appliance
Cooking, Drinking	5%	Reuse boiling water in soups or other cooking; save unused drinking water - 5% savings assumed

Table 18 (Continued)

End Use	Overall Savings from Water Conservation	Derivation and Sources
Bathroom Sink[d]	50%	Collect running water while waiting for water to get hot; turn off water while not in use, e.g. while lathering hands and face or brushing teeth; use cup while brushing teeth , install aerator
Utility Sink	50%	Install aerators and apply all relevant measures given for bathroom sink
Exterior Use	50%	Landscape watering: Use household greywater Water with hand-held hose, soak hose, or drip irrigators Eliminate use of sprinklers Water during low wind periods Do not overwater plants Plant drought-resistant varieties Collect rainwater in barrels Sidewalks: Sweep, do not wash Swimming Pools: Cover to reduce evaporation loss Empty pool Car Wash: Wash and rinse with bucket, not hose

[a] Personal communication with staff of Marin Municipal Utility District.

[b] Department of Water Resources, State of California, Sacramento, "Water Conservation in California," Bulletin 198, 1976.

[c] Personal communication with a commercial laundry.

[d] Milne, Murray, Residential Water Conservation, California Water Resources Center Report No. 35, Davis, CA, March 1976.

Table 19

Water Conservation Measures Applicable to Industry[a]

	Food & Kindred Prod.	Petroleum & Coal	Paper & Allied Prod	Chemicals & Allied Prod.	Lumber & Wood Prod.	Stone, Clay & Glass	Primary Metals
Water Consumption[b] (10^6 gallons)	83852	55043	55646	26185	22013	15167	10335
Percentage of Total Industrial Water Use	27	18	18	8	7	5	3
Type of Conservation Measure[c]							
1. Housekeeping							
a. leak plugging	X	X	X		X		X
b. waste reduction	X	X	X		X	X	
2. Cooling							
a. dry		X				X	
b. wet	X	X	X	X	X	X	X
c. spray ponds							X
3. Effluent Reduction for Reuse							
a. filter	X	X			X	X	X
b. reverse osmosis							X
c. flocculent						X	X
d. counter flow	X				X		X
e. reuse as is	X		X	X	X		X
f. wetting agents							X
g. closed systems		X		X	X		X
h. high pressure steam	X				X		X
Savings of Water and Energy from Water Conservation (%)[d]	5-7	24-48	10-50	5	5	5	5

[a]X denotes applicability as indicated in the source document listed in c below.

[b]Department of Water Resources, State of California, Sacramento, "Water Use by Manufacturing Industries in California 1970," Marcy 1977.

[c]U.S. Environmental Protection Agency. Development Document for Proposed Effluent Limitations Guidelines and New Source Performance Standard for ___ (Industry) (14 separate documents used). Point Source Category 440 Series. Washington, D.C., Jan. 1974.

[d]U.S. National Commission on Water Quality Report, Washington, D.C., April 1976.

industry and process-specific measures within each category will be presented in a more complete treatment of the residential and industrial sectors to be issued separately.

Results

The calculations described above provide an estimate of the 1977 water and related energy use in the residential and industrial sectors without water conservation (Table 20). Industrial water-related energy requirements are given by industry and HSA in Table 21 to show where each type of production is concentrated. The totals are 1694 billion gallons of water and 6.5 billion kwh of electricity. Total annual electricity use in California is approximately 150 billion kwh, so without water conservation the energy requirements for water consumption are approximately 4.5 percent of statewide electricity use.

A comparison of water consumption during the first four months of 1977 in the major urban areas with information for the same time period in 1976 yields an estimate of water conservation that is presently being implemented.[18] The statewide reduction is 13 percent, with the most appreciable savings occurring in the San Francisco, Central Coastal, North Coastal and Delta Central HSA's (18-20 percent) and the least occurring in the South Coastal and Sacramento Basin (1-3 percent). An application of the overall 13 percent reduction to the 1977 estimates yields a savings of 220 billion gallons of water, or two percent of the state's total water use, and 0.9 billion kwh, or 0.6 percent of total electricity consumption in California.

If the conservation measures listed in Tables 18 and 19 were fully implemented, water consumption would be reduced by 35 percent with a concomitant energy savings of 39 percent (Tables 22 and 23). This amounts to two percent of the state's total energy use and five percent of its water use. A comparison of these figures with the savings currently being achieved indicates that only 35 percent of the potential savings are being realized. Moreover, the savings potential shown in Table 22 and 23 are believed to be conservative, primarily because data for the industrial sector are inadequate to assess the full potential for water conservation, and because greater savings have already been reported for some water districts (e.g., EBMUD and MMWD).

Table 20

Water and Associated Energy Consumption by HSA

Hydrologic Study Area	Without Water Conservation					With 100% Water Conservation Implementation				
	Residential			Industrial		Residential			Industrial	
	Water 10^6 Gal.	Electricity 10^6 kwh	Natural Gas 10^6therms	Water 10^6 Gal.	Electricity 10^6 kwh	Water 10^6 Gal.	Electricity 10^6 kwh	Natural Gas 10^6therms	Water 10^6 Gal.	Electricity 10^6 kwh
1. North Coastal	12028	69	22	27213	6	7061	41	13	24741	5
2. San Francisco Bay	241230	1334	353	161401	144	137802	786	210	137165	126
3. Central Coastal	48530	232	67	17687	4	27527	139	40	16329	3
4. South Coastal	608883	3554	865	128660	141	346515	2101	515	110779	123
5. Sacramento Basin	115853	312	93	24406	6	62438	186	55	22897	5
6. Delta-Central Sierra	33679	119	36	53277	16	18611	70	22	46191	14
7. San Joaquin Basin	45736	126	35	23320	15	24560	73	21	22086	14
8. Tulare Basin	86027	257	60	18118	19	45957	148	36	16893	18
9. North Lahontan	3024	11	3	1152	1	1672	7	2	1094	1
10. South Lahontan	21851	93	24	7033	6	12070	55	14	6432	6
11. Colorado Desert	13990	47	12	1104	1	7589	28	7	1024	1
12. Total California	1230823	6155	1570	463371	357	691801	3632	935	405632	316

Table 21

Energy Requirements for Total Water Delivery During 1977
(Thousands of Kilowatt-Hours)

		Food and Kindred Products	Lumber and Wood Products	Paper and Allied Products	Chemical and Allied Products	Petroleum and Coal Products	Stone, Clay and Glass Products	Primary Metals	Other Industries	Total Industries
1	North Costal	69	1043	4863	1	6	4	0	1	5987
2	San Francisco Bay	33610	1883	27629	17302	53513	4660	3609	2435	144641
3	Central Costal	1945	4	149	159	510	804	49	76	3696
4	South Costal	33187	322	16255	11740	50048	11790	9539	7679	140560
5	Sacramento Basin	2224	1766	1267	247	16	71	7	15	5613
6	Delta-Central Sierra	8209	350	1703	2013	2819	472	36	63	15665
7	San Joaquin Basin	13251	329	150	476	12	396	6	16	14637
8	Tulare Basin	11287	2139	30	2920	1755	703	69	121	19024
9	North Lahontan	1	329	0	0	0	3	0	0	334
10	South Lahontan	1873	52	140	153	736	904	459	333	6033
11	Colorado Desert	178	4	12	86	30	184	144	12	651
12	Total California	105836	8222	52199	36481	109445	19992	13918	10749	356842

Table 22

Residential Water and Associated Energy Consumption by End Use

End Use	Without Water Conservation			With 100% Water Conservation Implementation		
	Water 10^6 gal	Elec 10^6 kwh	Nat Gas 10^6 therms	Water 10^6 gal	Elec 10^6 kwh	Nat Gas 10^6 therms
Toilet	213658	441	0	153834	318	0
Bathing	170927	2426	769	73498	1043	331
Laundry	74780	1565	529	64316	1346	455
Dishwashing	32055	453	145	18912	268	86
Cooking	25639	53	0	24357	50	0
Bathroom Sink	17093	244	77	8546	122	39
Utility Sink	10677	152	49	5339	76	25
Exterior	685998	821	0	342999	410	0
TOTAL	1230832	6155	1570	691801	3632	935

Table 23

Industrial Water and Associated Energy Use by Sector

Sector	Without Water Conservation		With 100% Water Conservation Implementation	
	Water 10^6 gal	Electricity 10^3 kwh	Water 10^6 gal	Electricity 10^3 kwh
Food and Kindred Products	115447	105836	109674	100544
Lumber and Wood Products	18215	8222	17304	7810
Paper and Allied Products	83527	52199	75175	46980
Chemical and Allied Products	53005	36481	50355	34657
Petroleum and Coal Products	159967	109445	121575	83178
Stone, Clay and Glass Products	16065	19992	15262	18992
Primary Metals	9656	13918	9173	13222
Other Industries	7489	10749	7114	10212
TOTAL	463371	356842	405632	315595

Water supply for the San Francisco HSA requires energy for distributional pumping while simultaneously generating energy at several hydroelectric plants along the Hetch-Hetchy and Mokelumne water supply systems. Water conservation will decrease the energy requirements for pumping but may not decrease electricity generation. On the Hetch-Hetchy system, water can be diverted for electricity generation at the two aqueduct power plants (Kirkwood and Mocassin), then returned to the Tuolumne River system at New Don Pedro Reservoir. Hence reduced water flow from Hetch-Hetchy to San Francisco may not adversely affect energy generation. On the Mokelumne system, there is no generating equipment on the water supply aqueduct; therefore reduced flows through this facility will not decrease energy generation.

Conclusions

The reduction in electricity consumption due to reduced industrial and residential water use, while large in absolute amount, is small relative to total statewide electricity consumption. These savings would lead to a decreased consumption of nonrenewable fuels and, consequently, to decreased pollutant emissions. The natural gas savings from residential water conservation however are more substantial, amounting to 635 million therms or 63.5 trillion BTU's.

The regions with the largest energy requirements for water delivery and distribution are the South Coastal, San Francisco and Tulare Basin HSA's. Moreover, the first two are the areas where the bulk of the state's population lives and where industry is concentrated. Water conserving measures in these areas, especially those that reduce the largest residential hot water use (bathing and laundry) can have a large impact on energy consumption. In the Tulare Basin HSA, due to the high energy requirements for groundwater pumping, substantial reductions in energy use could be achieved by reducing exterior water use.

Overall residential water consumption can be reduced by about 44 percent by implementing the water conservation measures listed in Table 18. These conservation measures can be implemented immediately at minimum financial outlay. Electricity and gas consumption associated with this water use can drop by the same percentage. These rates of water and associated energy savings have already been realized in some water districts, but

generally the water savings are only 35 percent of the potential indicated in Tables 18 and 19.

Energy is required to deliver and distribute water, to heat water for residenital use and to treat waste water. Of these, energy for water heating is the dominant usage. Bathing,the second highest interior end use, requires the most energy because of the large volume of hot water used. More energy is saved in the form of natural gas than electricity because most residential hot water heaters use gas.

Overall industrial water consumption and its associated energy requirements for delivery and distribution can be reduced by 12 percent (Table 23). Because some of these conservation measures for water reuse require retrofitting existing equipment or installing new machinery, not all savings could be realized by this summer. The conservation measures that can be applied most immediately are 1) housekeeping measures such as leak plugging, waste reduction, elimination of unnecessary cleaning, and turning off pumps and spigots not in use. 2) closed-cycle cooling water reductions such as filter and automatic temperature control installation, reuse of cooling blowdown water,[19] and 3) reuse of process water where extensive retrofitting of equipment is not required.

From the data gathered thus far, the greatest savings potential among the large industrial water users occurs in the Paper Products and Petroleum sectors (Table 19). A tentative conclusion is that large inroads could be made by concentrating water conservation efforts in these sectors. This conclusion bears further investigation and does not imply that significant savings are not achievable in other sectors. Special attention should be given to the Food Processing sector because it is the largest industrial water user.

IV. ELECTRICITY SUPPLY

Steam electric generation forms the bulk of energy generating capacity in California. Roughly 23,300 MWe of a total in-state capacity of 32,800 MWe are supplied by steam electric generation. Most of the steam electric power plants are located along the coast and use sea water for once-through cooling. Presently fresh water requirements for the power plants sited inland amount to roughly 32,000 acre-feet per year. Adequate fresh water supplies for these power plants this year are available. The drought is therefore not expected to directly affect steam electric generation in California.

In terms of electricity supply, the largest effect of the drought is the impairment of hydroelectric generation in California. Table 24 lists the amount of hydroelectric energy received by California utilities in the previous two years, and the amounts expected for 1977. As can be seen, the decline in this resource has been dramatic. PG&E, with hydroelectric generation comprising 38 percent of its total generating capacity in an average water year, expects only 32 percent of its normal in-state hydroelectric energy generation for 1977. Month-by-month energy supplies are shown in Fig. 3 for PG&E, along with a comparison with 1976 and 1975. (Note that energy and power for PG&E is on a service area basis and includes USBR and DWR resources and demands.) Last year as in-state hydroelectric generation decreased more energy was purchased from the Pacific Northwest. This year with rainfall less than 50 percent of normal in the Columbia River Basin the California utilities do not expect to receive non-firm hydroelectric energy.

Throughout this past Spring, the utilities revised their estimates of hydroelectric energy downward, as a comparison of the three submissions to the CERCDC shows.[1] The last of these submissions is based on snow survey data of April 1, 1977, and estimates of future rainfall.[1c] Since that time, rainfall during April and May was slightly above projections; hence it appears that PG&E will be able to generate about three percent more from its hydroelectric resources than is indicated in the last submission to CERCDC.[1c] No further changes in hydroelectric energy availability are anticipated, since little additional rainfall is expected before October.

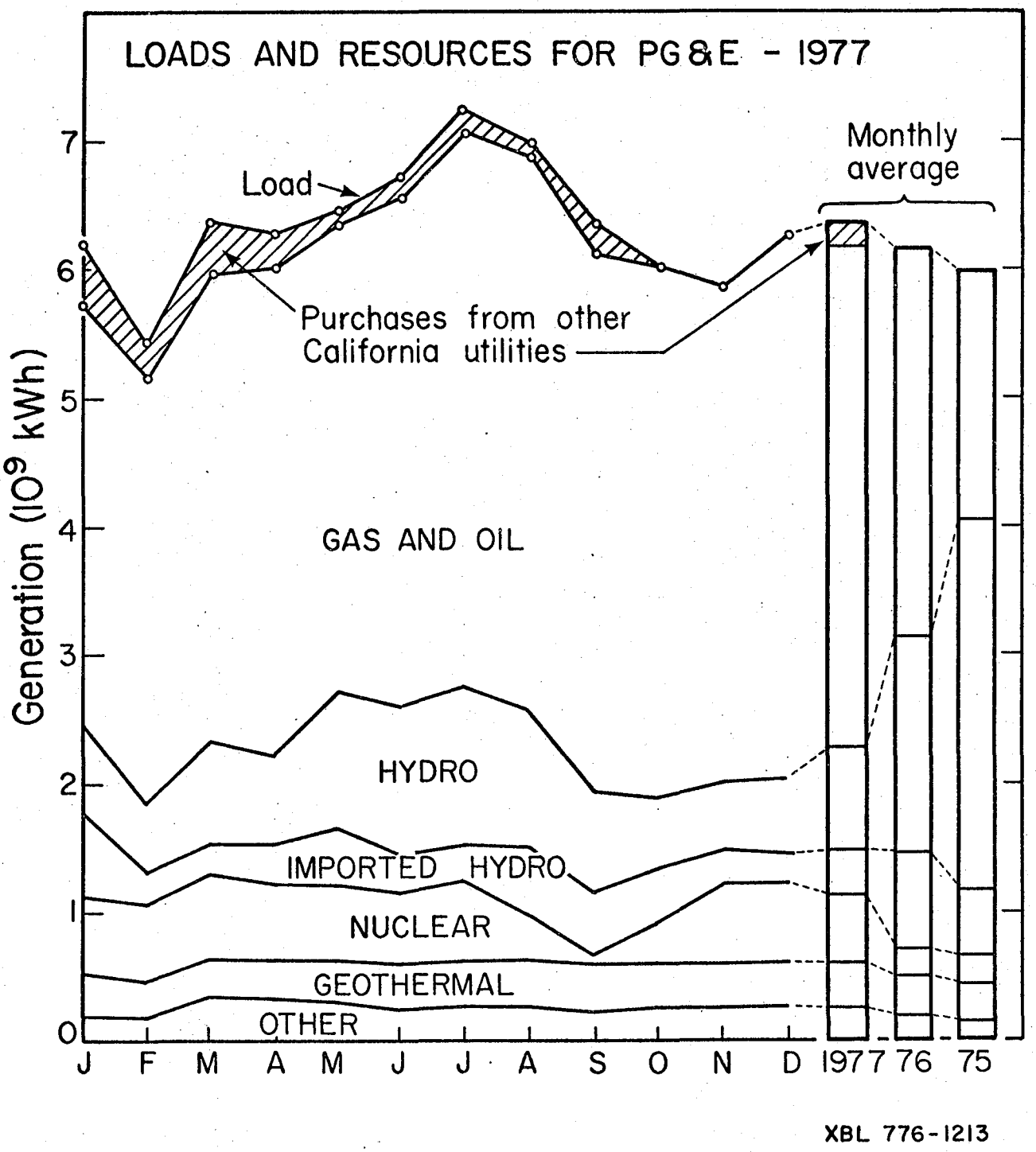

Fig. 3 Monthly load and resources for PG&E with a comparison to previous years

Table 24

Hydroelectric Supply in California
(10^6 kwh)

Service Area	1975[a,b]	Percent of total supply to service area	1976[a]	Percent of total supply to service area	1977[c]	Percent of total supply to service area	Change 1975-76 (%)	Change 1976-77 (%)
In-State Supply								
PG&E	30521	43	17812	24	9667	13	-42	-46
SCE	6300	11	4075	7	4603	7	-35	+13
LADWP	2319	11	2012	9	1156	6	-13	-43
SDG&E	52	0.6	30	0.3	45	0.4	-43	+50
Total Hydroelectric Supply[d]	39191	25	23928	14	15471	9	-39	-35
Total Electrical Energy Supply for State[d]	157336		166265		171168		+ 5.7	+ 2.9

[a]Source: Quarterly Fuel and Energy Summary, Vol. 2, No. 4, 4th Quarter, 1976, CERCDC.

[b]1975 had higher than normal runoff levels and this should not be viewed as a baseline or "normal" water year.

[c]Source: Combined Response of California Electric Utilities, Docket 77-EA-1, May 11, 1977, CERCDC.

These totals exclude those utilities not included in the loads and resources listed in Ref. c above. The largest of those omitted are the Imperial Irrigation District and Pacific Power and Light. In 1975, 1589 GWh of hydroelectric energy was generated by these utilities, while for 1976, 1024 GWh were generated by these hydroelectric resources.

The expected statewide peak loads and capacity resources available to meet them are shown in Fig. 4 for the months of June through September. The capacities are corrected for planned maintenance and the monthly reserve margin is also shown.

The following sections discuss the hydroelectric and thermal supplies, a reliability analysis of the capacity resources and an analysis of the expected environmental effects due to increased fossil fuel use.

Hydroelectric Energy Supply

From conversations with members of the staffs of DWR, USBR, and PG&E, the strategy for hydroelectric generation in California this drought year appears to be to limit reservoir releases to stream flow maintenance and contracted water requirements, with many if not most of the contract water deliveries being curtailed somewhat. Energy generation has been a byproduct of these necessary water releases rather than a primary justification for them. The generation schedule for hydroelectric energy available to PG&E from within California is being dictated almost exclusively by downstream water needs. This means there is little flexibility in the monthly water delivery schedule that would allow a delay of water releases until the summer peak. Therefore the shortfall in California hydroelectric generation, especially for peaking capacity will continue to be made up by increased use of thermal generation.

With regard to in-state hydroelectric sources, in an average water year PG&E has nearly 5600 MWe of hydroelectric capacity in its service area (this includes DWR, USBR, irrigation and water districts). This year the peak capacity is expected to drop to 5000 MWe in May and decline steadily throughout the summer to a low point of 3234 MWe (see Appendix A) in October. (October is the beginning of the next water year.) This capacity decline is expected as reservoir levels decrease, although several of the powerhouses are at the base of long penstocks, thus will experience little decrease in capacity. On the other hand at Shasta with its 450 MWe power plant at the base of the dam, both energy production and capacity will decrease. Appendix B shows the expected decline in reservoir storage levels for PG&E, USBR and CDWR throughout the remainder of this year. One notes there is little water carry-over for next year. If 1978 is similar

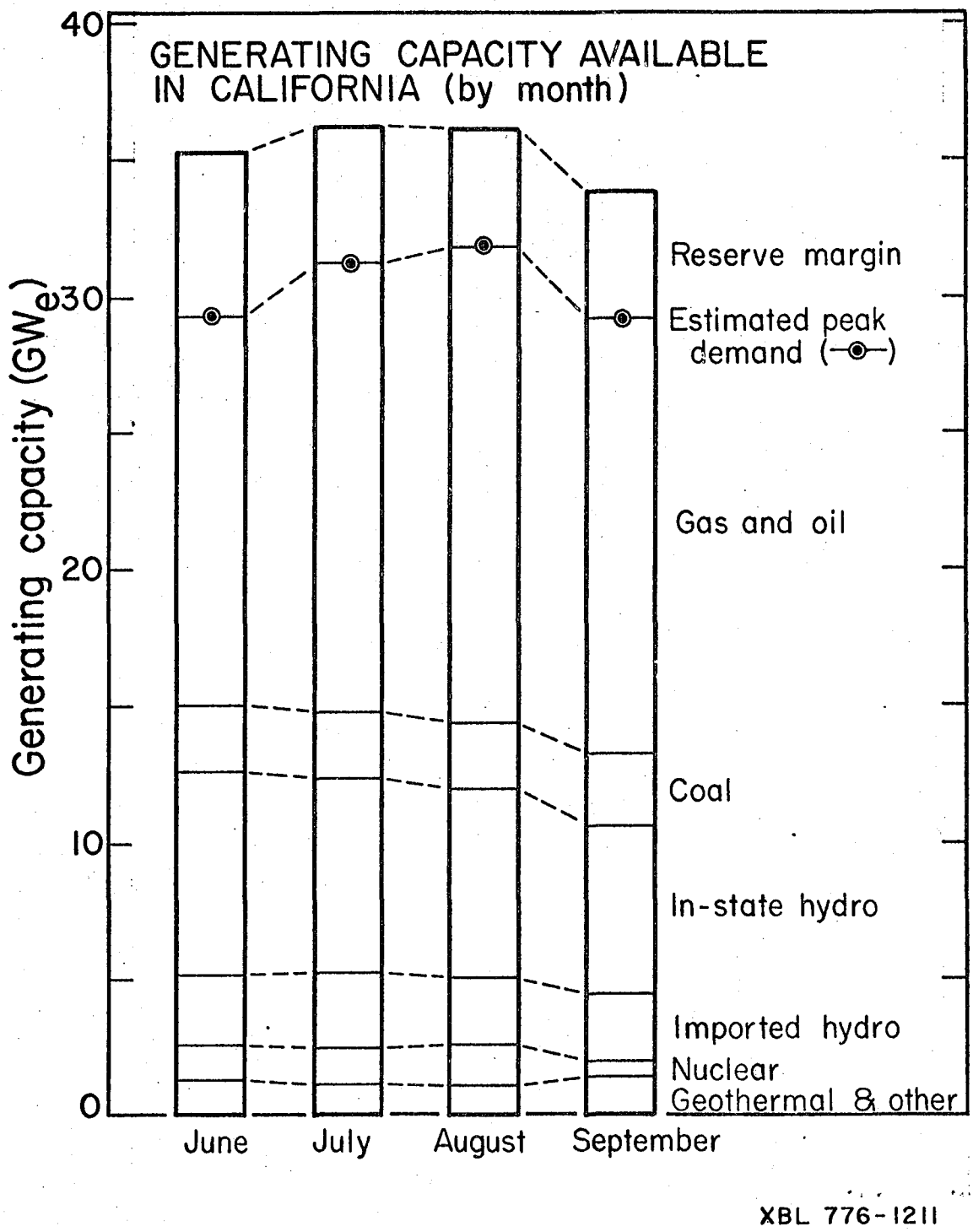

Fig. 4 Capacity resources available for California by month, summer 1977

to the past two years, water for energy production will be in extremely short supply.

Hydroelectric capacity for SCE shows a similar, though slower, decline throughout the summer. Since part of SCE's resource is Hoover Dam, located on the lower Colorado River, the decline in generating potential is not as great due to the large storage capacity at Lake Mead.

LADWP is in a similar situation with regard to in-state resources (or resources under their operational control). Part of the resource is power from Hoover Dam, which has not been substantially affected by the drought. In fact, hydroelectric capacity peaks in August, then declines, while the energy available from this resource declines through the summer, with a one month increase in August.

The situation relative to Pacific Northwest (PNW) power is somewhat different. Although "excess" or "dump" hydroelectric energy will not be available this year, the California utilities expect to receive 2526 MWe in July and 2576 MWe in August (all firm power) and almost 5350 GWh of energy for 1977. This includes 206 MWe of DWR's 300 MWe of Canadian Entitlement Power (CEP). Since water releases in the PNW do not have the same downstream constraints as in California, some hydroelectric generation can be delayed until summer. This allows "banking" of energy by the California utilities (notably PG&E); that is, energy from California thermal generating plants is transmitted to the PNW and used to serve local loads in place of PNW hydroelectric energy. This displaced hydroelectric potential is banked in the form of water retained for release at a later time. PG&E had, as of May 9, banked nearly 700 GWh. According to information in Ref. 1c they expect to draw on part of this energy in August, September and October, primarily to offset energy that will not be available from Rancho Seco nuclear power plant, which is expected to be shutdown for refueling beginning August 19.

PG&E expects 1500 MWe of firm power to be available from the Northwest from June through September (see Appendix A). Four hundred MWe of this will come from Portland General Electric (PGE) and 600 MWe from the Bonneville Power Administration (BPA). This power will be available for PG&E's service area load on an energy-exchange basis. An additional 400 MWe will be delivered to the U.S. Bureau of Reclamation's Central Valley Project (CVP) from a coal-fired power plant in Centralia, Washington. The

final 100 MWe is Canadian Entitlement Power (CEP) contracted for through the California State Department of Water Resources (DWR).[20] The CVP and the SWP have contracted for the energy that comes with their 500 MWe power. PG&E has been banking energy which can be used to help support 1000 MWe of the 1500 MWe.

During normal year operations the DWR utilizes CEP power (100 MWe), some additional in-state utility power (20 MWe), and recovery generation from San Luis, Castaic, and Devil Canyon (30 to 50 MWe) for on-peak pumping. The use of this power on-peak is not dictated by water delivery requirements; there is sufficient flexibility in the State Water Project at present delivery levels to pump entirely off-peak. However, since there are no contractual or other incentives some of the SWP pumps are operated continuously through the peak to reduce the frequent start-up and shut-down occurences. Operation of these pumps during off-peak hours would relieve PG&E's on-peak load. PG&E and DWR are at present negotiating to allow PG&E to utilize the 100 MWe of released CEP power for other loads.

SCE has 650 MWe of contract (firm) power from the PNW. Of this 464 MWe is from BPA, 86 MWe is CEP power via DWR contracts, and 100 MWe is from Portland GE. Both the BPA and Portland GE capacities are on an energy exchange basis, i.e., the energy taken with capacity must be returned.

SDG&E similarly has 112 MWe of exchange energy power available from Washington Water Power, and another 20 MWe of CEP power via DWR. Among the four major utilities, SDG&E has no hydroelectric generating capability of its own. The only in-state source of hydroelectric power and energy to SDG&E is from its share of the DWR operation at Oroville-Thermalito.

LADWP has 525 MWe of power from BPA, also on an energy exchange basis. However, the recent submissions to CERCDC indicate that LADWP expects to obtain only 200 MWe in June, 250 MWe in July, 300 MWe in August and 200 MWe in September. Apparently this decreased capacity is due to recently instituted requirements by BPA that LADWP return the exchange energy within 24 hours. Given the shape of the LADWP load curve, and the fossil-fired capacity available, energy to support only 300 MWe (at peak) is all that these limitations would allow.

The expected results of hydroelectric operations are presented in Appendix A and are summarized in Table 24. PG&E's plans call for energy from hydroelectricity to have been 706 GWh for April and to increase each month into July reaching a peak generation of 1204 GWh. Hydroelectric generation decreased by 127 GWh in August, and then falls dramatically in September and October. This pattern of generation would fit the seasonal pattern of water releases which peak with summer irrigation releases.

In considering the generating capacity available for the coming summer pumped storage potential should not be overlooked. There are three pumped storage facilities in California located at San Luis Reservoir, at Lake Oroville, and at Castaic Lake. At San Luis and Oroville, water release requirements prevent storage of water until needed solely for generation. However, they are expected to have sufficient water to generate electricity during the summer peak. If their afterbays are kept relatively empty at crucial times, then water releases for electricity genration need not coincide with water deliveries. The water in the afterbay could then either be delivered at the appropriate time or pumped back into the main reservoir for use in a subsequent critical period. This pump-back operation is expensive due to the energy losses and the unavailability of cheap off-peak power. Clearly there is no reason to use pumped storage to meet the peak on days when other power is available. But on days when the peak load might otherwise not be met these pumped storage facilities could be used.

Castaic Lake operated by LADWP has approximately 850 MWe of capacity, which could be used in a pump-back mode of operation. However, due to the unavailability of cheap off-peak energy, the operation of Castaic in such a manner appears to be economically unattractive. LADWP presently includes only part of this capacity in their submittals, claiming the remainder as spinning reserve. Should an unexpectedly tight peak demand situation occur this year this facility could be used to full capacity.

Thermal-Electric Energy Supply

The shortfall in hydroelectric energy supply will be made up primarily by greater reliance upon thermal generation sources. Of these, the predominant fuel is oil, comprising nearly 70 percent of the total statewide

capacity. Some natural gas (category P-5) is available as boiler fuel, primarily in the PG&E service area. However, most of the fossil-fired plants, once fired almost exclusively by natural gas, have switched to oil although most of these plants are still capable of using natural gas as fuel.

Although PG&E has nearly 7300 MWe of fossil-fuel capability, this resource will not be adequate to supply all the energy requirements expected during the summer months of June through September. PG&E has made arrangements to purchase make-up energy from the other California utilities, 63 percent from SCE, 26 percent from LADWP and 11 percent from SDG&E. In this context, it should be noted that the 900 MWe nuclear power plant at Rancho Seco is still scheduled for refueling beginning the latter part of August and all of September. As discussed in the previous section, PG&E will draw on its energy banked in the PNW as well as purchase energy from the other California utilities during that period.

With respect to capacity to meet peak loads, the reserve margin for PG&E (without interconnection support) is expected to be between 4.3 and 8.0 percent for the critical summer months.[1c] The operational spinning reserve requirement used by PG&E is taken to be the size of the largest single unit plus three percent of the peak load. For the PG&E service area, the largest single unit is Rancho Seco (nominally 900 MWe). Three percent of the annual peak load expected in July is 440 MWe, hence the capacity margin equivalent of the spinning reserve is 1340 MWe, or 9 percent of the expected peak demand. For July PG&E expects a margin of 738 MWe after scheduled maintenance. The remaining margin will be made up by 600 MWe from southern California.

The capacity margin of the three major southern California utilities (after scheduled maintenance) is 4119 MWe in July and 3540 MWe in August, or 25 percent and 20 percent of the respective monthly peaks. Combined with PG&E, the statewide reserve margin is expected to be 15.5 percent in July and 13.1 percent in August. Thus interconnection support will enable PG&E to have an adequate reserve margin and at the same time will not adversely affect the margin of the other California utilities. We discuss reliability and loss of load probability in the following section.

We have calculated the gas and oil fuel requirements for the California utilities based upon their expected energy requirements. These results are

presented in Table 25 along with data for 1975 and 1976. Both the shortage of hydroelecrric energy and the declining availability of P-5 natural gas have contribured to the increased use of oil.

Due to increased degradation in air quality in the major industrial air basins (see environmental effects section below), the California Air Resources Board (CARB) has ordered the conversion to 0.25 percent sulfur fuel oil in the South Coast Air Basin, and to 0.5 percent sulfur oil elsewhere. The estimated fuel oil requirements averaged over the four summer month period is about 430,000 bbls/day. The availability of these fuels has been investigated by the FEA.[21] It appears that existing refinery capacity plus the availability of low sulfur crude oil (primarily from Indonesia) for blending with higher sulfur-content oils are adequate to supply the demand for these fuels in California. Since the loss in hydroelectric generation will be made up by the increased use of oil, the extra cost associated with this can be estimated. Using the supply forecasts for 1977 (Ref. 20), an estimated 33,500 GWh would have been generated by the instate hydroelectric capacity in a year of average rainfall. Comparing this with the present estimate for 1977 shown in Table 24, the difference is approximately 18,000 GWh, which is equivalent to an additional 29 X 10^6 barrels of oil. Using an average west coast price of $13 per barrel for 0.5 percent sulfur residual fuel oil,[21] the extra cost is approximately $375 million. This estimate is a lower limit, since the price of 0.25 percent sulfur fuel oil has been estimated to be an additional $0.80 to $1.10 per barrel.[21] The total cost will therefore increase as utilities in the South Coast Basin switch to the lower sulfur content fuel.

One additional facility that has <u>not</u> been included as a resource for this summer is Scattergood Unit #3, a gas-fired facility with low emissions, operated by LADWP. With P-5 gas unavailable in southern California, this 285 MWe plant has been placed on stand-by while waiting for permits to convert to use oil as fuel. Negotiations are currently in progress regarding transfer of gas from PG&E to SCE and LADWP for use as boiler fuel. However, LADWP has indicated[1c] that its share of the energy to be transferred would not be sufficient to fully utilize Scattergood Unit #3 at it minimum capacity (80 MWe). The transferred gas would therefore be used as supplemental fuel at other steam plants rather than at Scattergood Unit #3. We discuss this issue in the section on environmental effects.

Table 25

Fuel Oil and Natural Gas Use by Electric Utilities

	1975		1976[a]		1977 (est.)[b]	
	Gas (10^9 ft^3)	Oil (10^6bbl)	Gas (10^9 ft^3)	Oil (10^6bbl)	Gas (10^9 ft^3	Oil (10^6bbl)
PG&E	157[c]	11.4[c]	197	26.9	141	51.2
SCE	71[d]	41.3[d]	63	45.0	31	67.5
LADWP	22[e]	15.0[e]	12	11.4	4	22.9
SDG&E	14[e]	9.4[e]	12	10.8	3	15.5
TOTAL CA	264	77.1	284	94.1	179	157.1
Total gas and liquid fuel (10^{12} BTU)	762		890		1176	

[a] Ref. 1b

[b] Ref. 1c

[c] Recorded data, Supply Forecast for Pacific Gas and Electric submitted to the California State Energy Resources Conservation and Development Commission by Pacific Gas and Electric, Docket No. 75-FOR-3, Form 6, p. 4, 1976.

[d] Recorded data, submittal by SCE to CERCDC, Docket No. 75-FOR-3, Form 2, pp. 1,2, 1976.

[e] Estimated from CERCDC, Quarterly Fuel and Energy Summary, Vol. 2, Nos. 1, 2, 3 and 4, 1976.

LOSS OF LOAD PROBABILITY FOR PG&E, SUMMER 1977

The risk of bulk power outages can be assessed quantitatively by use of the loss of load probability (LOLP). This measures, for a given generating system made up of individual units, each with a forced outage rate, the probability that forecasted load exceeds the capacity resources of the system. Probabilities are conventionally represented by real numbers between 0 and 1. To inject a more intuitive flavor into the discussion of reliability, utility engineers typically translate the probability of an outage into more familiar units such as the expected number of days of outage per year. PG&E uses the inverse of this notion, namely the number of years per day of load loss. Under normal conditions PG&E plans for a reliability index of at least 10 each month of the year. This is the PG&E interpretation of the familiar reliability objective that LOLP should be equal to one day in ten years. Because there are potential ambiguities involved in using the index, we refer to the explanation PG&E has offered of its method in its response to interrogatories associated with CERCDC Docket No.75-FOR-3. Exhibit 4 of the PG&E response shows a sample calculation for a summer month in 1983. The procedure is as follows:

a. calculate $LOLP_i$ for each day i of the month
b. $\Sigma\ LOLP_i$ is interpreted as the expected number of outage days for that month
c. the reliability index $C \equiv (31/365)/\sum_i LOLP_i$.

A trivial substitution shows that for a reliability index of 10, we must have $\Sigma LOLP_i \leq 8.49 \times 10^{-3}$.

It is worth noting that the above interpretation of the reliability criterion that LOLP equal one day in ten years in only one of several possibilities. Another interpretation of the one day in ten years criterion is that $\Sigma LOLP_i \leq .10$ days, where the summation is done over the whole year. This latter notion is equivalent to PG&E's method provided each month has roughly the same risk and that risk is near the limit $(12(8.49 \times 10^{-3}) \cong .10)$. As we shall see, however, risk varies quite sensitively with slight changes in load, so that PG&E's method turns out to be a more strict interpretation than the other possibility. Indeed, there are still more demanding versions of the one day in ten years criterion, but they need not concern us here.[22]

With these semantic considerations on reliability in our minds, we can begin a quantitative assessment of the situation anticipated by PG&E in its service area this summer. Responding to CERCDC interrogatories in Ref.1a, PG&E provided the following data on the monthly reliability index.

	Reliability Index	
	Isolated	With 600 MWe Support
March	0.6	8.2
April	2.1	59.0
May	1.0	10.0
June	1.2	13.0
July	0.6	4.9
August	0.4	3.1
September	0.6	7.3
October	560.0	> 1000.0
November	8.1	260.0
December	43.0	> 1000.0

Because the data in column (1), PG&E as an isolated system, show a significant probability of outages, it is quite likely that PG&E will have to rely upon interconnections to meet its summer peak load. For example, the reliability index for the isolated system in August corresponds to a monthly LOLP of .212, or a 21.2 percent chance of load loss ($\Sigma LOLP_i$ = (31/365)/0.4 = .2123). A more realistic interpretation of this number, however, is that it represents the likelihood that PG&E will have to rely upon interconnection support. The more realistic risk facing PG&E this summer is tabulated in column (2). The 600 MWe level of support corresponds roughly to Edison's spinning reserve. The California Power Pool agreement requires that members maintain spinning reserve equal to 5 percent of their peak demand. (Note this is a less strict spinning reserve criterion than the operational criterion discussed above.) SCE is forecasting a peak of 11.55 GWe which translates into about 580 MWe of spinning reserve. Due to diversity of outages this is readily available to aid PG&E. The August risk to PG&E is then approximately 2.7 percent for loss of load when this level of support is considered ((31/365)/3.1 = .0274).

Assessing the risk faced by PG&E by use of a single probability is less informative than looking at the components of that risk as a function of forecasted load variations. We will calculate $LOLP_i$ for the few days in July and August with the highest forecasted loads. This calculation shows that most of the risk in each month is concentrated on one or two days. It also shows that relatively small changes in supply or demand can alleviate the risk considerably. Thus voluntary conservation, load management and/or additional intertie support will allow a manageable solution to the potential problem facing PG&E. To establish this quantitatively we must delve into the complexities of LOLP calculations.

LOLP is calculated using data on capacity resources, forced outage rates, forecasted loads and forecasted maintenance. Numerical simulation techniques are typically used to calculate the probability of various outages occurring simultaneously. Instead of convolving the outage distributions exactly, we use an approximate analytic technique which short-cuts a good deal of calculation with little cost in accuracy. This technique, which has been described in detail elsewhere,[23] requires the calculation of quantitites that are elementary combinations of the moments associated with generator outage probabilities. With a tabular representation of the variance and higher moments of these distributions, we calculate LOLP using an expansion related to the normal distribution.

There are three types of capacity resources available to PG&E, thermal units, hydroelectric units, and Pacific Northwest power from the 500 KV intertie. Data on the capacity and outage rates for thermal units were supplied by PG&E in their response to interrogatories in References 1a, 1b, and 1c. For the purpose of LOLP calculations it is common to partition the set of generators into a small number of sets, where each unit in a given set has approximately the same capacity and outage rate. The PG&E tabulation presents the data in this way, using twelve sets of generator types. For smaller units (200 MWe and less) the outage distribution is represented by just a binary, on-off model. For units larger than 300 MWe, partial outages are represented by a three-state model which includes an outage rate for unit deratings that are typically around 20 percent capacity. In Table 26, the moments and expansion coefficients for the PG&E thermal units are calculated. Partial outages are treated as generators with capacity equal to the size of the partial outage. The statistical parameters of the partial

Table 26

Parameters Used in Loss of Load Probability Calculations

Generator Categories (category i)	n_i	α_i	L_i	$\sigma_{s_i}^2$	a_{3_i}	a_{4_i}	a_{5_i}
1. Avon, Martinez, Oleum 1&2, Humboldt Bay 1,2, & 3, Potrero 1&2, Kern 1	10	,0535	.015	.0004	0	0	0
2. Hunter's Point 2&3, Kern 2, Contra Costa 1-3, Moss Landing 1-3	9	.113	.021	.0024	.0003	0	0
3. Hunter's Point 4, Pittsburg 1-4, Morro Bay 1&2	7	.157	.033	.0055	.0008	.0001	0
4. Contra Costs 4-5, Moss Landing 4-5	4	.112	.036	.0017	.0002	0	0
5. Contra Costs 6&7, Morro Bay 3&4, Pittsburgh 5&6	6	.333	.030	.0193	.0061	.0018	.0004
	*6	.055	.247	.0034	.0001	0	0
6. Potreto 3	1	.207	.041	.0016	.0003	.0001	0
7. Moss Landing 6&7	2	.739	.040	.0419	.0285	.0176	.0084
	*2	.100	.308	.0043	.0002	0	0
8. Pittsburg 7	1	.720	.070	.0337	.0209	.0106	.0024
	*1	.180	.215	.0055	.0006	0	0
9. Hunter's Point 1, Potrero 4-6, Gas Turbine 1-3, Geysers 5-11	14	.048	.060	.0018	.0001	0	0
10. Geysers 1&2	2	.012	.040	0	0	0	0
11. Geysers 3&4	2	.027	.080	.0001	0	0	0
12. Case A, July - Rancho Seco 1	1	.726	.130	.0596	.0320	.0101	-.0060
	*1	.145	.172	.0030	.0003	0	0
Case A, August- Rancho Seco 1	1	.884	.130	.0884	.0578	.0222	-.0253
	*1	.177	.172	.0044	.0005	0	0
Case B, July, August - Rancho Seco 1	1	.875	.130	.0865	.0561	.0213	-.0153
	*1	.175	.172	.0044	.0005	0	0
13. Case A, July - PG&E hydroelectric power	100	.050	.0075	.0019	.0001	0	0
Case A, August - PG&E hydroelectric power	103	.050	.0075	.0020	.0001	0	0
Case B, July - PG&E hydroelectric power	98	.050	.0075	.0019	.0001	0	0
Case B, August - PG&E hydroelectric power	91	.050	.0075	.0017	.0001	0	0
14. Pacific Northwest Power	2	.750	.001	.0011	.0008	.0006	.0004

*The second set of numbers is for the partial outage state.

Notation: n_i = number of units n category i; α_i = average capacity of units in category i (in units of gigawatts); L_i = outage rate for category i

Definition of Parameters: $\sigma_{s_i}^2 = n_i\alpha_i^2 L_i(1-L_i)$; $a_{3_i} = n_i\alpha_i^3 L_i(1-L_i)(1-2L_i)$; $a_{4_i} = n_i\alpha_i^4 L_i(1-L_i)(1-6L_i[1-L_i])$; $a_{5_i} = n_i\alpha_i^5 L_i(1-L_i)(1-2L_i)(1-12L_i[1-L_i])$

outage state are added to that corresponding to the full outage for the units type in question.

Data on PG&E's hydroelectric resources and Pacific Northwest power is less detailed than that for thermal units in Refs. 1a, 1b, and 1c. PG&E lists gross capacity available from these resources. For hydroelectric, they indicate that outage calculations are done assuming 50 MWe blocks with an outage rate of .0075. There is not much physical basis for this block assumption since the average capacity of turbines in the hydro system is smaller than this, but the approximation is reasonable enough. For modelling purposes we assume that the hydro capacity corresponds to n_i units of 50 MWe apiece. The Pacific Northwest power is imported to the PG&E service area on the two 500 KV AC lines. The outage rate for this resource is extremely low; we use .001 which is used by PG&E.[24] For modelling purposes we assume that the 1500 MWe of Pacific Northwest power is imported equally over the two lines, and so can be represented as two 750 MWe generators with full outage rates of .001. The statistical parameters associated with these resources are calculated and tabulated in Table 26.

LOLP is calculated with our approximation by means of the following expressions. We first define a parameter b in terms of a load W, and the number of units n_i in category i, their average capacity α_i, and their forced outage rate L_i.

$$b = [\sum_i n_i \alpha_i (1-L_i) - W]/\sqrt{2}\sigma_s^2, \qquad (1)$$

where $\Sigma n_i \alpha_i (L-L_i)$ is the mean available capacity. The first step in our calculation involves the normal probability distribution; we compute

$$1/2\mathrm{Erfc}(b) = \frac{2}{\sqrt{\pi}} \int_b^\infty e^{-t^2} dt. \qquad (2)$$

LOLP is just the quantity in (2) plus some expansion terms. We write this as follows

$$\mathrm{LOLP} = 1/2\mathrm{Erfc}(b) + \frac{e^{-b^2}}{2b\sqrt{\pi}}\left[\frac{a_3}{6}\left(\frac{1}{\sigma_s^2}\right)^{3/2}[\sqrt{8}\,b^3 - \sqrt{2}\,b] + \frac{a_4}{24}\left(\frac{1}{\sigma_s^2}\right)^2[4b^4-6b^2] + \frac{a_5}{120}\left(\frac{1}{\sigma_s^2}\right)^{5/2}[2^{5/2}b^5-2^{3/2}6b^3+3\sqrt{2}\,b]\right] \quad (3)$$

Equations (1)-(3) are derived elsewhere.[23]

Three submittals have been made to CERCDC (Refs. 1a, 1b,1c). Since the amount of hydroelectric resource has varied, we have picked the two extreme cases for reliability analysis. These are Case A, with the larger amount of hydroelectric resource[1a] (March 9 submittal) and Case B, the latest submittal, with a smaller hydroelectric resource estimate.

We will use Equations (1)-(3) together with the PG&E 1977 load forecast and Table 26 to calculate LOLP. Quantities which will be used repeatedly in these calculations are listed in Table 27. As stated earlier, the risk of interest corresponds to the case where PG&E has 600 MWe of perfectly reliable support. To quantify this case we simple increase the mean available capacity by 0.60 GWe.

For Case A the three peak days expected in August correspond to loads of 14.56, 14.02, 13.80 GWe respectively while the mean available capacity is 15.57 GWe. We will see that LOLP decreases by an order of magnitude with each demand decrease. For the peak day

$$W = 14.56$$
$$b = 1.01/0.612$$
$$= 1.65$$
$$1/2\mathrm{Erfc}(1.65) = 9.80 \times 10^{-3}$$
$$\mathrm{LOLP} = 9.80 \times 10^{-3} + [1.95 + 0.59 + 0]1.12 \times 10^{-2}$$
$$= 3.83 \times 10^{-2}$$

Table 27

System Parameters for Two Alternative Cases

System Parameters	Case A August	Case A July	Case B July and August
$\sigma_S^2 (=\sum_i \sigma_{S_i}^2)$	.1873	.2145	.2156
$a_3 (=\sum_i a_{3_i})$	.0913	.1173	.1156
$a_4 (=\sum_i a_{4_i})$	.0372	.0423	.0521
$a_5 (=\sum_i a_{4_i})$	.0019	-.0174	-.0037

Similar calculations for the next four highest loads produces the results shown in Table 28.

Comparing these results for August with the PG&E submissions in Ref. 1a, we find a somewhat higher risk for August than PG&E is forecasting. Recalling the PG&E data, their reliability index for August translates into an LOLP of .0274 compared to our .0421. It should be observed that this discrepancy does not have a very great physical significance because LOLP is an extremely sensitive measure of reliability. Although there is no simple universal relationship between LOLP and reserve margin (a physical unit) a reasonable rule of thumb is that a factor of 2 in LOLP corresponds to 0.5 percent in reserve margin. Thus a recent study by the New York Power Pool shows that changing LOLP by a factor of 8 corresponded to a 2 percent change in reserve requirements.[25] This rule of thumb suggests that the difference between our August LOLP calculation and that of PG&E amounts to about 70 MWe which is well within load forecast error. However, we have renormalized our LOLP computation to reproduce this result, and use the resulting parameters to provide renormalized LOLP calculations for all the cases we investigate here.

Next we calculate the risk variation for July. Typically the PG&E load peaks in July or August. It is a matter of conservative forecasting to assign the peak load to August, because that is a time of lesser hydroelectric resource and therefore potentially greater risk. In 1977, July will also have more capacity available from Rancho Seco, 884 MWe as opposed to the August forecast of 726 MWe. The decline in capacity reflects the gradual derating associated with the refueling overhaul scheduled for late August. The change in Rancho Seco capacity means that we must recalculate the statistical parameters for that unit. The partial outage state for July is 20 percent of capacity with the same outage rate as August. The new systems parameters are listed below in Table 27. As before we limit attention to the case of the PG&E system with 600 MWe of perfectly reliable support. As in the case of the August risk variation, LOLP declines by roughly an order of magnitude with each step down from the peak load forecast. For July the mean available capacity is 15.80 GWe. Using a similar calculational procedure the July risk variation is also shown in Table 28.

Table 28

Results of Loss of Load Probability Calculations

Peak Day	August Load (GWe)	August LOLP (calc)	August LOLP (renorm)	July Load (GWe)	July LOLP (calc)	July LOLP (renorm)
CASE A:						
1	14.56	3.83×10^{-2}	2.27×10^{-2}	14.49	1.54×10^{-2}	9.18×10^{-3}
2	14.02	2.71×10^{-3}	2.42×10^{-3}	14.19	2.97×10^{-3}	1.94×10^{-3}
3	13.80	5.44×10^{-4}	9.45×10^{-4}	13.86	2.73×10^{-4}	3.90×10^{-4}
4	13.73	3.08×10^{-4}	6.78×10^{-4}	13.65	4.38×10^{-5}	1.29×10^{-4}
5	13.71	2.59×10^{-4}	6.24×10^{-4}			
TOTAL			2.74×10^{-2}			1.16×10^{-2}
CASE B:						
1	14.47	9.93×10^{-2}	5.93×10^{-2}	14.63	7.63×10^{-2}	4.56×10^{-2}
2	13.93	2.75×10^{-2}	3.14×10^{-2}	14.33	3.61×10^{-2}	2.19×10^{-2}
3	13.71	1.08×10^{-2}	2.60×10^{-2}	13.99	8.88×10^{-3}	8.71×10^{-3}
4	13.65	7.98×10^{-3}	2.35×10^{-2}	13.78	2.70×10^{-3}	4.96×10^{-3}
TOTAL			1.40×10^{-1}			8.11×10^{-2}

For Case B, in estimating their supply resources in the latest submittal (Ref. 1c) PG&E has modified several important variables. First, hydroelectric capacity for the two critical months is down. The decrease is 432 MWe for July and 634 MWe for August, an 8 percent and 13 percent decline respectively. Second the peak load forecast has changed. The July load is up 139 MWe, the August load is down 91 MWe. This change shifts the peak to July. Finally, PG&E assumes increased August capacity from Rancho Seco. Where Table 2 in the Loads and Resources Report of March 9 lists 884 MWe for July, 726 MWe for August and zero for September and October because of refueling, the May 11 data give an average of roughly 880 MWe through August. These changes alter our earlier calculations.

To re-estimate LOLP with those data, we first adjust the values of system parameters in Table 26. Categories 12 and 13 are the only ones altered. For July and August, Rancho Seco will be treated as 875 MWe with a partial outage state of 175 MWe. The same outage rates will be used for these new capacity values. To modify the hydroelectric resource we alter n_i, which in this case corresponds to the number of 50 MWe blocks of hydro than can be dispatched. Due to changes in miscellaneous categories we adjust n_i to 98 for July and 91 for August. This will yield the May 11 estimates[1c] of total PG&E capacity for those months. The mean available capacities are then 15.44 GWe for July and 15.12 GWe for August. The new system parameters are tabulated in Table 27.

As noted earlier in our discussion the monthly LOLP is a sum over the "riskest" days of the month. However, for Case B, we have the peak day, but no monthly load shape. Therefore to calculate LOLP we use the load model from PG&E's March 9 submission. Conversations with PG&E planners revealed that the distribution of daily peaks from month to month, which we will call the load shape, is fit to peak forecasts. In this case the peak has shifted from August to July, but the ratio of the second highest July load to the peak July load is constant. To calculate the load shape numerically for July and August we exclude the 87 MWe of interruptible load and use the table of load shape data supplied in Ref. 1a. The results are tabulated in Table 28 below, along with the LOLP for this configuration (with 600 MWe of support).

We use the renormalization terms to adjust these calculations. These adjustment terms grow with the increasing risk so this is a conservative

adjustment. The adjusted LOLP for July then is 8.1 percent and for August 14.0 percent. We repeat that this should be interpreted as the probability of requiring support beyond the 600 MWe planning level. We present our results for Cases A AND B in Fig. 5. The lower curve is Case A for August, with the daily risk renormalized to PG&E's calculation presented in Ref. 1a. The upper curve is calculated for July, using data from Case B. In order to plot any other month on the same curve, one adds to the expected load the change in supply capacity, corrected for the forced outage rate. For example, in Case B there is 300 MWe less hydroelectricity in August than July, which translates into an increase in the equivalent load of ∿300 MWe, since the forced outage rate for hydroelectric generation is so low. The open circles represent the peak days for the month indicated.

As we noted in our earlier discussion on demand, the temperature variation associated with the peak demand forecast translates into a load uncertainty of 311 MWe in the PG&E area. The concomitant effect upon risk can be seen graphically from the curves in Fig. 5. We have illustrated this for the peak day in July for Case B and the peak day in August for Case A. For the first of these an increase of 311 MWe increases the LOLP by a factor of 1.7, and a decrease of 311 MWe decreases LOLP by a factor of 2. In the second example, ±311 MWe translates into an increase in LOLP by a factor of 2.1 or a decrease by a factor of 3.5.

The main qualitative conclusion from these results is the dramatic change in risk that occurs with load changes of 300-500 MWe (see Fig. 5). For Case A our July results show 80 percent of the risk concentrated on one day. For August the peak day involves about 85 percent of the risk. For Case B, the more restrictive hydroelectric case, one day in Jyly represents 56 percent of the risk and 83 percent of the risk in two days in July. For August, nearly 42 percent of the risk is on one day, and 65 percent on two days. These results suggest that the potential problem facing PG&E is quite limited in nature and amenable to a wide variety of solutions. Among the potential solutions are conservation and load management strategies on the demand side and increased interconnection support on the supply side.

On a statewide basis the latest estimated reserve margin will reach its minimum value of 13.1 percent in August. This is still adequate to carry the load reliably. Calculations in Ref. 23 using a very strict

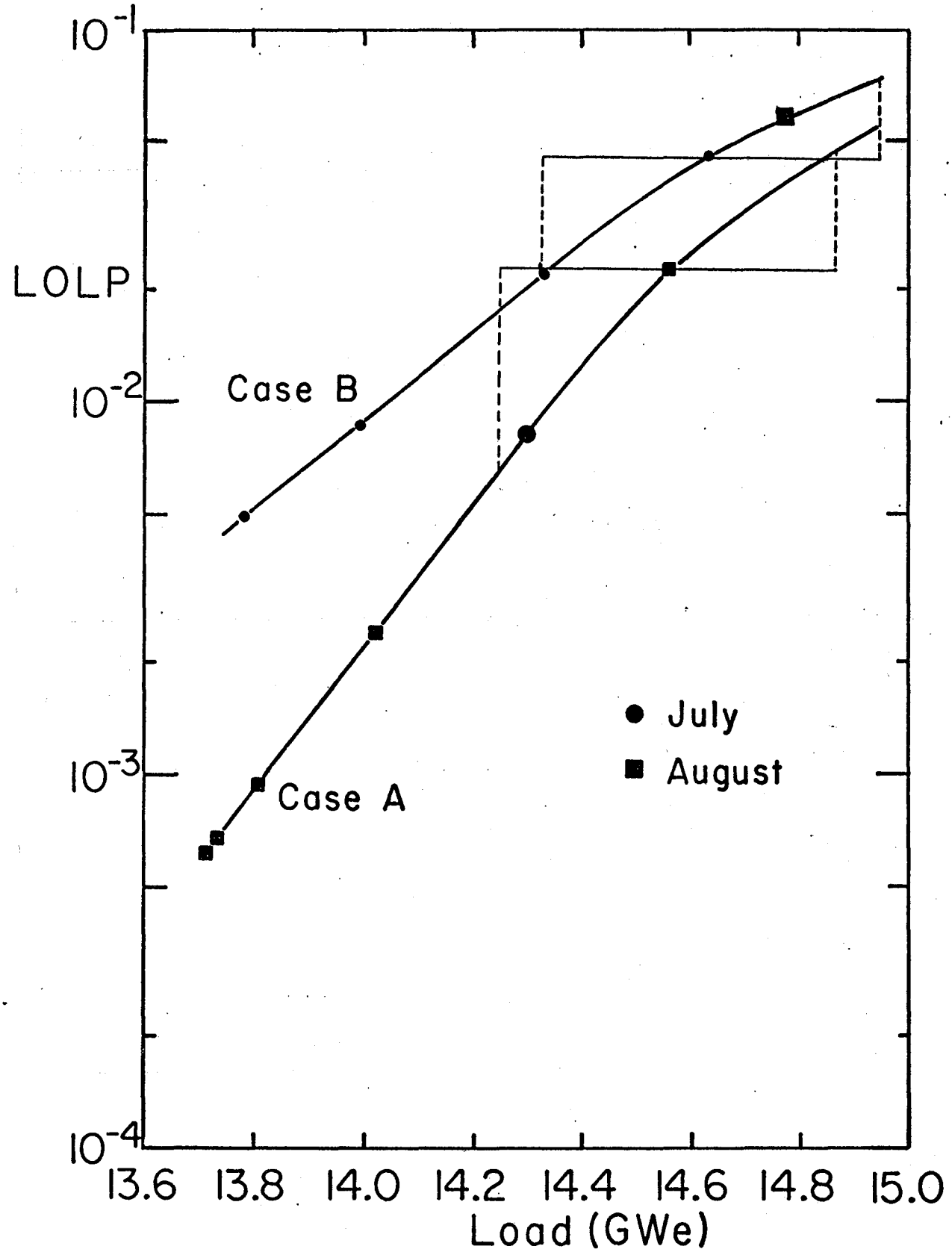

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Fig. 5 Risk (LOLP) as function of load for PG&E with 600 MWe of support. The two supply cases are discussed in the text.

reliability criterion (20 times more demanding than PG&E's) found a reserve margin of 14.8 percent was required. This factor of 20 would easily allow for the roughly 1.7 percent difference in reserve margin for 1977. Indeed preliminary calculations for a drought scenario in 1978 show that a reserve margin for the state of 11 percent would give reliability at PG&E's desired reliability criterion. It must be recalled, however, that these estimates assume no institutional obstructions to full co-ordination. This means full utilization of Castaic pumped storage among other things. It is unlikely that single-area dispatch will be required in 1977, but the possibility of extreme conditions raises the necessity of examining the potential obstacles.

Finally it must be remembered that there is uncertainty in all of the data used here. Hydroelectric capacity calculations are subject to error as well as load forecasts. An emergency program of conservation measures remains an attractive option if supply deficiencies are further aggravated.

The PG&E assumption of 600 MWe of interconnection support is quite conservative. Data submitted by the other California utilities in CERCDC Docket No. 77-EA-1 show several times this amount of support available. Our calculations show, as Fig. 5 indicates, that an 800 MWe change on either the demand or supply side reduces the risk below PG&E's own reliability criterion of 8.49×10^{-3}.

ENVIRONMENTAL EFFECTS

One of the impacts due to the decreased availability of hydroelectric energy will be increased emissions caused by the use of more fossil fuel for thermal electric generation. This will be especially so in the South Coast and South Central Coast Air Basins, since nearly all of the oil-fired capacity operated by SCE and LADWP is located in these basins. Both SCE and LADWP have experienced decreases in hydroelectric generation potential, requiring increased steam-electric generation using oil as fuel. At the same time, the additional energy demand placed upon these utilities by PG&E will add to oil fuel use, and will incrementally affect emissions in these two air basins.

The monthly emissions for June through September are shown in Table 29. The use of gas instead of oil as fuel to supply energy to PG&E reduces the incremental NO_X emissions by about a factor of three, and reduces the incremental SO_X emissions to very nearly zero. Further reductions of NO_X can be achieved by utilizing Scattergood Unit #3 a 285 MWe gas-fired plant operated by LADWP. However, LADWP indicates that this plant will not be used under a partial load condition.[1c] If Scattergood Unit #3 were to generate all the energy transferred to PG&E during June, July and August as shown in Appendix A, this plant would operate at capacity factors of 0.57, 0.63 and 0.34, respectively. For September 164 GWh of PG&E's expected need of 196 GWh from SCE and LADWP power plants could be met by this plant operating at a capacity factor of 0.80. The remaining energy could then be generated by other facilities in the area. The emissions calculations shown on line 3 of Table 29, using NO_X emissions factors from Ref. 26, include this extra capacity (beyond Scattergood Unit #3) for September.

We have also calculated the capacity factor and gas required to offset the extra emissions in the South Coast Air Basin. These calculations assume the use of Scattergood Unit #3 for the necessary offset, with the exception of September where we have used an average emission rate for SCE plants using natural gas. The amount of natural gas required for this offset is small compared with the gas proposed for use to supply energy transferred to PG&E. The total amount used is approximately 15 percent of the P-5 gas expected to be available to PG&E during this four-month period.

Table 29

Monthly Emissions in the South Coast and South Central Coast Air Basins (tons)

	June	July	August	September
SCE, LADWP Load:[a] (1977)				
SO_X (as SO_2)	8466	9450	9878	7131
NO_X (as NO_2)	4959	5528	6110	5580
Increment due to energy transfer to PG&E:				
1. Oil Fuel[a]				
SO_X	187	209	116	230
NO_X	186	266	138	357
2. Gas Fuel[a]				
SO_X	0	0	0	0
NO_X	62	84	48	121
3. Natural Gas for Scattergood + SCE[b]				
SO_X	0	0	0	0
NO_X	17	19	10	44

[a]Source: Ref. 1c

[b]Present work

It appears, then, that most if not all of PG&E's energy shortfall could be offset by energy conservation practices. The measures discussed above probably include some overlap between categories, but with a reasonable effort a monthly savings potential of 600 to 800 GWh statewide, or 250 to 300 GWh per month for PG&E could be realized. As we noted in our discussion on reliability, such savings can aid in reducing PG&E's need for interconnection capacity support. Furthermore, the effect upon emissions can be estimated from the data in Table 29. These conservation programs applied to the SCE and LADWP service areas could save as much as 10 to 15 percent of the electricity projected to be generated by oil- and gas-fired plants in these service areas. This would have a concomitant effect on emissions in the South Coast and South Central Coast Air Basins (reduction in SO_X would scale linearly with energy, while NO_X, which is dependent upon specific boiler parameters and heat-rate curves, would not be reduced as much).

We have not estimated the costs of these conservation programs although only programs that do not rely upon the installation of large hardware devices can be readily implemented by the end of the summer. Hence, we expect the costs per GWh saved to be quite low. By way of comparison, the energy transferred to PG & E by way of the California Power Pool costs 31 mills/kWh,[1c] or in excess of $30,000 per GWh. Thus it appears that energy conservation programs are economically attractive as well.

The peak summer energy demands coincide with periods of significant air quality problems in areas such as the South Coast and South Central Coast Air Basins.[26,27] The staff of the South Coast Air Quality Management District expects that as the amount of fuel oil used in the South Coast Basin increases, the number of days the standard for oxidant in combination with sulfate is exceeded will increase by as much as 20 percent.[27]

On peak demand days, the electrical output of power plants operated by SCE and LADWP increases by more than 20 percent over the average daily output. This translates into increased emissions of NO_X by nearly 33 percent and of SO_X by almost 21 percent above average daily emissions.[1b] Historically the greatest incidence of sulfate-oxidant episodes has occurred in July,[27] during which time PG&E will be receiving energy from utilities in this basin. Moreover, the number of oxidant episodes is usually 18-20 per month throughout the summer. Further increments of natural gas could be dispatched as boiler fuel in anticipation of these episodes.

Finally, implementation of energy conservation programs can also alleviate impacts due to increased emissions. The expected amount of energy required for PG&E for the summer momths ranges from 80 GWh to 220 GWh per month. These are comparable with the quantities of energy saved in many of the conservation programs we discuss in Section III.

PG&E serves approximately 40 percent of the commercial floor space in California.[28] Our earlier estimate of a potential savings of 300 GWh per month in the commercial sector then becomes about 120 GWh per month for PG&E. Similarly, from Table 22, the savings in energy due to water conservation in the residential sector is approximately 200 GWh per month at 100 percent implementation. As discussed in Section III, the present level of water conservation measures in California is about 30-35 percent of what can be implemented. An assumption of 40 to 50 percent implementation by the end of the summer appears reasonable, which corresponds to 80 to 100 GWh per month in energy savings, or 30 to 40 GWh per month for PG&E. A listing of potential conservation measures, as discussed by the CPUC are summarized in Table 6. Although few specific details as to implementation are given, enforecement of CPUC Rule 14.1 and further voluntary conservation measures can amount to a savings of about 265 GWh per month.

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APPENDIX A

This appendix contains the summaries of the May 1977 responses by the four major California electric utilities to the California Energy Resources Conservation and Development Commission (Docket No. 77-EA-1). The utilities responding were Pacific Gas & Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, and Los Angeles Department of Water and Power. Two sets of data are presented for each utility: energy and fuel projections and capacity projections.

The first line in each table is the projected load by month either in GWh or MWe. The remainder of each table is the breakdown of each category of resource that is available to meet the projected load and the reserve margins that should be available.

5-9-77

MAJOR CAL ELECTRIC UTILITIES
SUMMARY ENERGY & FUEL REPORT

1977 ADVERSE CONDITIONS

	(1) JAN	(1) FEB	(1) MAR	(2) APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL TOTAL
GAS SUPPLY AND OIL REQUIREMENTS													
10. G & O REQMNT FOR LOAD													
EQ KBBL													
P G & E	5470	5217	6038	6226	5894	6530	7122	6992	6986	6522	6159	6630	75786
S C E	5929	5545	6518	5737	4994	5232	5911	6211	5924	6251	5906	5866	70024
L A D W P	1627	1662	1600	1553	1808	1823	2118	2351	2157	2200	2097	2134	23130
S D G & E	1337	1251	1421	1189	1238	1192	1314	1291	1341	1308	1266	1346	15494
TOTAL	14363	13675	15577	14705	13934	14777	16465	16845	16408	16281	15428	15976	184434
11. GAS SUPPLY													
A. GAS AVAIL													
EQ KBBL													
P G & E	582	2096	2069	2800	3400	1900	1800	1700	2000	2900	1900	400	23547
S C E	170	846	1737	459	178	179	430	439	394	145	109	84	5170
L A D W P	16	145	403	65	0	0	0	0	0	0	0	0	629
S D G & E	3	120	324	94	3	2	3	3	3	2	3	3	563
TOTAL	771	3207	4533	3418	3581	2081	2233	2142	2397	3047	2012	487	29909
B. PLANNED													
EQ KBBL													
P G & E	582	2096	2069	2800	3400	1900	1800	1700	2000	2900	1900	400	23547
S C E	170	846	1737	459	178	179	430	439	394	145	109	84	5170
L A D W P	16	145	403	65	0	0	0	0	0	0	0	0	629
S D G & E	3	120	324	94	3	2	3	3	3	2	3	3	563
TOTAL	771	3207	4533	3418	3581	2081	2233	2142	2397	3047	2012	487	29909
C. TRANSFERS													
EQ KBBL													
P G & E	0	0	0	0	0	0	0	0	0	0	0	0	0
S C E	0	0	0	0	0	0	0	0	0	0	0	0	0
L A D W P	0	0	0	0	0	0	0	0	0	0	0	0	0
S D G & E	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0

(1) Recorded Data
(2) Preliminary recorded data

5-9-77

MAJOR CAL ELECTRIC UTILITIES
SUMMARY ENERGY & FUEL REPORT

1977 ADVERSE CONDITIONS

	(1) JAN	(1) FEB	(1) MAR	(2) APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL TOTAL
12. OIL REQMNT TO MEET													
A. CAP, 9A KBBL													
P G & E	--	--	--	--	2375	4422	5083	5165	4637	3746	4413	6422	--
S C E	--	--	--	--	7550	7276	8219	8312	7602	7569	7432	7582	--
L A D W P	--	--	--	--	2813	2982	3285	3285	3179	3203	2993	2861	--
S D G & E	--	--	--	--	1566	1604	1662	1581	1516	1487	1415	1597	--
TOTAL	--	--	--	--	14304	16284	18249	18343	16934	16005	16253	18462	--
B. REQ, 9B KBBL	(Required before electric transfers to PG&E)												
P G & E	5642	3612	4633	3874	2494	4630	5322	5292	4986	3622	4259	6230	54596
S C E	5759	4699	4781	5278	4816	5053	5481	5772	5530	6106	5797	5782	64854
L A D W P	1611	1517	1197	1488	1808	1823	2118	2351	2157	2200	2097	2134	22501
S D G & E	1334	1131	1097	1095	1235	1190	1311	1288	1338	1306	1263	1343	14931
TOTAL	14346	10959	11708	11735	10353	12696	14232	14703	14011	13234	13416	15489	156882
C. MARG, 9C KBBL	(Before electric transfers to PG&E)												
P G & E	--	--	--	--	-119	-208	-239	-127	-349	124	154	192	--
S C E	--	--	--	--	2734	2223	2738	2540	2072	1463	1635	1800	--
L A D W P	--	--	--	--	1005	1159	1167	934	1022	1003	896	727	--
S D G & E	--	--	--	--	331	414	351	293	178	181	152	254	--
TOTAL	--	--	--	--	3951	3588	4017	3640	2923	2771	2837	2973	--
D. PLANNED, 9E, KBBL													
P G & E	4888	3121	3969	3426	2375	4422	5083	5165	4637	3622	4259	6230	51197
S C E	6484	5190	5238	5631	4883	5181	5622	5853	5733	6106	5797	5782	67500
L A D W P	1611	1517	1283	1554	1841	1879	2182	2385	2251	2200	2097	2134	22934
S D G & E	1334	1131	1199	1197	1252	1220	1346	1307	1389	1306	1263	1343	15287
TOTAL	14317	10959	11689	11808	10351	12702	14233	14710	14010	13234	13416	15489	156918

(1) Recorded data
(2) Preliminary recorded data

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5-9-77

MAJOR CAL ELECTRIC UTILITIES
SUMMARY CAPACITY REPORT
1977 ADVERSE CONDITIONS

	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
14. MARGIN AFTER SCHED MAINT								
A. (AVAIL CAP RES-PEAK) MW								
P G & E	635	1147	738	632	855	1645	1557	2219
S C E	3429	3502	2669	2351	2214	2359	2323	2876
L A D W P	690	776	1048	839	1042	941	970	734
S D G & E	313	468	402	350	546	410	401	323
TOTAL	5067	5893	4857	4172	4657	5355	5251	6152
B. PERCENT OF MONTH PEAK %								
P G & E	4.8	8.0	5.0	4.3	6.5	15.1	13.7	19.0
S C E	37.1	35.8	23.8	20.3	20.4	23.1	24.3	29.0
L A D W P	23.1	21.8	27.9	20.7	28.9	28.8	31.4	22.6
S D G & E	20.1	28.6	24.3	19.8	35.9	27.6	25.7	19.2
TOTAL	18.8	20.1	15.5	13.1	16.0	20.7	20.6	23.2

5-9-77

MAJOR CAL ELECTRIC UTILITIES
SUMMARY POWER PLANT EMISSIONS REPORT

1977 ADVERSE CONDITIONS

	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1. REQ FOR LOAD, E & F RPT, 9B								
A. SOX TONS								
P G & E			SAME	AS	PLANNED			
S C E	6116	5566	6080	6138	5415	5932	5189	4467
L A D W P	2876	2900	3370	3740	1716	1750	1668	1697
S D G & E	1315	1275	1445	1420	1475	1435	1390	1475
B. NOX TONS								
P G & E			SAME	AS	PLANNED			
S C E	3270	3440	3840	4074	3871	4286	4033	3986
L A D W P	1397	1519	1688	2036	1709	1673	1594	1793
S D G & E	946	914	1040	1013	1070	1046	1011	1061
C. PARTICULATES TONS								
P G & E			SAME	AS	PLANNED			
S C E	882	906	984	1031	977	1078	1013	995
L A D W P	271	273	318	353	323	330	314	320
S D G & E	223	204	239	220	225	230	220	230
2. PLANNED, E & F RPT, 9E								
A. SOX TONS								
P G & E	4986	8565	9733	9879	8835	7163	8271	11755
S C E	6167	5664	6188	6200	5570	5932	5189	4467
L A D W P	2929	2989	3471	3794	1791	1750	1668	1697
S D G & E	1331	1298	1471	1434	1506	1435	1390	1475
B. NOX TONS								
P G & E	5887	7405	8252	8283	7655	7113	7127	8808
S C E	3349	3560	3974	4163	4053	4286	4033	3986
L A D W P	1444	1585	1820	2085	1884	1673	1594	1793
S D G & E	959	937	1066	1027	1109	1046	1011	1061
C. PARTICULATES TONS								
P G & E	559	865	975	986	898	757	836	1131
S C E	894	928	1008	1045	1012	1078	1013	995
L A D W P	276	282	327	358	338	330	314	320
S D G & E	227	210	246	225	239	230	220	230
3. TRANSFERS, E & F RPT, 9F								
A. SOX TONS								
P G & E	0	0	0	0	0	0	0	0
S C E	51	98	108	62	155	0	0	0
L A D W P	53	89	101	54	75	0	0	0
S D G & E	16	23	26	14	31	0	0	0
B. NOX TONS								
P G & E	0	0	0	0	0	0	0	0
S C E	79	120	134	89	182	0	0	0
L A D W P	47	66	132	49	175	0	0	0
S D G & E	13	23	26	14	39	0	0	0
C. PARTICULATES TONS								
P G & E	0	0	0	0	0	0	0	0
S C E	12	22	24	14	35	0	0	0
L A D W P	5	9	9	5	15	0	0	0
S D G & E	4	6	7	5	14	0	0	0

NOTE: DATA FOR JAN, FEB, MAR & APRIL ARE NOT AVAILABLE

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APPENDIX B

The following table presents reservoir projections through December of 1977. Projections are presented for reservoirs operated by Pacific Gas & Electric Company, the Bureau of Reclamation and the California State Department of Water Resources. The purpose of this table is to indicate the severity of the drought, and, given current and expected operations of these facilities, to show that the storage carryover into the 1977-1978 water year will indeed be small. (A water year runs from October through September.)

Hydro Operation
Forecasted Monthly Reservoir Storages Based on Conditions as of April 1, 1977 Using 1976 Runoff
End of Month Storages (Thousands of Acre-feet)

Reservoir	Reservoir Storage Capacity	June	July	August	September[a]	October	November	December
Pacific Gas & Electric[b]								
McCloud	35.2	35.0	33.0	28.0	25.0	28.0	33.0	35.0
Lake Almanor	1143.0	609.0	578.0	540.0	500.0	500.0	500.0	500.0
Bucks Lake	105.6	49.0	49.0	45.0	41.0	37.0	34.0	30.0
Little Grass Valley	93.0	48.0	45.0	42.0	40.0	40.0	40.0	40.0
Sly Creek	65.0	11.0	10.0	9.0	8.0	8.0	9.0	10.0
Bullards Bar	966.1	293.0	270.0	246.0	221.0	203.0	192.0	178.0
Jackson Measows	69.2	8.0	3.0	3.0	0.0	0.0	0.0	0.0
Bowman Lake	90.7	20.0	16.0	7.0	1.5	1.5	1.5	2.0
Fordyce	46.7	15.0	9.0	3.5	3.5	0.0	0.0	0.0
Sapulding	74.8	23.0	21.0	19.0	12.0	9.0	6.0	5.0
Rollins	66.0	14.0	14.0	15.0	16.0	13.0	11.0	9.0
French Meadows	136.4	52.0	51.0	50.0	50.0	50.0	50.0	50.0
Hell Hole	207.6	95.0	93.0	91.0	90.0	90.0	90.0	90.0
Lower Bear	52.0	6.0	5.0	5.0	4.0	4.0	4.0	4.0
Salt Springs	141.9	9.0	8.0	7.0	6.0	7.0	6.0	6.0
Donnells	64.3	9.0	2.0	2.0	2.0	2.0	2.0	2.0
Beardsley	97.8	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Exchequer	1025.0	219.0	201.0	180.0	166.0	162.0	156.0	150.0
S. Cal. Edison	560.0	183.0	146.0	131.0	122.0	120.0	127.0	130.0
Crane Valley	45.4	21.0	21.0	21.0	19.0	18.0	18.0	18.0
Couriright	123.3	0.9	0.8	0.7	0.6	0.6	0.5	0.4
Wishon	129.1	89.0	69.0	48.0	28.0	29.0	29.0	28.0
Isabella	570.0	71.0	54.0	30.0	30.0	40.0	50.0	50.0
Lake Pillsbury	86.8	21.0	18.0	15.0	12.0	12.0	13.0	14.0
California Department of Water Resources								
Oroville	3520.0	1227.0	1063.0	895.0	878.0	828.0	817.0	829.0
Central Valley Project[c]								
Shasta	4552.0	881.0	642.0	580.0	580.0	751.0	939.0	1370.0
Clair Engle	2448.0	750.0	520.0	315.0	261.0	235.0	256.0	322.0
Whiskey Town	241.0	238.0	238.0	213.0	95.0	30.0	34.0	51.0
Folsom	1010.0	248.0	194.0	146.0	130.0	147.0	216.0	385.0
Millerton	521.0	197.0	149.0	136.0	135.0	139.0	156.0	168.0
San Luis[d]	2039.0	809.0	496.0	240.0	380.0	360.0	543.0	733.0

[a]End of 1977 water year.

[b]Pacific Gas & Electric forecast.

[c]Source: Report of Operations, April 1977, BUreau of Reclamation, Central Valley Operations Coordinating Office.

[d]San Luis is a joint Bureau of Reclamation and California State Department of Water Resources project. The storage figure given is a total of both shares.