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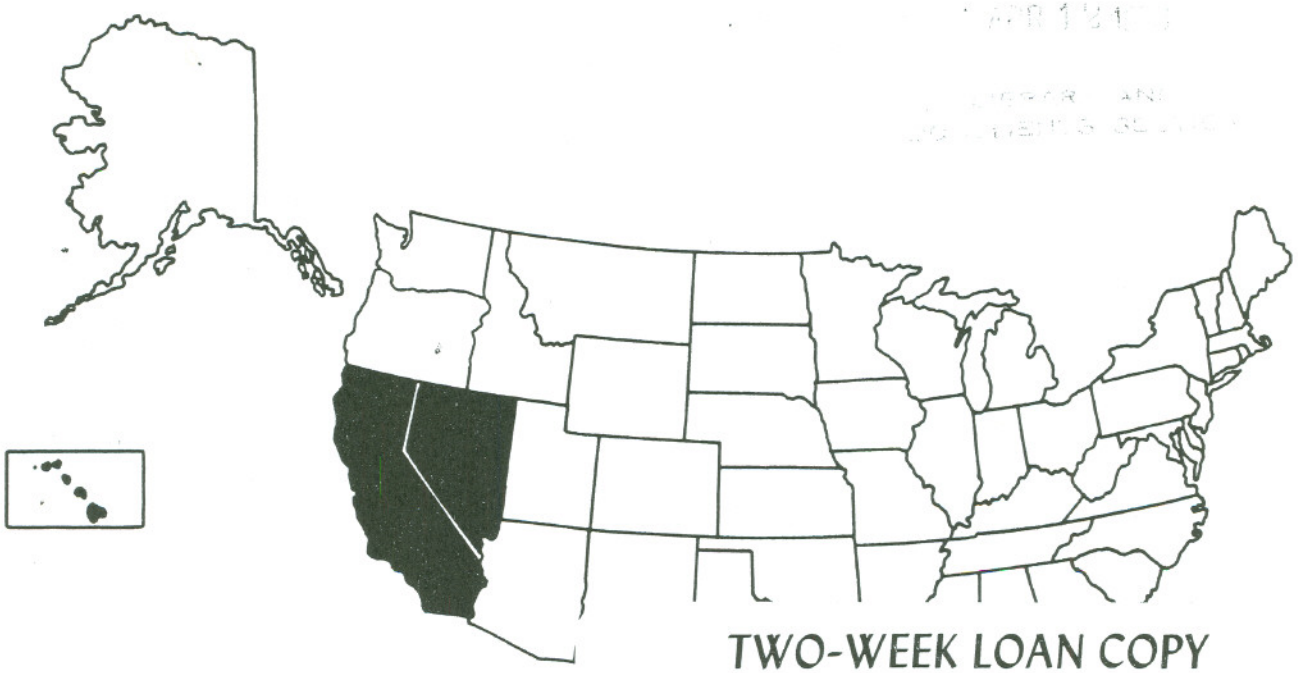
Potential Electricity Impacts of a 1978 California Drought

January 1978

ENERGY ANALYSIS PROGRAM



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POTENTIAL ELECTRICITY IMPACTS OF A 1978 CALIFORNIA DROUGHT

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Table of Contents

Section		Page
	List of Tables	iv
	List of Figures	vi
	SUMMARY	vii
	Electricity Demand and Supply During 1977	ix
	Electricity Demand and Supply During 1978	x
	Remedial Measures for Demand	xiv
1	INTRODUCTION	1
2	ELECTRICITY DEMAND	5
	Electricity Use During 1977	5
	Demand Appraisal for 1978	13
3	ELECTRICITY SUPPLY	17
	Supply Assessment for 1977	17
	Supply Availability for 1978	18
4	IMPACTS OF SUPPLY OPTIONS	51
	Environmental Effects	51
	Average Prices for Pacific Gas and Electric Company	62
5	REMEDIAL MEASURES FOR DEMAND	73
	Conservation	74
	Load Management	80
	Load Shedding	88
APPENDIX A	CAPACITY AND ENERGY SUMMARY	95
APPENDIX B	FORCED OUTAGE RATES	101
APPENDIX C	CALIFORNIA AGRICULTURAL ENERGY DEMAND	109
	Introduction	109
	Energy Use in Agriculture (1977)	112
	Projected Energy Demand for Agricultural Pumping in the Central Valley (1978)	115
	References	119

List of Tables

Table	Title	Page
1	PG&E Quarterly Sales Comparisons	6
2	Statewide Quarterly Sales Comparisons	7
3	Comparison of Historical and Predicted Demand for Energy and Peak Capacity	11
4	PG&E Service Area Peak Loads and Loads Adjusted for Temperature	12
5	Summary of LBL Scenarios for Energy and Peak Demand	14
6	Monthly Electrical Energy Loads for PG&E for 1977 and Three Load Cases for 1978	16
7	Reservoir Storage on October 1	21
8	PG&E Area 1978 Hydroelectric Resources Assuming Average Precipitation	24
9	PG&E Area 1978 Hydroelectric Resources Assuming 1977 Runoff	26
10	New Generating Units Expected in 1978	29
11	Energy Supply and Demand Balances for PG&E for 1978 Assuming Continued Drought Conditions	32
12	Peak Load Capacity for PG&E for the Summer of 1978	33
13	Statewide Supply-Demand Balances for Energy	35
14	Statewide Capacity Balance and Reserve Margins	36
15	Summer Peak Load Order by Month for 1977 and Estimated Loads for 1978	47
16	Statewide Loss-of-Load-Probability Results for August 1978	49
17	History and Outlook of Power Plant Fossil Fuel Use and Emissions in South Coast Air Quality Management District	56
18	Estimated Peak Day Emissions from Power Plants in South Coast Air Quality Management District, 1978	57
19	Emission Factors for Southern California Electric Utilities	58
20	Expected Emissions due to Energy Transfers in 1978	59

List of Tables (continued)

Table	Title	Page
21	1978 Estimates of Variables Constant Across Scenarios	65
22	Estimated 1978 Fuel Expense	66
23	PG&E Generation in 1976 by Fuel Type and Average Price	66
24	Dry Year 1978 PG&E Generation by Fuel Type and Average Electricity Price	69
25	Wet Year 1978 PG&E Generation by Fuel Type and Average Electricity Price	70
26	Nuclear and Geothermal Generation Assumptions	72
27	PG&E's Schedule No. A-17	83
28	PG&E's Schedule No. A-18	89
A-1	Energy Generating Capability of Major Southern California Electric Utility Companies	96
A-2	Southern California Resources Available for Summer 1978	97
B-1	Forced Outage Rates for Individual Power Plant Units and Major Interconnecting Transmission Lines	103
C-1	California Precipitation	111
C-2	Monthly Electricity Sales to Agriculture (1975-77) PG&E Service Area	113
C-3	Energy Use and Generation for State and Federal Water Conveyance Projects	118

List of Figures

Figure	Title	Page
1	Comparative Sales by Quarter for PG&E 76 vs. 75, 77 vs. 76	8
2	Comparative Sales by Quater, Statewide 76 vs. 75, 77 vs. 76	9
3	Risk Curves for PG&E 1978 Compared to 1977	41
4	Interconnection Support Required for Demand Cases D and E	43
5	Effect of Diablo Canyon on PG&E Risk	44
6	Statewide Risk Curve for 1978 Under Various Assumptions	46
7	Distribution of Annual Average Daily SO_x Emissions in the South Coast Air Basin, 1974, Stationary Sources	53
8	Distribution of Annual Average Daily NO_x Emissions in the South Coast Air Basin, 1972-73, Stationary Sources	54
B-1	Diablo Canyon Forced Outage Rate	107
C-1	Reduced Precipitation Due to the Drought by Area	110
C-2	Electricity Sales to Agriculture	114

POTENTIAL ELECTRICITY IMPACTS OF A 1978 CALIFORNIA DROUGHT

SUMMARY

California has endured a severe drought for the past two years. As a consequence surface water supplies during 1977 decreased to levels not experienced in the recent history of California. Hydroelectric supplies, which rely on surface runoff, also decreased to record lows raising questions regarding the adequacy of electricity supplies to meet summer peaks during 1977 and 1978. Through 1977 electricity supplies, aided by conservation of electricity by consumers, power pooling and other measures were adequate to meet demand. However, supplies were more expensive due to increased reliance on thermal generation to compensate for hydroelectric losses.

If the drought were to continue for another year, how would it affect electricity supply and demand in California? What would be the impact on power plant emissions and on electricity rates? And finally, what remedial measures should be considered in prudent planning? Key aspects of these questions are analyzed in this study sponsored by the U.S. Department of Energy. To analyze the impact of supply options on reliability and electricity prices, two separate models were modified and implemented. These models along with the overall methodology, although implemented primarily with data for 1978 in appropriate sections of the report, would be generally applicable for analyzing the adequacy of electricity supply during any year.

In our analysis, electricity demand and supply during 1977 are reviewed before analyzing the prospective situation during 1978. Hydroelectric supplies for 1978 are assumed at the level anticipated by the electric utility companies. These supply estimates are based on the 1977 levels of runoff. The hydroelectricity thus generated would be slightly lower than that estimated for 1977. Also on the supply side, because of the uncertainty associated with the introduction of the Diablo Canyon 1 nuclear power plant, we analyzed the supply options with and without Diablo Canyon Unit 1. The major findings of our study discussed later in detail are presented below:

1. Statewide electricity demand during 1977 did not increase at the rate anticipated by the electric utility companies. Demand in the Pacific Gas and Electric Company (PG&E) service area, the area most affected by the drought, actually declined from 1976 levels. The significant factors that may have contributed to reduced demand are: voltage reduction, a sharp increase in electricity rates, reduction in electricity requirements for surface water pumping, lower summer temperatures and "heightened conservation consciousness" induced by the drought.
2. In 1978, with statewide coordination of electricity resources and continued energy conservation on the part of consumers, electricity supplies would be adequate to meet projected electricity demands with sufficient reserves during the summer peak months. Supplies, at a minimum reserve margin of 12.7 percent, would be adequate without the inclusion of Diablo Canyon nuclear power plant in the PG&E supply system.
3. Transfers of electricity generated from oil-fired power plants in the South Coast Air Basin to PG&E could lead to as much as a ten percent increase in nitrogen oxide emissions from power plants in this basin during the peak summer months. The already frequent violations of air quality standards in this basin may increase because of these emissions. At the same time due to the mandated lower sulfur content of oil for 1978, sulfur oxide emissions will decrease markedly.

   The difference in 1978 electricity prices between a normal versus dry weather year would be almost 20 percent for the PG&E system. This large difference results from the increased oil and nuclear generation, which replaces inexpensive hydroelectric generation. Inclusion of Diablo Canyon nuclear result in a maximum change of less than three percent in electricity prices.
4. Although 1978 electricity supplies appear adequate, implementation of remedial measures would provide insurance against unforeseen systems failures and would result in long-term benefits. Conservation, load management and load shedding practices which could be implemented in California are therefore examined in detail.

ELECTRICITY DEMAND AND SUPPLY DURING 1977

Statewide electrical energy sales during the first and second quarters of 1977 increased 1.6 percent and 0.9 percent over sales in the corresponding quarters of 1976. For the PG&E service area, where hydroelectric generation capability has been most severely affected, the figures are 0.5 percent and -1.5 percent, respectively, during the same period and -1.0 percent for the entire year. Peak demand during 1977 dropped for both statewide coincident demand and for the PG&E service area from the 1976 levels. These changes in energy sales and peak demand are well below the increases forecasted by the electric utility companies. The main factors contributing to this slower growth appear to be 1) the voltage reduction instituted by the utility companies, although this has not yet been fully implemented statewide, 2) the substantial increase in electricity prices over the past year, 3) a generally cooler summer with lower peak temperatures, 4) reduced energy requirements for water pumping, and 5) the "heightened conservation consciousness" induced in part by the drought and by public information campaigns. Adequate data were not available, however, to develop a reliable estimate of the contribution made by each of these factors.

Industrial and agricultural electricity sales between the first two quarters of 1976 and 1977 increased faster than residential and commercial sales both statewide and in the PG&E service area. Second quarter 1977 commercial sales as compared with second quarter 1976 sales actually declined in both the PG&E service area and statewide. Sales to agriculture for the first three quarters have increased from 4.34 billion kWh in 1976 to 4.47 billion kWh in 1977 in the PG&E service area. These should be compared with sales of 3.59 billion kWh during a comparable period in 1975, a "normal" water year.

Decreased water deliveries in 1977 resulted in reduced energy requirements for water pumping in both the Central Valley Project and State Water Project. In 1976 the electricity requirements for the two projects net of recovery generation were 1.2 billion kWh and 3.0 billion kWh, respectively, whereas in 1977 the corresponding electricity requirements were 0.6 billion kWh and 1.6 billion kWh.

On the electricity supply side there appear to have been no major problems through 1977. In part preplanned coordination among the utilities for energy transfers from southern California and the Pacific Northwest to PG&E allowed the utility to maintain sufficient reserves throughout the year. Except for a brief interval in early September when reserve margins for PG&E dropped below 6 percent the utility experienced no major supply problems. Statewide, utilities had access to ample fuel supplies; in fact southern California utilities received considerably more natural gas from their suppliers than anticipated. This unexpected supply did result in increased oil storage costs for the utilities; however, the use of gas instead of oil generally decreased pollutant emissions and fuel costs.

ELECTRICITY DEMAND AND SUPPLY DURING 1978

Demand

The four major utility companies in California, Pacific Gas & Electric, Southern California Edison (SCE), Los Angeles Department of Water and Power (LADWP), and San Diego Gas & ELectric (SDG&E), jointly submitted a 1978 electricity demand and supply forecast to the California Energy Resources Conservation and Development Commission (CERCDC) in August 1977. The estimated statewide electricity demand for 1978 is 3.9 percent higher than the 1977 forecast, and coincident peak demand is up 4.7 percent over the 1977 forecast. Comparable estimates for the PG&E service area are a 4.7 percent increase in both electricity demand and peak load over the 1977 estimates. The actual demand through July 1977 in both cases has been well below the 1977 forecast.

Because PG&E is the utility most severely affected by the drought, we analyzed three 1978 demand scenarios for PG&E. The first assumed a 4.7 percent increase in electricity demand, the second assumed no growth in demand over 1977, and the third postulated a two percent decrease in demand. The growth rate in the first scenario is the same as the rate forecasted by PG&E, whereas the two lower estimates are motivated by the declining growth recorded between 1976 and 1977. The monthly distribution of demand in each case was based on 1977 recorded and estimated demand for

PG&E. Demand for 1978 in the other utility service areas was assumed to remain at the same level forecasted by those utilities in their submittals.

From a separate analysis of agricultural energy demand, the total groundwater pumped in the Central Valley for agriculture in 1977 was estimated to be 14.7 million acre-feet. In 1978, the groundwater that will be used to make up for surface water deficits is expected to reach 17 million acre-feet. Since this water will be pumped from depths that are 5 to 10 feet lower, on the average, than those of last year, the estimated electrical demand in agriculture will increase about 11 percent over 1977 levels.

The five reasons stated earlier for the low demand in 1977 compared to PG&E forecasts for 1977 provide some clues to the demand levels for 1978 in the event of a continued drought. Voltage reduction has already been introduced, and further selective reductions may be possible. The decrease in water consumption from 1977 to 1978 will be smaller than the reduction during 1977, thus producing a smaller decrease in sales than it did this year. Electricity price increases next year are likely to be less than this year since hydroelectric supplies will decrease only slightly from the already low supplies and the largest factor in these price increases has been the additional cost of oil-fired electricity generation. The actual impact on sales will depend on the price differential, the absolute price and the residual impact of the price increase persisting in 1978.

Temperature changes primarily affect system peak loads. Milder temperatures prevailed during 1977 with most incidences of high temperatures occurring on weekends, normally a time of lower peak demand. Although the peaks were lower than anticipated this year, the high peak levels forecasted by the utilities could come about if high temperatures prevail next summer. PG&E in its forecasts projected a 4.7 percent growth in sales and in peak demand. However, the factors considered above suggest that in the event the drought continues, 1978 PG&E sales may be less than projected by the company and may not be significantly different from sales in 1977.

Supply

Our supply scenarios are based primarily on the utility submittals to CERCDC with the changes presented in the next three paragraphs. Diablo Canyon Units 1 and 2 (1060 MWe each) are presently in the licensing process. The date on which these nuclear power plants may be placed in service will be determined largely by the Nuclear Regulatory Commission (NRC). It now appears that August is the earliest possible startup date for Unit 1, with Unit 2 delayed until 1979. We have analyzed the supply situation with and without Diablo Canyon Unit 1.

For PG&E, Geysers geothermal Units 12 (106 MWe) and 15 (55 MWe) have also been delayed until September and December 1978, respectively. The nuclear unit at Humboldt Bay (63 MWe), out of service since July 1976, is not expected to return during 1978. For SCE and SDG&E, the planned refueling of San Onofre (430 MWe) in July and August has been delayed past September, based on information from SCE and CERCDC.

Finally, we assume full use of both the Castaic pumped storage facility (1170 MWe) operated by LADWP and the LADWP share of the Pacific Northwest DC intertie (an additional 200 MWe). No changes were assumed in the 6731 MWe statewide peak hydroelectric capacity projected for a continuing drought year, which is down from the 7382 MWe projected for 1977. Favorable changes in weather would increase this figure as well as increase the availability of hydroelectric imports from the Pacific Northwest.

Our analysis indicates that any of these supply scenarios provide adequate electric energy and power to meet the projected demand. Our worst case assumptions yield a statewide capacity reserve margin of 12.7 percent for the peak month of August 1978, which is the same as forecasted by the utilities in their joint submittal. Under these same conditions, the excess energy generation capability drops to a minimum of 6.5 percent in July 1978, compared with the utilities' estimate of 8.3 percent.

Reliability of the coordinated electricity supply system in California and of the PG&E supply system, measured by the loss-of-load probability (LOLP) index, was estimated for various supply options. Our calculations indicate that with the change in statewide resources mentioned above and without Diablo Canyon Unit 1, there is sufficient capacity to reliably meet the statewide coincident peak load predicted by the utilities, with

the monthly LOLP a factor of three below the PG&E risk criterion of 8.5 x 10^{-3}. For the PG&E system we have estimated the amount of additional support required to meet the system load with and without Diablo Canyon Unit 1. To meet PG&E's predicted loads with a monthly LOLP of 8.5 x 10^{-3}, the utility would require 1300 MWe and 1900 MWe, respectively, of outside support above and beyond the "perfect" support of 600 MWe. While this level of support is available from other utility companies, as shown in their supply forecasts, it requires significant loading of the available transmission line capacity. Interconnections between PG&E and the Pacific Northwest, and with SCE can handle these capacities, but with greater system consequences if transmission outages occur.

Impacts

Based on these separate demand and supply scenarios average prices* for PG&E were estimated for two meteorological cases for 1978. The first is for the amount of hydroelectric generation anticipated if the drought continues in 1978 and the second for wet year hydroelectric generation equivalent to that in the 1975 calendar year. The various demand and supply scenarios do not significantly alter the average prices. On the other hand, the dry and wet year hydroelectric generation changes the average price by 20 percent. Average electricity prices for a dry year cluster around 4.2¢/kWh and for a wet year around 3.5¢/kWh for these scenarios. Having Diablo Canyon in the supply system reduces the prices only slightly due to decreased expense for fuel oil and for electricity transfers, with the decrease more pronounced during a dry year. Prices also decrease slightly with an increase in sales as the returns to invested capital are distributed over a larger sales base.

In the South Coast Air Basin power plants are major contributors to sulfur oxide (SO_X) and nitrogen oxide (NO_X) emissions. The formation of sulfur oxides is directly linked to the sulfur content of fuel oil, which is mandated by law to average 0.25 percent sulfur in 1978, down from the estimated average level of 0.32 percent in 1977. Average sulfur oxide emissions (156 tons/day) in 1978 are therefore expected to be well below the

*The term average price refers to average revenues at an assumed 9.2 percent rate of return.

1977 levels (208 tons/day). Increased fuel oil use in recent years has led to a dramatic increase in NO_X emissions in power plants, up 70 percent in 1977 from 1976 levels (163 vs. 95 tons/day). During 1978 these emissions will increase another 5 to 10 percent. Any transfer of energy from the South Coast Air Basin to PG&E will add as much as ten percent to the power plant SO_X and NO_X emissions during the summer peak months. Unfortunately, it is impossible at this time to determine a simple quantitative relationship between power plant emissions and air quality, which is a complex function of meteorology, topography, the interaction of pollutants and removal processes. It appears that the average meteorological conditions relevant to photochemical smog formation in this air basin were not affected by the drought in 1977.

REMEDIAL MEASURES FOR DEMAND

In view of the supply alternatives that are available to meet a continued drought, it does not appear that measures to restrain demand are essential to avert an emergency. However, there are several reasons why any plan for dealing with electricity needs during the drought should contain measures aimed at controlling demand. First, a growth in demand significantly beyond the 4.7 percent projected by PG&E could seriously strain the supply system. Second, the available supply alternatives are more costly, hence measures which can avert the need for some of the alternatives will reduce the financial burden that must be borne by the California economy. Third, demand control can provide insurance against unforeseen system failures or conditions such as extremely hot weather during the summer which might otherwise create excessive peak demand. Finally, measures for moderating demand growth should be pursued because of long-term benefits. The heightened conservation consciousness of consumers during the drought should increase the receptivity to energy conservation initiatives and thus provides an opportunity to make progress toward long-term objectives.

We have examined three strategies for reducing demand: conservation, load management, and load shedding. The conservation strategy aims

at reducing electricity consumption. The load management strategy aims at shifting electricity consumption from periods when demand for electricity is high to periods of lower demand. The load shedding strategy aims at reducing electrical loads during extreme peaks in demand or at times when equipment failures create a sudden shortage of generating capacity.

During the next year several conservation programs could be implemented. As a first step both the federal and state agencies need to place increased emphasis on an expanded public information program. A second step, which would be warranted if the situation grows more serious, would be the enforcement of CPUC Rule 14.1 especially where it affects conspicuous consumption. The last step would be mandatory reductions in electricity use by all customers. While such a program is not likely to be required, it is prudent to develop a plan for implementing such reductions. Such programs can be highly effective as evidenced in 1973 in the LADWP service area where an overall saving of more than 12 percent was achieved during the Arab oil embargo.

The only load management effort directly related to the drought so far has been the rather modest advertising campaigns by the utilities and by CERCDC. As a continuing program, however, both the CPUC and CERCDC are requiring utilities to implement time-of-use pricing. Two steps that could be taken to increase load management in the current situation are to intensify the public information campaign and to accelerate the implementation of time-of-use rates. It may also be possible to make improvements in existing time-of-use rate schedules, especially in their treatment of the energy cost adjustments.

Load shedding as the term is used here means to discontinue the operation of electricity-using equipment on short notice; it may be done either by the customer or by the utility. If the drought continues and neither the supply alternatives nor energy conservation and load management are sufficient to maintain the supply-demand balance, then load shedding will be necessary to maintain supply system operation. The first to be affected by load shedding would be those customers who were contractually obligated to reduce their loads when requested to do so. Efforts then would probably be made to achieve voluntary load reductions based on appeals to the public. If this were not sufficient, rotating blackouts would have to be initiated. One objective in planning for a possible continuation of

the drought is to increase the probable response in the first two steps above so that losses associated with indiscriminant blackouts can be avoided.

During 1977 PG&E identified large customers who would be willing voluntarily to shed a combined load of 500 MW, roughly three percent of its load. One strategy that might be implemented if the drought continues is an incentive program which would encourage more customers to participate in this voluntary arrangement.

In conclusion, the analysis of electricity supply and demand highlights two themes which need to be emphasized. The first is increased statewide coordination not only among the electric utility companies, but also among government agencies and the utilities. The second is increased electricity conservation and load management practiced by consumers. In anticipation of a drought during 1977 the three major private utilities, PG&E, SCE and SDG&E and the municipal utility LADWP made arrangements for a smooth transfer of electricity to PG&E on a contractual basis. These transfers helped PG&E meet its loads without resorting to any drastic load reduction measures. Increased electricity conservation practiced by consumers whether induced by higher prices, voltage reduction, or heightened awareness of energy consumption decreased 1977 electricity use below the 1976 levels.

The commendable response of both the utility companies and electricity consumers to the electricity supply constraints experienced during 1977 should not go unobserved. The primary lesson to be learned from this response to the drought is that there is considerable potential for coordination of electricity supplies and for electricity savings through conservation in California. These two themes should be further explored by concerned agencies for their applicability during a normal year.

SECTION 1

INTRODUCTION

During the past two years California has endured a drought whose severity is unmatched by any previous two-year period in the recorded history of the state. Reservoirs which normally supply a substantial fraction of California's water and nearly a quarter of the state's electrical energy needs reached all-time lows in 1977. Hydroelectric generation during 1977 provided only a fraction of its normal contribution to electricity supply. The success in meeting peak demands without resorting to load shedding in 1977, even if at times the reserve margin was small, is a tribute to skillful use of thermal electric generating capacity, power pooling and voluntary conservation of electricity by consumers. However, the added use of oil and gas for thermal generation of electricity necessary to compensate for losses in hydroelectric production resulted in higher electricity rates and increased air pollutants in already impacted air sheds.

If the drought were to continue for another year, what would be the effect on California's electricity supply and demand? What would be the impact on power plant emissions and electricity rates? What remedial measures should be considered in prudent planning? This study, in cooperation with the San Francisco Operations Office and the Division of Technology Overview of the Departmentof Energy was designed to conduct an early and timely investigation of the key aspects of these questions in order to avoid last minute crisis solutions. To analyze the impact of supply options on reliability and electricity prices, two separate models were modified and implemented. These models along with the overall methodology, although implemented primarily with data for 1978 in appropriate sections of the report, would be generally applicable for analyzing the adequacy of electricity supply during any year.

Specifically the study was designed to 1) examine the effects of the drought on electricity supply and demand during 1977, 2) anticipate the consequences of a continued drought on electricity supply and demand during 1978, 3) assess the impacts of supply options on electricity rates

and on air pollution, 4) evaluate strategies to reduce the probability of future electricity shortages and 5) convene a conference to promote discussion of ideas to mitigate the adverse impacts of the drought.

During 1977 the drought forced electric utility companies and customers to make several changes in the electricity supply and use patterns. These changes in patterns provide some insight into the possible demand for electricity during 1978. In section 2 we first analyze the growth in different components of demand during 1977. Based on this analysis, various possible growth levels for peak loads and energy demand are projected for 1978. A detailed description of agricultural demand is presented in Appendix C.

Electricity supplies, in spite of the drought during 1977, were adequate to meet demand during the entire year. A continuation of the drought would result in further reduction of depleted hydroelectric supplies. Section 3 examines the alternative supplies available statewide to replenish the hydroelectric supplies, especially for the PG&E service area. The adequacy of these supplies to meet the projected demands during 1978 is evaluated along with estimates of system reliability for several supply options.

Two major impacts of the drought on electricity supply have been the increase in electricity rates and in air pollution due to the increased thermal generation of electricity. In Section 4 we focus on the impacts of various supply options for 1978 on 1) average price of electricity for the Pacific Gas & Electric Company (PG&E) and 2) on air pollutants in the South Coast Air Basin. Average prices were estimated only for PG&E, because it is the utility most affected by the drought. Air pollutants were examined in the South Coast Air Basin because additional thermal generation to supply electricity to PG&E would increase the already high levels of air pollutants.

To match electricity demand and supply either demand or supply or both could be changed. Within the relatively short span of time before next summer, when electricity use typically peaks, it would be difficult to augment existing and planned supplies. Most of the practicable changes are therefore confined to reducing demand. In Section 5 three types of remedial measures to reduce demand are examined—conservation, load management and load shedding.

This report makes no attempt to forecast electricity demand for 1978. Instead we examine three demand projections based on the demand level in 1977 to bracket the probable range for 1978. On the supply side, because of the uncertainty associated with the introduction of the Diablo Canyon power plant, we analyze the supply options with and without Diablo Canyon Unit 1. Hydroelectric generation for 1978 is assumed to be at the level anticipated by the utilities if the drought were to continue for another year.

Analysis of air quality impacts is limited to estimates of air pollutants and to a qualitative discussion of the impacts of air quality. Health effects of these pollutants were not examined.

Impacts of voluntary and mandatory conservation on electricity sales are difficult to quantify. Most of the discussion of conservation is therefore qualitative, although where possible estimates of reduction in sales and demand for electricity are included. On the other hand load management and load shedding are more amenable to analysis and these sections include specific measures and their quantitative impacts.

Early in December 1977 the study team organized a conference to examine the problems and share ideas on measures that can be instituted in the short term to ensure a balance in electricity supply and demand. The conference was attended by staff members of the electric utility companies, state and federal government agencies, research institutions and public interest groups. The three panels at the conference provided a forum for the discussion of the effects of the drought on electricity demand and electricity supply and a discussion of measures to match demand and supply. The demand and supply panels provided up to date information on electricity sales and on hydroelectric and other electricity supplies available to California. The discussion on remedial measures generated new ideas for implementing some of these measures. Relevant ideas and information provided at the conference were included in appropriate sections of this report.

SECTION 2

ELECTRICITY DEMAND

ELECTRICITY USE DURING 1977

It is instructive to review the electricity sales in California during 1977. Especially important in this respect are whether electrical energy sales increased or decreased during this time, and in which end-use sectors and areas the change occurred. We have obtained sales data by end-use billing category for the first two quarters of 1977 and quarter-by-quarter for all of 1975 and 1976 from the California Energy Resources Conservation and Development Commission (CERCDC) for all electrical utilities in California. These data are summarized in Tables 1 and 2 for the PG&E service area and statewide. Sales are compared quarter-by-quarter for 1975, 1976 and part of 1977 in Figs. 1 and 2 where the rate-of-change in sales has been plotted. One can see that there has been a general decline statewide and a sharper drop in the PG&E service area for relative changes in sales over this time period.

Statewide electrical energy sales during the first and second quarters of 1977 increased 1.6 percent and 0.9 percent over sales in the corresponding quarters of 1976. For the PG&E service area, where hydroelectric generation capability has been most severely affected, the figures are 0.5 percent and -1.5 percent, respectively, during the same periods. Attempting to unfold the various factors leading to the decline in the growth of sales is difficult, if not impossible quantitatively. One can, however, identify major elements or factors thought to have had an influence: 1) the voltage reduction instituted by the utility companies, although this has not yet been fully implemented statewide, 2) the substantial increase in electricity prices over the past year, 3) a generally cooler summer with lower peak temperatures, 4) reduced energy requirements for water pumping, and 5) the "heightened conservation consciousness" induced in part by the drought and by public information campaigns. These elements are discussed in more detail in the various sections of this report.

Table 1

PG&E Quarterly Sales Comparisons[a]
(TWh)

Year/Quarter		Billing Category: Residential	Commercial	Industrial	Agriculture	Other	Combined Industrial[b]	Total
1975	I	5.32	4.10	3.59	0.49	1.35	5.43	14.86
	II	4.65	4.23	3.61	1.30	1.18	6.09	14.97
	III	5.08	4.71	4.01	1.81	1.43	7.25	17.04
	IV	5.05	4.58	4.02	0.52	1.69	6.23	15.85
TOTAL		20.09	17.63	15.24	4.11	5.65	25.00	62.72
1976	I	5.48	4.37	3.73	0.76	1.67	6.16	16.02
	II	4.73	4.41	4.07	1.64	1.26	6.97	16.10
	III	5.44	4.92	4.39	2.05	1.55	7.99	18.35
	IV	5.13	4.69	4.27	0.52	1.25	6.04	15.86
TOTAL		20.77	18.39	16.47	4.98	5.73	27.18	66.33
1977	I	5.62	4.34	4.05	0.84	1.26	6.15	16.10
	II	4.73	4.30	4.17	1.66	1.00	6.83	15.86
Changes by Quarter (in percent)								
1976 vs. 1975	I	3.0	6.6	3.9	55.1	23.7	13.4	7.8
	II	1.7	4.3	12.7	26.2	6.8	14.4	7.5
	III	7.1	4.5	9.5	13.3	8.4	10.2	7.7
	IV	1.6	2.4	6.2	0	-26.0	-3.0	0.1
TOTAL		3.4	4.3	8.1	21.2	1.4	8.7	5.8
1977 vs. 1976	I	2.6	0.7	8.6	10.5	-24.6	-0.2	0.5
	II	0	-2.5	2.5	1.2	-20.6	-2.0	-1.5

[a]Data source: California Energy Resources Conservation and Development Commission, Form EU-06, 1977

[b]Combined Industrial = industrial + agricultural + other.

Table 2

Statewide Quarterly Sales Comparisons[a]
(TWh)

Year/Quarter		Billing Category: Residential	Commercial	Industrial	Agriculture	Other	Combined Industrial[b]	Total
1975	I	11.54	9.68	9.41	0.68	3.95	14.04	35.26
	II	10.04	9.69	9.63	1.61	3.55	14.79	34.52
	III	10.96	10.97	10.12	2.35	4.20	16.67	38.59
	IV	10.99	10.60	10.18	0.83	4.39	15.40	36.99
TOTAL		43.53	40.94	39.34	5.47	16.08	60.89	145.35
1976	I	11.80	10.20	9.60	0.98	4.42	15.00	37.00
	II	10.27	10.25	10.18	2.06	3.80	16.04	36.55
	III	11.81	11.62	10.79	2.70	4.54	18.03	41.46
	IV	11.18	11.06	10.73	0.83	3.52	15.08	37.33
TOTAL		45.06	43.13	41.30	6.57	16.28	64.16	152.35
1977	I	12.12	10.38	10.30	1.06	3.75	15.11	37.61
	II	10.34	10.24	10.55	2.11	3.63	16.29	36.87
Changes by Quarter (in percent)								
1976 vs. 1975	I	2.3	5.4	2.0	44.1	11.9	6.8	4.9
	II	2.3	5.8	4.7	28.0	7.0	8.5	5.9
	III	7.8	5.9	6.6	13.0	8.1	8.2	7.4
	IV	1.7	4.3	5.4	0	-19.8	-2.1	0.9
TOTAL		3.5	5.3	5.0	20.3	1.2	5.4	4.8
1977 vs. 1976	I	2.7	1.8	7.3	8.3	-15.2	0.7	1.6
	II	0.7	-0.1	3.6	2.4	- 4.5	1.6	0.9

[a]Data source: California Energy Resources Conservation and Development Commission, Form Eu-06, 1977

[b]Combined Industrial = industrial + agricultural + other.

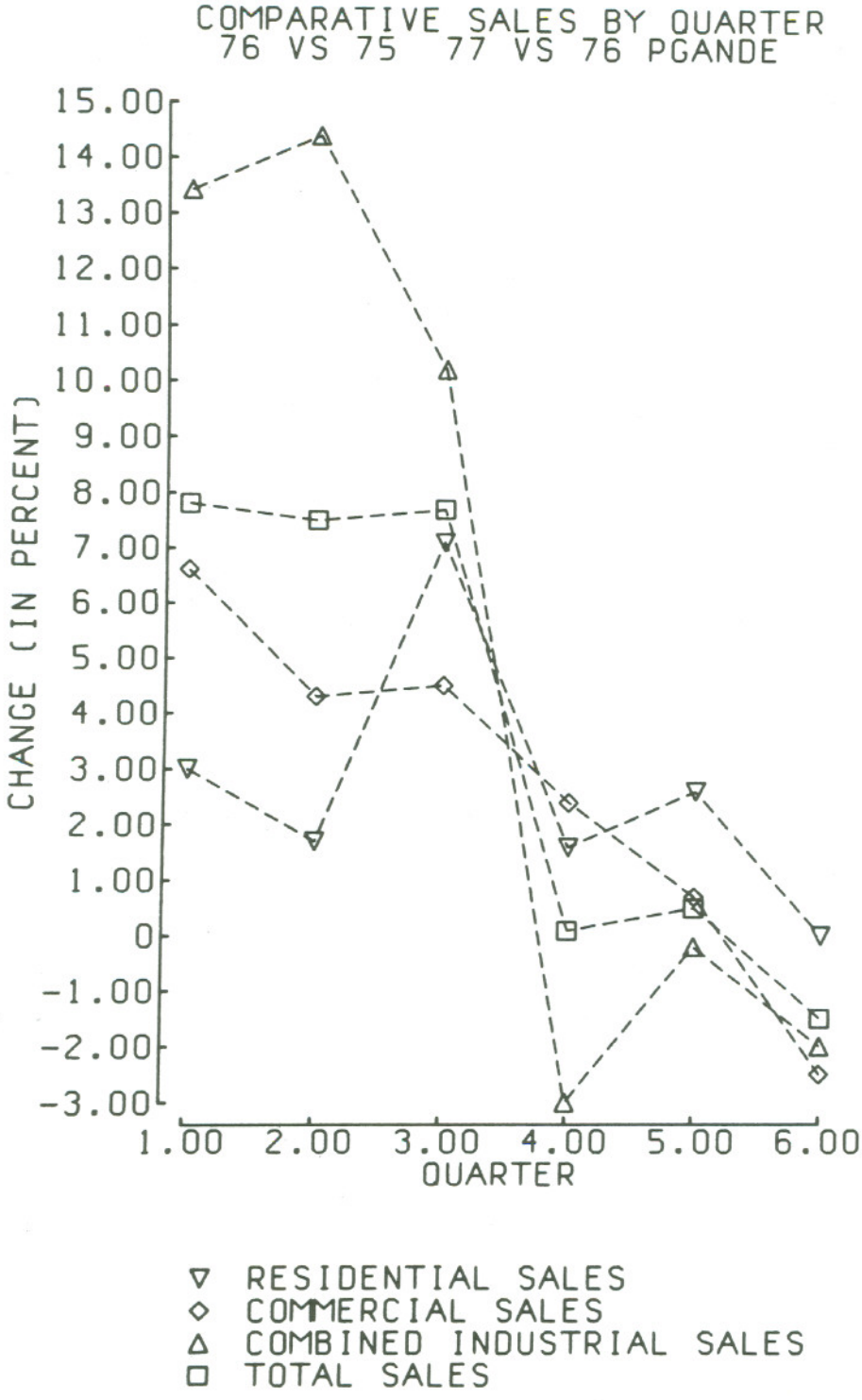

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Figure 1. Quarterly Sales Comparisons. Quarter 1 is 1976 (I) vs 1975 (I), quarter 2 is 1976 (II) vs 1975 (II), etc; quarter 5 is 1977 (I) vs 1976 (I) and quarter 6 is 1977 (II) vs 1976 (II).

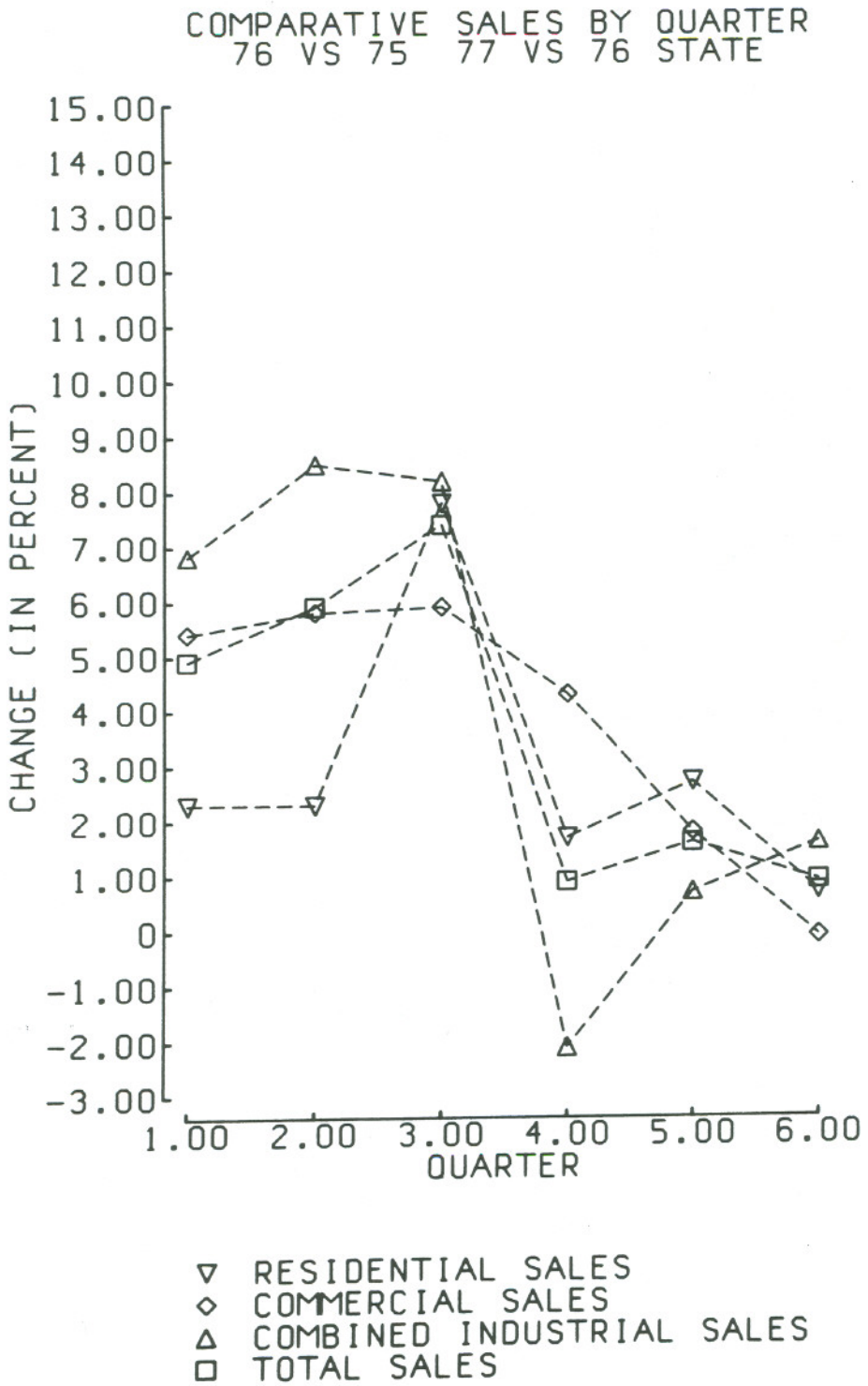

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Figure 2. Quarterly Sales Comparison. See caption for Figure 1 for explanation.

As indicated by the data in Tables 1 and 2, industrial and agricultural electricity sales between the first two quarters of 1976 and 1977 increased faster than residential and commercial sales, both statewide and in the PG&E service area. While agricultural loads for PG&E have risen sharply over the past two years, the increase in 1977 was smaller than in 1976. A more detailed analysis of agricultural energy use is presented in Appendix C. Second quarter 1977 commercial sales actually declined below the second quarter 1976 levels both statewide and in the PG&E service area. Residential sales show a similar trend, though they did not drop below the level of last year. Industrial sales, however, continued to grow throughout the period although the second quarter 1977-1976 comparison shows the smallest increase.

Decreased water deliveries in 1977 resulted in reduced energy requirements for water pumping in both the Central Valley Project and State Water Project. In 1976 the electricity requirements for the two projects net of recovery generation were 1.8 billion kWh and 3.0 billion kWh, respectively, whereas in 1977 the corresponding electricity requirements are estimated to be 0.8 billion kWh and 1.6 billion kWh.[1,2] This decline is reflected primarily in the "other" category in Tables 1 and 2.

The overall energy load both statewide and in the PG&E service area for the first half of 1977 did not increase to the levels forecasted earlier by the utilities. This is shown in Table 3 for the PG&E service area, where the recorded data for 1977 are compared with forecasted levels.

The trends shown for aggregate statewide data and for PG&E are somewhat characteristic of other utilities. SDG&E and LADWP show a similar decline in growth rate in sales as PG&E, although the rate of growth remains positive. SCE, however, shows a different pattern, with significantly higher sales in both the first and second quarter of 1977 than for the same period in 1976.

Peak demand also dropped in 1977 compared with 1976 for both the statewide coincident demand, and for PG&E. The historical trend for peak loads for PG&E is shown in Table 4, along with temperature-adjusted loads. The 1977 peak for PG&E was lower in part due to cooler summer temperatures; however, even the temperature-corrected peak lies below the predicted peak. These data are also compared with PG&E and CERCDC predictions.

Table 3

Electricity Demand by Major Utility Service Area
(energy for load in 10^9 kWh)[a]

	1975[b]	1976[b]	Percent Change 1975-76	Projected[c] 1977	Actual 1977	Percent Change 1976-77	Projected[d] 1978
PG&E[e]	71.71	74.20	3.5	76.12	73.75	-0.6	79.68
SCE[e]	56.51	59.59	5.5	64.35	63.35	6.3	66.08
LADWP[f]	17.65	18.80	6.5	20.66	18.50	-1.6	21.34
SDG&E	8.79	9.13	3.9	10.04	10.00	9.5	10.81

[a]Note that the values for 1975 and 1976 are from a different source than those for 1977. The accounting bases may not be quite the same; hence comparisons should be made with caution.

[b]Source: Quarterly Fuel and Energy Summary, Volume 3, Number 1, First Quater 1977, CERCDC.

[c]Source: Reference 5.

[d]Source: Reference 6

[e]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 service area and Municipal Water District (MWD) in the SCE area.

[f]Source: Reference 37, LADWP loads only.

Table 4

PG&E Service Area Peak Loads, and Loads Adjusted for Temperature.[a]

Year	Peak Demand (MWe)				
	Recorded	Temperature Adjustment	Final Load	Predicted	
				PG&E	CERCDC[b]
1970	9864	+ 90	9954		
1971	10913	-127	10786		
1972	11772	-623	11149		
1973	12212	+ 27	12239		
1974	12964	+379	13343		
1975	13129	448	12681		
1976	13932	- 68	13864		13858
1977	13815	+533	14348	14605[c]	14425
1978	---	---	---	15316[d]	15015

[a] Data and adjustments from Ref. 3. The recorded data and predictions do not include deliveries to Sierra Pacific Power. In 1976 and 1977, this amounted to 108 MW.

[b] Predictions from Ref. 4.

[c] Ref. 5

[d] Ref. 6

DEMAND APPRAISAL FOR 1978

The four major electric utility companies in California, Pacific Gas & Electric (PG&E), Southern California Edison (SCE), Los Angeles Department of Water and Power (LADWP) and San Diego Gas & Electric (SDG&E) jointly submitted a 1978 electricity demand and supply forecast to the CERCDC in August 1977.[6] The estimated statewide electricity demand for 1978 is 3.9 percent higher than the 1977 forecast, and coincident peak load is up 4.7 percent over the 1977 prediction. Comparable estimates for the PG&E service area are 4.7 percent increase in both electricity demand and peak load over the 1977 estimates. The actual demand through July 1977 in both cases has been well below the 1977 forecast.

To analyze the factors that may influence the energy impacts of a continued drought in 1978, we have constructed a set of demand scenarios, focusing on the PG&E service area rather than statewide. Based upon historical data, and the utilities' own projections of demand, we have devised three demand cases; the first assumes a 4.7 percent increase in electrical energy demand, based on PG&E's estimates; the second assumes no growth in demand over 1977; and the third assumes a decline in demand of two percent compared with 1977. These latter two are motivated by the declining growth recorded between 1976 and 1977. They also assume a continued response to higher electricity prices and public responsiveness in efforts to conserve both water and energy in a third drought year. These cases are summarized in Table 5. The monthly distribution of demand in each case was based on 1977 recorded and estimated demand for PG&E. Demand for 1978 in the other utility service areas was assumed to remain at the same level forecasted by those utilities in their submittals.

If the drought does extend into a third year, it appears possible that low or negative growth rates might continue, as the public responds to calls for continuing water and energy conservation, and to increasing energy prices. Fig. 1 indicates that there was a sharp change in the growth rates in sales (demand) beginning the fourth quarter of 1976, at least part of which is explained by increased public awareness that the drought was continuing with no sign of slackening during that normally rainy period. The lower growth rates have continued into 1977.

Table 5

Summary of LBL Scenarios for Energy and Peak Demand[a]

Energy (in TWh)		Utility	Case A	Case B	Case C
For PG&E					
	Growth Rate	4.7	4.7	0	-2.0
	Energy Supply	79.68	77.29	73.82	72.34
Statewide[b]					
	Energy Supply	177.91	175.52	172.05	170.57
Peak Demand (in MWe)					
			Case D	Case E	
For PG&E					
	Growth Rate	4.7	11.0	0	---
	Peak Demand	15428	15428	13815	---
Statewide[b]					
	Peak Demand	33445	33445	31832	---

[a]See text for detailed discussion.

[b]No estimates were made for energy and peak demand for other California utilities, only PG&E.

The five reasons stated earlier for the low demand in 1977 compared to PG&E forecasts for 1977 provide additional insight as to the demand levels for 1978 in the event of a continued drought. Voltage reduction has already been introduced, and further selective reductions may be possible. The decrease in water consumption from 1977 to 1978 will be smaller than the reduction during 1977, thus producing a smaller change in sales. Electricity price increases in 1978 are likely to be less than in 1977 since hydroelectric supplies will decrease only slightly from their already low levels and, the largest factor in these price increases has been the additional cost of oil-fired electricity generation. The actual impact on sales will depend on the price differential, the absolute price and the residual impact of the price increase persisting in 1978.

For agriculture in 1978, the groundwater that will be used to make up for the surface water deficits is expected to reach 17 million acre-feet compared with 14.7 million acre-feet for 1977. Since this water will be pumped from depths that are five to ten feet lower, on the average, than those of last year, the estimated electrical demand in agriculture will increase about 11 percent over 1977 levels. This increase will not have a major impact on total demand since agriculture forms only a small fraction of demand. Appendix C contains a more in depth discussion of the impacts.

Temperature changes primarily affect system peak loads. Milder temperatures prevailed during 1977 with most incidences of high temperatures occurring on weekends, normally a time of lower peak demand. Although the peaks were lower than anticipated this year, the high peak levels forecasted by the utilities could come about if high temperatures prevail on weekdays next summer. PG&E in its forecasts projected a 4.7 percent growth in sales and in peak demand. However, the factors considered here suggest that in the event the drought continues, 1978 PG&E sales may be less than projected by the company and may not be significantly different from sales in 1977. Estimated month-by-month PG&E energy loads for 1978 are shown in Table 6 for each of the three load growths.

Table 6

Monthly Electrical Energy Loads for PG&E for 1977, and Three Load Cases for 1978

	1977		1978 Estimates[b]		
	Predicted[a]	Actual	Case A	Case B	Case C
January		6227	6520	6227	6102
February		5448	5704	5448	5339
March		6375	6675	6375	6248
April	6282	6114	6401	6114	5992
May	6419	5823	6097	5823	5707
June	6705	6510	6816	6510	6380
July	7229	6983	7311	6983	6843
August	6976	6965	7292	6965	6826
September	6340	5983	6264	5983	5863
October	6007	5760	6031	5760	5645
November	5885	5650[c]	5916	5650	5537
December	6227	5978[c]	6259	5978	5858
TOTAL	76120	73816	77286	73816	72340

[a]Ref. 5.

[b]All three cases are based on 1977 actual (+ 2 months estimated) with the following changes in monthly loads from 1977 to 1978:

Case A: +4.7 percent
Case B: 0 percent
Case C: -2 percent

[c]Estimates of load based on the predicted loads corrected for the average difference of -4.0 percent between actual and predicted loads for April through October.

SECTION 3

ELECTRICITY SUPPLY

SUPPLY ASSESSMENT FOR 1977

A review of the supply situation during this past summer reveals few major difficulties in meeting peak loads and energy demands. A number of factors contributed to this. As noted in the discussion of demand, the generally cooler summer combined with conservation efforts reduced energy and capacity requirements. At the same time PG&E, the utility most significantly affected by the drought, made contractual arrangements for both transfers of energy and capacity support with other utilities for the summer of 1977. This outside support amounted to a maximum of 600 MWe in August:[7] 430 MWe from SCE, 70 MWe from SDG&E and 100 MWe from the Salt River Project (Arizona). Additional firm energy supplies from the other California utilities, as high as 300 GWh per month, and from the two Nevada electric utilities. Sierra Pacific Power and Nevada Power Company, totaling about 120 GWh per month were also made available. The summer month energy deficit for PG&E was expected to run about -2 to -2.5 percent of load, or about -120 to -180 GWh per month. By comparison, the overall statewide energy margin (excess generating capability) was anticipated to be a minimum of 1650 GWh during the summer. PG&E also stored energy with BPA in the Pacific Northwest, totaling about 1000 GWh; this energy was withdrawn by PG&E during the latter part of the summer.

Peak capacity margins for PG&E were expected to be small, with a minimum margin of 4.3 percent expected for August. However, the cooler maximum summer temperatures and conservation efforts held the peak load for the PG&E service area to 6 percent less than the predicted peak; corrected for temperature variation, this peak load was still about 260 MWe less than predicted. Early in September PG&E's reserve margins dropped below 6 percent due to an unexpected outage at Pittsburg 7, a large (720 MWe) fossil-fueled plant. The additional capacity required for an adequate operating margin was obtained from operation of additional

units at the San Luis pumped-storage facility (USBR and DWR) and through use of additional units at the Hyatt-Thermalito generation at Oroville even though the low water conditions made such operation marginal. These additions at the two facilities totaled almost 300 MWe in extra generating capacity.[8] In addition, 300 MWe of capacity on the PNW intertie was made available by SCE for PG&E. Also, a portion of the energy stored by PG&E in the BPA system earlier in the year was returned to PG&E. The peak power available to California on the AC and DC interties totaled over 3200 MWe[9] in this period.

This pre-planned coordination among the utilities and with the PNW for both capacity support and energy transfer for PG&E increased system resilience at a time of high peak loads in southern California. The early recognition of the potential problems by the CERCDC and the utilities themselves (including the Engineering and Operating Committee of the California Power Pool) was important in providing for these contingencies.

There were apparently no major problems with regard to the availability of fuels during 1977. The electric utilities in southern California did have considerably more natural gas available than anticipated, which prompted some concerns about storage for contracted oil supplies. It appears since these utilities can no longer obtain priority P-5 gas on a firm basis, the availability of excess or "dump" gas from local gas utilities is quite unpredictable. This compounded by the fact that these local suppliers are dependent upon out-of-state sources of natural gas which serve a variety of other customers as well. Hence changes in the weather, or other factors that can affect gas demand, will sometimes free large quantities of gas on a one-time or "spot" basis. Since California Air Resource Board (CARB) requirements* call for the preferential use of P-5 gas in the South Coast Air Basin on certain episode days when available as a means of reducing emissions, all the excess gas made available is used by the electric utilities.

SUPPLY AVAILABILITY FOR 1978

There are a number of variables that will affect the amount of power and energy available for loads in 1978. Fundametal to an analysis of the

*Rule 715.1, adopted August 25, 1977, by CARB for the South Coast Air Quality Management District.

supply picture is the assumed level of runoff into the reservoirs for hydroelectric generation. Several new thermal facilities are also expected to be available during 1978. These supply assumptions and resources are analyzed in the following sections, and the supply-demand balances are constructed for the various supply and demand scenarios we describe.

Hydroelectric Supply

We have investigated the availability of hydroelectric energy and capacity in northern California for 1978 under two conditions: first, a return to normal levels of runoff into streams and reservoirs, and second, a continued drought with the same runoff as during 1977. We have also looked into acquiring additional electrical energy and capacity (primarily hydro) from out-of-state sources.

Hydroelectric energy is generated in northern California by a variety of agencies—public and private utilities, municipal water districts, local irrigation districts, and state and federal water agencies. The reservoirs owned by the water and irrigation districts are primarily used to store water for subsequent delivery to customers. Power generation is a source of additional revenue. The state and federal agencies, DWR and USBR, operate reservoirs for water storage, flood control, stream flow and water quality maintenance, as well as for power generation. In response to a drought these agencies will only generate power with water that must be delivered, whereas during a normal year they may release surplus water to generate electricity.

The scheduling of hydroelectric generation within its service area is done by PG&E. The water agencies inform PG&E of the total amount of water they plan to release. PG&E schedules the timing of these releases 24 hours in advance based on its forecast of the next day's loads. These forecasts are updated during the day as more recent weather data are acquired. The DWR power plants at Oroville, for example, are tied into PG&E's computer control system, so they are automatically dispatched under normal conditions. USBR is not yet tied into this system. They are informed by PG&E of the desired release schedule, and they decide which generators will operate to provide the desired capacity.

Conditions During 1977. After two years of below normal precipitation the reservoirs in northern California are at their lowest recorded levels. Furthermore, the ground is very dry and water tables have been lowered. Even if there is normal precipitation during 1978, runoff into reservoirs will be less than normal.

In Table 7 we present conditions at the major northern California reservoirs which supply hydroelectric energy. Here we compare the carryover storage on 1 October 1977 with the average carryover for the previous ten years. For the USBR reservoirs this year's carryover is about 18 percent of normal, and for the DWR reservoirs, it is 30 percent of normal. For the major reservoirs in the PG&E system, the average carryover is about 44 percent. For power generation the situation is more serious because many of the largest reservoirs have minimum storages below which no power can be generated.* During the summer of 1977 these reservoirs were kept above their minimum power pool. To conserve water, generation was discontinued at some power plants owned by municipal water and irrigation districts where the discharge water was not being delivered to the municipal users.

The lower storage levels reduced the hydroelectric capacity available to PG&E during July 1977 to 5019 MWe, which is 738 MWe less than what would have been available in a normal year. PG&E expects about 13 percent of its energy in 1977 will have been supplied by hydroelectric sources compared to about 40 percent during a normal year.

Hydroelectric Supply Under Normal Runoff Conditions. If the amounts of runoff into the reservoirs during the water year beginning 1 October 1977 are at their long-term average levels, then by next October most of the reservoirs will be at their normal carryover storage. Under this same situation, nearly normal supplies of hydroelectric capacity and energy will be available for the critical months next summer. The water impounded to bring the reservoirs up to their normal levels will not generate any electricity this year, so the total hydroelectric energy for 1978 will be lower than usual from normal runoff conditions.

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*The minimum power pools shown in Table 7 are engineering design levels. Until this year there has been no operating experience at these low water levels. At some reservoirs power can be generated below the minimum pool if proper precautions are taken; at others power generation might be discontinued above this level if there is a danger of damaging the turbines.

Table 7
Reservoir Storage on 1 October
(10^3 Acre-feet)

Reservoir	Capacity	Average Year	1977	Minimum Power Pool
Pacific Gas & Electric				
McCloud	35.2	24.0	24.9	
Lake Almanor	1308.0	821.1	541.7	
Bucks Lake	103.0	62.6	36.6	
Little Grass Valley	93.0	60.5	31.1	
Sly Creek	65.1	33.5	13.4	
Bullards Bar	961.3	594.2	258.1	
Jackson Meadows	68.5	43.3	4.6	
Bowman Lake	68.0	46.7	16.2	
Fordyce	46.7	65.1	4.9	
Spaulding	74.8		56.3	
Rollins	66.0	50.0	5.3	
French Meadows	133.7	68.1	38.2	
Hell Hole	208.4	130.5	77.8	
Caples Lake	21.6	15.5	5.6	
Lower Bear	48.5	23.2	7.3	
Salt Springs	139.4	76.9	4.2	
Donnells	64.5	32.0	11.3	
Beardsley	97.5	75.5	3.7	
Lake McClure	1026.0	561.8	93.7	115
So. Cal. Edison	571.2	314.6	148.0	
Crane Valley	45.4	26.1	17.7	
Courtright	123.3	41.8	0.9	
Wishon	128.0	88.6	79.8	
Isabella	570.0	184.6	36.4	30
Lake Pillsbury	93.7	44.0	9.8	
California Department of Water Resources				
Oroville	3537.6	2461.4	915.2	852

Table 7 (Continued)

Reservoir	Capacity	Average Year	1977	Minimum Power Pool
U.S. Bureau of Reclamation				
Shasta	4552.0	3152.5	627.5	502
Clair Engle	2448.0	1859.5	241.3	313
Whiskeytown	241.1	222.8	216.5	
Folsom	1010.3	676.1	164.8	90
San Luis	2038.8	1521.4	277.5	
Other Agencies				
Hetch Hetchy	360.4	238.9	113.8	
Pardee	210.0	186.4	82.8	
Don Pedro	2030.0	897.5	306.4	309
Englebright	70.0	50.3	65.4	

Source: California Department of Water Resources, personal communication, November 1977.

In a normal year USBR expects a total inflow of 9.5 million acre-feet into Shasta, Clair Engle and Folsom Reservoirs.[10] This would permit Shasta and Folsom to reach their usual operating levels by next spring. It would take about two years of average runoff to get storage at Clair Engle to its normal carryover storage. Under current plans USBR will deliver 100 percent water supply to its customers, but no surplus water will be delivered in order to increase carryover storage. Storage on 1 October 1978 in these three reservoirs would total 5.4 million acre-feet which is approximately 86 percent of normal. The generation for the year ending 1 October 1978 would be 2.5 billion kWh with normal runoff as compared to about 6 billion kWh if the reservoirs had started with normal carryover.

DWR has formulated operational criteria for the State Water Project based on the amount of runoff that occurs during 1978.[11] If there is an average runoff of 4.35 million acre-feet and the SWP meets the contracted deliveries of 1.8 million acre-feet, Lake Oroville would reach normal operating levels by May. Full generating capacity would be reached by April. The total energy generated at Hyatt-Thermalito is would then be nearly 1.1 billion kWh during the twelve-month period ending 1 October 1978. Usually these plants produce about 2.4 billion kWh annually.

Under conditions of normal runoff, PG&E will be able to meet downstream water requirements and still store water to meet peak summer power demands. The capacity available during July and August would be about 100 MWe lower than would be expected if there were normal carryover storage. A summary of the resources within its service area available to PG&E, including USBR and its share of DWR plants, is shown in Table 8. About 22 percent of its energy load during 1978 could be supplied by these resources.

Hydroelectric Supply Under Continued Drought Conditions. A continuation of the drought through 1978 will have more severe impacts than during 1977. Water levels in reservoirs will be lower and less water will be released, thus further reducing both hydroelectric energy and capacity. A statewide summary of the situation next year may be found in the response of the California electric utilities to requests for information

Table 8

Pacific Gas & Electric Company Area 1978 Hydroelectric Resources Assuming Average Precipitation
Megawatts

	Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec
Pacific Gas & Electric Co. owned hydro	2396.5	2407.4	2410.0	2421.1	2426.6	2436.3	2428.3	2425.3	2412.8	2412.1	2413.7	2409.3
Area Hydro Owned by Others												
USBR-CVP	832.0	873.0	870.0	882.0	875.0	901.0	908.0	894.0	862.0	865.0	862.0	865.0
DWR-Hyatt and Thermalito (PG&E share)	251.0	259.0	301.0	332.0	456.0	470.0	456.0	442.0	358.0	346.0	346.0	349.0
EBMUD	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Merced Irrigation District	32.5	35.4	40.9	51.2	61.9	78.9	81.9	77.7	72.8	66.5	60.8	56.5
Nevada Irrigation District	67.5	67.5	67.5	67.5	67.5	67.5	67.5	67.5	67.5	67.5	67.5	67.5
Oakdale & So. San Joaquin Irrigation District	35.0	36.8	38.2	58.1	75.5	87.8	96.8	91.3	83.5	76.7	74.9	71.4
Oroville-Wyandotte Irrigation District	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0
Placer County Water Agency	235.1	234.9	234.9	235.7	237.5	240.8	241.1	239.8	239.0	237.5	236.2	235.5
City & County of San Francisco	303.6	302.7	302.0	302.0	306.1	309.0	315.2	312.6	309.9	307.3	305.2	302.6
Sacramento MUD	638.0	641.0	645.0	647.9	650.3	652.2	652.8	652.2	646.4	645.9	648.9	649.6
Yuba County Water Agency	242.0	247.4	261.7	286.1	290.2	328.1	314.3	304.1	297.4	283.3	274.4	280.5
TOTAL	5125	5197	5263	5376	5539	5664	5654	5599	5441	5401	5380	5379
Capacity Not Usable Due to Energy Limitations[a]	783	617	945	924	191	0	0	0	0	664	0	0
Usable Area Hydro	4342	4580	4318	4452	5348	5664	5654	5599	5441	4737	5380	5379

[a]Usable hydro capacity can be increased by purchasing energy from outside area sources, if available.

Source: Reference 3

by CERCDC.[6] More detailed data on usable hydroelectric capacity for next year is presented in Table 9, assuming runoff equal to 1977 levels.

USBR operating policy[10] if there is a repeat of 1977 conditions (total inflow of 3 million acre-feet) will result in a carryover storage of 444,000 acre-feet in their reservoirs. Clair Engle and Whiskeytown lakes will be steadily drawn down throughout the year. Generation at Trinity powerhouse would have ceased in December 1977. Shasta reservoir will reach a peak storage of 1.2 million acre-feet in March while Folsom will reach a peak storage of 200,000 acre-feet in April. Both reservoirs will be drawn down below their minimum power pools by July or August. By September the combined USBR capacity would drop to 323 MWe which is less than one-quarter of the installed capacity. USBR expects to generate 1.26 billion kWh during the year ending 1 October 1978, or about twenty percent of normal.

For DWR the situation is similar. If the inflow to Oroville is only 750,000 acre-feet, the reservoir will be drawn down 460,000 acre-feet by October first. Releases would total 1.2 million acre-feet which is two-thirds of normal. There would be no generation at Hyatt after March and the system capacity would then be 48 MWe. Energy generation for the year ending 1 October 1978 will total 0.2 billion kWh. The pumped storage capability at both Hyatt and Thermalito is currently used very little because of of the energy penalty due to 70 percent overall efficiency.

PG&E expects that after another dry year carryover storage in their reservoirs will be at or below this year's carryover. As shown in Table 9, the useable hydroelectric capacity available to PG&E will be reduced to 4343 MWe during July and 4249 MWe during August. These are about 700 MWe below the 1977 capacity and about 1400 MWe below rated capacity for the same months. Only 11 percent of PG&E's energy load will come from hydroelectric sources within its service area, including USBR and DWR.

Out-of-State Transfers. The California utilities have contracts with utilities in the Pacific Northwest for delivery of power and

Table 9

Pacific Gas & Electric Company Area 1978 Hydroelectric Resources Assuming 1977 Runoff
Megawatts

	Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec
Pacific Gas & Electric Co. Owned Hydro	2360.6	2358.3	2350.9	2360.6	2363.8	2365.8	2356.1	2350.0	2349.6	2339.0	2339.1	2337.4
Area Hydro Owned by Others												
USBR	721.0	759.0	766.0	794.0	763.0	744.0	470.0	422.0	393.0	399.0	400.0	401.0
DWR-Hyatt and Thermalito (PG&E share)	256.0	251.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0
EBMUD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Merced Irrigation District	32.0	32.1	32.3	33.7	34.0	34.5	32.3	0.0	0.0	0.0	0.0	0.0
Nevada Irrigation District	67.5	67.5	67.5	67.5	67.5	67.5	67.5	67.5	67.5	67.5	67.5	67.5
Oakdale and So. San Joaquin Irrigation Districts	35.0	35.0	35.0	60.0	60.0	60.0	35.0	35.0	35.0	35.0	35.0	35.0
Oroville-Wyandotte Irrigation District	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0
Placer County Water Agency	234.6	233.6	232.8	232.8	232.9	233.5	231.7	229.8	228.3	226.5	224.9	223.6
City & County of San Francisco	119.0	56.0	56.0	57.0	87.0	117.0	117.0	117.0	117.0	87.0	57.0	57.0
Sacramento MUD	627.0	632.0	635.0	639.0	644.0	646.0	643.0	640.0	636.0	635.0	634.0	632.0
Yuba County Water Agency	244.5	244.5	247.0	251.5	254.0	258.5	257.5	255.0	251.5	248.9	242.5	242.0
TOTAL	4782	4754	4564	4629	4639	4660	4343	4249	4211	4171	4133	4128
Capacity Not Usable Due to Energy Limitations[a]	1275	1146	1529	1267	624	0	0	0	28	482	316	274
Usable Area Hydro	3507	3608	3035	3362	4015	4660	4343	4249	4183	3689	3817	3854

[a]Usable hydro capacity can be increased by purchasing energy from outside area sources if available.

Source: Reference 3

energy on an energy-exchange basis. The energy taken with the capacity must be returned within a fixed period of time. Up to 2687 MWe of firm power will be available during July and August 1978. This is down by 114 MWe from that available in August 1977 because of a contractual change in Canadian Entitlement power. PG&E expects to receive 1400 MWe in its service area next summer compared with 1500 MWe this year. In addition, the service area will receive firm energy up to 252 GWh per month and SDG&E will receive up to 30 GWh per month from the northwest utilities. Over the calendar year 1978 these transfers will total about 3170 GWh.

In the first year of the drought in California in 1976, excess energy from the Pacific Northwest amounted to more than 7000 GWh for PG&E. Last year the drought conditions extended generally over the Western U.S. and little, if any, excess energy was available from the Pacific Northwest. The energy available from the Northwest primarily offsets oil-fired generation in California.

PG&E banked energy with BPA during the winter and spring last year. Energy from thermal power plants in California was sent north to displace hydroelectric energy there. The water not released was stored until the summer when PG&E drew its "bank account" to provide additional energy, especially during the time when the Rancho Seco nuclear power plant was shut down for maintenance.

New peaking hydroelectric units are scheduled to be added at several facilities in the Columbia River system totaling an additional 2900 MWe (name plate) by August 1978. Since the energy potential of the Columbia River system is almost fully utilized at these facilities, additional peaking resources add capacity but do not represent new sources of energy.

The BPA has recently investigated the possibilities of having excess energy available in the Pacific Northwest Coordinated System as a function of historical rainfall conditions.[12] Recent heavy rainfalls and reduced loads in the Pacific Northwest have increased the probability of having surplus energy available to California during 1978, especially during the summer months. Presently, firm energy contracts between the PNW and utilities in California utilize less than 20 percent of the full transmission capability of the AC and DC intertie; hence surplus energy in excess of 2000 GWh per month could be transferred if it were available.

Energy surplus projections based upon rainfall and stream flow conditions during the past forty years have been made, and by April 1 maximum energy would be available if rainfall and runoff in the first half of 1978 match conditions in 9 out of 40 years. By April 15, the maximum energy would be available in 21 out of 40 years, and by May 1 in 30 out of 40 years. In general the availability of surplus energy extends only through the end of July, at which point the storage capability on the Columbia River system is at its maximum value. Large amounts of surplus energy would have the additional benefit for California utilities in that part of it could be purchased as peaking capacity exchange energy. Thus the California utilities would not be required to actually generate and transmit this exchange energy to the PNW.

If rainfall and runoff in the Pacific Northwest return to normal, there is little reason to bank energy in the BPA system. If the drought continues throughout the west, PG&E plans to bank energy again next year. The decision on banking will be made after January first when the hydrological conditions in the Pacific Northwest will be better known.

Thermal Supply

In general, the thermal supply picture for 1978 is similar to that for 1977. PG&E is the only utility expecting to be able to burn P-5 natural gas in any sizable quantity, although if the experience of this past summer is any guide, additional gas in substantial quantities might be available to utilities in southern California on an unpredictable "spot" basis. Under continued drought conditions in 1978, the make-up energy source will continue to be oil. The further decline in hydroelectric energy will be partially offset by an additional 643 MWe of new thermal resources (not including Diablo Canyon 1), scheduled to be available by August 1978. We have listed these units and their expected completion dates in Table 10.

Our supply scenarios are based primarily on the utility submittals to CERCDC[6] with changes presented in the next two paragraphs. Diablo Canyon Units 1 and 2 (1060 MWe each) are presently in the licensing process. The date on which these nuclear power plants may be placed in service will be determined largely by the Nuclear Regulatory Commission (NRC). It now

appears that June is the earliest possible startup date for Unit 1, with Unit 2 delayed until 1979. We have analyzed the supply situation with and without Diablo Canyon Unit 1 and discuss this further below. Additional PG&E resources, Geysers geothermal Units 12 (106 MWe) and 15 (55 MWe), have also been delayed until September and December 1978, respectively. The nuclear unit at Humboldt Bay (63 MWe), out of service since July 1976, is not expected to return. The seismic safety of this plant is presently undergoing review by the NRC. We have assumed it will not be available in 1978. For SCE and SDG&E, the planned refueling of San Onofre (430 MWe) in July and August has been delayed past September, based on information from SCE and CERCDC.

Finally, we assume full use of both the Castaic pumped storage facility (1170 MWe) operated by LADWP and the LADWP share of the Pacific Northwest DC intertie (an additional 200 MWe). While LADWP in their submittal to CERCDC[6] does not include all the capacity available from these facilities, conversations[13] with LADWP indicate that the reason for this derating is due to the diseconomies of using oil-fired generation to use as pump-back energy for Castaic, or return energy for the DC intertie. However, there are no physical limitations on the full use of these resources; hence, we have included them at their full value in our resource list. It should be noted that neither facility adds very much in the way of energy, since Castaic is a net energy consumer (60-70 percent overall efficiency, so it consumes about 3 kWh pumping energy to produce 2 kWh) and the energy on the DC intertie must be returned (exchange energy), usually with about a 24-hour turnaround. However, the additional peaking capacity might well be an essential state resource next summer.

We have treated the issue of Diablo Canyon as a separate element. The latest estimate from PG&E is for commercial operation under an interim license by August 1, 1978, with a two month pre-commercial start-up period. With a 30-45 day period to load fuel, the issuance of an interim operating license would have to be done no later than the end of April, 1978, in order for this schedule to be met. However, the latest estimate from the NRC[14] is that an interim operating license proceeding will not begin until about April 15. The issues surrounding the application for an operating license are in contention and are not likely to be resolved in a short time period.

Table 10

New Generating Units Expected in 1978 (MWe)

Utility	Description	Unit Size	Total Size	Date Expected
PG&E	Oakland Combustion Turbines 1-3	57	171	May
	Geysers Geothermal Unit #12	106	106	Sept.[a]
	Geysers Geothermal Unit #15	55	55	Dec.[a]
	Diablo Canyon Nuclear Unit #1	1060	1060	August[b]
SCE	Coolwater Combined Cycle #3	236	236	April
	Coolwater Combined Cycle #4	236	236	Aug.
LADWP	Castaic Pump Storage Unit #5	225	1170[c]	Feb.
	Castaic Pump Storage Unit #6	210	1305[d]	Oct.
	Scattergood Gas-fired Unit #3	284	284[e]	Aug.
SDG&E	Encina Oil-fired Steam Unit #5	292	292	Oct.

[a]Delayed from original schedule.

[b]August is the most recent target date, but availability for service depends upon licensing proceedings.

[c]The addition of Unit #5 brings the total rating of Castaic to 1170 MW.

[d]Although each of the large generator units at Castaic are the same size, there are synergistic flow limitations causing each unit to be derated to 210 MWe. These six units, plus the existing smaller unit #7 have a total capacity of 1305 MW.

[e]This is not a new unit; however, it can only operate on natural gas as fuel. The utility anticipates having this fuel available in August and September.

According to data from the NRC,[15] the average time from startup to commercial operation for nuclear power plants larger than 400 MW is about six months, with five of the 51 nuclear plants in this size category achieving commercial operation in two months or less from start-up. The time required to achieve commercial operation at Trojan, a plant very similar to the Diablo Canyon units, was approximately six months. Nevertheless we have assumed that commercial operation will begin August 1, in order to assess the impact of the availability of Diablo Canyon on system reliability, prices in the PG&E system, and the level of imported energy required by PG&E. Clearly, the introduction of Diablo Canyon Unit 1 during 1978 will reduce the amount of imported energy PG&E will require. Given our assumed start-up date, the estimates here can be thought of as the most optimistic case in that regard.

We have indicated in Tables 11 and 12 the energy and capacity available in the PG&E system for 1978. As we noted in our earlier discussion two changes have been made in PG&E's assumptions shown in their submittal to CERCDC.[1] First, we do not include the 63 MWe Humboldt Bay nuclear unit, and Geysers 12 and 15 are delayed, as shown in Table 11. Based on PG&E estimates we use an 82.5 percent monthly capacity factor for energy from Rancho Seco and an 85 percent capacity factor for gas and oil generation (with a 400 MW forced outage level). We have calculated the energy expected from Diablo Canyon, using PG&E's estimate for two months of pre-commercial energy and a 60 percent capacity factor after August 1. This capacity factor assumption is close to the industry-wide average and is probably optimistic in view of the experience at other nuclear facilities during the first months of commercial operation.

These resources are then compared with the peak load and energy demand scenarios we have described earlier. It should be noted that having Diablo Canyon on-line does not completely obviate the need for imported energy for PG&E for 1978, although for the lowest demand case no further imports would be required beyond July.

The demand assumptions have the largest effect on the supply-demand balance for both energy and capacity requirements. The capacity margins shown inTable 12 do not reflect operating reserve requirements. We

Table 11

Energy Supply-Demand Balances for PG&E for 1978 Assuming Continued Drought Conditions

	Energy (GWh)												
Supply	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	1978 Total
Resource Type													
Total Area Hydro[a]	590	573	629	747	760	866	1078	1001	817	686	506	480	8733
Northwest Firm Hydro	236	208	228	252	252	252	252	252	252	252	232	152	2820
Nuclear[b,c]	554	500	552	532	542	519	537	537	520	70	0	501	5364
Geothermal[b,d]	336	304	336	325	336	325	336	336	396	407	396	444	4277
Other Receipts[e]	287	276	297	253	234	240	264	285	273	253	276	270	3208
Gas & Oil Generation[b,f]	3780	3300	3591	3383	3780	4087	4350	4350	3965	3717	3720	4097	46120
I. Total Energy - PG&E System	5783	5161	5633	5492	5904	6289	6817	6761	6223	5385	5130	5944	70522
Diablo Canyon Unit[1]	0	0	0	0	0	260	400	473	458	473	458	473	2995
II. Total Including D.C.	5783	5161	5633	5492	5904	6549	7217	7234	6681	5858	5588	6417	73517
Demand[g]													
Case A	6520	5704	6675	6401	6093	6816	7311	7292	6264	6031	5916	6259	77286
Case B	6227	5448	6375	6114	5823	6510	6983	6965	5983	5760	5650	5978	73816
Case C	6102	5339	6248	5992	5707	6380	6843	6826	5865	5645	5537	5858	72340
Balances													
I-A	-737	-543	-1042	-909	-189	-527	-494	-531	- 41	-646	-786	-315	-6764
I-B	-444	-287	-742	-622	+ 81	-221	-166	-204	+240	-375	-520	- 34	-3294
I-C	-319	-178	-615	-500	+197	- 91	- 16	- 65	+358	-260	-407	+ 86	-1818
II-A	-737	-543	-1042	-909	-189	-267	- 94	- 58	+417	-173	-328	+158	-3769
II-B	-444	-287	-142	-622	+ 81	+ 39	+234	+269	+698	+ 98	- 62	+439	- 299
II-C	-319	-178	-615	-500	+197	+169	+374	+408	+816	+213	+ 51	+559	+1177

[a] Based on data from Ref. 6, with changes discussed in text.

[b] After scheduled maintenance.

[c] Includes only Rancho Seco, using c.f. = 82.5 percent.

[d] Geysers 12 available Sept. 1; Geysers 15 available Dec. 1.

[e] Includes output from combustion turbines, four units operated on refinery by-products, hydroelectric generation allocated to PG&E on the SWP system but out of PG&E's service area.

[f] Assumes c.f. = 85 percent and 400 MWe forced outage level.

[g] See Table 6 for details.

Table 12

Peak Load Capacity for PG&E for the Summer of 1978
Capacity (MWe)

Capability	June	July	Aug.	Sept.
Resource Type[a]				
Total Hydro[b]	4660	4343	4249	4183
Northwest Firm Hydro	1400	1400	1400	1400
Nuclear	873	875	875	875
Geothermal	502	502	502	608
Other				
A. Combustion Turbines	387	394	403	390
B. Refinery Plants	179	179	179	179
C. State External Resources	101	106	141	139
D. Firm Hydro Capacity	0	0	0	0
E. Miscellaneous Area Purchases	0	0	0	0
F. Total, Other	667	679	723	708
Gas and Oil Steam	7278	7278	7278	7278
Total Capability	15380	15077	15027	15052
Scheduled Maintenance				
A. Nuclear	0	0	0	0
B. Geothermal	0	0	0	0
C. Refinery Plants	0	0	0	0
D. Combustion Turbines	0	0	0	0
E. Gas and Oil Steam	200	0	0	400
F. Total, Scheduled Maintenance	200	0	0	400
I. Available Capacity Resource	15180	15077	15027	14652
Diablo Canyon Unit 1	0	0	1060	1060
II. Total Including D.C.	15180	15077	16087	15712
Expected Peak Load[c]				
Case D	14550	15428	15424	13881
Case E	13465	13519	13815	13229
Balance				
I-D	630	-351	-397	771
Margin (percent)	4.3	-2.3	-2.6	5.6
I-E	1715	1558	1212	1423
Margin (percent)	12.7	11.5	8.8	10.8
II-D	630	-351	663	1831
Margin (percent)	4.3	-2.3	4.3	13.2
II-E	1715	1558	2272	2483
Margin (percent)	12.7	11.5	16.4	18.8

[a]Based on data in Reference 6, with changes described in text.

[b]See Table 9 for details.

[c]See Table 5.

discuss this below in our analysis of the effects of our scenarios on system reliability.

Up to this point, we have focussed on PG&E in our supply-demand assessments. PG&E is expected to require interconnection support and imported energy for several months in 1978, depending upon the demand scenario chosen. We next analyze the supply-demand picture from a statewide perspective. As noted earlier, we have used the supply and demand projections of the three other major electric utilities in California as reported to the CERCDC,[6] with basically three changes: the deferral of refueling for San Onofre past the summer peak months, the full use of the pumped storage generating capacity at Castaic, and full use of firm capacity in the DC intertie. The detailed monthly resource schedules for the southern California utilities are shown in Appendix A. Tables 13 and 14 show the statewide energy and capacity balances for each scenario for PG&E. By way of comparison the energy and capacity margins from the joint utility submittal to CERCDC[6] are also shown.

On a statewide basis, there is instate energy generation capability to service the highest energy for load demands in 1978. If one distributed PG&E's imported energy requirements among the other three utilities as was done in 1977, the fractional increase in oil-fired generation is small in each of these utility service areas. It is interesting to note that the lowest energy margins are expected for February and March, a time when the scheduled maintenance is expected to be large and the hydroelectric generation low. Also shown in Table 13 is a summary of the minimum surplus energy expected from the Pacific Northwest on the basis of 30 out of the last 40 years. Should excess energy be available, it can be seen that it offsets completely PG&E's energy input requirements for all months from March to July.

A key element in the discussion of interconnection support are the transmission line linkages between PG&E and the utilities in southern California and in the Pacific Northwest. The main links with the Pacific Northwest are the two 500 kV AC lines, operated in California primarily by PG&E and in Oregon by BPA and Portland General Electric, and the 800 kV DC line operated by BPA and LADWP between Celilo, Oregon (near Dalles)

Table 13

Statewide Supply-Demand Balances for Energy
(GWh)

	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	1978 Total
Statewide Load													
PG&E Demand Cases													
Case A	14644	13012	14670	14125	14127	14983	16195	16352	14610	14303	13849	14642	175516
Case B	14351	12756	14370	13838	13857	14677	15867	16025	14329	14032	13583	14361	172046
Case C	14226	12647	14243	13716	13741	14547	15727	15886	14211	13917	13470	14241	170570
Southern California Excess (Total)	1370	1036	1216	1603	1363	1740	1802	1882	1772	1437	1322	1628	18171
Statewide Balance I-A	633	493	174	694	1174	1213	1308	1351	1731	791	536	1313	11407
Ratio of Balance to Total Load	4.3	3.8	1.2	4.9	8.3	8.1	8.1	8.3	11.8	5.5	3.9	9.0	6.5
Statewide Balance I-B	926	749	474	981	1444	1519	1636	1678	2012	1062	802	1594	14877
Ratio of Balance to Total Load	6.5	5.9	3.3	7.1	10.4	10.3	10.5	10.5	14.0	7.6	5.9	11.1	8.6
Statewdide Balance I-C	1051	858	601	1103	1560	1649	1786	1817	2130	1177	915	1714	16353
Ratio of Balance to Total Load	7.4	6.8	4.2	8.0	11.4	11.3	11.4	11.4	15.0	8.5	6.8	12.0	9.6
Statewide Balance II-A	633	493	174	694	1174	1473	1708	1824	2189	1264	994	1786	14402
Ratio of Balance to Total Load	4.3	3.8	1.2	4.9	8.3	9.8	10.5	11.2	15.0	8.8	7.2	12.2	8.2
Statewide Balance to II-B	926	749	474	981	1444	1779	2036	2151	2470	1535	1260	2067	17872
Ratio of Balance to Total Load	6.5	5.9	3.3	7.1	10.4	12.1	12.8	13.4	17.2	10.9	9.3	14.4	10.4
Statewide Balance II-C	1051	858	601	1103	1560	1909	2176	2292	2588	1650	1393	2187	19348
Ratio of Balance to Total Load	7.4	6.8	4.2	8.0	11.4	13.1	13.8	14.4	18.2	11.9	10.2	15.4	11.3
Comparison w/Ref. 6[a]	6.9	4.6	6.6	9.7	7.9	10.6	8.3	9.0	13.0	10.9	10.3	14.3	9.4
Bonneville Power Administration surplus energy:													
Median Year	0	0	0	674	1860	1800	1860	--[b]	--	--	--	--	--
Best Year	0	1680	1360	1800	1860	1800	1860	--[b]	--	--	--	--	--

[a]As submitted by the utilities in Ref. 6.
[b]Surplus energy is generally unavailable beyond the end of July.

Table 14

Statewide Capacity Balance and Reserve Margins (in MWe)

		June	July	August	September
Capacity Margin in Southern CA[a]		4803	3809	3703	3405
PG&E Area Spinning Reserve Requirements[b]					
Three Percent of Load	Case D	437	463	463	416
	Case E	404	406	414	397
Largest Risk	Case I	—875 (Rancho Seco - all 4 months)—			
	Case II	875	875	1060 (Diablo Canyon 1)	
Total PG&E Reserve Requirement					
I-D		1312	1338	1338	1291
I-E		1279	1281	1289	1272
II-D		1312	1338	1523	1476
II-E		1279	1281	1474	1457
PG&E: Balance[c] - Reserves					
I-D		-682	-1689	-1735	-520
I-E		436	277	-77	151
II-D		-682	-1689	-860	355
II-E		436	277	798	1026
Statewide Capacity Balance					
I-D		4121	2120	1968	2885
Ratio to Coincident Peak		13.8%	6.4%	5.9%	9.3%
I-E		5239	4086	3626	3556
Ratio to Coincident Peak		18.2%	13.2%	11.4%	11.8%
II-D		4121	2120	2843	3760
Ratio to Coincident Peak		13.8%	6.4%	8.5%	12.2%
II-E		5239	4086	4501	4431
Ratio to Coincident Peak		18.2%	13.2%	14.1%	14.6%

[a]From Table A-2, Appendix A

[b]PG&E uses a more stringent spinning reserve requirement than other California utilities of 3% of the expected peak load plus the single largest contingency.

[c]From Table 12.

and Sylmar, California (near Los Angeles). These lines are rated at continuous load carrying capabilities of 1250 MW for each AC line and 1400 MW on the DC line for a total of 3900 MW. (These ratings on the AC lines are conservative.)

The interconnection with southern California is primarily through three 500 kV AC lines between PG&E and SCE. Physically, two of these share a common right-of-way, with the third loacted in a separate corridor. The continuous load carrying capability of this interconnection is rated by SCE and PG&E as 2000 MW. Because this interconnection is vital to both systems, the contingency planning conservatively assumes the loss of two of the three lines. This results in the 2000 MW rating as being the higest load a single 500 kV AC line may carry reliably .

Other factors play a considerable role in the complex question of power transmission and utility system interconnections. It is not the intention here to discuss these issues in authoritative detail but to note that transmission issues within the WSCC are complicated by "loop-flow" problems cause by non-uniform transmission path impedances in the interconnected WSCC area. For planning purposes, BPA usually assumes that 300 MW of the AC intertie is not available in the summertime due to loop-flow problems. Recent loading of the connection between the Pacific Northwest and the northeast portion of theWSCC (Montana, Idaho, Wyoming) resulted in about 800 MWe of south to north loop-flow through the California interties. This flow uses transmission capacity going in the same direction; hence it inhibits full use of the transmission line links. A detailed study of the loop-flow implications of the interconnection support required by PG&E has not been made; such a study is beyond the scope of this analysis.

Examination of the energy and capacity requirements exhibited in Tables 11 and 12 shows that in every case the transmission links can provide the support required, over and above firm capacity commitments already made for 1978. One should note, however, that the backup support will also require transmission line capability. We pursue this point in the following discussion of reliability and reserve margins.

Supply System Reliability

The risk of bulk power outages has been estimated for PG&E and for the statewide bulk power system using the loss-of-load-probability (LOLP) method. As in our earlier report,[16] which contains a more detailed discussion of the interpretation of LOLP, we use PG&E's interpretation of the one day in 10 years criterion for loss of load. This yields a lower value for the limit on LOLP than other interpretations of the same one day in 10 years criterion. For the purposes of this study, we adopt PG&E's evaluation, which gives an upper limit on the monthly LOLP of 8.5×10^{-3}.

The method of calculating LOLP is different than in our earlier report. Instead of an analytic approximation for the probability of outages using an expansion of the normal distribution, we arrive at LOLP from a straight-forward combination of the probability of outages for each unit. These probabilities can then be tabulated as a function of available capacity for each utility or as a regional or statewide system. This method is fairly standard and is in use within the utility industry.[17]

Associated with each power plant or unit available for load is the probability of a full outage (the forced outage rate, FOR), the possibility of a partial outage (for some units, but not all), and the probability of full-load service (which is simply 1 - the partial and full outage rates). In a system with more than one unit, the probability of having a given amount of capacity available is the combination of the probabilities of all possible ways of arriving at that given capacity. Once such a table of probabilities for a given utility system is constructed, the probability of <u>not</u> being able to meet a given load (that is, a loss-of-load) is simply the integral along that curve from 0 MWe to the load in question. This approach treats the individual units at each power plant, as well as the individual plants as independent operational entities. A more sophisticated approach might be to include common-mode failures, or probabilities, as well, but the data available to us do not include these types of system failures. In general, it is felt that the individual plant outage rates dominate in bulk power system failures.

To illustrate our LOLP method, consider a system with two plants, 50 MW and 25 MW, with forced outaged rates FOR_1 and FOR_2, respectively. The probability that unit 1 is on is $(1 - FOR_1)$, and similarly, for unit 2 it is $(1 - FOR_2)$. The following table illustrates the possible generating configurations and their associated probabilities:

both plants on (50 + 25 = 75 MWe):	$(1 - FOR_1) \times (1 - FOR_2)$
plant 1 on; plant 2 off (50 MWe):	$(1 - FOR_1) \times FOR_2$
plant 1 off; plant 2 on (25 MWe):	$FOR_1 \times (1 - FOR_2)$
both plants off (0 MWe):	$FOR_1 \times FOR_2$

For a system load of 60 MW, the LOLP is then the sum of the possible outage states up to 60 MW, or

$$FOR_1 \times FOR_2 (@0\ MW) + (1 - FOR_2) \times FOR_1\ (@25\ MW) + (1 - FOR_1) \times FOR_2\ (@50\ MW).$$

If a third power plant is added to this system with, for example, 75 MW of capacity with a partial outage state of 50 MW at probability FOR_4 and a complete outage rate of FOR_3, then the probability vs. available capacity table (or curve) looks like:

0 MW:	$FOR_1 \times FOR_2 \times FOR_3$
25 MW:	$(1 - FOR_2) \times FOR_1 \times FOR_3$
50 MW:	$(1\ FOR_1) \times FOR_2 \times FOR_3 + FOR_1 \times FOR_2 \times (1 - FOR_4)$
75 MW:	$(1 - FOR_1) \times (1 - FOR_2) \times FOR_3 + FOR_1 \times FOR_2 \times (1 - FOR_3) + FOR_1 \times (1 - FOR_2) \times (1 - FOR_4)$
100 MW:	$(1 - FOR_1) \times FOR_2 \times (1 - FOR_4) + (1 - FOR_2) \times (1 - FOR_3)$
125 MW:	$(1 - FOR_1) \times (1 - FOR_2) \times (1 - FOR_4) + (1 - FOR_1) \times FOR_2 \times (1 - FOR_3)$
150 MW:	$(1 - FOR_1) \times (1 - FOR_2) \times (1 - FOR_3)$

This can be extended to systems containing a larger number of units, and a simple computer algorithm has been constructed to keep track of the number of capacity states available and their associated probabilities. For a system such as PG&E, with nearly 170 units, the complicated process of keeping track of these states and probabilities is then straightforward.

Loss-of-load-probability curves under several assumptions have been calculated for both PG&E as a separate system, with interconnection support, and for the state considered as a fully interconnected system.

The individual generating units, their full forced outage rates, and their partial outage states (where these exist) have been tabulated in Appendix B.

We first show a comparison among the risk curves for PG&E for July 1977 and July and August 1978 in Figure 3. The curves all have nearly identical shapes, but the curves for 1978 are displaced by about 400 MWe from July 1977; that is, in order to achieve an equivalent level of reliability for the same load, an additional 400 MWe of support beyond the 1977 level will be needed for the PG&E system should the drought continue into a third year. One can also see from this comparison that for PG&E the July risk curve is about 15 percent lower than for August, for the same load. This is due primarily to the additional hydro PG&E expects to have available in July beyond the hydro capacity in August.

Throughout the rest of this discussion we focus on August loads and resources as the month with greatest "risk" for PG&E. As noted earlier in the supply-demand discussion, we have selected two cases for analysis, one case with essentially no change over 1977, and one which adopts the utility peak load projections (see Table 5). In order to arrive at monthly LOLP risk figures, one must know what the second, third, fourth, etc. peak days will be in a given month. We use an average of the historical data for July, August and the first part of September of 1977 to construct the monthly load ranking one might expect for August 1978. These are tabulated in Table 15. From the ratios presented in this table, one can estimate the peak loads given an expected peak day for the month. One can then compute the additional support PG&E will require in order to have $\Sigma_i \text{ LOLP}_i \leq 8.5 \times 10^{-3}$. The risk curves for 1978 plotted in Figure 3 include 600 MW of "perfect" support (that is, no FOR is associated with this capacity). Using the two peak demand cases we described previously and the relationship among peak days, the amount of displacement of the August risk curve can be derived in order to meet the monthly LOLP criterion. For Case D, with the maximum peak demand of approximately 15400 MWe, the August 1978 curve requires a displacement of 1900 MW of additional support. For Case E, with no change

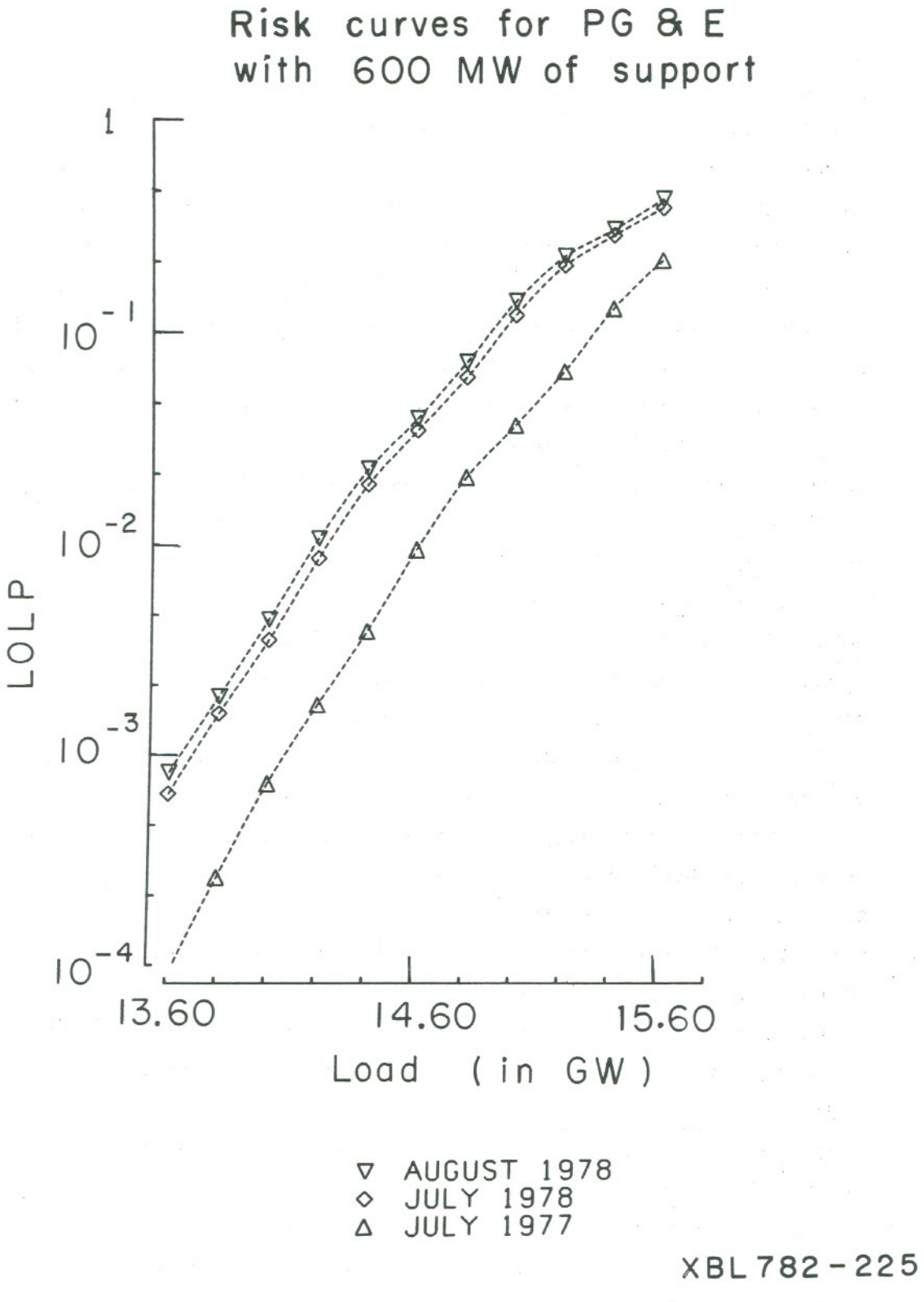

Figure 3. Comparison of Risk of Loss-of-Load for PG&E Assuming 600 MWe of Interconnection Support

in peak demand from 1977, the displacement of the curve amounts to 300 MWe of support (Figure 4) In the first case, the amount of outside support arrived at through this procedure is larger than the support PG&E contracted for during the summer of 1977. In the second case the extra support is actually smaller than that acquired by PG&E for the summer of 1977. In actuality, such support is available through the transmission system and hence has the forced outage rate of the transmission system. However, the effect of the transmission system FOR of 0.1 percent is negligible compared with FOR's for generators in the PG&E system. As discussed earlier, the transmission line capacity interconnecting the PG&E system with southern California utilities and the Pacific Northwest is substantial and should be able to carry this additional load.

We then proceed to investigate the effect on the PG&E system of having Diablo Canyon Unit 1 on-line. As noted in earlier supply-demand discussion, the most optimistic projection calls for commercial power by August 1, which is one of the months of highest load for PG&E. As shown in Appendix B, the forced outage rates have been estimated for this plant for the period before the first refueling, after this refueling and at "maturity." However, it is difficult to estimate these outage rates for the first month of service of this plant. We have followed the procedure suggested in Reference 18 that the difference between the immature and mature forced outage rates declines exponentially from plant start-up. Using the outage rates given by PG&E, this allows one to estimate the outage rates close to start-up. The details are described in Appendix B. In order to assess the effects of including Diablo Canyon 1 in the resource mix for August, we bracket the FOR's by using the values derived in Appendix B and the immature outage rates given by PG&E.

It is then of interest to calculate the resulting LOLP curves for the PG&E system and compare the results including Diablo Canyon Unit 1 with those for the PG&E system without Diablo Canyon. This comparison will give the amount of outside support this plant would replace. The risk curves for PG&E with and without Diablo Canyon are shown in Figure 5. The difference between curves A and B is equivalent to displacing the curve with Diablo Canyon on-line by about 500 MW.

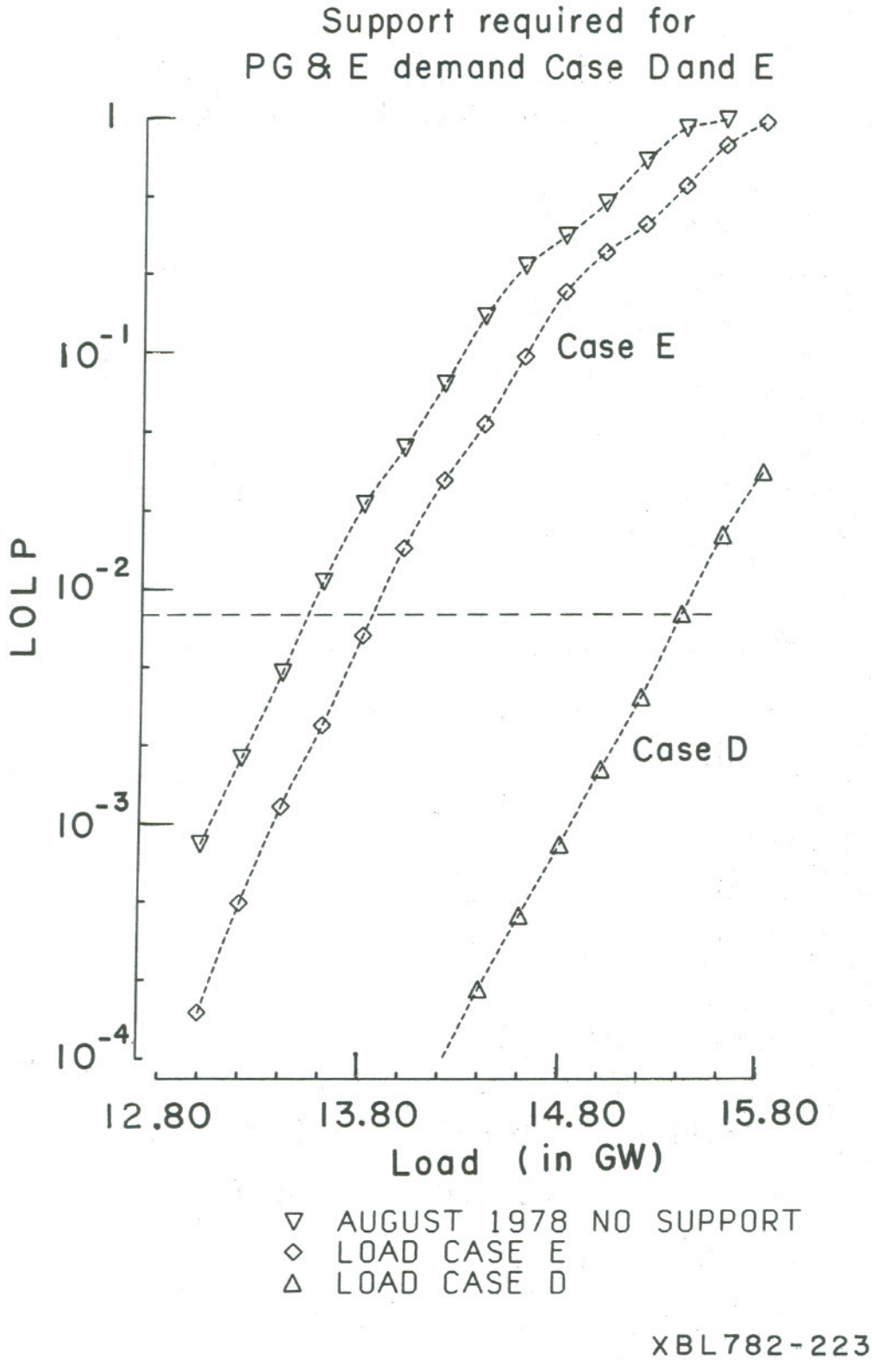

Figure 4. Support Required by Demand Cases D and E in Order to Meet Loss-of-Load Criterion of One Day in Ten Years

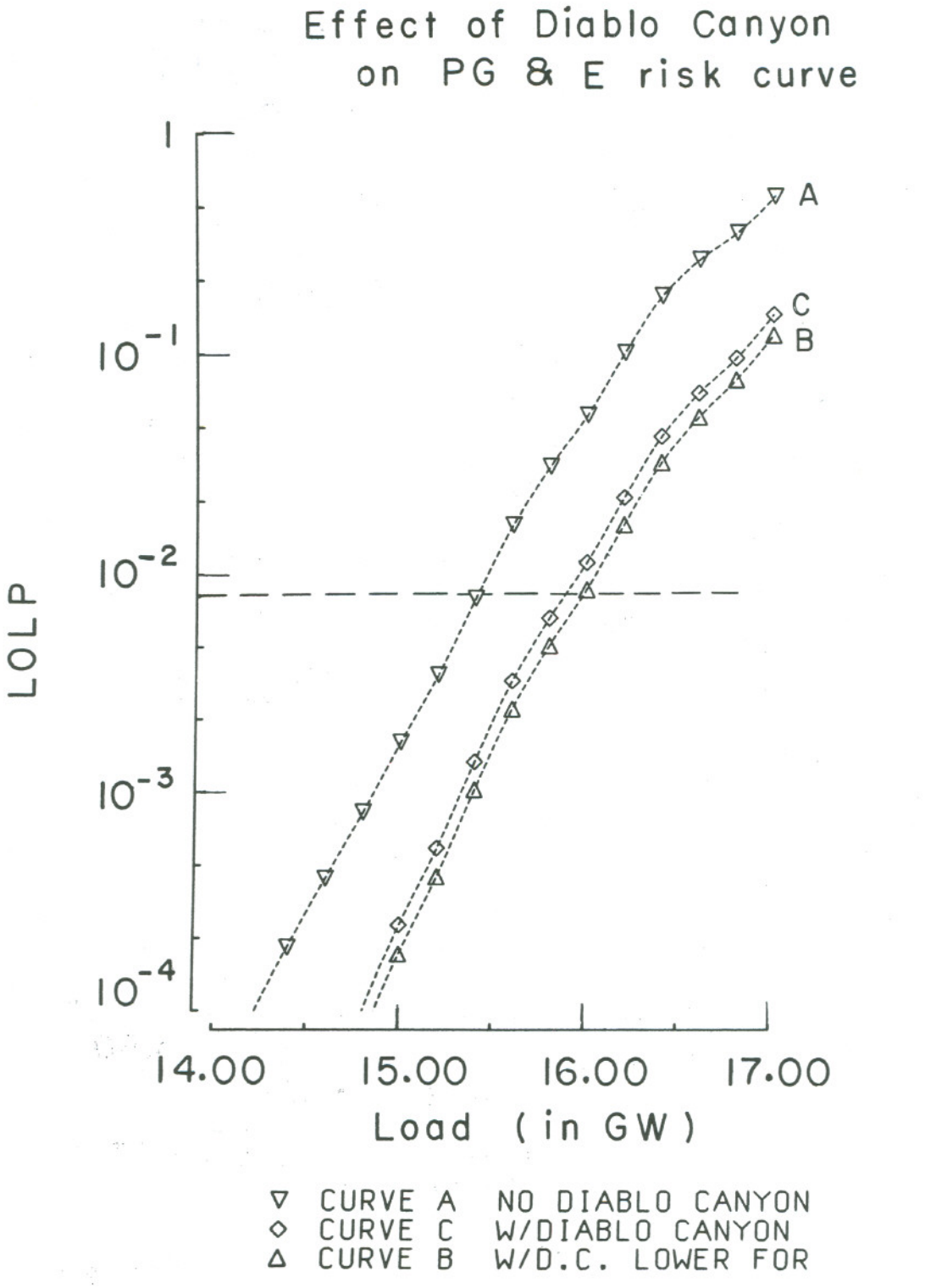

Figure 5. Comparison of PG&E Risk of Loss-of-Load With and Without Diablo Canyon. The difference between curves B and C indicates the sensitivity to the assumed value for the forced outage rate.

Also shown in Figure 5 is the curve (curve C) resulting from the assumption of the higher outage rate for the Diablo Canyon plant. If this curve were matched up with curve A, the effect of having Diablo Canyon Unit 1 available for load in August would be even smaller, equivalent to about 400 MWe of support.

Thus, the inclusion of Diablo Canyon into the PG&E resources for August 1978 adds the equivalent of 400-500 MWe to peak load capability. At the same time, operating reserve margin requirements would increase, since Diablo Canyon would then be the largest single unit in the PG&E system. According to Reference 3, PG&E uses as an operating margin 3 percent of the load plus the largest single risk. With Diablo Canyon on-line, this latter element increases by about 200 MWe since the next largest risk in PG&E's service area system is the 875 MWe Rancho Seco nuclear power plant.

For the statewide system, LOLP has been calculated for four different cases. As discussed in the supply section, several changes have been made in the list of resources available for the summer of 1978, including full use of Castaic pumped storage, San Onofre, and full use of the DC intertie to the Pacific Northwest. We treat this as the reference case (curve A), and the results are presented graphically in Figure 6. As noted in Appendix B, the utilities do not use identical forced outage rates for the same, jointly-owned facilities. Curve B in Figure 6 labelled "higher FOR" shows the effect on the reference case of using the highest value for the forced outage rates on the DC intertie, Mohave 1, 2 and San Onofre 1. The resulting aggregate difference is almost a factor of two in LOLP compared with the reference case. By way of comparison, the risk curves based upon utility submittals to the CERCDC in August 1977,[6] with and without Diablo Canyon 1 have also been computed. The results are shown in Figure 6 as curves C and D, respectively. These results include the use of San Onofre during August, since the refueling schedule has been pushed back, and do not include Geysers 12 or Humboldt Bay 3.

Using the statewide peak load information in Table 15, we then tabulate the monthly LOLP for our reference case and the utility

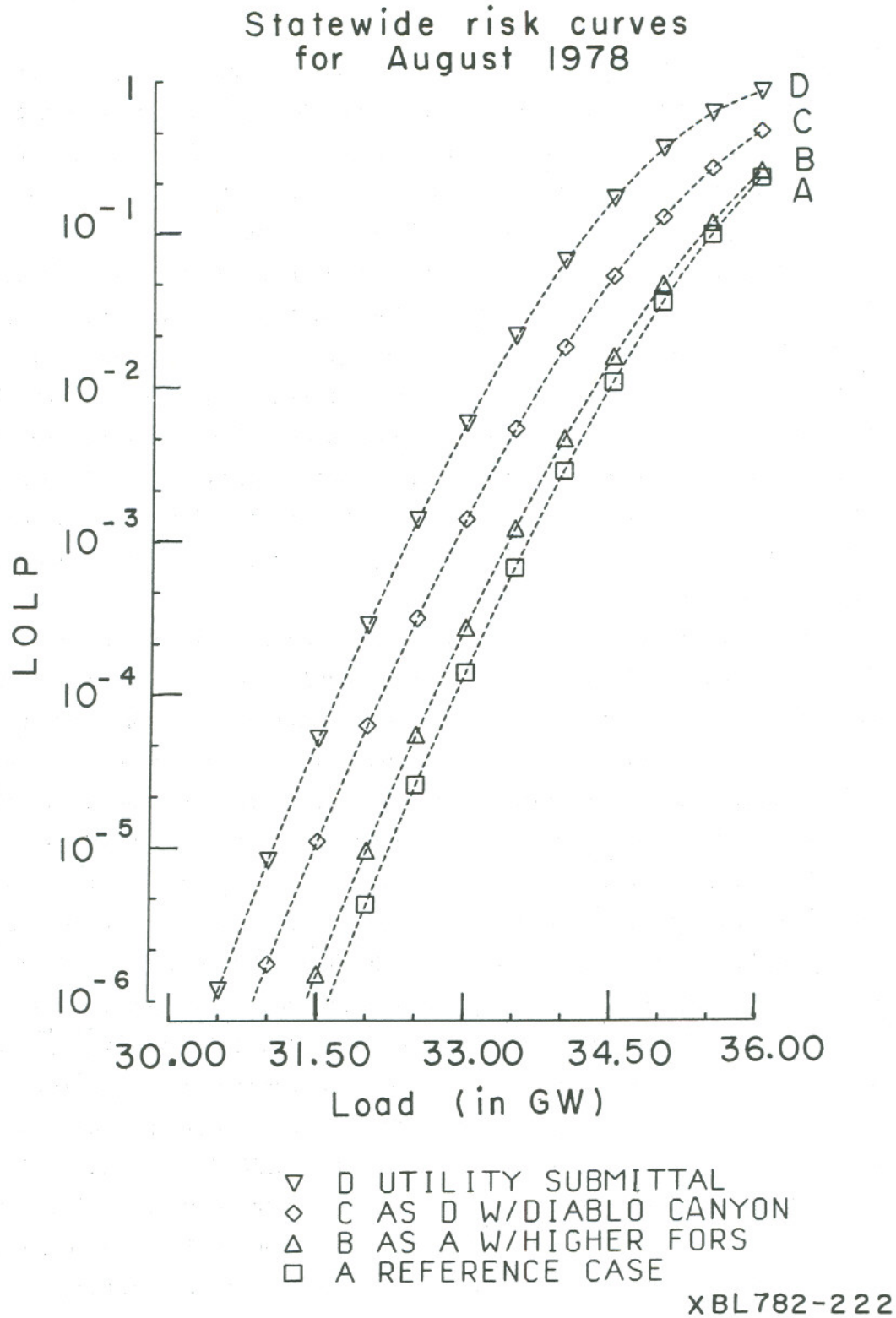

Figure 6. Comparison of the Effect of Different Statewide Generating Resources Upon Loss-of-Load Probability. See text for details.

Table 15

Summer Peak Load Order by Month for 1977 and Estimated Loads for 1978

	Peak Day	In Order of Decreasing Load								
1977 Historical	1	2	3	4	5	6	7	8	9	10
PG&E:										
July	13519	12913	12859	12854	12852	12777	12772	12634	12549	12489
Ratio to peak	1.	.955	.951	.951	.951	.945	.945	.935	.928	.924
August	13815	13443	13394	12777	12771	12716	12417	12381	12344	12320
Ratio to peak	1.	.973	.920	.925	.924	.920	.899	.896	.894	.892
September	13299	13276	13039	---[a]	---	---	---	---	---	---
Ratio to peak	1.	.998	.980							
Average Ratio	1.	.976	.967	.938	.938	.933	.922	.915	.911	.908
Statewide										
July	29853	29517	29127	29102	28032	27730	27694	27600	27160	27084
Ratio to peak	1.	.989	.976	.975	.939	.929	.928	.925	.910	.907
August	29766	29234	29114	28585	28462	27887	27535	27237	27132	27042
Ratio to peak	1.	.982	.978	.960	.956	.937	.925	.915	.912	.908
September	30030	29657	29445	---[a]	---	---	---	---	---	---
Ratio to peak	1.	.988	.981							
Average Ratio	1.	.986	.978	.968	.948	.933	.926	.920	.911	.908
1978 Estimates[b] (in MWe)										
PG&E - Case D	15428	15058	14919	14471	14471	14394	14225	14117	14055	14009
Statewide - Case D	33445	32977	32709	32375	31706	31204	30970	30769	30468	30368

[a] Only the three highest peak days were used for September, since September generally is a cooler month and the loads decrease.

[b] Peak days are taken from Table 5.

submittal cases. These are shown in Table 16. In all but one of these cases, the monthly LOLP is well below the PG&E criterion of 8.5×10^{-3}. For the modified utility submittal case, without Diablo Canyon, the peak day would exceed the LOLP criterion of 8.5×10^{-3}. Note that with the inclusion of either Diablo Canyon (curve D) or full use of Castaic and the DC intertie (reference case, curve A), the total monthly LOLP drops below this criterion. It would appear that, from a statewide perspective, the utilities' projected coincident load for summer 1978 can be met with little risk. Further, the least risk case arises from full use of the Castaic pumped storage facility and the DC intertie. This statewide result indicates that the additional support that may be required by PG&E for August can be provided by other California utilities without the risk, as measured by LOLP, increasing beyond PG&E's planning criterion.

As we noted in our earlier paper, the shape of these risk curves also suggest that conservation or load management can have significant benefit in reducing risk, since the curve is steepest in that region. Hence, 200 to 300 MWe of load reduction through load management results in a bigger change in LOLP than an equivalent amount of outside support.

Table 16

Statewide Loss-of-Load-Probability Results for August 1978

Peak Load[a] (MWe)	LOLP			
	A[b]	B[c]	C[d]	D[e]
33445	4.23×10^{-4}	7.81×10^{-4}	1.47×10^{-2}	3.53×10^{-3}
32977	9.34×10^{-5}	1.87×10^{-4}	4.17×10^{-3}	9.55×10^{-4}
32709	3.75×10^{-5}	2.82×10^{-5}	1.91×10^{-3}	4.27×10^{-4}
32375	1.17×10^{-5}	2.56×10^{-5}	6.97×10^{-4}	1.52×10^{-4}
31706	9.21×10^{-7}	2.25×10^{-6}	7.54×10^{-5}	1.58×10^{-5}
31204	1.25×10^{-7}	3.08×10^{-7}	1.20×10^{-5}	2.46×10^{-6}
30970	4.83×10^{-8}	1.21×10^{-7}	5.04×10^{-6}	1.02×10^{-6}
30769	2.07×10^{-8}	5.25×10^{-8}	2.32×10^{-6}	4.69×10^{-7}
30468	5.66×10^{-9}	1.46×10^{-8}	7.05×10^{-7}	1.41×10^{-7}
30368	3.64×10^{-9}	9.46×10^{-9}	4.70×10^{-7}	8.29×10^{-8}
TOTAL	5.67×10^{-4}	1.07×10^{-3}	2.16×10^{-2}	5.08×10^{-3}

[a]From Table 15.

[b]Reference case, curve A in Figure 5.

[c]Curve B in Figure 5.

[d]Modified utility submittal, without Diablo Canyon, curve C in Figure 5.

[e]Modified utility submittal, including Diablo Canyon, curve D in Figure 5.

SECTION 4

IMPACTS OF SUPPLY OPTIONS

ENVIRONMENTAL EFFECTS

Introduction

This section provides an estimate of the amount of air pollutants to be expected in the South Coast Air Basin due to transfers of energy to PG&E from Southern California Edison (SCE) and Los Angeles Department of Water and Power (LADWP) during 1978. To provide the proper perspective in which to view these emissions, the amount of total emissions and the relative contribution from power plants are discussed, as are the geographical and temporal distributions of these emissions. Regulation of the oil sulfur content and decreased gas availability and their effects on emissions patterns are also considered.

The effect of these emissions on air quality in the South Coast Air Basin is difficult to estimate. Air quality is a complex function of emissions, meteorology, topography, the complex interaction of pollutants, and removal processes. We have looked at historical air quality indices in the Basin and the impact of the drought as measured by these indices.

Emission Inventories

Although emission inventories taken[19-23] in the South Coast Air Basin differ in geographical area and number of sources covered, they show no serious disagreement with regard to the magnitude of power plant emissions. These emissions, expressed as annual averages, comprised 149 tons per day[20] or 43 percent of the NO_x and 140 tons per day[21] or 45 percent of the SO_x from stationary sources in 1972-73 and 1974, respectively. When mobile sources are also taken into account, these values decrease to 12 percent of total NO_x and 43 percent of total SO_x emissions.[19] Approximately 80 percent of these power plant emissions occur in Los Angeles County.

Combustion of liquid fuels is the largest stationary source of SO_x, and utility power plant boilers are the biggest stationary users

of liquid fuels. The amount of SO_x released is directly proportional to the amount of fuel burned and the sulfur content of the fuel. The dominant sources of SO_x after power plants are refineries and carbon plants. Basin-wide stationary sources such as these contribute more than four times as much oxides of sulfur as do mobile sources.

The geographical distribution of emissions is shown in Figure 7. Of the nine grid squares with the highest emissions, eight contain power plants as the largest source.

Combustion of fuels produces NO_x, primarily as NO, with oil fuel generating more NO_x than gas. The amount of NO released is dependent on many factors (including combustion temperature and concentrations of atmospheric nitrogen and atomic oxygen) and, in power plants, is load-dependent. The dominant stationary sources in the South Coast Air Basin are electric utilities, petroleum industries, mineral processing industries, and metallurgical industries.

The geographical distribution of NO_x emissions from stationary sources is shown in Figure 8. Five grid squares with high values are located close together in southwest Los Angeles County and contain power plants and refineries. These major sources are usually upwind of the heavily populated areas.

Power Plant Emission Trends

The amount of emissions depends upon the amount of energy generated for a given time period as well as the type of fuel used. The use of natural gas in those plants capable of using either gas or oil will significantly reduce emissions. The amounts of emissions from power plants using gas and oil respectively are: NO_x, 0.79 vs. 1.37; SO_x, 0.005 vs. 1.40 (0.22 percent sulfur content of oil); and particulates, 0.015 vs. 0.300 pounds per equivalent barrel.[24] (The amount of gas equal in energy to a barrel of oil is taken to be 6000 cubic feet.)

The enactment of Rule 431.2 by the South Coast Air Quality Management District (SCAQMD) requires steam generators in power plants in the Basin to burn oil with a sulfur content of 0.25 percent or less. Previously, Rule 431 required all stationary sources to burn

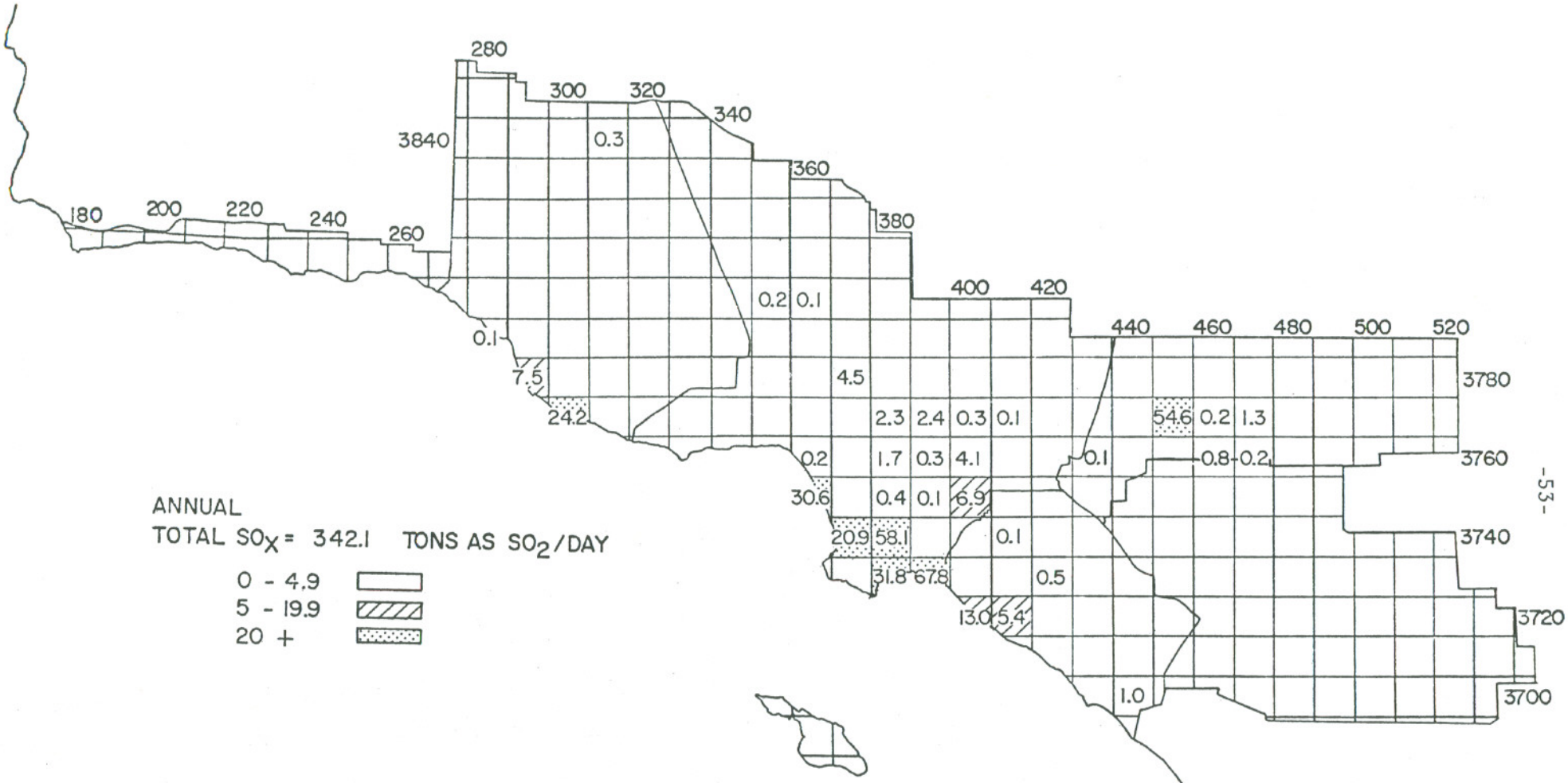

Figure 7. Distribution of Annual Average Daily SO_x Emissions in the South Coast Air Basin, 1974, Stationary Sources*

*Source: Reference 21 (As of September 1976, the South Coast Air Basin does not include any part of Ventura or Santa Barbara counties.)

5802-432

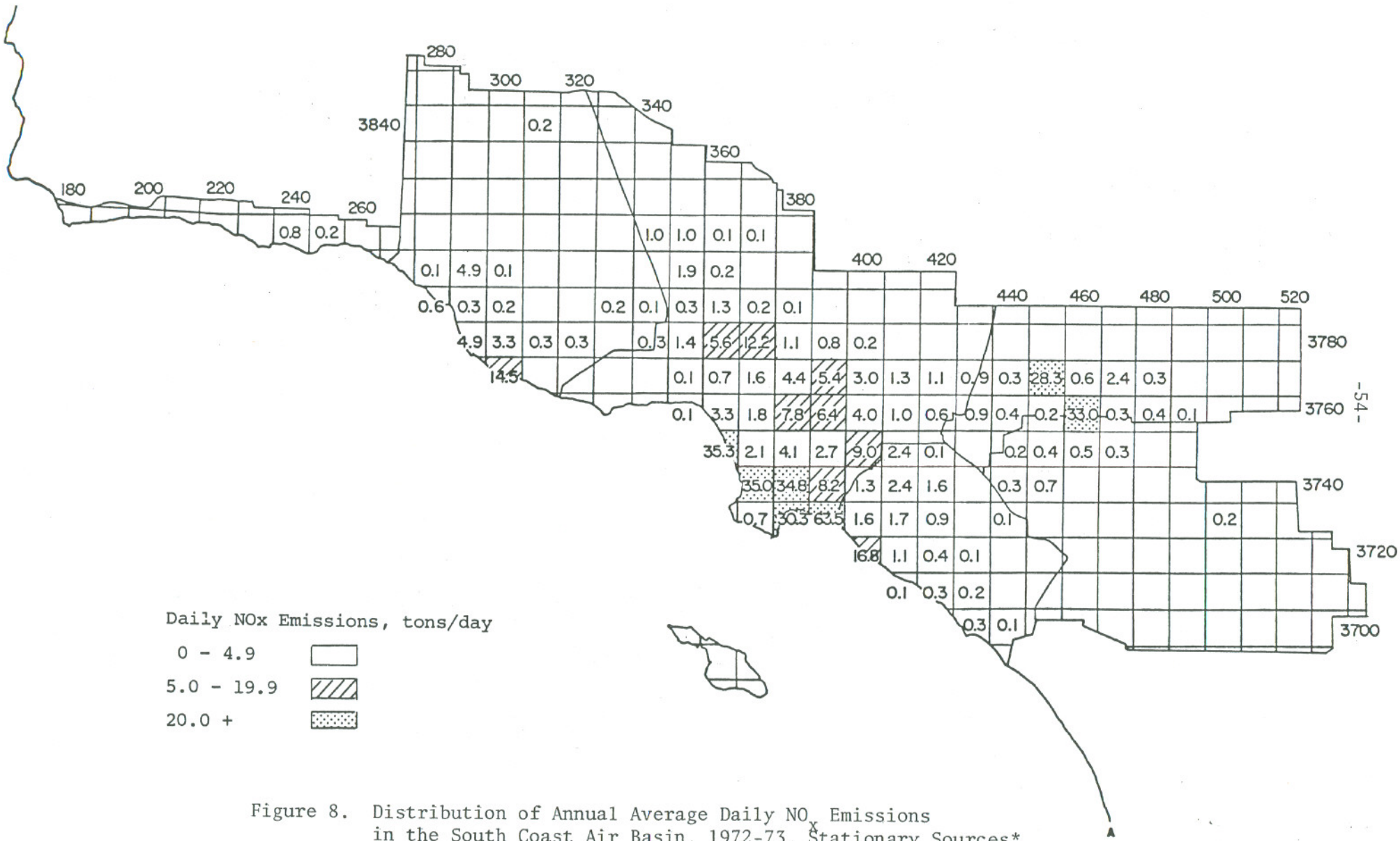

Figure 8. Distribution of Annual Average Daily NO_x Emissions in the South Coast Air Basin, 1972-73, Stationary Sources*

*Source: Reference 20

5800-179

oil with 0.5 percent sulfur. Since utilities have been using oil averaging 0.32 percent sulfur in 1977, this change will significantly reduce power plant SO_x emissions in 1978. Estimates of future emissions must include consideration of increasing total fuel use, decreasing gas supplies and changes in regulation of sulfur content of oil. A projection by staff at SCAQMD indicates that the 1978 SO_x emissions from power plants will be 75 percent of the 1977 levels, thus bringing emissions down to a level between the 1974 and 1975 amounts (Table 17). Other estimates, when corrected for the low sulfur restriction, are in agreement.[21,22,24]

Increased fuel use and decreasing availability of gas have meant a dramatic increase in NO_x emissions from power plant boilers, about 70 percent higher in 1977 than in 1976 (Table 17). It is expected (from utilities' and SCAQMD projections) that 1978 will be a year of further increases in NO_x emissions, up 5-10 percent from 1977. While automobiles are the major contributors of NO_x emissions, any increase in emissions of precursors to smog in this air basin can adversely affect air quality.

Seasonal emission patterns have also changed as a result of decreased gas availability. Historically, power plants burned gas in summer and oil in winter but now use oil year round. Thus, while winter emissions have increased with increased fuel use, summer power plant emissions have increased more rapidly as cleaner burning gas has been replaced by oil.

The relative importance of power plant emissions can change, even if the absolute amounts (in tons) of emissions from power plants do not change. For example, attempts are being made through regulation to reduce NO_x emissions from automobiles, their principal source. As these restrictions succeed in reducing the automotive contribution, stationary sources (if not simultaneously regulated) can come to represent an increasing percentage of total NO_x emissions. This situation is expected to bring stationary and mobile sources to parity in their NO_x emissions around 1980.[20]

1978 Power Plant Emissions and Transfers

Total and peak day emission estimates for each month in 1978 are given in Table 18. These peak day estimates are derived from the

Table 17

History and Outlook of Power Plant Fossil Fuel Use and Emissions in South Coast Air Quality Management District

Year	Fuel (10^6 barrels of oil equivalent/year[a])		Fraction of Gas in Fuel Use (%)	Emissions (tons/day)	
	Total Fuel	Gas		SO_2	NO_x
1974	56	17	31	147	93
1975	58	13	22	167	98
1976[b]	55	10	18	166	95
1977[b]	80	6	8	208[c]	163[e]
1978[b]	81	--	--	156[d]	172[e]
1979[b]	84	--	--	162[d]	178[e]
1980[b]	84	--	--	162[d]	178[e]

Source: John Stuart, "Fossil Fuel Emissions in the South Coast Air Quality Management District and the Role of Solar Energy in Reducing These Emissions," paper presented at the Helio-science Institute Conference, Palm Springs, May 2, 1977.

[a]One barrel of oil is equivalent to 6000 cf of natural gas.

[b]1976 and future years are estimated values.

[c]Fuel is estimated to have an average sulfur content of 0.32 percent.

[d]Sulfur content of fuel is mandated to be 0.25 percent or less after 1978. SCAQMD expects an average sulfur content of .22 percent.

[e]These estimates use an NO_x emission factor of 1.55, based on higher expected loads for power plants in the South Coast Air Basin. cf. D. Danielson, Testimony before CPUC, Case No. 10292, South Coast Air Quality Management District, May 1977.

Table 18

Estimated Peak Day Emissions from Power Plants in South Coast Air Quality Management District, 1978[a]

Month	Monthly Emissions (Tons)			Estimated Peak Day Emissions (Tons)		
	SO_X	NO_X	Particulate	SO_X	NO_X	Particulate
April	4758	4752	640	172	179	23
May	4973	4809	658	176	174	23
June	4945	4803	668	190	188	26
July	5718	5400	772	214	215	29
August	5503	5379	791	215	224	31
September	5064	5057	729	196	206	28
October	5519	5251	739	208	209	28
November	5139	4823	699	200	194	27
December	5255	4927	713	191	179	25

[a]Actual emissions will depend upon load and type of fuel used. These totals include in-basin thermal generating plants owned by SCE (except Coolwater, Mandalay and Ormond Beach), LADWP, Burbank, Glendale and Pasadena.

[b]Source: Reference 25.

projected monthly emissions using ratios of peak day to average day emissions from 1976 data,[25] the latest year for which the data are available. Transfers are not included, since the amount of energy transfers that will occur on a peak day is not known.

A continued deficit in water available for hydroelectric plants would cause increased dependence on steam generation plants in the South Coast Air Basin, in part due to transfers of energy to PG&E. Because of uncertainties about gas supplies, it is assumed that all transfers will be met by the combustion of oil, with concomitant increased emissions of air pollutants.

Data supplied by the utilities to CERCDC include projections of monthly oil usage and emissions of SO_x, NO_x and particulates for 1978. Emission factors based on oil consumption by power plants were derived as follows.

A linear relationship is observed (as expected) between emissions of SO_x and particulates and the amount of oil burned whereas for NO_x emissions the linear relationship serves as a close approximation. The load and choice of units to meet that load and the individual plant parameters must be known for estimating emissions. Use of a linear approximation for each utility is estimated to give less than a 5 percent error in the Basin-wide totals. The emission factors (pounds per barrel oil) used for calculating emissions due to transfers are shown in Table 19.

Table 19

Emission Factors for Southern California Electric Utilities[a]
(pounds per barrel oil)

	SO_2	NO_2	Particulates
SCE	1.492	1.372	0.159[b]
LADWP	1.591	1.671	0.300
SCAQMD	1.40	1.370	0.300

[a]Source: Reference 6

[b]This emission factor differs from the factor of .382 for SCE in Reference 25. It is not clear why this emission factor for particulates has changed.

From Section 3, two estimates of expected transfers were obtained. The ratio of energy per quantity of oil burned, obtained from submittal data,[6] are used to calculate the amount of oil required for a given amount of transferred energy. From this the expected emissions are calculated, using ratios of emissions to oil consumption derived from the linearity assumption. The transfers are partitioned between SCE and LADWP in the amounts 71 percent and 17 percent, respectively (based on actual transfers from April through July, 1977). The balance of PG&E's shortfall is expected to be met by SDG&E.

The emissions resulting from energy transfers from the South Coast Air Basin to PG&E, shown in Table 20, would add as much as 10 percent to the power plant SO_x and NO_x emissions during the summer peak months. These calculations are performed using averages for each utility. Note that if less efficient, or "dirtier," plants are used at high load, and if transfers occur at high loads, then the values in Table 20 will be underestimates of true emissions resulting from transfers. The calculation of particulate emissions does not include the significant contribution of secondary particulates, i.e., those formed by oxidation of SO_x to sulfate and NO_x to nitrate.

Table 20

Expected Emissions Due to Energy Transfers in 1978

	June	July	August	September
Transfers:				
GWH (10^9 kWh)[a]	200-500	150-475	0-200	0-100
10^3 bbls oil	(275-689)	(207-654)	(0-275)	(0-138)
Emissions (tons):				
SO_x (as SO_2)	208-520	156-495	0-208	0-104
NO_x (as NO_2)	196-493	148-468	0-196	0-98
Particulates	26-64	19-61	0-26	0-13

[a]See Table 13.

Air Quality

California air quality standards are violated on a regular basis in the South Coast Air Basin.*[24] While the exact relationship between emissions and air quality is elusive, it seems reasonable to infer that increased violations may be expected for the nitrogen dioxide and perhaps oxidant standards in 1978 unless other circumstances offset the increased NO_x emissions from power plants. On the other hand, violations of the sulfur dioxide and sulfate standards should decrease as a result of decreased emissions when lower sulfur oil is burned in power plants.

It is important to note that seasonal patterns strongly affect when these violations occur. Thus oxidant and oxidant-sulfate episodes occur with greater frequency in summer,[26] when electricity demand is also high. This effect tends to amplify the importance of additional power plant emissions due to transfers at these times when ambient pollutant levels are already high. (Care must be exercised when relying on historical data; where power plants traditionally burned gas in summer and oil in winter, oil is now used all year.[20] Therefore, measures to decrease oil burning, including conservation efforts and increased use of gas, while important at all times, are particularly critical during peak days of summer months.

So far it has not been possible to quantify the impact of power plant emissions on local air quality. One study[22] has been able to show a correlation between SO_x emissions from non-utility sources and ambient (annual average) SO_2 measured at Los Angeles and Long Beach because identifiable sources (automobiles, chemical plants, and other non-utility combustion of fuel) had low effective stack heights and were located close to the air quality monitoring stations.

In the absence of a known quantitative relationship between power plant SO_x emissions and air quality, it is difficult to predict the quantitative effects on air quality due to changes in those emissions. Part of the difficulty in obtaining such a relation resides in the changing geographical distribution of emissions from year to year as generating capacity increases and in the domination of ground level air quality monitors by nearby, ground level sources.

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*In 1975, there were 78 violations of the one-hour nitrogen dioxide standard, 62, 48 and 307 violations of the 24-hour sulfur dioxide, particulate sulfate, and suspended particulate standards, respectively.

The effect of NO_x emissions on air quality are even more difficult to predict. Both reactive hydrocarbons and oxides of nitrogen are precursors of oxidants, particularly ozone. The formation of oxidants depends upon the topography of the area. In addition many other parameters which change with time are important, including the geographical distribution and amounts of emissions (or ambient levels) of several pollutants (including carbon monoxide, nitric oxide, nitrogen dioxide, hydrocarbons of different reactivities and ozone). Meteorological parameters describing the solar radiation intensity, temperature, relative humidity, and wind speed and direction at different altitudes are needed. Chemical interactions among the pollutants are complex and various species may be absorbed by clouds or by substances on the earth's surface.

A detailed analysis of oxidant prediction models has been published.[27] The simplest methodologies—rollback models—apply to changes in hydrocarbon emissions for a constant hydrocarbon-to-NO_x ratio. The most sophisticated models employ physicochemical relationships and large amounts of input data to give a detailed description in time and space distributions of pollutant concentrations. Due to their complexity, these models are used to describe relatively short time periods (i.e., worst day) in great detail, rather than giving statistical information for a season. Empirical relationships are best suited to this type of statistical prediction and may be based on smog chamber or atmospheric measurements.

Both an empirical relationship based on aerometric data[28] and a smog chamber model[29] agree that an increase in present levels of NO_x emissions (or ambient levels) for fixed hydrocarbon emissions (or air quality) will result in lower maximum oxidant concentrations <u>locally</u>. Yet the maximum oxidant concentration possible at a site downwind of the source at a later time will be dependent on precursor levels including transported NO_x, with the effect that air quality at this site would be adversely affected.

No stronger effort was made to quantify air quality predictions because 1) new models promising improved predictive capability are

under development but not yet verified and 2) data essential to the accuracy of such an analysis is currently incomplete. (An inventory of hydrocarbon emissions by source and reactivity is expected to be completed by early 1978.)

Even when emissions for the Basin are well characterized, the air quality (and subsequent health effects) is highly dependent upon meteorological conditions. To estimate ozone levels on a particular day, the SCAQMD uses a composite Meteorological Index which includes data on inversion strength and height, atmospheric stability, radiation and pressure gradients.[30] An examination of the monthly average of this index for the summer months of 1977 indicates that the drought conditions did not, on the average, create meteorological conditions significantly different from previous years. The average of the meteorological index for the summer months in the base period, 1970-1974, is 17.8 parts per hundred million of equivalent ozone concentration. The average of that index for the summer months of 1977 is 17.7 parts per hundred million of equivalent ozone concentration.

In conclusion, transfers of electricity to PG&E from the South Coast Air Basin would add as much as 10 percent to the emissions next summer. Of the two major pollutant emissions, SO_x emissions are expected to decrease during 1978 due to lower sulfur content of oil while NO_x emissions are expected to increase due to increased generation and to a larger fraction of oil fuel use. Air quality standards have been violated regularly in the past in this basin so any additional emissions due to transfer of electricity to PG&E will further deteriorate air quality in this basin.

AVERAGE PRICES* FOR PACIFIC GAS AND ELECTRIC COMPANY

During 1977 electric utilities in the state resorted to thermally-generated electricity to make up for the losses in hydroelectric generation. However, meeting the state's electricity demand with increased oil- and gas-fired generation is costly; average prices for the 12

*The term prices, as used throughout this section for 1978, refers to average revenues at an assumed 9.2 percent rate of return.

months prior to September 30, 1977, for PG&E, the utility most affected by the drought, were 38 mills/kWh, up from 28 mills/kWh during 1976.[31] If the drought were to continue for another year, these prices would increase further. To what extent these prices would increase and how they would respond to changes in demand and supply during 1978 are questions we examine in this section.

To compare the effect of the drought on electricity prices during 1978, we estimated average prices for 1978 for two cases. The main difference in these cases is the amount of hydroelectric generation which would be available during 1978. In the first case we assume the amount of hydroelectricity anticipated by the utilities if the drought continued in 1978.[6] In the second case, prices are evaluated under normal rainfall conditions, and hydroelectricity is assumed available at the 1975 level of generation.

In each case three options were considered for nuclear and new geothermal supplies: 1) the PG&E supply forecast as submitted to the CERCDC,[6] 2) the PG&E forecast but with Diablo Canyon 1 power plant delayed until August and Geysers 12 and 15 delayed until the fall,* and 3) the PG&E forecast with Diablo Canyon 1 delayed past 1978 and with the Geysers delayed as in the second option. Increased hydroelectric generation during a wet year would displace expensive transfers and oil-fired electricity generation in each of the three options. The second and third options are identical to those examined in Section 3.

Electricity rates were estimated for each of these supply options to satisfy three levels of demand for 1978. The three levels called for a 4.7 percent, zero percent and -2.0 percent change from 1977 sales as explained in Section 2. In all 18 scenarios, 9 under each weather case were examined (3 options x 3 demand levels x 2 weather cases).

Model

Our model to predict average electricity prices given various electricity supply and demand scenarios is based on a "rate equation" presented in Kahn *et al.*[32] The rate equation performs a simple

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*Humboldt Bay Unit 3 assumed not available in options 2 and 3.

accounting of the various elements which enter into the cost of generating and distributing electricity. The equation considers both fixed costs such as administrative expenses and capital charges and variable costs, such as fuel and maintenance, as well as tax impacts of both federal income taxes and investment tax credits.

The rate euqation determines an average price of electricity as follows:

$$P = \left[\frac{I + D + M_F + T + F}{(1 - r_R)} + \frac{E - (r_F a + i)\,\Delta K}{(1 - r_R)(1 - r_F)} \right] \frac{1}{Q} + \frac{M_V}{1 - r_R}$$

where

P = average price per kWh

Q = annual energy demand (kWh)

I = interest expenses on bonded debt

D = depreciation charges

M_F = fixed maintenance expenses

T = property taxes

F = fuel expenses

E = earnings after interest expense

ΔK = capital additions to rate base

M_V = variable maintenance expenses per kWh

a = accelerated depreciation factor

i = investment tax credit rate

r_R = revenue tax rate

r_F = federal income tax rate

This rate equation assumes that tax savings are "flowed-through" to the customers, which is the accounting practice in California. We further assume that the utility earns its allowed rate of return, that is,

$$E = Kr_B - I$$

where

I and E = interest and earnings after interest, as above

K = rate base

r_B = authorized rate of return on rate base

Table 21

1978 Estimates of Variables Constant Across Scenarios

Variable	Comments	1978 Value
K	Net value of electric plant in 1976[a]	$\$5.052 \times 10^9$
r_b	As authorized in 1977	9.2%
B	1976 proportion of debt attributable to electric plant = (bonded debt) x $\left(\frac{\text{net electric plant}}{\text{total utility plant}}\right)$[a]	$\$2.465 \times 10^9$
i_b	Based on 1976 embedded interest rate of 6.97%	8%
D	As in 1976[a]	$\$150.1 \times 10^6$
M_F	M_F = Administrative and General Expenses + Customer Accounts + Purchased Power - Franchise Requirements - Regulatory Commission Expenses. As in 1976[a] plus 9% annual growth (annual growth rate of 16.5% in 1969-74[b])	$\$323.85 \times 10^6$
T	As in 1976[a] plus 2% annual growth (average annual rate 1969-73)[b]	$\$108.45 \times 10^6$
ΔK	Estimate as of September 1975[c]	$\$435.0 \times 10^6$
M_V	M_V = Operating and Maintenance Expenses - Fuel Expenses - M_F. As in 1976[a] plus 6% annual growth (7.3% annual rate 1969-74)[b]	3.6 mills/kWh
a	Assumes first year accelerated depreciation is 20% greater than book depreciation	20%
i	Investment tax credit	10%
r_R	Average of 1969-74 rates[b]	1.3%
r_F	Federal income tax rate	46%

[a]Reference 33

[b]Reference 32

[c]PG&E submission to the California Public Utilities Commission, under Amended Application 55509 and 55510, February 1975, Amended October 1975.

Table 22

Estimated 1978 Fuel Expense

Type of Generation	Unit Cost (mills/kWh)
Hydroelectric	0
Other Receipts[a]	17
Nuclear	7
Geothermal	11
Gas	19
Oil	24
Intrastate Transfers	32

[a]Other receipts include refinery and gas turbine generation.

Table 23

PG&E Generation in 1976 by Fuel Type and Average Price

	Generation (GWh)
Hydroelectric	8,112
Gas and Oil	37,276
Nuclear	197
Geothermal	3,615
Gas Turbines	73
Purchases	2,773
Interchanges	10,338
TOTAL	62,384
Average Price of Electricity	32.8 mills/kWh

I, the interest expense on bonded debt, is determined as

$$I = Bi_b$$

where

B = bonded debt

i_b = embedded interest rate on bonded debt

Three of the inputs to the rate equation change with the scenario being examined. In particular, these variables include Q, the annual energy demand, F, the fuel expense and K, the rate base. Other variables are assumed constant across scenarios. ΔK, the capital additions to rate base, through which the impact of the investment tax credits is registered, is held constant. For rate-making purposes, these credits are based on a five-year moving average of capital additions to rate base. If large changes in rate base were entirely reflected in ΔK, the one-year impacts would be overstated in our equation. However, additions to rate base are added to K, the rate base, thus influencing earnings through the rate-of-return-on-rate-base multiplier.

In order to estimate the total fuel expenses (F in the rate equation) under different generation scenarios, we need to estimate the fuel expense per kWh of each type of generation. Fuel expense for hydroelectric power is assumed zero. Nuclear fuel is assumed to cost 7 mills per kWh.[34] Conversations with SMUD officials indicate that the expected cost of electricity from Rancho Seco to PG&E would be around 11 mills/kWh. This figure is equivalent to our assumed fuel costs plus the variable maintenance costs. Rancho Seco power delivered to PG&E is therefore considered in our model as though it were part of the PG&E system. Geothermal "fuel" is assumed to cost 11 mills per kWh in steam expense.[33] Intrastate transfers are assumed to cost 32 mills per kWh to PG&E. Although these are not strictly fuel costs, they are treated as such in the model. We assume 6.287×10^6 Btu per barrel of fuel oil, and costs of \$2.40 per 10^6 Btu for fuel oil and \$1.90 per 10^6 Btu for gas. Assuming equal heat rates for oil and gas generation, we arrive at costs of 24 mills per kWh for oil generation and 19 mills per kWh for gas generation. These figures are summarized in Table 22.

The model was validated with data for 1976. Data on electricity generation by fuel type and on electricity sales were available to us for 1976.[33] Financial and fuel price data was also available from the same source. Table 23 shows the generation by fuel type for 1976. Our estimated average revenue for 1976 is 32.8 mills/kWh, as compared with the actual revenue of 27.8 mills/kWh.[31] The lower actual revenue is mainly due to deduction from expenses of excess fuel adjustment costs accumulated prior to 1976. These costs estimated at 4 mills/kWh bring our estimates within a reasonable range of the actual revenue.

Estimates of 1978 Prices

Our earlier demand and supply analysis in Sections 2 and 3 was based on projections for PG&E's entire service area. This service area includes utilities such as USBR, DWR and SMUD along with several smaller utilities. Since the intent of this section is to estimate average prices for PG&E, the service area generation figures had to be adjusted to reflect generation required for PG&E.

The 1978 energy for loads for the PG&E service area shown in Tables 24 and 25 are our projections as outlined in Section 2. Generation requirements for PG&E are estimated by subtracting the electricity generated or the electricity acquired for sale by USBR and SMUD in the PG&E service area. These two utilities would have generated or purchased outside the PG&E area approximately 7500 GWh during a dry 1978 and approximately 9,800 GWh during a wet year for sale to their customers. Firm transfers from USBR to SMUD are included in the SMUD figure. Electricity supplied to DWR by other utilities is also deducted from the load and other receipt categories.

To meet the PG&E generation requirements, two sets of generation mixes, one each for a dry and a wet year, were developed. Hydroelectric generation for a dry 1978, by PG&E and by the smaller utilities that supply energy to PG&E such as EBMUD, Merced Irrigation District, etc., was assumed at the level anticipated by PG&E under adverse water conditions.[5] Wet year hydroelectric generation was assumed at the 1975 level of generation.

Table 24

Dry Year 1978 Generation for PG&E
by Fuel Type (GWh) and Average Electricity Prices (mills/kWh)

	Case I			Case II			Case III		
Energy for Load PG&E Service Area[a]	77286			73816			72340		
USBR Generation[b]	2100			2100			2100		
SMUD Generation[c]	5440			5440			5440		
External DWR Load[d]	1078			1078			1078		
Generation for PG&E	68668			65198			63722		
Dry Year Generation Mix Scenarios	1	2	3	4	5	6	7	8	9
Hydroelectric[e]	7126	7126	7126	7126	7126	7126	7126	7126	7126
Nuclear	9795	5356	2361	9795	5356	2361	9795	5356	2361
Geothermal	4522	4277	4277	4522	4277	4277	4522	4277	4277
Other Receipts[f]	2130	2130	2130	2130	2130	2130	2130	2130	2130
Gas	16505	16505	16505	16505	16505	16505	16505	16505	16505
Oil	28590	28944	28944	25120	28944	28944	23644	28328	28944
Transfers	0	4330	7325	0	860	3855	0	0	2279
Average Electricity Prices	41.7	42.7	43.0	42.9	43.1	43.1	42.5	42.9	43.2

[a] Generation for load figures from Section 2.

[b] Includes 2800 GWh from Pacific Northwest and 1200 GWh of USBR generation. Firm transfers of 1900 GWh from USBR to SMUD are deducted and shown in the SMUD figure.

[c] From SMUD, Reference 37.

[d] DWR loads met by utilities other than PG&E. From Reference 6.

[e] From Reference 35.

[f] Includes generation from refineries and gas turbines.

Table 25

Wet Year 1978 Generation for PG&E
by Fuel Type (GWh) and Average Electricity Prices (mills/kWh)

	Case I			Case II			Case III		
Energy for Load PG&E Service Area[a]	77286			73816			72340		
USBR Generation[b]	4452			4452			4452		
SMUD Generation[c]	5440			5440			5440		
External DWR Load[d]	1078			1078			1078		
Generation for PG&E	66316			62846			61370		
Wet Year Generation Mix Scenarios	1	2	3	4	5	6	7	8	9
Hydroelectric[e]	24169	24169	24169	24169	24169	24169	24169	24169	24169
Nuclear	11495	7056	4061	11495	7056	4061	11495	7056	4061
Geothermal	4522	4277	4277	4522	4277	4277	4522	4277	4277
Other Receipts[f]	2130	2130	2130	2130	2130	2130	2130	2130	2130
Gas	16505	16505	16505	16505	16505	16505	16505	16505	16505
Oil	7495	12179	15174	4025	8709	11704	2549	7233	10228
Average Electricity Prices	34.7	35.1	35.1	34.9	35.3	35.3	34.9	35.4	35.4

[a]Generation for load figures from Section 2.

[b]USBR firm sales of 6352 GWh assumed met by USBR generation and inputs from Pacific Northwest. Firm transfers of 1900 GWh from USBR to SMUD are deducted and shown in the SMUD figure.

[c]From Reference 37.

[d]DWR loads met by utilities other than PG&E. From Reference 6.

[e]1975 PG&E service area generation of 30521 GWh minus USBR generation for its own load of 6352 GWh.

[f]Includes generation from refineries and gas turbines.

Table 26 illustrates the various assumptions regarding annual generation and additions to rate base for nuclear and new geothermal units. Generation from natural gas fuel is assumed to be at the level anticipated for 1978 in the utility submissions.[2]

With changing demand scenarios, varying amounts of electricity generated from oil and transfers from southern California utilities are necessary. Tables 24 and 25 present the oil generation and transfers which when added to generation by other fuel types are adequate to meet demand under each scenario.

The difference in average price (as shown in Tables 24 and 25) is significant under wet and dry meteorological conditions. Under drought conditions large amounts of expensive oil generation must be substituted for hydroelectric power that has no fuel cost. The difference in prices between comparable wet and dry year scenarios is approximately 20 percent.

Prices increase when less nuclear and geothermal generation is available and higher cost oil generation and intrastate transfers must be relied upon. However, this increase is less than one percent. The impact of having larger nuclear generation in the supply system is more pronounced during a dry year. In this case nuclear generation displaces oil generation and transfers that are a larger proportion of total generation.

Average prices always decline with increasing demand as fixed capital charges are distributed over larger electricity sales. However, the decrease in price is again less than one percent in each case.

We should emphasize that these average revenue figures are better estimates of differences among scenarios than of absolute levels of revenue. There is always considerable uncertainty to the actual rate of return on rate base that utilities will realize, as distinguished from the authorized rate of return. Inflation forecasts are also, of course, uncertain. On the other hand, under present accounting practices authorized by the California Public Utilities Commission, all changes in fuel expenses are reflected in customer bills as a result of the fuel adjustment clause. Although PUC reviews these adjustments the procedures are simpler than for other rate increases.

Table 26

Nuclear and Geothermal Generation Assumptions

Scenario		Annual Generation (GWh)[a]	Addition to 1976 Rate Base (million dollars)
Scenarios 1, 4, 7 in Tables 24 and 25			
Diablo Canyon			
Unit 1	Operational January	5762	623[b]
Unit 2	Operational October	1177	
Humboldt Bay	Operational January	496	
Geyser Geothermal		4522	40[b]
Unit 12	Operational July		
Unit 15	Operational September		
Scenarios 2, 5, 8 in Tables 24 and 25			
Diablo Canyon			
Unit 1	Operational August	2995	312[c]
Unit 2	Delayed Past 1978	0	
Humboldt Bay	Delayed Past 1978	0	
Geysers Geothermal		4277	40
Unit 12	Operational September		
Unit 15	Operational December		
Scenarios 3, 6, 9 in Tables 24 and 25			
Diablo Canyon	Delayed Past 1978	0	
Humboldt Bay	Delayed Past 1978	0	
Geysers Geothermal		4277	40
Unit 12	Operational September		
Unit 15	Operational December		

[a] Nuclear generation from Rancho Seco available to PG&E would amount to 2361 GWh during a dry year,[36] and 4061 GWh during a wet year since increased hydroelectric generation by SMUD would make more nuclear energy available to PG&E.

[b] Estimated completed cost of Diablo Canyon Unit 1 and Geysers Units 12 and 15, 1976 PG&E Annual Report.[33]

[c] Discussions with CPUC reveal no clear indication as to the percentage of Diablo Canyon capital cost which would be considered for inclusion in the rate base. We have assumed that only half the costs would be considered if the plant became operational in August.

SECTION 5

REMEDIAL MEASURES FOR DEMAND

In view of the supply alternatives that are available to meet loads during a continued drought, it does not appear that measures to restrain demand are essential to avert an emergency. However, there are several reasons why any plan for dealing with electricity needs during the drought should contain measures aimed at reducing demand. First, a growth in demand significantly beyond the 4.7 percent projected by PG&E could seriously strain the supply system. Second, the available supply alternatives are more costly, hence measures which can avert the need for some of the alternatives will reduce the financial burden that must be borne by the California economy. Third, demand reduction can provide insurance against unforeseen system failures or conditions such as extremely hot weather during the summer which might otherwise create excessive peak demand. Finally, measures for moderating demand growth should be pursued because of long-term benefits. The heightened conservation consciousness of consumers during the drought should increase the receptivity to energy conservation initiatives and thus provide an opportunity to make progress toward long-term objectives.

We have examined three strategies for reducing demand:

- conservation,
- load management, and
- load shedding.

The conservation strategy aims at reducing electricity consumption. The load management strategies shift electricity consumption from periods when demand for electricity is high (hot summer afternoons) to periods of lower demand (nights and weekends). The load shedding strategies reduce electrical loads during extreme peaks in demand or at times when equipment failures create a sudden shortage of generating capacity.

These three strategies already play a role in the operation of the electricity supply system in California. They have importance both for the short term in dealing with the present adverse weather conditions and for the long term in improving the efficiency of the system. We discuss each of these strategies in turn, first describing existing continuing

programs and emergency programs adopted during the past year, then examining additional measures that might be adopted if adverse weather conditions continue.

CONSERVATION

Energy conservation measures can be divided into two types: improved efficiency of use and curtailment of use. Improved efficiency measures aim to "do the same job" with less energy. Examples include improved performance for refrigerators and air conditioners, increased insulation, co-generation, etc. Curtailment measures are usually first aimed at superfluous uses such as outdoor lighting during daylight hours, and lighting and space conditioning in unoccupied spaces. The next targets for curtailment are usually lighting for competitive purposes and measures which require minor adjustments in living habits. Examples of the former are display lighting and outdoor advertising, the latter include changes in thermostat settings and reduced lighting levels.

Continuing Programs

Existing electricity conservation programs in California are aimed primarily at improved efficiency, but there are also some efforts to achieve curtailments. Two state agencies, the CPUC and the CERCDC, and the utility companies are the institutions with primary responsibility for carrying out these programs.

Performance standards are probably the most significant element in the CERCDC conservation program. These standards, which the CERCDC is mandated to establish [PRC 254021(G)-(C)],are of two types: appliance standards and building codes. Appliance standards establishing the maximum permissible energy consumption for new refrigerators, freezers, and air conditioners became effective on Nov. 1, 1977. Initially, these standards will only remove a few of the most inefficient appliances from the market, but the second phase of standards, which come into force two years after the initial standards, will have a more significant impact. The CERCDC estimates that annual electricity savings from the new standards will be about 1.9 billion kWh by 1985.[38] Appliances for which the Commission is now developing standards include water heaters and space heaters.

Building codes mandating reduced energy consumption have been in effect for residential construction for about three years and will come into force for commercial structures on Jan. 1, 1978. Stronger provisions governing residential buildings have been developed and will be in effect on March 11, 1978. The commercial standards will have a large impacts on electricity consumption in new construction because they will reduce energy requirements for lighting and for air conditioning. The existing residential standards have resulted in improved thermal integrity of new construction largely by requiring increased insulation and by limiting window area. The new standards will result in further improvements in thermal integrity and will place stringent restrictions on the use of electric resistance heating.

In addition to mandatory standards, the CERCDC is sponsoring a number of programs which are expected to achieve their ends primarily through education. Included among these are building energy audit programs, a program to aid commercial building operators in reducing lighting, and consumer education programs.

The most significant conservation step by the CPUC was undoubtedly its decision (Decision No. 84902) that the rate of return on investment allowed to regulated utilities would be in part determined by their effectiveness in promoting energy conservation. As a consequence, all of the regulated electric and gas utilities have established energy conservation programs; these are discussed further below.

The CPUC also has regulations which curtail certain uses of electricity. CPUC Rule 14.1 includes provisions which

- prohibit the lighting of billboards,
- prohibit outdoor lighting during daylight hours,
- require thermostat settings of 65°F for heating and 78°F for cooling
- require a 15 percent reduction in lighting for recreational or cultural activities, and
- prohibit interior lighting in commercial buildings during non-business hours.

However, the first of these measures has been suspended and efforts to enforce the remaining measures have been relaxed since the rule was established in 1974.[39]

The PG&E program is typical of the conservation efforts of the regulated utilities. The program, which had a 1976 budget of about $9 million

includes efforts to stimulate insulation, commercial and industrial energy audits, and solar energy demonstrations. The emphasis of these programs is on public and consumer information. In a recent attempt to evaluate the effectiveness of these programs, PG&E estimated that its efforts had saved a total of 218,000 kWh in 1976. The largest share of this saving, 103,000 kWh, was attributed to the commercial-industrial audit program.[40]

In addition to its efforts to encourage conservation actions by its customers, PG&E has reduced the voltage supplied to residential circuits. This measure was accomplished by reducing the upper limit of the "normal range" for service voltage from 126 volts to 122 volts. (The lower limit, 114 volts, was not changed.) The effect is to reduce the amount of energy supplied to electricity-using devices. In some cases, e.g., lights, this results in lower energy consumption; in other cases, e.g., electric heat, equipment just operates for a longer period with no change in total energy consumption. An added consumer benefit of voltage reduction is increased service life for some equipment, particularly incandescent light bulbs.

The voltage reduction program was undertaken at the urging of the CPUC which had proposed the measure as early as 1962. Based on test results in PG&E's service area, C.T. Coffey of the CPUC has estimated that the effect of the voltage reduction was a three percent savings in energy for those customers affected.[41] This will mean a total annual savings of more than 750 GWh.* Coffey believes that technology is available to selectively reduce the voltage even further without causing any customers to receive service at voltages below the lower limit of the normal range.

In addition to the programs of the state energy agencies and the utilities, a number of other agencies are attempting to encourage conservation. The federal role has been limited for the most part to funding support for some of the programs described above. There are also some direct federal efforts such as the weatherization program conducted by the Economic Opportunity Commission in Fresno. Some other state agencies have established conservation offices (Caltrans, for example) and a number of local programs are underway.

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*Coffey estimates that 1977 savings by voltage reduction were 620 million kWh. Since the program was implemented after February 1977, annual savings should be significantly greater than this.

1977 Adverse Weather-year Programs

Neither the CERCDC nor the CPUC has initiated any conservation programs in 1977 designed to deal with electricity shortages caused by the drought. However, staff from these agencies did conduct studies of possible measures; efforts were also made to monitor the situation so that vigorous public appeals for conservation could be made if a shortage appeared to be imminent. PG&E mounted an advertising campaign in its service area to alert its customers to the fact that electricity supplies were tight and that shortages might develop.

Although formal programs for dealing specifically with drought-induced energy supply problems have been limited, the very vigorous water conservation programs may have served to build a "conservation consciousness" among the public which affected demand for electricity. This could, in part, account for the very slow growth in electricity sales during 1977 although other factors including higher prices and temperate weather may also have contributed.

Possible Additional Emergency Measures

In developing long-term strategies for energy conservation, those programs which improve the efficiency of energy use are usually favored since they do not require changes in living habits. However, efficiency programs usually require changes in energy-using equipment. This means either that new equipment must be produced or that technically-trained persons must refit old equipment. The time involved in carrying out these processes is such that new programs for improving efficiency rarely have much impact in the short term. Thus, if adverse weather conditions necessitate a significant reduction in the demand for electricity, a heavy reliance will have to be placed on curtailment measures.

While efficiency measures can have only a limited impact in the short run, other policy considerations dictate that these measures should not be neglected in the current situation. The drought has focussed attention on immediate supply constraints, but the long-term need for energy conservation is, of course, still with us. Programs which combine some measure of efficiency with curtailment will have long-term benefits as well as short-term impact.

In the present situation, with both supply and demand uncertain, it is prudent to consider a range of conservation programs. The most modest of these might be a voluntary program emphasizing efficiency and curtailment of superfluous uses; the most drastic, a mandatory program requiring some curtailment by all users.

Voluntary programs are, as noted above, already in effect. However, several factors suggest that efforts in this direction could be increased substantially in the near term, especially in the area of public information. First, the existing programs are rather modest. Advertising has been limited mostly to radio spots and there has been almost no media coverage of drought-related electricity supply problems. Many people are unaware that any problems exist. Second, the heightened "conservation consciousness" induced by the drought is likely to make people more responsive to appeals for electricity conservation. Third, emphasis on improved efficiency as been surprisingly absent in much of the advertising. Except for the insulation campaigns, most appeals have been for curtailment of superfluous uses.

Thus, a logical first step toward increased conservation in the short-term would be a greatly expanded public information program. To maximize long term as well as short term impacts, the program should include increased emphasis on efficient use of energy. For example, the energy use labels now appearing on many new refrigerators and air conditioners should be explained, and consumers should be told of the life-cycle cost savings that can be realized by purchasing energy-efficient appliances. Increased public information efforts by federal and state agencies would be especially valuable since many people are distrustful of utility-sponsored advertising.

A second step, which would be warranted if the situation grew more serious, is enforcement of CPUC Rule 14.1, especially where it affects conspicuous consumption. Curtailment of outdoor lighting and lighting in unoccupied spaces (e.g., office buildings at night) would save only a relatively small amount of energy (less than one percent),[39] but this action would have a public impact similar to that achieved by turning off water fountains and other decorative uses of water. Many people would be encouraged to curtail non-essential uses in their homes and places of work. It should be noted that complete enforcement of Rule 14.1 would be very difficult if not impossible. This is especially true in the case of thermostat settings (68°F for heating and 78°F for cooling) in the residential sector.

However, as shown by the results of water conservation programs, when the public perceives a need for conservation, voluntary compliance can be substantial.

A more drastic step is a conservation program which mandates electricity use reductions by all customers. While such a program is not likely to be required in the present situation, it is prudent to develop a plan for implementing such reductions so that unforeseen events will not find the state unprepared. The CPUC, in the context of its Case No. 9884, is attempting to deal with the issues raised by mandatory plans. However, the major regulated utilities all contend that such programs would be unworkable.

Recent California experience demonstrates that mandatory programs can be very effective. (But they are not necessarily "workable" administratively, as we discuss below.) In 1973 the Los Angeles Department of Water and Power (LADWP) was purchasing fuel oil from Arab suppliers. When the Arab oil embargo was imposed, LADWP's supplies were disrupted and the city of Los Angeles was faced with the potential of severe electricity shortages. To meet this crisis the City Council adopted an ordinance in December 1973 which mandated electricity use reductions. The ordinance required cutbacks relative to the previous year's usage of 10 percent, 20 percent, and 10 per cent for residential, commercial, and industrial users respectively. The ordinance was expected to achieve an overall savings of 12 percent and this target was exceeded during the entire period that the ordinance was in effect. Adverse economic impacts resulting from the ordinance appear to have been minor or non-existent.[42]

The ordinance contained stiff penalties for noncompliance: a 50 percent surcharge on the entire bill and, if the surcharge failed to induce compliance, service disconnection. However, for a variety of reasons, these penalties were never invoked. First, the crisis was short-lived—a wet year in the Pacific Northwest made it possible to import substantial hydroelectric power, and the fuel market eased. Thus, the City Council was able to suspend the penalty provisions of the ordinance on January 24, 1974 and suspend the entire ordinance on May 22, 1974. Second, there were major administrative problems. The ordinance had established an appeal procedure for customers who felt that the amount of electricity allotted to them should be adjusted and LADWP was inundated with appeals. Little headway was made in processing these appeals before the penalty provisions were suspended.

Some observers felt that proper processing of appeals was completely beyond the resources of LADWP and thus, that enforcement of the ordinance would have been impossible.

One view of the Los Angeles experience is that compliance was essentially voluntary and was motivated by the public perception that conservation was necessary. Another view is that the threat of enforcement was sufficient to insure compliance by all of those who could do so without great difficulty. Whatever the case, it is clear that the practice of adopting a mandatory program and then not enforcing its sanctions cannot be repeated very often without engendering serious credibility problems for public authorities. Thus, the CPUC faces a very considerable difficulty in developing contingency plans, especially in view of the negative attitude of the regulated utilities.

It must be emphasized that, while the conservation measures discussed above can have a short-term impact, it will take some time and effort to put them in place. If these measures are to be available for dealing with adverse weather conditions, some of this effort must be expended before it is certain that any measures are in fact necessary. Still, in view of the potential cost of power outages, it would be irresponsible to take no action. At the very least, a program should be undertaken to inform the public of potential shortages and of the conservation measures that could avert these shortages.

LOAD MANAGEMENT

As the earlier sections of this report show, electricity shortages caused by a continuation of the drought are most likely to be manifested as shortages of generating capacity during periods of high electricity demand. In California these high demand periods occur during very hot weekday afternoons. Conservation measures can reduce demand during these periods, but their impact is more "across the board" as opposed to "on-peak." Load management is a strategy aimed specifically at reducing peak demand. This strategy attempts to shift the time of electricity consumption from peak to off-peak periods.

There are two basic methods of load management: operational shifts and energy storage. Operational shifts involve changing the time during which energy consuming operations are conducted. Examples include rescheduling of operations in industrial plants (running electric furnaces, large compressors, etc. during off-peak hours), and night irrigation of croplands (water pumping for this purpose now consumes substantial amounts of on-peak energy). Energy storage involves the use of systems which draw electricity during off-peak hours but perform their functions at other times. Some technologies such as pumped storage regenerate electricity. However, most of these methods have substantial economies of scale and thus, with the exception of electric car batteries, are more appropriate for utilities than for utility customers. Most customer-owned energy storage systems involve thermal storage for space conditioning and water heating. Storage space heaters and water heaters are widely used in western Europe but are not common in the United States. Storage air conditioners, which make ice or chill a tank of water during off-peak hours and draw on this cold storage during peak hours would be the most useful storage technology for summer peaking utilities such as California's. However, this technology is not well established and only a few systems, in demonstration projects, are operating at this time.

Continuing Programs

Existing efforts to improve electrical load management in California are based primarily on an indirect method, time-of-use (TOU) pricing. TOU pricing sets higher charges for the use of electricity during peak demand periods than for use during off-peak periods. It is assumed that customers who can shift their operations or develop storage systems will do so if the benefits of lower off-peak electricity costs exceed the cost of making changes. In western Europe, where this strategy is widely used, experience has shown that TOU pricing can be effective.[43]

The CPUC has primary responsiblity for implementing TOU pricing in California. Based on the proceedings of its Case 9804, the CPUC has ordered the regulated utilities to establish TOU rate schedules for all customers who have peak demands in excess of 500 kW (Decision No. 85559).

At this time only one of the mandated TOU schedules, PG&E's A-17 has been in force for more than a few months.* A-17 is for customers with peak demands of 4000 kW or more and it affects about 7-8 percent of PG&E's total peak demand. The rates on the schedule reflect changes in demand which occur on a seasonal, weekly, and daily basis. Details of the schedule are given in Table 27.

Under the shedule shown in Table 27, a customer operating electricity-using equipment continuously during a summer month** would pay $29.40 per kW-month, corresponding to an average price of 4.1 cents kWh. (Note that about three-fourths of this cost is accounted for by the energy cost adjustment.) With continuous operation the price per kWh would be about 6.6 cents on peak, 3.8 cents on partial peak, and 3.4 cents off-peak. If this same customer shifted all of his on-peak operations to off-peak, he would then pay about $25.00 per kW-month for a saving of about 13 percent on his monthly bills. Customers whose operations were initially predominantly on-peak could, of course, achieve relatively larger savings by shifting to off-peak operation.

Estimates of the impact of A-17 on peak demand are just becoming available. PG&E has released an analysis which indicates that between February, when the schedule became effective, and July, A-17 customers had shifted their use patterns so that peak demands were about three percent (∿30 MW) lower than would have been expected without the new rate schedule.[44] It is difficult to make such estimates because many factors other than TOU prices influence demand. Among the factor that must be considered are the very steep increase in the average cost of electricity during 1977 and changes in the general level of economic activity. However, the fact that a few of its customers have reduced their on-peak demands very dramatically has persuaded PG&E that at least some of the observed shift is due to the new rates. Even if the other factors could be separated out, the full impact of A-17 would not be known for some time. First, it can be expected that

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*SDG&E's schedule No. A-6 for customers with demands in excess of 4000 kWh became effective on Sept. 17, 1977; SCE's schedule No.TOU-8 for customers with demands in excess of 5000 kW became effective on Oct. 14, 1977. LADWP although not under CPUC jurisdiction, will begin implementing TOU rate schedules on Dec. 25, 1977.

**Assumed to be 30 days with 21 weeksdays, 5 Saturdays, and no holidays.

Table 27

PG&E's Schedule No. A-17

Rates	Per Meter Per Month	
	Period A	Period B
Customer charge:	$715.00	$715.00
Demand charge (per kW of maximum demand)		
On peak:	$ 3.45	$ 2.30
Partial peak:	0.28	0.28
Off peak:	-0-	-0-
Energy charge (per kWh)		
On peak:	$0.00807	$0.00807
Partial peak:	0.00607	0.00607
Off peak:	0.00407	0.00407
Energy cost adjustment (per kWh):	$0.03064	$0.03064
Fuel collection balance adjustment (per kWh):	- 0.00047	- 0.00047

Time Periods

Period A (May 1 - September 30)

On peak	12:30p - 6:30p Mon-Fri*
Partial peak	8:30a - 12:30p Mon-Fri*
	6:30p - 10:30p Mon-Fri*
	8:30a - 10:30p Saturday*
Off peak	10:30p - 8:30a Mon-Sat*
	All day Sunday + Holidays

Period B (October 1 - April 30)

On peak	4:30p - 8:30p Mon-Fri*
Partial peak	8:30a - 4:30p Mon-Fri*
	4:30p - 10:30p Mon-Fri*
	8:30a - 10:30p Saturday*
Off peak	10:30p - 8:30a Mon-Sat*
	All day Sunday + Holidays

*Except holidays

customers will take some time to learn the most efficient operating practices under the new rates and second, the new rates may have made it economic to make capital improvements to facilitate off-peak operation—such improvements frequently take several years to implement. On the basis of trends observed through July 1977, PG&E estimates that peak demands for A-17 customers may be more than seven percent lower by the end of 1978 than would have been expected in the absence of A-17.

The CERCDC is also making efforts to promote load management. These efforts are centered on two programs: load management standards for utilities and the "Electric Utilities Demonstration Project." The Public Resources Code (PRC 25403.5) requires the CERCDC to "...adopt standards by regulation for a program of electrical load management for each utility service area." In establishing these standards the Commission is to consider at least the following measures:

1) adjustments in rate structure
2) end-use storage systems, and
3) mechanical and automatic devices for load control.

The Commission is to enforce its standards by refusing to certify new power plant sites for any utility that is not in compliance.

Although the load management standards are still being developed, the Commission staff has already indicated that it will recommend implementation of TOU pricing for the large customers of the non-regulated utilities (municipal utilities, irrigation districts, etc.). Since the regulated utilities are already adopting TOU rate schedules under CPUC order, almost all large electricity users in the state will have to pay TOU prices—the one major exception being customers of the U.S. Bureau of Reclamation.

The CERCDC staff is also considering additional load management standards, but has indicated that it believes further studies are needed before the standards are promulgated. Much of the necessary work is now being conducted in the Electric Utilities Demonstration Project. This project, coordinated by the Commission and funded in part by the Department of Energy, is exploring a variety of load management methods. Several of the demonstrations are related to the implementation of TOU pricing for small customers. For example, existing electricity meters for these customers only record total use and cannot supply information about the time of use. Experiments are being conducted with different types of metering systems in

in the hope of finding one that can provide the necessary information reliably and at a reasonable cost. Air-conditioner cyclers and other devices which can periodically interrupt the operation of electricity-using equipment are also being studied. We will examine these further when we discuss load shedding.

The utility companies, in addition to implementing the TOU pricing orders of the CPUC, are participating in the Demonstration Project. In part, this participation is motivated by CPUC Decision 85559 which ordered investigations of load management methods. Utility studies are not limited to participation in the demonstration project—they are conducting a number of experiments on their own. For the most part, these experiments are similar to those in the Demonstration Project.

1977 Adverse Weather-year Programs

The only load management effort directly related to the drought has been the inclusion of messages encouraging load management in utilities advertising campaign. This campaign, in addition to promoting conservation, has urged consumers to defer such activities as clothes and dish washing to off-peak hours. As discussed earlier, these advertising efforts have been fairly modest.

While not directly drought related, an advertising campaign which emphasizes load management has also been developed by the CERCDC in 1977. This campaign uses a cartoon alligator called "Later Gator" who urges consumers to defer the use of electricity to off-peak hours. However, this campaign has as yet received very little exposure.

Possible Additional Emergency Measures

Many load management measures, such as energy storage and operational shifts that require equipment modifications, have long lead times. Measures of this type cannot have much impact in the short term. If a continuation of the drought necessitates emergency load management efforts, then we will have to rely on measures that shift electricity use patterns without requiring new equipment. Such measures can be encouraged both by incentive and by public information campaigns.

At this time, load management differs from electricity conservation in that, while the latter results in direct financial rewards, most customers have no direct incentives to undertake the former. This may make it difficult to promote load management with advertising campaigns. Thus, a priority concern in dealing with the current situation is the improvement of the incentive structure.

Since new metering systems would be required, it is not possible in the short term to extend load management incentives to residential and small commercial customers. However, it may be possible to accelerate the implementation of TOU rates for customers with maximum demands in excess of 500 kW. If the schedules now in effect are followed TOU rates for these customers will not be fully implemented before the summer of 1978 (CPUC Decision No. 86543). Again there is a problem with metering since, although the technology of TOU recording meters for large users is well established, not all of the customers have the right type of meter. The current plan is to install proper meters at all customers' services and then implement the rates. Given the present circumstances, it might be better to establish the rates and implement them customer-by-customer as the meters are installed. PG&E estimates that customers with loads between 500 and 4000 kW are about 14 percent of its peak load.[45] If these customers respond in the same way as the larger customers, then implementation of TOU prices by February 1978 would reduce peak demand about 60 MW by the summer of 1978.

A second measure, which could be implemented for customers already on TOU rate schedules, is the inclusion of TOU incentives in the energy cost adjustment. This adjustment is now based on the average cost of fuel and purchased energy and constitutes the biggest fraction of the electricity bill for large customers. An advantage of including TOU incentives in the energy cost adjustment is that it encourages load shifting by customers who cannot reduce their monthly maximum demand. That is, some customers may conduct operations which require the maximum demand on only a few days each month. Since the present rate structure places almost all of the penalty for peak use in the demand charge, these customers will have little reason to shift any of their routine daily operation to off-peak if this has no impact on their maximum demand.

Load shifting at times other than the day of the customer's maximum demand has two benefits: first, the customer's maximum demand may not be

coincident with the system's maximum demand and second, load shifting can produce significant energy savings. This latter benefit has not always been recognized because it is not evident from the time of use variation in average fuel cost. Because hydroelectric power is used for peaking, the average fuel cost on peak may actually be lower than for off-peak. But this is beside the point if reducing peak demands will result in a lower total cost for energy during the entire operating period. This would appear to be the case in California. For example, a significant amount of peak energy is supplied by banked energy in the Pacific Northwest. Energy generated in California off-peak is sent north permitting BPA to reduce generation at its dams. The energy is then returned on peak. If, instead of banking, the off-peak energy were used directly in-state, there would be two savings: there would be no north-south losses in transmission (about a 15 percent effect)[46] and capacity payments would be avoided.

While the absence of direct financial incentives may make it difficult to promote load management with advertising campaigns, it may be possible to persuade consumers that the less tangible benefit of a lower risk of outages makes the effort worthwhile. This should be easiest to do for load management measures which do not require either much inconvencience or persistent effort. An example of such a measure is shifting the operation of swimming pool filter pumps. These pumps are activated by timers and usually operate for between 4 and 8 hours; many of them now operate during peak hours. The CERCDC estimates that if filter pump and other pool system operations were shifted to off-peak hours in the PG&E service area, more than 100 MW could be realized.[47] A campaign to reset filter pump timers could be especially effective if it were done in cooperation with swimming pool maintenance contractors.

LOAD SHEDDING

As we use the term here, load shedding means to discontinue the operation of electricity-using equipment on short notice (0-24 hours) and may be done either by the customer or by the utility. (Others have used the term to mean utility controlled service interruption made without notice.) In principle, some load shedding can occur even when there is not an unplanned capacity shortage such as might occur in 1978. Some customers have equipment that can be interrupted occasionally without great loss. If the loss caused by interruptions is less than the cost of building sufficient generating capacity to guarantee reliable supply during peak demand periods, then these customers will prefer to be interrupted on occasion if they receive a rate reduction commensurate with the capacity savings that this makes possible.

If the drought continues and neither the supply alternatives described elsewhere in this report nor energy conservation and load management measures are sufficient to maintain the supply-demand balance, then load shedding will be necessary to maintain the stability of the supply system. The first to be affected by load shedding would be those customers who were contractually obligated to reduce their loads when requested to do so. Then efforts would probably be made to achieve voluntary load reductions based on appeals to the public. If this were not sufficient, rotating outages would have to be initiated. One objective in planning for a possible continuation of the drought is to increase the probable response in the first two steps above so that losses associated with indiscriminant outages can be avoided.

Continuing Programs

On a continuing basis there are two load shedding issues: the development of appropriate rate schedules for interruptible service to large users and the development of load controllers (e.g., air-conditioner cyclers). Only PG&E serves customers on an interruptible schedule at this time. Rates for this schedule, No. A-18, are shown in Table 28. (SCE has offered an interruptible rate schedule for about two years but has no interruptible customers.) A-18 is limited to very large customers (more than 5000 kW of

Table 28

PG&E's Schedule No. A-18

Rates	
Demand charge	
Minimum charge (per year):	$60,000
On-peak (per kW of maximum demand per month)	1.31
Off-peak (per kW of demand in excess of maximum on-peak demand per month):	0.33
Energy charge (per kWh):	$0.00528
Energy cost adjustment (per kWh):	$0.03064
Fuel collection balance adjustment (per kWh):	-$0.00047
Time Periods	
On peak 6:30a - 10:30p	Mon-Sat*
Off peak 10:30a - 6:30a	Mon-Sat*
All day Sunday + Holidays	

*Except holidays

of maximum demand) who are supplied at 60,000 volts or higher. New A-18 customers must be willing to enter into an initial 10-year contract and pay for any necessary extension of transmission facilities. A-18 customers can be curtailed "when in the utilities sole judgment its reserve, energy resources or transmission margin or any combination of these is needed to meet the dmeands of its regular customers on firm rates..." In addition, A-18 customers are subject to automatic interruption by underfrequency relay whenever the frequency on the utility's system drops below 59.75 hertz (plant protection load is exempt from automatic interruption).

Under the schedule shown in Table 28, a customer operating electricity-using equipment continusouly would pay about $26.80 per kW-month corresponding to an average price of 3.7 cents per kWh. This is about 10 percent less than firm A-17 summer rates and five percent less than firm A-17 winter rates. However, if the A-18 customer manages his load so that none of it occurs during the on-peak hours defined in schedule A-17, he realizes no reduction in rates—and would actually be paying about $1.30 per kW-month more than an A-17 customer operating on this load management schedule.

PG&E now has six customers on this schedule with a total maximum demand of about 130 MW. However, all of this demand is not likely to be coincident with system peaks since the largest of these customers generates its own power and uses A-18 power as standby only. In the event of a need to interrupt power because of a capacity shortage during a peak period, PG&E estimates that the interruptible power under A-18 will be closer to 90 MW.

In addition to customers covered by A-18, PG&E has contractual agreements with some research facilities (Stanford Linear Accelerator Center, Ames Laboratory and LBL) which require these customers to interrupt part of their loads as soon as possible after receiving telephone notice. For the most part, the interruptible portion of the load at these facilities is associated with occasional large experiments and, while the potential interruptible load exceeds 70 MW, PG&E believes that these loads are unlikely to be coincident with the system peak.[48]

Since the benefits to the utility of interruptible power are quite substantial and the inconveniences to the customer can be considerable, the cost reductions for A-18 customers appear to be rather small. This is parti-

cularly true for customers who are able to manage their loads to reduce peak demands. This may account for the fact that two of the six A-18 customers have given notice that they wish to change to A-17.

Both the CPUC and the CERCDC seem disposed to encourage the use of interruptible service. However, there is not at present much activity being devoted to the development of more attractive or flexible rate schedules. In the future it is likely that proposals will be considered to make interruptible service available to smaller customers and to establish a separate rate for customers who are willing to accept curtailments but do no wish to have underfrequency relays. (The former reduces the requirement for generating capacity at peak times, the latter reduces the requirement for spinning reserves at all times.)

The second continuing load management strategy involves the use of load controllers which interrupt the operation of energy-using equipment. In California, the type of load control equipment most likely to be used is the air-conditioner cycler for residential customers. These devices periodically interrupt the operation of an air conditioner causing it to cycle during peak periods rather than run continuously. They can be activated by a radio signal, a signal imposed on the power line (ripple control), or a temperature sensor. The basic effect of this equipment is to raise the temperature of the space being cooled, i.e., the strategy is equivalent to utility control of customer thermostats on peak days.

One risk in the use of cyclers is that customers can defeat their purpose by buying larger air conditioners which are sufficient to cool the space during the "on" part of the cycle. For this reason cycler programs will probably have to be voluntary and the incentive will have to be less than the cost of a larger air conditioner (i.e., it cannot be cheaper for customers to buy oversized air conditioners with cyclers than to buy properly sized equipment without cyclers).

Several of the experiments now being conducted in the Electric Utilities Demonstration Project involve the use of cyclers. Results as yet are inconclusive, but apparently customer acceptance and equipment performance have been satisfactory to date—so much so that the CERCDC staff has indicated that it is strongly considering the implementation of standards requiring air conditioner cycling programs.

1977 Adverse Weather-year Programs

In response to the adverse weather conditions PG&E has contacted their large customers and asked them to agree to voluntarily shed load during emergencies. PG&E reports that it has found about 500 MW of load that customers will shed on request. PG&E does not count this in its loads and resources planning since it is strictly voluntary.

In addition to its voluntary program, PG&E has developed plans to institute rotating outages (RO's) if all other measures fail. The service area has been divided into 20 blocks each of which has about five percent of the system load. In the event of an unavoidable capacity shortage these blocks will be shed in rotation. At present these blocks do not discriminate between customers. The CPUC has asked PG&E and the other utilities to develop RO plans that will permit certain essential customers to continue to be served. SCE has stated that for the most part it will be able to do this, but PG&E reports that the way its circuits are arranged will make it impossible to develop RO plans which discriminate by customer.

Possible Additional Emergency Measures

The fact that PG&E is able to get a significant amount of load shedding on a purely voluntary basis suggests that a program which offered some incentives might increase the amount of interruptible load for the short term. Probably there are not many customers who would be interested in A-18 even if the limit were lowered below 5000 MW since there is such a long period of contractual obligation and since they would be subject to interruption without notice.

If a rate could be devised which offered a short-term contract (i.e., for the duration of the drought) and provided notice to the customers, this might be more acceptable. For example, demand metered customers could receive a discount on the demand charge (say $1.00 kW per month) for each kW that they agreed to shed. Since it is usually possible to forecast the development of extreme peak demands well in advance, a notice of 30 minutes could be given. Shedding would be under the control of the customer, but if he failed to shed he would have to pay some fairly still penalty (say $10.00 per kW).

The advantage of such a rate would be twofold. First, it would reward those customers who are now making a voluntary contribution to improve the system's reliability. Second, it would attract customers who were less public spirited to make a similar contribution.

A second measure that might be considered is a program to improve the reliability of standby electricity sources. Some customers who would suffer serious losses in the event of a power outage have standby generators. However, the reliability of these sources is often questionable; first because maintenance is frequently sporadic, and second because most of them have very limited fuel supplies.

These standby systems might be improved if the utilities offered a high reliability service to customers needing it. This service could include a routine standby equipment maintenance and testing program and an emergency fuel supply program. Because the utility maintenance crews would provide service to many customers, they would be able to devote full time to these operations. This would probably result in much better maintenance service than that which could be provided by a plant engineer who only devotes a small portion of his time to standby equipment. Pooling the emergency supply needs of all customers with standby could make it possible to develop special contracts with fuel suppliers whereby the suppliers would suspend normal deliveries during emergencies in order to service the standby systems.

In principle, the standby generators could be turned on <u>before</u> an RO was necessary—the reduction in load might avert outages and the utility's regular supply could back up the standby generators.

APPENDIX A

CAPACITY AND ENERGY SUMMARY

Tables A-1 and A-2 summarize the energy and capacity resources, respectively, available for 1978 for the three southern California utilities. As noted in Section 3 of the report, several changes have been made in the submittals by the utilities to CERCDC (Reference 6), and these are reflected in these tables.

Table A-1

Energy Generating Capability of Major Southern California Electric Utility Companies[a]
(in GWh)

	1978 Adverse Conditions												
	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Annual Total
Resources													
Hydro													
SCE	200	207	246	276	286	432	418	370	307	262	249	274	3527
LADWP	58	44	74	130	138	78	51	51	39	44	59	64	830
SDG&E	1	1	0	1	1	1	1	1	0	0	0	0	7
TOTAL	259	252	320	407	425	511	470	422	346	306	308	338	4364
Northwest Firm													
SCE	0	0	0	0	0	0	0	0	0	0	0	0	0
LADWP	0	0	0	0	0	0	0	0	0	0	0	0	0
SDG&E	29	27	30	29	30	29	29	29	29	29	29	30	349
TOTAL	29	27	30	29	30	29	29	29	29	29	29	30	349
Coal													
SCE	874	791	741	731	674	847	874	874	773	461	647	814	9101
LADWP	492	370	397	397	492	476	492	492	476	410	305	397	5196
SDG&E	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	1366	1161	1138	1128	1166	1323	1366	1366	1249	871	952	1211	14297
Nuclear													
SCE	223	201	223	216	223	216	223	223	216	0	92	223	22729
LADWP	0	0	0	0	0	0	0	0	0	0	0	0	0
SDG&E	56	50	56	54	56	54	56	56	54	0	24	56	5702
TOTAL	279	251	279	270	279	270	279	279	270	0	116	279	2851
Other Receipts													
SCE	358	307	353	343	345	272	293	272	239	337	329	361	3809
LADWP	0	0	0	0	0	0	15	15	15	0	0	0	45
SDG&E	12	10	12	10	18	12	10	9	9	15	32	27	176
TOTAL	370	317	365	353	363	299	318	296	248	352	361	388	4030
Gas & Oil Generation													
SCE	4486	4020	4454	4638	4522	4682	5245	5345	4944	5130	4746	4809	57021
LADWP	1749	1470	1686	1637	1745	1904	1983	2188	2118	1994	1759	1891	22124
SDG&E	956	846	939	865	867	889	996	1017	914	1027	984	1065	11365
TOTAL	7191	6336	7079	7140	7134	7475	8224	8550	7976	8151	7489	7765	90510
Total Capability													
SCE	6141	5526	6017	6204	6050	6449	7053	7084	6479	6190	6063	6481	75737
LADWP	2299	1884	2157	2164	2375	2473	2541	2746	2633	2448	2123	2352	28195
SDG&E	1054	934	1037	959	972	985	1092	1112	1006	1071	1069	1178	12469
TOTAL	9994	8344	9211	9327	9397	9907	10686	10942	10118	9709	9255	10011	116401
Energy for Load													
SCE	5445	4884	5377	5245	5455	5530	5992	6080	5635	5549	5294	5593	66079
LADWP	1739	1581	1715	1662	1741	1794	1967	1983	1829	1811	1704	1814	21340
SDG&E	940	843	903	817	838	843	925	997	882	912	935	976	10811
TOTAL	8124	7308	7995	7724	8034	8167	8884	9060	8346	8272	7933	8383	98230
Excess Capability													
SCE	696	642	640	959	595	919	1061	1004	844	641	769	888	9658
LADWP	560	303	442	502	634	679	524	763	804	637	419	538	6855
SDG&E	114	91	134	142	134	142	167	115	124	159	134	202	1658
TOTAL	1370	1036	1216	1603	1363	1740	1802	1882	1772	1437	1322	1628	18171

[a]Data from Ref. 6, except as noted.

[b]San Onofre refueling rescheduled from July and part of August to October and part of November.

Table A-2

Southern California Resources Available for Summer 1978[a]
(MWe)

Resource Type/Utility	June	July	August	September
Hydro + Pumped Storage				
SCE	1503	1463	1451	1435
LADWP[b]	1874	1874	1874	1874
SDG&E	5	5	5	5
TOTAL	3382	3342	3330	3314
Northwest Firm Capacity				
SCE	650	650	650	650
LADWP[c]	525	525	525	525
SDG&E	112	112	112	112
TOTAL	1287	1287	1287	1287
Coal				
SCE	1653	1653	1653	1653
LADWP	866	866	866	866
TOTAL	2519	2519	2519	2519
Nuclear				
SCE[d]	349	349	349	349
SDG&E[d]	88	88	88	88
TOTAL	437	437	437	437
Other				
SCE	307	307	307	307
LADWP[e]	-75	-75	-75	0
SDG&E[f]	- 9	- 9	- 9	- 9
TOTAL	223	223	223	298
Gas/Oil				
SCE	10049	10049	10283	10283
LADWP	2984	2984	3268	3268
SDG&E	1920	1914	1912	1878
TOTAL	14953	14947	15463	15429

Table A-2 (Continued)

	June	July	August	September
Scheduled Maintenance				
SCE[d]	892	0	0	1188
LADWP	344	0	0	183
SDG&E[d]	20	0	0	0
TOTAL	1256	0	0	1371
Total Capacity Available				
SCE	13619	14471	14693	13489
LADWP	5830	6174	6458	6350
SDG&E	2096	2110	2108	2074
TOTAL	21545	22755	23259	21913
Loads				
SCE	10202	11652	12012	11272
LADWP	3418	3967	4090	3874
SDG&E	1727	1823	1919	1881
TOTAL: So. California	15347	17442	18021	17027
Operating Reserve Requirements:[g]				
3% of load + largest risk				
SCE (7% of peak)	714	816	841	789
LADWP (largest risk)	560	560	560	560
SDG&E (7% of peak)	121	128	134	132
TOTAL:	1395	1504	1535	1481
Loads + Reserves				
SCE	10916	12468	12853	12061
LADWP	3978	4527	4650	4434
SDG&E	1848	1951	2053	2013
TOTAL	16742	18946	19556	18508
Capacity Margin				
SCE	2703	2003	1340	1428
LADWP	1852	1647	1808	1916
SDG&E	248	159	55	61
TOTAL	4803	3809	3703	3405

A-2 Footnotes

[a]Data from Reference 6, except as noted.

[b]LADWP apparently does not derate either its Owens Valley and Aqueduct hydro facilities (193 MWe) or its share of Hoover (511 MWe) due to drought conditions. This figure includes full use of these facilities in addition to Castaic pumped storage (1170 MWe).

[c]This is the full capacity allocation to LADWP in the 800 KV-DC intertie with the Pacific Northwest.

[d]The refueling for San Onofre (430 MWe) has been rescheduled from July and August until after September.

[e]Sales of peak capacity to Nevada Power Company.

[f]Sales of peak capacity to CDWR and California Power Pool.

[g]Criteria for operating (spinning) reserves differ among the utilities. SCE and SDG&E use 7% of the expected peak load, which is the California power pool requirement. LADWP uses the single largest contingency, which for its system is its share of the DC intertie, or 560 MWe. See Reference 37 for details.

APPENDIX B

FORCED OUTAGE RATES

In Table B-1, we list forced outage rates for individual generation units and major interconnecting transmission lines for California. Also tabulated are partial outage states forthese plants for which these are available. While several new plants are expected to be added to the resource base in California, we have treated Diablo Canyon as a separate question. Because this plant might be available as part of PG&E's resources for August 1978, the effects on system reliability depend upon the forced outage rate used. PG&E uses three sets of outage rates, depending upon the relative 'maturity' of the plant. For the initial operational period up to the first refueling, the full FOR is 14 percent, and the partial (20 percent derating) is 23.3 percent. Beyond the first refueling (14-18 months after start-up) the FOR values are 12 percent (full) and 17 percent (partial). At plant maturity, which is expected to be about four years after start-up, the FOR's are 10 percent (full) and 11 percent (partial).

The forced outage rate before the first refueling is more applicable toward the end of the time period. In order to estimate the forced outage rate for August (assuming on August 1 date for commercial operation) we use the functional form of the FOR suggested in Ref. 18:

$$FOR\ (t) = FOR_M + (FOR_0 - FOR_M)\ e^{-0.075t} \qquad (1)$$

where FOR (t) is the forced outage rate at time t (in months), FOR_M is the mature FOR, FOR_0 is the initial immature forced outage rate. One can see that at time t=0, FOR (t) = FOR_0 . In order to find FOR_0, one can rearrange the equation to give:

$$FOR_0 = FOR_M + (FOR\ (t) - FOR_M)\ e^{0.075t} \qquad (2)$$

PG&E's estimates for the forced outage rates fix FOR_M, and provide several values for FOR(t). These latter outage rates actually apply over a span of time, hence we pick several times, solve for FOR_0, and average the results. This procedure results in FOR_0 = 19 percent for the full forced outage rate,

and FOR_0 = 38 percent for the partial outage rate. These are consistent with the PG&E estimates for the immature outage rates, as can be seen in Figure B-1.

Table B-1

Forced Outage Rates for Individual Power Plant Units and Major Interconnecting transmission lines for California. Generating Capacities shown are for August 1978; changes for July 1978 are noted in the footnotes.

Utility	Facility	Number of Units	Unit Size (MWe)	Forced Outage Rates (in percent) Partial	Full
PG&E	Avon, Martinez, Oleum #2	3	46		1.5
	Oleum #1	1	41		1.5
	Humboldt Bay #1	1	52		1.5
	Humboldt Bay #2	1	53		1.5
	Potrero #1	1	56		1.5
	Potrero #2	1	58		1.5
	Kern #1	1	74		1.5
	Hydroelectric units—dispatched	78	50		.8
	in ∿50 MWe blocks	10	49		.8
	Hunters Point #2, #3	2	107		2.1
	Kern #2	1	106		2.1
	Contra Costa 1-3, Mos Ldg. 1	4	116		2.1
	Moss Landing 2	1	115		2.1
	Moss Landing 3	1	117		2.1
	Hunters Point 4, Morro Bay 1,2	3	163		3.3
	Pittsburg 1-3	3	153		3.3
	Pittsburg 4	1	148		3.3
	Contra Costa 4, Moss Ldg. 4	2	117		3.6
	Contra Costa 5	1	115		3.6
	Moss Landing 5	1	100		3.6
	Hunters Point 1, Potrero 4-6	4	49		6.0
	Mobile Emergency Units 1-3	3	15		6.0
	Geysers 5-10	6	53		6.0
	Geysers 11	1	106		6.0
	Geysers 1	1	11		4.0
	Geysers 2	1	13		4.0
	Geysers 3,4	2	27		8.0
	Potrero 3	1	207		4.1
	Contra Costa 6,7	2	340[b]	24.7	3.0
	Morro Bay 3,4	2	338[b]	24.7	3.0
	Pittsburg 5	1	315[b]	24.7	3.0
	Pittsburg 6	1	325[b]	24.7	3.0
	Moss Landing 6,7	2	739[c]	30.8	4.0
	Pittsburg 7	1	720[d]	21.5	7.0
	Rancho Seco	1	875[e]	17.2	13.0
	Oakland 1-3	3	54[f]		6.0
	Diablo Canyon 1	1	1060	—See text—	
SCE	Ormond Beach 1,2	2	750		4.0
	Redondo 7,8	2	480		6.7
	Alamitos 5,6	2	480		6.7
	Four Corners 4,5	2	384		9.2
	El Segundo 3,4	2	335		3.3
	Alamitos 3,4	2	320		3.3
	Etiwanda 3,4	2	320		3.3
	Huntington Beach 4	1	225		5.0

Table B-1 (Continued)

SCE	Huntington Beach 1,2	2	215		2.7
	Huntington Beach 3	1	215		5.0
	Mandalay 1,2	2	215		2.7
	Alamitos 1,2	2	175		2.4
	El Segundo 1,2	2	175		2.4
	Redondo 5,6	2	175		2.4
	Etiwanda 1,2	2	132		2.0
	Alamitos 7	1	121		4.4
	Etiwanda 5	1	121		4.4
	Huntington Beach 5	1	121		4.4
	Mandalay 3	1	121		4.4
	Coolwater 2	1	81		1.3
	Redondo 1,2,4	3	74		1.3
	Redondo 3	1	70		1.3
	Coolwater 1	1	65		1.3
	San Bernadino 1,2	2	63		1.3
	Ellwood 1	1	54		5.0
	Highgrove 3,4	2	45		1.3
	Long Beach 10,11	2	50		4.0
	Highgrove 1,2	2	33		1.3
	Long Beach 8	1	311[k]	15.1	2.7
	Long Beach 9	1	232[m]	15.1	2.7
	Coolwater 3,4[g]	2[g]	236[n]	8.7	4.9
	Hydroelectric units	11[h]	51		1.3
	∿50 MWe block size	18[h]	50		1.3
LADWP	Haynes 5,6	2	344		6.0
	Scattergood 3[j]	1[j]	284		6.0
	Haynes 2	1	232		5.0
	Haynes 4	1	227		5.0
	Haynes 1	1	222		5.0
	Haynes 3	1	220		5.0
	Scattergood 1,2	2	179		5.0
	Valley 3	1	171		5.0
	Valley 4	1	160		5.0
	Navaho 1-3	3	183		8.0
	Valley 1,2	2	101		4.0
	Harbor 5	1	94		4.0
	Harbor 3,4	2	92		4.0
	Harbor 2	1	79		4.0
	Harbor 1	1	78		4.0
	Harbor 6-9	4	19		12.0
	Castaic	5	225		3.0
	Hydroelectric units	17	50		1.0
SDG&E	Encina 4	1	287		3.0
	South Bay 4	1	220		3.0
	South Bay 3	1	198		4.0
	South Bay 2	1	142		1.6
	South Bay 1	1	140		1.6
	Encina 2,3	2	102		1.6

Table B-1 (Continued)

SDG&E	Encina 1	1	100	1.6
	Silver Gate 2	1	64	1.0
	Silver Gate 3,4	2	64	2.0
	Station B #25	1	35	2.0
	Station B #24	1	28	2.0
	Station B #21,22	2	15	2.0
	Silver Gate 1	1	38	2.0
	Kearney GT 2	1	71	4.0
	Kearney GT 3	1	73	4.0
	Miramar	1	46	4.0
	North Island GT 1,2	2	23	4.0
	Naval Training Center	1	20	4.0
	El Cajon	1	21	4.0
	Division	1	20	4.0
	Encina GT 1	1	20	4.0
	South Bay GT 1	1	20	4.0
SCE, LADWP	Mohave 1,2	2	600[p]	8.9[p]
SCE, SDG&E	San Onofre 1	1	430[p]	3.4[p]
PG&E, USBR	500 kV AC Intertie w/PNW	1	1612[q]	.1[q]
LADWP, SCE	800 kV DC Intertie w/PNW	1	1075[q]	2.2[q]

[a]For July : 88 units @ 50 MWe; 1 unit @ 49 MWe.

[b]Reduce the capacity available by 55 MWe for the partial outage state.

[c]Reduce the capacity available by 100 MWe for the partial outage state.

[d]Reduce the capacity available by 180 MWe for the partial outage state.

[e]Reduce the capacity available by 175 MWe for the partial outage state.

[f]For July: 51 MWe for each unit.

[g]Reduce to 1 unit for July, since Coolwater 4 will not be available until August.

[h]For July: 13 units @ 50 MWe; 16 units @ 49 MWe.

[j]Scattergood 3 is not expected to be available in July under the assumption that natural gas for boiler fuel will not be available then.

[k]Reduce the capacity available by 66 MWe for the partial outage state.

[m]Reduce the capacity available by 49 MWe for the partial outage state.

Table B-1 (Continued)

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[n]Reduce the capacity available by 113 MWe for the partial outage state.

[p]For shared facilities, the FOR is a weighted average:

Mohave 1,2: SCE 442 MWe/unit; FOR = 9.2

LADWP 158 MWe/unit; FOR - 8.0

Weighted average FOR = 8.9

San Onofre 1: SCE 344 MWe FOR = 3.3

SDG&E: 86 MWe; FOR = 4.0

Weighted average FOR = 3.4

[q]The AC and DC interties are shared. The firm power loading shown for both is typical, though some shifting of load between the AC and DC lines occurs. The FOR for the AC lines is generally agreed to be 0.1%. For the DC line, SCE uses 2.2% and LADWP uses 6.0%. We have used 2.2%.

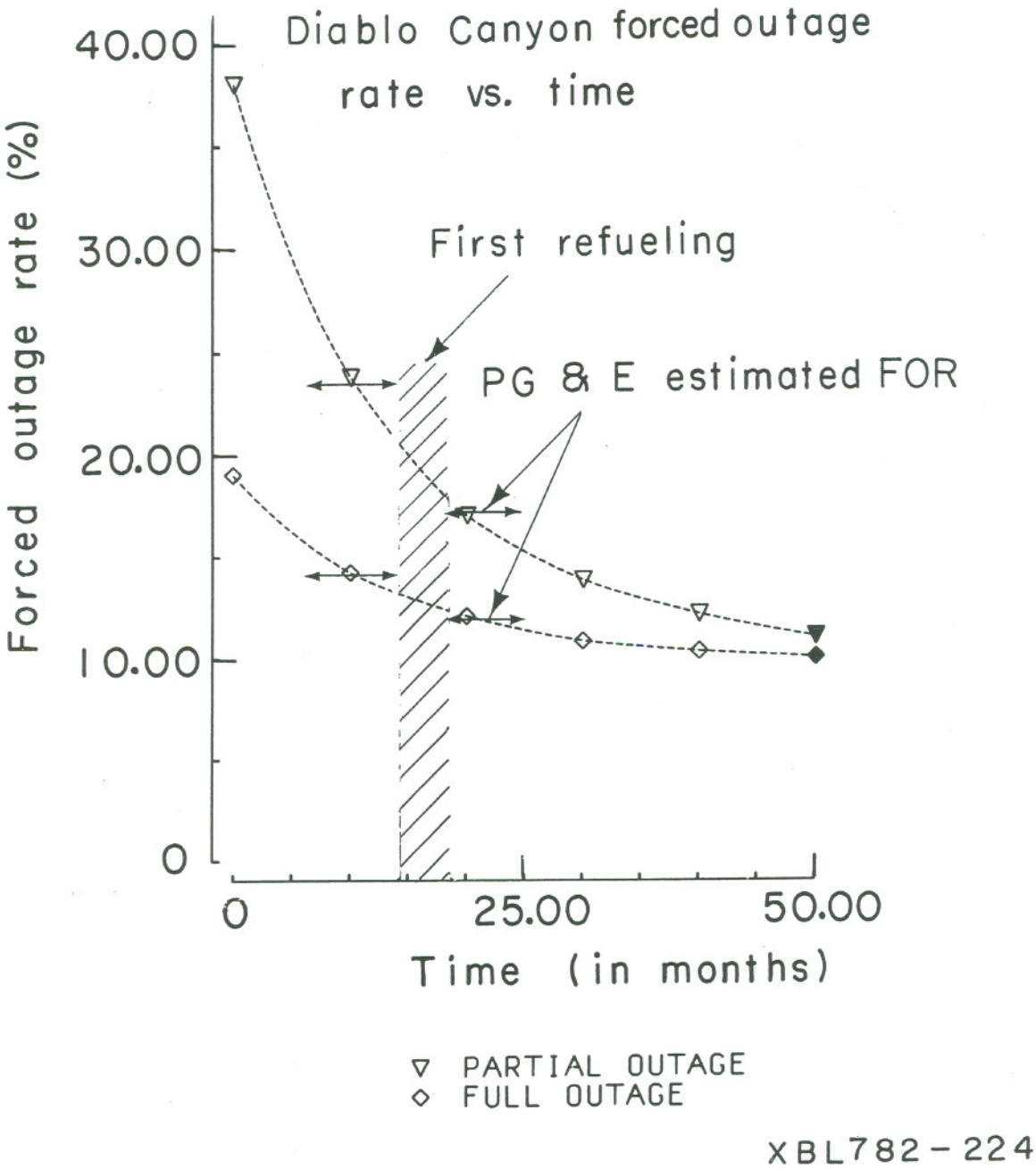

Figure B-1. Forced Outage Rates for Diablo Canyon as a Function of Time, With Time Zero as the Start of Commercial Operationn. The first refueling period is shown as a band, since the exact refueling data is uncertain. The shaded symbols represent PG&E's assumed values for the outage rates at plant maturity.

APPENDIX C

CALIFORNIA AGRICULTURAL ENERGY DEMAND

INTRODUCTION

California's agricultural industry has experienced a second year of drought conditions north of the Tehachapi Mountains. Water shortages during 1977 have been of only minor concern to agriculture in southern California and most central coast areas, but are particularly troublesome and costly in the Central Valley.

A map of California shown in Fig. C-1 depicts the reduced precipitation due to the drought by area. Table C-1 contains a comparison of the average precipitation in various areas of the state between a "normal" year and the 1976-77 water year. As demonstrated by the map and the corresponding table, the central coast counties and those of the coastal and desert regions of southern California received precipitation that was close to normal. Furthermore, this water was available in the past year to agriculture in the southern California area which generally relies upon surface water from the Colorado River; this eliminates any drought threat to this region. Other areas of the state, namely the north coast, San Francisco Bay, mountain, and Central Valley (Sacramento and San Joaquin Valleys) did not fare as well.

Although contributing only about three percent directly to the value of agricultural production in California, the mountain area supplies most of the surface water used by the Sacramento and San Joaquin Valleys. This water is usually stored in reservoirs located in that area. In the 1976-77 water year, however, these areas generally have received the lowest percentage of the State's precipitation. As of July 1977, reservoir storage in the State was about 37 percent of average.[49]

The Sacramento and San Joaquin Valleys, which comprise the Central Valley, account for nearly 60 percent of the State's cash receipts from farm marketing of crops. Since nearly 80 percent of the estimated water use in agriculture and 75 percent of the energy requirements for pumping occur in the Central Valley, our analysis focuses on this geographic area. In addition, the major part of the Central Valley lies within Pacific Gas and Electric Company's (PG&E) service area.

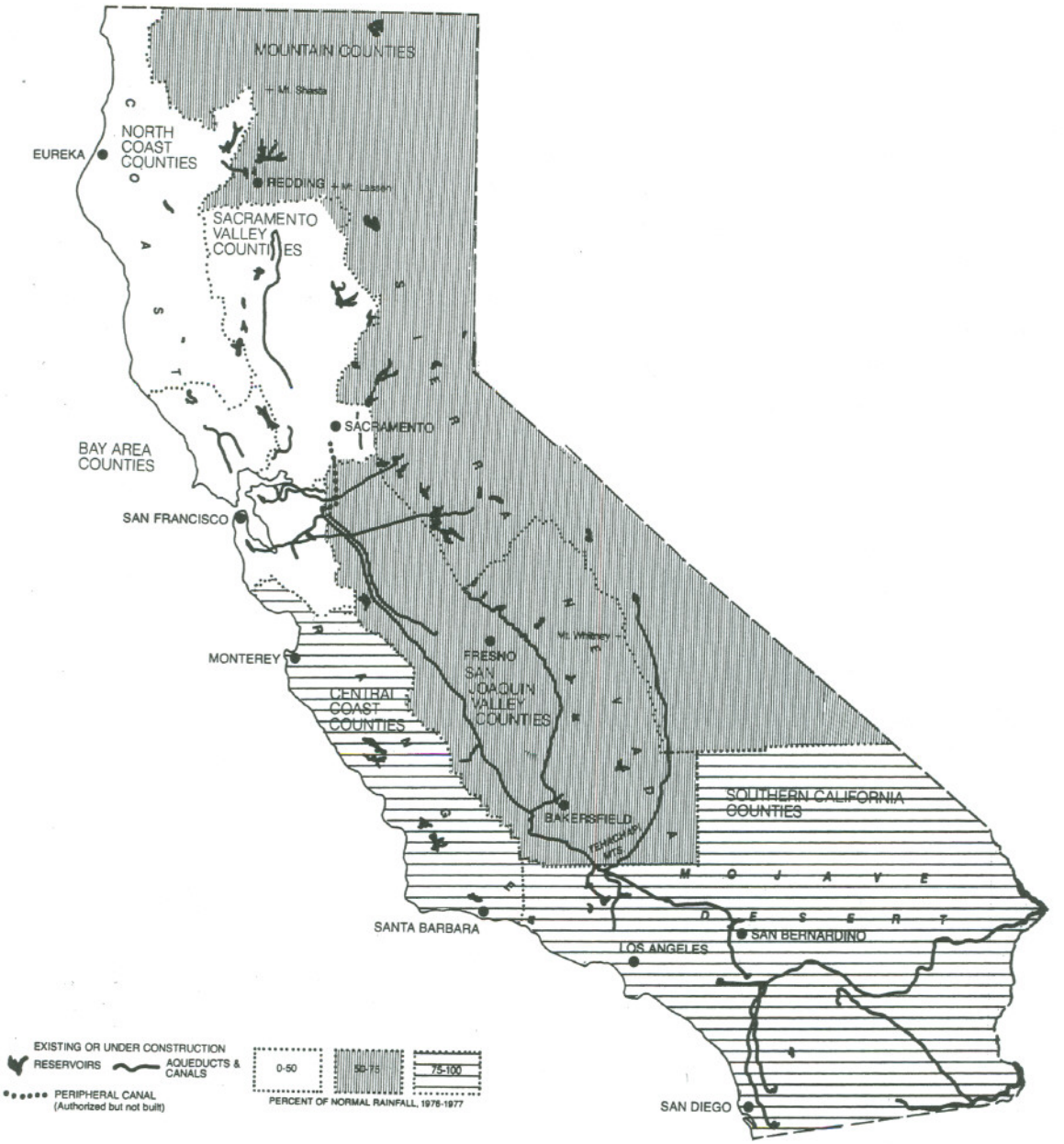

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Figure C-1. Reduced Precipitation Due to the Drought by Area

Table C-1

California Precipitation[a]

Areas	Normal Year (inches)	Percent of Normal (July 1974-June 1975)	Percent of Normal (July 1976-June 1977)
North Coast	37.6	105	42
San Francisco Bay	21.6	96	47
Central Coast	12.6	96	88
Sacramento Valley	20.4	100	48
San Joaquin Valley	9.5	91	68
Southern California[b]	7.9	57	94
Mountain	32.4	94	58

[a]Average precipitation at weather stations in each area as reported by California Crop and Livestock Reporting Service, USDA (July-June weather year).

[b]Average of coastal and desert stations.

ENERGY USE IN AGRICULTURE (1977)

Energy use in pumping of irrigation water varies widely across California according to the water source, the method of irrigation, and the water requirements of the various crops. In a dry year it is expected that agriculture's contribution to peak demand will increase due to decreased surface water deliveries and a consequent increase in groundwater pumping. The increased demand will occur especially in areas where the decrease in surface water supply has been the greatest (e.g., Central Valley).

Table C-2 contains the monthly electricity sales to agriculture in PG&E's service area for 1975-77. The data for 1975 and 1976 include sales by PG&E and of other utilities in PG&E's service area (e.g., Modesto Irrigation District, Turlock Irrigation District, Bureau of Reclamation, etc.). In addition, the total state agricultural sales are included for 1975 and 1976 as a means of comparison.

The highest monthly demand for agriculture in PG&E's service area occurred in July during both 1975 and 1976. The growth in electrical sales to agriculture was more than 20 percent between 1975 and 1976 reflecting a response to the first year of the drought. PG&E's service area represented over 75 percent of the total statewide electricity sales to agriculture during both 1975 and 1976. PG&E's maximum monthly sales for agriculture in 1977 took place in August and was less than 10 percent higher than the previous year. The lower rate of growth during 1977 probably corresponds to a more efficient use of water by farmers during the second year of the drought. Furthermore, not all of the surface water deficit could be made up through groundwater pumping because of certain physical limitations. The total yearly sales to agriculture in 1976 were 20 percent greater than in 1975, while they increased by only 3 percent in 1977.

A graphical representation of PG&E's electricity sales to agriculture during 1975, 1976 and 1977 is presented in Fig. C-2. The graph shows a steady increase in electricity use from January through the peak periods in July and August followed by a steady decrease during the last quarter of the year. This pattern in total agricultural requirements corresponds

Table C-2

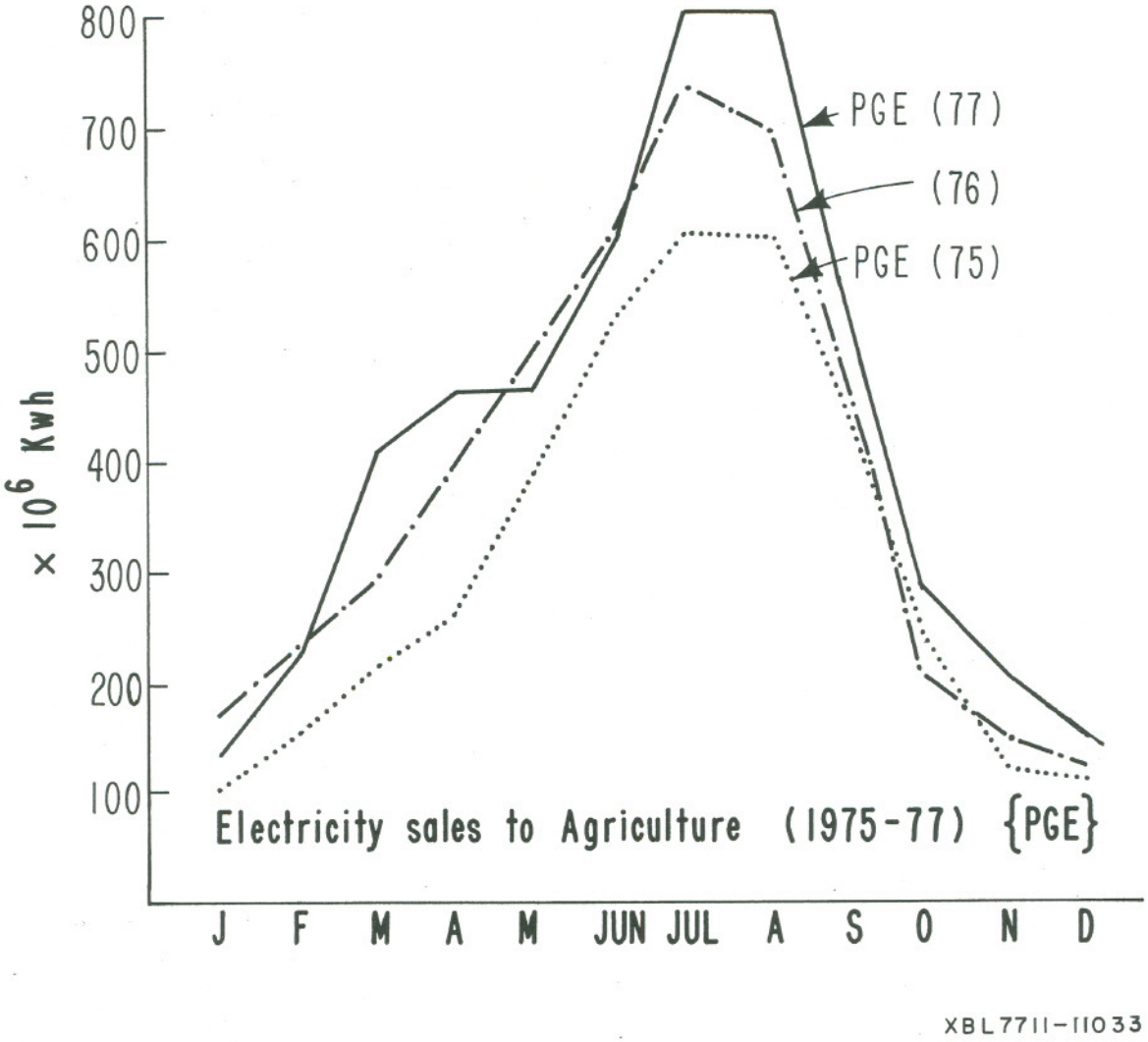
Monthly Electricity Sales to Agriculture (1975-77)
(10^6 kilowatt-hours)

	1975		1976		1977
	PG&E[a]	Statewide	PG&E[b]	Statewide	PG&E[c]
January	109.64	158.0	186.7	252.25	137.66
February	161.60	219.3	254.51	333.43	224.86
March	222.89	298.43	322.21	398.11	410.01
April	285.77	362.1	432.24	534.22	462.33
May	425.31	522.83	542.95	689.7	466.61
June	584.17	723.88	663.22	838.64	601.84
July	657.12	836.38	790.08	1023.99	803.95
August	654.04	838.97	744.74	965.9	804.79
September	494.54	674.3	517.29	712.95	556.07
October	272.83	416.08	324.11	356.6	292.66
November	130.67	226.34	160.77	257.58	200.75
December	112.29	188.61	136.87	220.29	152.18
Yearly Total	4110.63	5465.21	4975.69	6579.65	5113.72

[a]"Electric Utility Sales Report Summary," California Energy Resources Conservation and Development Commission, 1975. Includes PG&E's sales and sales of the following utilities: Bureau of Reclamation (Central Valley Project), City of Roseville, Modesto Irrigation District, Plumas-Sierra Rural Electric, Sacramento Municipal Utility District and Turlock Irrigation District.

[b]"Electric Utility Sales Report Summary," California Energy Resources Conservation and Development Commission, 1975.

[c]Personal communication, Pacific Gas & Electric Company, September 30, 1977. Includes PG&E sales only.


800
700
600
500
400
300
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100
× 10^6 Kwh
PGE (77)
(76)
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Electricity sales to Agriculture (1975-77) {PGE}
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Fig. C-2

to the periods when irrigation pumping demands are the greatest. The 1977 data, although incomplete, exhibit a similar form.

Decreased water deliveries in 1977 resulted in reduced energy requirements for water pumping in both the CVP and SWP. In 1976, the CVP required 1.79 billion kWh for deliveries to agricultural users in the San Joaquin Valley. During 1977 the CVP used only about 800 million kWh for a savings of over 900 million kWh.[50] The DWR staff reported a total net energy use of about 2.95 billion kWh in 1976. This year with reductions in surface water deliveries, the estimated net energy requirement of the SWP is 1.58 billion kWh.[51] These combined reductions totaled over 4.5 billion kWh and were a factor in PG&E's ability to meet peak electricity demand this past summer.

PROJECTED ENERGY DEMAND FOR AGRICULTURAL PUMPING IN THE CENTRAL VALLEY (1978)

The method for determining the estimated energy demand for agricultural pumping in the Central Valley for 1978 differs from that used in our previous report.[16] In that report the energy use per acre was multiplied by the estimated planted acreage to give the total energy use for selected crops according to the water source and irrigation method. The total energy requirements for pumping in the Valley during 1977 were calculated to be 5.91 billion kWh.[16] This value compares with a slightly lower estimate of 5.05 billion kWh made by the PG&E staff.[52] The calculations in our previous report, however, included energy use per acre-foot from both ground and surface sources as well as the energy required for moving the surface water within the state and federal water projects.

It is premature at this time to make estimates of cropping patterns for 1978 because there are still the uncertainties of this year's crop production, the commodity market and the future water picture. Therefore, in order to project energy demands for irrigation in 1978 we will consider an assessment of the pumping of groundwater in the Valley, as a whole, at the 1977 level, but from greater depths. This estimate will be compared to pumping additional water from wells to make up the projected 1978 surface water deficits.

The total groundwater pumped in the Central Valley in 1977 is estimated to be 14.7 million acre-feet (2.5 million acre-feet in the Sacramento Valley and 12.2 million acre-feet in the San Joaquin Valley.[44] In 1978, it is expected that groundwater pumped in the Valley will come from depths that are five to ten feet lower, on the average, than those of last year. This represents an additional 9 to 18.5 kWh per acre-foot of groundwater pumped.

The average energy use during 1977 was estimated in our previous report to be 301 kWh per acre-foot for groundwater and 158 kWh per acre-foot for surface water sources.[16] If we assume similar cropping patterns in 1978 as in 1977 and the use of the same amount of groundwater (e.g., 14.7 million acre-feet), the estimated electrical demand in agriculture for next year would be 5.83 billion kWh. This calculation accounts for a 24 percent reduction in surface deliveries. However, if groundwater is used to make up the entire surface water deficit in 1978 (total groundwater supply equal to 17 million acre-feet), the estimated energy requirements will be 6.56 billion kWh. This latter value represents nearly an 11 percent increase in estimated demand over 1977.

In our previous report we calculated the increase in agricultural peak load due to the dry year conditions of 1977.[16] In order to predict the peak load generating capacity it is necessary to estimate the monthly increase in agricultural energy demand and combine this value with the monthly load factor as provided by PG&E. The estimated monthly load factor used by PG&E is determined by an econometric model which compares daily, weekly and monthly load values.

Since the monthly energy requirements for agricultural pumping and the estimated monthly load factor are not available at this time, we can only make gross estimates of agriculture's contribution to the maximum peak load in 1978. If we assume that the monthly increase in agricultural electricity demands compares to the yearly percentage increase in the total energy requirements for agriculture as it has in 1975 and 1976, an increase of 89 million kWh is derived. Using an estimated monthly load factor of 0.650 (average 1977 value for July and August), we estimate that an additional 190 MWe on peak will be required. This increased electricity requirement probably will not affect the electrical reserve capacity in a significant way.

We have summarized in Table C-3 the recorded energy use and generation by the SWP and CVP for 1975 through 1977. The decline in water deliveries in 1977 compared with 1975 is accompanied by reduced energy requirements for pumping. For 1978, only rough estimates of the energy savings available from pumping less surface water in the federal and state projects can be made at this time. If the precipitation and runoff in 1978 are similar to that of 1977, both the SWP and CVP will deliver less water for agriculture, which will require subsequently less energy for pumping. The savings therefore will be equal to or greater than that experienced in 1977.

Table C-3

Energy Use and Generation for
State and Federal Water Conveyance Projects
(in GWh)

	Calendar Year		
	1975	1976	1977
California Water Project[a]			
Water Deliveries (10^6 acre-ft)	1.89	2.06	0.57[b]
Gross Pumping Energy	3849	3430	1240
Energy to MWD[b]	--	20	570
Total Energy Required	3849	3450	1810
Recovery Generation	816	500	230
Net Energy Required[c]	3033	2950	1580
Hyatt-Thermalito Generation[d]	2344	1339	731
Pump-back Energy	58	53	140
Net H-T Generation	2285	1286	591
Central Valley Project (USBR)[e]			
Total Water Deliveries (10^6 acre-ft)	~6.5	6.0	3.3
CVP Project Energy Use	1295	1232	561
Preference Customers	5043	5041	4970
Other[f]	2869	1254	376
Total Energy Required	9207	7527	5907
CVP Generation (in California)	6096	4312	3012
Net Energy Required[g]	3111	3215	2895

[a]Source: E.J. Terhaar, J. Klein, Personal Communication, Department of Water Resources, November 1977, February 1978.

[b]In 1977 DWR agreed to transfer 570 GWh of energy available to it from the California suppliers to the Metropolitan Water District (MWD) for pumping an additional 318,000 acre-ft of water from the Colorado River for delivery to MWD customers. Normally MWD would have received this water directly via the California Aqueduct.

[c]This energy is supplied via contracts with California utilities and with utilities in the Pacific Northwest (Canadian Entitlement Power).

[d]This energy from the Oroville complex is sold directly to California utilities and is not used directly by the SWP for pumping energy.

[e]Source: R. Greenhalgh, Personal Communication, USBR, February 1978.

[f]Includes sales to PG&E, interchange and transmission losses.

[g]This energy is generally supplied by utilities in the Pacific Northwest (including USBR share of the Centralia coal plant) and by PG&E.

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