LBL-6367
UC-97e c.1
TID-4500-R66

Energy and Environment Division

Electrical Load Management For The California Water System

Betsy Krieg, Ike Lasater, and Carl Blumstein

July 1977

Lawrence Berkeley Laboratory University of California/Berkeley

Prepared for the U.S. Department of Energy under Contract No. W-7405-ENG-48

Printed in the United States of America
Available from
National Technical Information Service
U. S. Department of Commerce
5285 Port Royal Road
Springfield, VA 22161
Price: Printed Copy, \$ 5.25 Domestic; \$10.50 Foreign
Microfiche, \$ 3.00 Domestic; \$ 4.50 Foreign

ELECTRICAL LOAD MANAGEMENT FOR THE CALIFORNIA WATER SYSTEM*

Betsy Krieg
Ike Lasater
Carl Blumstein†

July, 1977

Energy and Environment Division
Lawrence Berkeley Laboratory
University of California
Berkeley, California 94720

* Work sponsored by the California Energy Resources Conservation Development Commission

† Author to whom correspondence should be addressed.

TABLE OF CONTENTS

INTRODUCTION 1

THE CALIFORNIA WATER SYSTEM 3

California Water Use 3

The Water Supply Projects 7

Electricity Production and Use 13

ENERGY CONSERVATION 18

Water Conservation 18

Pump Efficiencies 19

Tunnels 20

LOAD MANAGEMENT 22

Technical Requirements 22

Power Contracts and Operating Schedules 31

CONCLUSIONS AND RECOMMENDATIONS 41

Power Contracts 41

Power Pooling 42

Further Studies 42

BIBLIOGRAPHY 45

APPENDIX A: DWR Alternative Futures 49

APPENDIX B: The State Water Project 51

LIST OF TABLES AND FIGURES

Table 1	Present and Projected Water Requirements by Use and Hydrologic Study Area, in 1000 acre-feet	5
Table 2	1972 Urban Water Use	6
Table 3	Average Annual Runoff of Streams and 1972 Water Demand in California	8
Table 4	Summary of Water Deliveries, Pumping Requirements and Power Generation for Major California Water Agencies . . .	15
Table 5	Projected Pumping Requirements for the State Water Project	23
Table 6	Present and Projected Energy Usage, Capacity, and Capacity Factors for Pumping Plants on the SWP	26
Table 7	Potentially Shiftable Pumping Load for the State Water Project at Full Development	28
Table 8	Annual Savings and Investment Justified for Peak Power Conservation	30
Table 9	Generation Capacity Factors for the Water Projects	32
Table 10	Generating Plants and Shiftable Generation for the State Water Project at Full Development	33
Table A-1	Alternative Futures	49
Table A-2	Alternative Future Populations	50
Table A-3	Alternative Future Irrigated Crop Acreages	50
Appendix B Tables:	Overview of the State Water Project	51
Figure 1	Map showing California hydrologic study areas	4
Figure 2	Map showing major surface water supply and conveyance facilities in California	10

INTRODUCTION

To meet its water needs California has developed an extensive system for transporting water from areas with high water runoff to areas with high water demand. This system annually consumes more than 6 billion kilowatt hours (kWh) of electricity for pumping water and produces more than 12 billion kWh/year of hydroelectric power.

From the point of view of energy conservation, the optimum operation of the California water supply system would require that pumping be done at night and generation be done during the day. Night pumping makes it possible for the pumps to be supplied with electricity from "base load" generating plants. These plants are more efficient (compared with "cycling" and "peaking" units using the same type of fuel) so night pumping saves energy. Night pumping also reduces requirements for capital investment in electric generating capacity since capacity requirements are determined by the peak demand on the electricity distribution system which occurs during the day. (This strategy of shifting electricity use from peak demand periods to offpeak periods is known as "load management".) Daytime hydroelectric generation conserves energy if it can be used to replace generation from inefficient fossil-fuel "peaking" units.

Two important sets of issues govern the feasibility of operating the water system according to this optimum schedule. The first is the technical issues of what facilities (e.g., pumping, generating, water storage) would be needed to adopt this strategy now and in the future, what they would cost, and what benefits they would yield in energy and capital savings.

The second set of issues concerns the institutional arrangements between the water projects and the electric utilities who purchase hydroelectric power from the projects and supply energy for pumping. These transactions are governed by contracts which set the prices for electricity and determine what, if any, differential in price exists between peak and offpeak power. The contracts thus determine the incentives for the water agencies to practice load management. Circumstances have greatly changed since most of these contracts were negotiated. Thus, the major institutional question is whether and in what way these contracts should be altered in light of the new situation.

This report examines both the technical and institutional aspects of load management for the water projects. Its purpose is to explain some of the actions which might be pursued and to develop recommendations for the California Energy Resources Conservation and Development Commission (ERCDC).

To allow readers who are unfamiliar with California's water projects to become acquainted with them, the first section of the report is devoted to a description of the water supply system. The second section of the report gives a brief description of various energy conservation methods, other than load management, that can be used in the management of water resources. These two sections provide the context for the analysis of load management which appears in the third section.

The report concludes with a discussion of three recommended actions for the ERCDC:

- The Commission should monitor upcoming power contract negotiations between the utilities and the water projects.
- It should determine the applicability of the power-pooling provisions of the proposed National Energy Act to water systems.
- It should encourage and support detailed studies of load management methods for specific water projects.

THE CALIFORNIA WATER SYSTEM

This section gives a short introduction to the California water system. It begins with a discussion of water use, giving the amounts and purposes of water use in the various regions of the State and then describes the large water projects which supply a substantial fraction of these water needs. Finally, it discusses electricity production and use associated with the water projects. Attention is focused on energy use for the State Water Project, not only because it already is the largest energy-user among the projects, but because its energy use is expected to increase more than four-fold in the future.

California Water Use

In 1972 California used about thirty-seven and a half million acre-feet (AF)* of water (DWR 160-74); about 85 percent of this was for agriculture. Most of the balance was for urban uses. Minor uses were for fish, wildlife, and recreation and for power plant cooling. Table 1 shows 1972 water use by amount and purpose for the various regions of the State; the regions given in this table are aggregations of the hydrologic study areas (HSAs) used for analysis by the California Department of Water Resources (DWR). A map of HSAs is shown in Figure 1.

Agricultural water irrigates about 9 million of California's 10½ million acres of cultivated land. As can be seen from Table 1, more than 75 percent of this use is in the Central Valley. In 1972 urban water use was approximately 68 percent residential, 18 percent industrial, 10 percent commercial, and 4 percent governmental (see Table 2). Almost half of the urban water use was in the South Coastal region.

In addition to the relatively small amounts of water supplied for fish, wildlife, and recreation, about 5 million AF are required for stream flow maintenance in a normal water year (DWR 160-74). This is not considered by the DWR to be a consumptive use since water can be withdrawn from the streams for other uses.

The DWR has prepared projections of future water requirements for California. These are given in Table 1. The projections are based on

---

* 1 AF = 43,560 cubic feet = 325,851 gallons; the amount of water necessary to cover one acre to the depth of one foot.

XBL 776-8970 A

FIGURE 1
HYDROLOGIC STUDY AREA BOUNDARIES

Table 1

Present and Projected Water Requirements by Use and Hydrologic Study Area, in 1000 acre-feet

	1972	1990[b]				2020[b]			
		I	II	III	IV	I	II	III	IV
Urban Water									
Central Valley HSAs[a]	1,198	1,739	1,700	1,663	1,530	2,923	2,661	2,489	1,862
South Coastal	2,370	3,130	3,050	2,980	2,670	4,830	4,360	4,120	2,980
San Francisco	990	1,480	1,460	1,430	1,340	2,240	2,070	1,940	1,570
Colorado Desert and South Lahontan	188	302	281	275	234	662	572	536	316
Other	297	452	442	429	381	763	695	641	453
	5,040	7,100	6,930	6,770	6,160	11,400	10,400	9,730	7,170
Agricultural Water									
Central Valley HSAs[a]	24,830	30,850	29,450	27,650	27,000	34,970	32,210	29,330	27,930
South Coastal	920	730	720	720	750	530	510	520	520
San Francisco	250	290	280	290	280	330	320	310	280
Colorado Desert and South Lahontan	3,530	3,620	3,620	3,620	3,620	3,570	3,570	3,570	3,570
Other	2,160	2,390	2,350	2,330	2,310	2,480	2,440	2,400	2,350
	31,700	37,900	36,400	34,600	34,000	41,900	39,000	36,100	34,600
Power Plant Cooling									
Central Valley HSAs[a]	20	220	110	70	60	670	360	220	130
South Coastal	--	--	--	--	--	--	--	--	--
San Francisco									
Colorado Desert and South Lahontan	0	140	80	50	40	350	180	130	80
Other	--	--	--	--	--	--	--	--	--
	38	390	220	150	130	1,100	580	350	210
Fish, Wildlife and Recreation									
Central Valley HSAs[a]	265	339	339	339	339	348	348	348	348
South Coastal	6	19	19	19	19	23	23	23	23
San Francisco	24	37	37	37	37	46	46	46	46
Colorado Desert and South Lahontan	24	38	38	38	38	48	48	48	48
Other	336	373	373	383	383	381	381	381	381
	655	806	806	806	806	846	846	846	846
TOTAL	37,400	45,800	44,400	42,300	41,100	55,300	50,800	47,000	42,800

Source: DWR Bulletin 160-74, Table 16, p. 89.

[a] Includes Sacramento Basin, Delta-Central Sierra, San Joaquin Basin, and Tulare Basin.

[b] Roman numerals refer to alternate possible futures, as defined in Appendix A.

Table 2

1972 Urban Water Use

Sector	Acre-Feet	Percent of Total Water Use*
Residential	3,429,240	9.17
Industrial	907,740	2.43
Commercial	504,300	1.35
Governmental	201,720	0.54
Total	5,043,000 acre-feet	13.49

Source: DWR 160-74

*Total water use in 1972 was 37,398,000 acre-feet.

four possible alternate futures (see Appendix A) and anticipate an increase in water demand of between 20 and 50 percent by the year 2020.

The Water Supply Projects

Estimates of California's surface water supply are based on an average annual runoff of 68 million AF. A comparison of average runoff and water demand, by hydrologic study area, illustrates California's problem with water supply: the locations of supply and demand are not well matched (see Table 3). More than 70 percent of the runoff is in two basins which have only 21 percent of the demand. Also, water demand is highest in the summer while runoff is highest in the spring; thus the times of supply and demand are not well matched either.

Groundwater drawn from wells supplies about 39 percent of the State's water needs (U.S. Bureau of the Census, 1972). In some areas, the groundwater--which is recharged by rainfall and runoff--is being withdrawn faster than its recharge rate. The resultant falling water-tables are cause for concern in the long run (see DWR 160-74).

The history of California's development is a history of water storage and water transfers. Water projects have been built by various Federal, State and local authorities:

- Federal agencies involved are the U.S. Bureau of Reclamation (USBR) and the U.S. Army Corps of Engineers (USCE).
- State projects are under the jurisdiction of the Department of Water Resources (DWR).
- Local agencies that have large projects include East Bay Municipal Utility District (EBMUD), the Imperial Irrigation District (IID), the Los Angeles Department of Water and Power (LADWP), the Merced ID, the Modesto and Turlock ID's, the Metropolitan Water District of Southern California (MWD), the City of San Francisco (SF), and the Yuba Water Agency.

The map in Figure 2 shows the projects operated by these and other agencies. Some of the water projects that operate major water conveyance facilities (canals, tunnels, and pipelines) are described below.

Table 3

Average Annual Runoff of Streams and 1972 Water Demand in California

Hydrologic Study Area	Average Runoff		1972 Water Demand	
	1000 AF	% of Total	1000 AF	% of Total
North Coastal	27,056	39.9	1,120	3.0
San Francisco Bay	3,346	4.9	1,260	3.4
Central Coastal	1,781	2.6	1,210	3.2
South Coastal	1,400	2.1	3,320	8.9
Sacramento Basin	21,082	31.1	6,610	17.7
Delta-Central Sierra	1,083	1.6	2,670	7.1
San Joaquin Basin	6,062	8.9	5,730	15.3
Tulare Basin	3,131	4.6	11,300	30.2
North Lahontan	1,535	2.3	454	1.2
South Lahontan	1,200	1.8	399	1.1
Colorado Desert	112	.2	3,340	8.9
	67,788	100.0	37,413	100.0

Source: California Statistical Abstract, 1975

The Central Valley Project (CVP), operated by the USBR, supplies the largest amount of water--about six million AF annually, mostly for agricultural uses. For the most part, the CVP does not deliver water to final users, but rather to local irrigation districts and water agencies. These local authorities operate pumps to lift water from CVP canals and maintain the local distribution network. In 1973, 48 such agencies were being served by the CVP.

The CVP was outlined for the first time in 1874 in a report on potential federal irrigation projects (Hundley, 1973). In 1930 California adopted a State Water Plan which included the major features of the CVP--a dam at what is now Lake Shasta, the Delta-Mendota Canal, and the Friant-Kern Canal (see Figure 2). Due to difficulty in obtaining the necessary financial backing through the sale of State bonds during the Depression, California was forced to drop the idea of constructing such a vast project using State money. The Federal government, however, was able to supply the necessary funds to build the CVP as a reclamation project. For further historical information on the CVP, see MacDiarmid, 1976.

The State Water Project (SWP), operated by the DWR, delivers water to more than 30 local agencies, the largest being the Kern Water Agency and the Metropolitan Water District of Southern California (MWD).

Major features of the SWP are the Oroville dam and the Hyatt-Thermalito pumped storage units in the north, the Delta pumping station, the San Luis reservoir (jointly operated by the State and the Federal government), the California Aqueduct, and the Edmonston pumping plant at the Tehachapi Mountains. The 444-mile long California Aqueduct, which runs along the west side of the Central Valley from the Sacramento-San Joaquin Delta to Southern California, now delivers about 1.5 million AF annually, one-third of which is for urban use. At full development the aqueduct is expected to deliver 4.5 million AF with about half of this for urban use. Detailed maps of the SWP together with information on water deliveries are given in Appendix B.

The Mokelumne Project, operated by the East Bay Municipal Utility District (EBMUD), consists of two dams (Pardee and Camanche) and a 94-

Figure 2 (facing page). Major surface water supply and conveyance facilities in California.

MAJOR SURFACE WATER SUPPLY AND CONVEYANCE FACILITIES 1974

LOCAL DEVELOPMENT
STATE WATER PROJECT
FEDERAL DEVELOPMENT

Taken from DWR 160-74

mile aqueduct. More than 200,000 AF per year are delivered from Pardee Reservoir to the East Bay via the Aqueduct. The first water from the Mokelumne arrived in 1929, six years after EBMUD was organized and five years before San Francisco's Hetch-Hetchy project delivered its first water. Camanche, downstream from Pardee, was built in the 1960s. Water from Camanche cannot be delivered to the East Bay, but the reservoir does augment the East Bay water supply by helping to maintain stream flows during the summer so that more water can be delivered from Pardee. Camanche is also used for flood control; for this reason its construction was partially funded by the Federal government.

The All-American Canal is operated by the Imperial ID and delivers about 3 million AF from the Colorado River to the Imperial Valley. The All-American is the successor to the Alamo Canal which was constructed by the California Development Company in 1901, partially in Mexican territory. Its dual nationality created major bureaucratic complications; moreover, the California Development Company was experiencing financial difficulties. The combination of these problems led to a lack of adequate maintenance. As a result, a flood in December 1904 breached the canal. By August 1905, the entire Colorado River was flowing through the Imperial Valley to the Salton Sea, the natural sink for the valley. The California Development Company was unable to repair the break; but because the rising waters of the Salton Sea were threatening the rail lines of the Southern Pacific Railroad, Southern Pacific undertook the repair work. After more than a year of effort, the break was closed in November 1906; a second break, which occurred in December 1906, was repaired by February 1907. This series of disasters resulted in the reestablishment of the Salton Sea (which had been nearly dry), the bankruptcy of the California Development Company, and the eventual construction of the All-American Canal totally on U.S. soil (Harding, 1960).

The Los Angeles Aqueduct delivers about ½ million AF per year to Southern California from the Owens Valley. The aqueduct was built by the LADWP between 1908 and 1913. To obtain the water rights needed, the

City of Los Angeles had acquired, by 1916, 125,000 acres of privately-owned land in the Owens Valley in addition to the public lands that Congress had allowed the City to buy. The result was that most of the irrigable land in the valley was taken out of production, causing local communities to suffer a drastic reduction in business. Bitterness between valley residents and the City grew, culminating in lawsuits and sabotage against the aqueduct. Eventually Los Angeles bought most of the land in the affected towns, thereby placating most of the opposition.

The Colorado River Aqueduct delivers about 1.2 million AF per year from the Colorado River to Southern California. The aqueduct originates at Parker Dam, 155 miles below Hoover dam on the California-Arizona border; it is 266 miles long with 93 miles of tunnels and 19 miles of pressure pipes. Water is lifted 1,617 feet to reach the terminal reservoir at Lake Mathews in the mountains east of the South Coastal Region.

The aqueduct was developed and is operated by the Metropolitan Water District of Southern California (MWD), an association of local water agencies (currently 27) organized under the Metropolitan Water District Act of 1927. Partly to avoid the problem of having a California district build a dam in Arizona, the actual construction work was performed by the USBR, under contract to the MWD. But once construction was started, the governor of Arizona declared martial law over the area of the the dam and sent in the National Guard to seize the site. Finally in 1935, Congress stepped in and specifically authorized the construction of the dam; the project was completed in 1941 (Harding, 1960).

The Hetch-Hetchy Project, operated by the City of San Francisco, delivers about ¼ million AF per year from Yosemite Valley to the San Francisco Peninsula. The Hetch-Hetchy Reservoir, built within the boundaries of the National Park, provides the major storage for the project. Below the reservoir, water flows through an extensive hydroelectric power generating system before it enters the final intake of a 150-mile aqueduct.

The construction of a reservior within a National Park required an act of Congress, since title to the land was to be passed from the national public to a local municipality. In spite of the protests of John Muir and other conservationists, Congress passed the Raker Act of 1913 which gave the City title to the land with certain restrictions on its use. The first water from the project was delivered in 1934.

Electricity Production and Use

The water supply system in California is both a consumer and a producer of energy. Electricity is used by pumps that move water in aqueducts, lift water from wells, and provide water pressure for local distribution systems; water purification and waste water treatment require both electrical energy and energy in the form of chemicals. Electricity is produced at hydroelectric plants below dams and on downhill sections of aqueducts.

Hydroelectric power generated within California supplies more than 1/5 of the electrical energy needs of the State; the projects discussed here provide about 1/3 of this hydropower. (For information on other hydroelectric developments, see DWR 194.)

There are three types of hydroelectric generation associated with the water projects: generation from primary storage, generation from pumped storage, and recovery generation. In generation from primary storage, water released from mountain storage reservoirs flows through hydroelectric plants located below the storage dams. This generation differs from that of hydroelectric projects operated solely for energy production in that the first priority governing water releases is the need of water users rather than electricity demand. (On the California projects, releases can often be timed so that both needs are accomodated.)

Pumped-storage generation is entirely for the purpose of meeting electricity demand. In a pumped-storage system, water is pumped uphill to a storage reservoir during periods of low electricity demand and released through generating facilities at periods of high demand. Inefficiencies in motors, pumps, turbines, and generators, frictional losses in pipes, and losses of electricity in transmission to and from the site, make pumped storage a net electricity consumer. However, if the electricity for pumping can be provided from "base load" plants with low fuel costs (e.g., nuclear, coal, and geothermal plants) and if the generation replaces electricity from "peaking" plants with high fuel costs (e.g., gas turbines), then pumped storage can be economically attractive.

The State Water Project is the only water supply development that has pumped storage capacity. Facilities are located at Oroville, at the San Luis Reservior, and above Castaic Lake. The San Luis facility (partly owned by the USBR) is unusual in that water is pumped into the reservoir primarily for water storage. Since water is usually stored during the winter and spring and released during the summer and fall, the by-product energy storage thus involves a seasonal cycle. (The San Luis facility can also operate on a daily cycle, but this is not the usual practice.) Except for generation incident to the operation at San Luis, the pumped storage capacity on the SWP is not being used very much. This is the result of a slower-than-anticipated increase in electricity demand and of delays in the construction of new nuclear-fueled generating capacity.

Recovery generation occurs at hydroelectric plants on downhill sections of aqueducts. It is called recovery generation because it "recovers" some of the electricity used to pump the water uphill. At present only the SWP has recovery generation facilities in the strict sense. The Los Angeles Aqueduct also has hydro-plants on its downhill sections, but the energy required to lift the water is provided by gravity since the initial intake for the aqueduct is above the highest lift required. The MWD is now in the process of installing about 50 MW of recovery capacity on its distribution system below Lake Mathews.

Table 4 summarizes the hydroelectric capacity and generation for the seven water projects in 1975. The table includes the small amount of electricity used in pumping for energy storage, but pumped-storage generation is not separately identified since the available reports do not distinguish it from primary or recovery generation. (None of these hydroelectric plants are exclusively for pumped-energy storage.) Plants operated by the LADWP in the Owens Valley are classified as primary,

Table 4

Summary of Water Deliveries, Pumping Requirements, and Power Generation for Major California Water Agencies

Operator	Project	Water Delivered (1000 AF)	PUMPING PLANTS: Pumping Plants: Installed Capacity (kW)	PUMPING PLANTS: Pumping Plants: Energy Used for Pumping (10^6 kWh)	PUMPING PLANTS: Pumped Storage Plants: Installed Capacity (kW)	PUMPING PLANTS: Pumped Storage Plants: Energy Used for Pumping (10^6 kWh)	GENERATION FACILITIES: Generation from Primary Storage[a]: Installed Capacity (kW)	GENERATION FACILITIES: Generation from Primary Storage[a]: Energy Generation (10^6 kWh)	GENERATION FACILITIES: Recovery Generation: Installed Capacity (kW)	GENERATION FACILITIES: Recovery Generation: Energy Generation (10^6 kWh)	Data Year
U.S. Bureau of Reclamation (USBR)	Central Valley Project (CVP)	6,009	414,000	951	--	--	1,106,880	6,289	227,200	34	1973[f]
California Department of Water Resources (DWR) Present Development (1975)	State Water Project (SWP)	1,911	1,187,720	3,849	467,700[b]	58	798,350	2,343	496,100[e]	816	1975[g]
Full Development		4,460	1,948,255	13,047	467,700[b]	556	798,350	2,858	730,700[e]	3,787	1975[h]
Imperial Irrigation District (IID)	All-American Canal	3,072	--	--	--	--	--	--	73,380	216 (est.)	1974[i]
Metropolitan Water District of Southern California (MWD)	Colorado River Aqueduct	1,194	300,000 (est.)	2,400	--	--	--	--	--	--	1974[j]
Los Angeles Department of Water and Power (LADWP)	Los Angeles Aqueduct	474	--	--	800,000[d]	--	124,000	630	106,500[e]	490	1975-7[k]
City of San Francisco, Hetch-Hetchy Water and Power (SF)	Hetch-Hetchy Aqueduct	246	--	--	--	--	292,000	2,000	--	--	1975[m]
East Bay Municipal Utility District (EBMUD)	Mokelumne Aqueduct	217	--	--[c]	--	--	15,000	120	--	--	1975[n]
STATE TOTALS (1975)		13,130	1,901,720	7,200	1,267,700	58	2,336,230	11,382	903,180	1,560	

[a]Includes generation from pumped storage from Hyatt/Thermalito

[b]Hyatt/Thermalito facilities only. San Luis facilities with a pumping capacity of 376,000 kW can, in principle, be used for pumped storage; but this is not contemplated in present plans. Castaic facilities (800,000 kW) are owned and operated by LADWP.

[c]Undetermined amount of pumping was done to increase flow rate of aqueduct. Total use by EBMUD for all pumping including distribution was 46 million kWh.

[d]At Castaic on the SWP

[e]Does not include LADWP share at Castaic (approximately 600 MW) which is part of the pumped storage facility.

[f]Data source: USBR, Central Valley Project Annual Report, 1973.

[g]Data source: DWR Bulletin 132-74, p. 12; 132-75, pp. 30-31; 132-76, pp. 14, 44-45.

[h]Data source: DWR Bulletin 132-75, pp. 30-31.

[i]Data source: IID Bulletin 1074.

[j]Data source: MWD, 36th Annual Report; Hagan and Roberts, 1975.

[k]Data source: DWR Bulletin 194, pp. 54-59; personal communication, Norm Buehring; LADWP press release by Elizabeth Wimmer, 17 March 1977.

[m]Data source: Hagan and Roberts, 1975; personal communication, Mr. Chung of Hetch-Hetchy Department of Water and Power.

[n]Data source: Hagan and Roberts, 1975; personal communication, Keith Carnes of EBMUD.

while Los Angeles Aqueduct plants on the west side of the San Gabriel Mountains are classified as recovery.

Energy consumption by the water projects is almost exclusively for water pumping. The bulk of this energy goes to lift water over the Tehachapi Mountains into the South Coastal Region. Table 4 gives the pumping capacity and energy use in 1975 for the projects. Capacity and energy for pressurizing local distribution systems are not included in the totals. For more details on pumping capacity and energy use for the SWP, see Table 6 below. For information on pumping from wells, see Knutson *et al.*, 1977; for water treatment see Roberts and Hagan, 1975.

Energy supply for water pumping does not present serious difficulties for the water projects at this time. Five of the projects--CVP, Hetch-Hetchy, Mokelumne, Los Angeles, and All American--are net energy producers. For the Colorado Aqueduct, a long-term contract was arranged when the Project was built for energy supply from dams on the Colorado River. For the SWP, the cost of current energy purchases is more than offset by sales of energy produced at Hyatt/Thermalito (see below under Power Contracts and Operating Schedules); however, this supply situation is expected to change dramatically. When the SWP is completed, it will require about 13.6 billion kWh per year for pumping. The project then will be producing about 6.6 billion kWh annually, of which about 3.8 billion kWh will be recovery generation (see Table 4). Therefore, DWR will need an additional 7 billion kWh at that time (DWR 132-76).

Possible sources of new supply being considered by the DWR are:

- any surplus from the Bonneville Power Administration,
- power from other Pacific Northwest sources,
- additional purchases from in-state suppliers (PG&E, SCE, SDG&E, LADWP),
- coal-fired plants in neighboring states,
- thermal plants in California,
- solar and wind energy.

In addition, DWR is participating in the development of two planned nuclear facilities (San Joaquin and Sun Desert) and is reevaluating proposed hydroelectric projects in the State which were never built--for economic or other reasons--but which now appear to have some near-term potential (see DWR 194).

ENERGY CONSERVATION

While the primary emphasis of this report is on load management for large water systems, a number of other energy conservation measures can be applied in the management of water resources. This section describes some of these measures in order to provide a context for the later discussion of load management.

Water Conservation

Water conservation is a resource management strategy that does not require energy conservation as a justification. Indeed, some water conservation methods require increased energy usage. Nevertheless, energy conservation is a frequent side benefit of water conservation, especially for urban water use.

There are several reasons why urban water use is usually more energy intensive than agricultural use. First, most urban uses lie to the west of coastal mountain ranges, over which the water must be lifted.* This is especially true for the South Coastal Region where the energy costs of additional water supplies are more than 2,000 kWh/AF. Second, many urban uses result in a need for waste water treatment, thus increasing the energy cost. Third, most urban waste waters drain into the ocean while agricultural waste waters are frequently reused, either directly or after percolating downward to recharge groundwater supplies.

Urban water conservation methods include leak plugging, flow restrictors for showers, lower-flush toilets, and reduced exterior watering. For a discussion of these methods, see DWR 198; for an estimate of the energy saving potential of water conservation in the South Coastal region, see Lasater, 1976. An added benefit of shower flow restrictors

---

*The fact that energy for the lift comes from gravity, as on the Mokelumne and Hetch-Hetchy Aqueducts, does not necessarily mean that no electricity cost is associated with water delivery. For example, power from the Mokelumne project is produced only by water released to the river channel below Pardee Reservoir and not by water released into the Aqueduct. As more water is delivered to the East Bay, less energy is produced. The situation is more complicated but essentially the same on the Hetch-Hetchy project. On the other hand, water delivery is required for some energy production on the Los Angeles Aqueduct.

is reduced energy consumption for water heating (Berman et al., 1976).

Since agriculture uses about 85 percent of the water consumed in the State (see Table 2), agricultural water conservation is the most important from the point of view of water as a resource. Changes in methods of water application, away from surface irrigation and toward sprinkler or drip irrigation, hold considerable promise for water saving (DWR 198). During application, water is lost due to evaporation, deep percolation, and runoff. Since deep percolation recharges groundwater supplies and runoff can frequently be reused, it is usually most important to reduce losses from evaporation. Drip-irrigation systems appear to be superior to sprinklers in this regard.

Both drip and sprinkler systems, however, must be pressurized; and this requires energy. Because they use less water, these methods can save energy if the water comes from deep wells or other relatively energy-intensive sources. But often, a pressurized system increases the total energy needed for irrigation (Roberts and Hagan, 1975).

Other methods of agricultural water conservation include shifting to less water-intensive crops and improving the timing of water application so that crops receive water only when it is needed (DWR 198).

One benefit of water conservation that usually receives little notice is that, by decreasing the demand on the capacity of water supply systems, the operational flexibility needed for load management is increased. That is, the less time a water system must operate to meet water needs, the easier it is to schedule operation at offpeak times.

Pump Efficiencies

Virtually all of the energy use associated with water supply is for pumping. Thus, an obvious energy conservation strategy is to seek improvements in the efficiency of this operation. Two different types of pumping facilities need to be considered: large operations typical of the aqueducts and small operations typical of on-farm wells.

In the large operations there does not appear to be much opportunity for significant gains in pumping efficiency. Because of the large amount of electricity needed by aqueduct pumping stations, considerable effort has already been expended on efficient design and construction, with the result that most operations are nearly as efficient as is technically feasible. Even new technology (e.g., superconducting electric motors) cannot be expected to make great improvements since most operations are already better than 85 percent efficient (see, for example, DWR 200, Volume IV).

There is somewhat more opportunity for improvement on small operations, which consume more than 4 billion kWh/year (Knutson, et al., 1977). Because these operations are widely dispersed, complete data on pumping efficiencies are not available. Although most utilities have pump testing programs, it is not certain that the pumps tested are a representative sample since the program is voluntary. Testing of pumps may be more frequent when some malfunction is suspected; or it may be more frequent for larger (usually more efficient) pumps since these run up larger power bills, making their operators more concerned with efficiency.

Nevertheless, it is possible to derive some estimates of efficiency from these pump-testing data. Knutson et al. cite results that give a capacity-weighted average efficiency for the pumps of about 60 percent; average efficiencies below 50 percent have also been reported (Sales, 1976). Even with the higher value, a 10 percent improvement in efficiency is well within the range of currently available equipment. Further technical improvements in small motors and pumps could also achieve significant gains.

There also may be some potential for load management at small pumping facilities. Changes in the operating schedules of these facilities so that more of the pumping is done during offpeak hours could reduce peak demand substantially, but would require some changes in irrigation practices (Berman et al., 1976).

Tunnels

Since such large amounts of energy are consumed in lifting water over the coastal ranges, one might well ask whether it would be possible to tunnel through these ranges. Although tunnels are usually much more expensive than surface facilities, most projects already have many miles of tunnels; and other, lower-level tunnels have sometimes been considered in the design phase of the projects. For example, a low-level Tehachapi crossing (1500-2000 ft. above sea level instead of the present one at 3000 ft.) was considered for the California Aqueduct; the idea was not pursued because geological conditions for tunneling were poor. The tunnel would have had to cross earthquake faults deep underground, and might have been hard to repair if the faults shifted (DWR 200, Volume II).

In view of the large sunk cost in existing facilities, it would be surprising if replacement of surface facilities with tunnels was cost effective; however, it is conceiveable that tunnels could be economical in the augmentation of existing capacity in order to facilitate load management. Certainly it would seem prudent to reexamine the tunneling alternative on any project that was designed before the recent escalation in energy costs but which has not yet been built.

LOAD MANAGEMENT

The term "load management" refers to a variety of strategies which seek to manage the timing of electricity use. The objective of these strategies is to shift use from periods of high demand to periods of low demand in order to make more efficient use of generating capacity. Load management can also produce energy savings since during offpeak periods electricity can be supplied from "base load" plants which are more efficient than "cycling" and "peaking" plants which operate only during periods of high demand. For more discussion of the general aspects of load management, see Gordian Associates, 1975, and FEA, 1975.

In this examination of load management strategies for the large water agencies in California, we take "load management" to include not only shifting electricity use for pumping to offpeak periods but also shifting hydroelectric generation to on-peak periods. Attention is focused on the SWP since it is the largest energy user and since its energy use is expected to increase greatly in the future. Furthermore, if present plans for the operation of the SWP are followed, most of its increased energy demand will be for on-peak power (see Table 5).

Two sets of issues must be considered in the analysis of load management strategies for large water projects. The first concerns the technical requirements for load management and has to do largely with needs for pumping and water storage capacity. The second concerns institutional requirements for load management and has to do with contracts between water agencies and power suppliers, and the economic incentives for load management provided by these contracts.

Technical Requirements

Water projects have typically been designed to minimize capital costs for construction. Although reliability and capacity to meet future demands have often been important considerations in the design, operating costs have usually been of secondary concern. Since water was free at the source, it was assumed that capital costs would always be the major component of the price of water delivered to the users. Water project planners did not anticipate the energy crisis.

Table 5

Projected Pumping Requirements for the State Water Project.

Period	Total Increase in Annual Energy Required for Pumping (10^9 kWh)	Increase in Annual On-Peak Energy Requirements (10^9 kWh)	Annual On-Peak Used as a Portion of Total Use (Percent)
1974-1980	2.5	1.1	21
1980-1995	5.0	3.1	39
1995-2010	1.7	1.3	44

Source: DWR Bullentin 132-74, p. 34.

Because of the high capital costs associated with their construction, water projects are designed for nearly continuous operation. None of the California projects were planned for pumping exclusively during offpeak periods to reduce operating costs by load management.

In principle, it is possible to redesign existing projects so that pumping can be done offpeak. This does not require that all of the project facilities be sized for offpeak operation; the conveyance facilities (canals, etc.) still can operate continuously. Increased pumping capacity, plus storage facilities before pumping stations (forebays) and after (afterbays), are the essential requirements. With these installations the system would operate in the following way:

- Water would flow continuously into the forebays and out of the afterbays;
- During offpeak periods the pumps would operate, drawing down the forebays and filling the afterbays;
- During peak periods the pumps would shut down, the forebays would fill, and the afterbays would be drawn down.

Thus, storage capacities of the forebays and afterbays would be determined by the volumes needed to hold and supply the flow of the conveyances during peak hours. The pumping capacity would have to be sufficient to lift all the project water during the offpeak period.

At first glance, designing water project pumping stations for offpeak operation may appear to be inordinately expensive. However, when this strategy is compared with one of the possible alternatives, pumped storage, some of its advantages become apparent. To meet the on-peak power requirements of a water project pumping station, a pumped storage facility would have to be substantially larger than the pumping station because of inefficiencies in pumping and hydroelectric generation and electricity losses in transmission. If we assume:

- a pumped-storage facility with the same head height as the pumping station,
- an 88 percent generation efficiency at the pumped-storage facility,

- a 7 percent loss in transmission to the pumping station, and
- an 88 percent efficiency at the pumping station,

then the flow at the storage facility would have to be about 40 percent greater than at the pumping station. Furthermore, there would be additional costs for generators and transmission facilities and the forebays and afterbays at the pumped-storage facility would be larger than would have been required for an enlarged pumping station.

While the above comparison suggests that sizing pumping stations for offpeak operation would be preferable to building pumped-storage facilities, there may be circumstances which favor the latter alternative. This is particularly true in the case of existing pumping stations, which would have to be enlarged; existing stations may, for example, be located in places where the construction of forebays and afterbays would be prohibitively expensive. Clearly, such site-specific problems have to be examined on a case-by-case basis to determine if an enlarged pumping station is technically and economically feasible. Nonetheless, in view of the large potential advantages of offpeak pumping, careful study of these problems would be worthwhile.

In order to assess the magnitude of the potential for load management, we made a more detailed analysis of the SWP. Table 6 summarizes some of the important data for the major pumping stations on the SWP, including the number of units at each station, the static head (height of the lift), the design flow, the motor capacity in kW, present and projected capacity factors, and present and projected annual energy use. From the point of view of load management, the capacity factor is the important datum. It is defined as

$$\text{capacity factor} = \frac{\text{annual use (kWh)}}{\text{station capacity (kW)}} \;/\; \text{hours per year}$$

and indicates the fraction of time during the year that a pumping station operates.

Table 6

Present and Projected Energy Usage, Capacity, and Capacity Factors for Pumping Plants on the SWP

Name	Number of Units	Normal Static Head (ft)	Total Design Flow (ft^3/sec)	Total[d] Motor Demand (kW)	Capacity Factor[e] 1975	Capacity Factor[e] Full Development	Annual Energy Use (million kWh) 1974	Annual Energy Use (million kWh) 1975	Annual Energy Use (million kWh) Full Development[f]
Hyatt (Oroville) (pumped storage)	3	500/600[a]	5,610	387,000	≈0	0.14			465
Thermalito (pumped storage)	3	85/102[a]	9,000	89,000	≈0	0.12			91
North Bay Aqueduct:									
Calhoun	6	33	120	500	--[g]	0.68			3
Travis	6	0	120	700	--[g]	0.82			5
Cordelia	3	448	48	2,300	0.17	0.69	2.50	3.50	14
South Bay Aqueduct:									
South Bay	9	545	330	21,000	0.53	0.90	66.73	98.23	166
Del Valle	4	0/38[b]	120	800	0.08	0.29	.31	.54	2
California Aqueduct (main line):									
Delta	11	244	10,303	248,000	0.26	0.62	475.30	567.98	1,355
San Luis									
Total	8	99/327[b]	11,000		0.08				
State Share			5,762	197,000		0.18	12.42	136.95	313
Dos Amigos									
Total	6	113	13,200		0.29				
State Share			7,100	97,000		0.71	193.19	249.84	607
Buena Vista	10[c]	205	5,049	101,000	0.25	0.84	184.80	227.76	746
Wheeler Ridge	9[c]	233	4,598	104,000	0.23	0.87	169.62	211.60	792
Wind Gap	9[c]	518	4,410	230,000	0.23	0.87	355.92	454.27	1,761
A. D. Edmonston (Tehachapi)	14[c]	1,926	4,095	776,000	0.24	0.87	1,252.96	1,582.46	5,916
Pearblossom	6	540	1,380	84,000	0.19	0.88	123.97	136.96	647
California Aqueduct (branches):									
Oso	8	231	3,128	70,000	0.22	0.73	102.56	135.57	446
Las Perillas	6	55	450	3,000	0.43	0.76	9.26	11.22	20
Badger Hill	6	151	450	8,000	0.43	0.80	24.46	29.93	56
Devil's Den	4	409	126	6,000	--[g]	0.97			51
Sawtooth	4	331	126	5,000	--[g]	0.94			41
Polonio	4	810	126	12,000	--[g]	0.96			101
Total, State Share							2,974	3,849	13,603[h]

[a] Minimum and maximum total pumping heads.

[b] Minimum and maximum static heads.

[c] Includes one spare unit. Edmonston will only have 11 units until 1983.

[d] Converted from horsepower by multiplying by 0.7457.

[e] Capacity factor = $\frac{\text{Annual Demand (kWh)}}{\text{Unit Capacity (kWh)}}$ /Hours Per Year.

[f] Projected average use.

[g] To be completed after 1980.

[h] This is the summary number given at the end of DWR Bulletins 132-75 and 132-76; it differs from the annual use estimate given on page 33 of DWR 132-76, which is 12,472,000,000 kilowatt-hours. The Draft EIR for the DWR Long-Range Energy Program, page II.11, states that the annual energy requirement at full development will be about 12 billion kWh. Note that the total in the table includes energy for pumpback at Hyatt/Thermalito—the total for water delivery only, is 13,047 million kWh.

To obtain a rough estimate of the load that is potentially "shiftable" from peak to offpeak, one can suppose that during whatever fraction of the year that is offpeak the pumps will operate at 100 percent capacity. Then, if the offpeak fraction of the year is less than the capacity factor,

$$\text{shiftable load} = \frac{\text{capacity factor - offpeak fraction}}{\text{capacity factor}} \text{ X annual use}$$

Table 7 gives such estimates for the SWP at full development (sometime after 1995).

Two possible definitions of the offpeak fraction are used in Table 7, 50 percent and 67 percent. The 50 percent fraction might correspond to a 12-hour daily peak. Less regular 50 percent schedules such as the one in contracts between DWR and electric utilities (in which peak is defined as 7:00 a.m. to 10:00 p.m. on weekdays and 1:00 p.m. to 10:00 p.m. on Saturday), would require greater capacity additions for full utilization of conveyances. The 67 percent period might correspond to an 8-hour daily peak. Definitions of this type are somewhat limited because actual peak loads for electrical utility systems do not follow a regular schedule. Loads fluctuate from day to day, from week to week, from season to season, and from year to year. Much of this variability depends on the weather, a factor beyond the control of contracts. Some of the implications of this variability will be discussed below under <u>Power Contracts and Operating Schedules</u>.

A further limitation of the estimates in Table 7 is that it may not be possible to accomodate the operating schedule of the SWP to the off-peak schedule. In particular, the Delta, San Luis, and Dos Amigos plants may have to operate at nearly 100 percent of capacity during certain seasons of the year, to store water during periods of high runoff or to meet agricultural demands.

In spite of these limitations, the estimates in Table 7 for potentially shiftable loads of 5 billion kWh/year for a 50 percent offpeak fraction and 2.4 billion kWh/year for a 67-percent offpeak fraction are a reasonable indication of the magnitude of the possible savings. To

Table 7

Potentially Shiftable Pumping Load for the State Water Project at Full Development

	Average Annual Energy Requirements (million kWh)	Annual Average Capacity Factor	Shiftable Load, 50% of Year Offpeak (million kWh)	Shiftable Load, 67% of Year Offpeak (million kWh)
North Bay Aqueduct:				
Calhoun	3	.68	1	0
Travis	5	.82	2	1
Cordelia	14	.69	4	0
South Bay Aqueduct:				
South Bay	166	.90	74	42
Del Valle	2	.29	0	0
California Aqueduct (main line):				
Delta	1,355	.62	262	0
San Luis State Share	313	.18	0	0
Dos Amigos State Share	607	.71	180	34
Buena Vista	746	.84	302	151
Wheeler Ridge	797	.87	339	183
Wind Gap	1,761	.87	749	405
A. D. Edmonston	5,916	.87	2,516	1,306
Pearblossom	647	.88	279	154
California Aqueduct (branches)				
Oso	446	.73	141	37
Las Perillas	20	.76	7	2
Badger Hill	56	.80	21	9
Devil's Den	51	.97	25	16
Sawtooth	41	.94	19	12
Polonio	101	.96	48	31
Total, State Share (rounded)	13,000		5,000	2,400

estimate the economic value of these savings it is necessary to know the difference in price between peak and offpeak power in the years after 1995. However, the value of this difference is uncertain and there is little information on which to base estimates. We have therefore used what we feel is a plausible range of values, from 1 to 5¢ per kWh (1977 dollars)*, to calculate the annual savings which might result from increased load management on the SWP. These are shown in Table 8.

While the possible savings shown in Table 8 cover a wide range, it is clear that, especially for the larger price differentials, very substantial investments in new facilities might be justified. To get some idea of the size of the expenditures that might be justified, we have computed the amounts of investment that can be amortized over a 30 year period with the savings. Since the amounts are sensitive to interest rates, we have made computations at both 5% and 10% interest. The results of these computations are given in Table 8. The range of the amounts in the Table, from $226,000,000 (2.4 billion kWh/yr savings, 1¢ price differential, 10% interest) to $3,843,000,000 (5 billion kWh/yr savings, 5¢ price differential, 5% interest) is too large for good decision making; the estimates need to be refined in further studies. But the amounts involved are sufficiently large to suggest that careful analysis of load management strategies by DWR is warranted.

The complement of offpeak pumping on the water systems is on-peak generation. However, technical limitations constraining on-peak generation are not as great as those associated with offpeak pumping. The main reason for this is that many of the generation facilities at the major storage reservoirs were built with sufficient capacity

*Currently, PG&E's large customers pay about 3¢ per kWh more in the summer and about 2¢ per kWh in the winter for 30 peak hours per week in the summer and 20 peak hours per week in the winter. A recent ERCDC study (Devanney, et al. 1977) estimated that peak power prices based on marginal costs for SDG&E should be between 3 and 6¢ per kWh, depending on the number of peak hours. (The lower figure was for 2568 hrs/yr and the higher for 1320 hrs/yr). If current trends in fuel prices continue, we can expect that differences in operating costs between peaking and base load plants will grow larger. For example, one study estimates that the difference in fuel cost between gas turbines and oil fired steam plants will be 3.4¢ (1975 dollars) per kWh in 1995 (Economic Sciences Corp, 1976).

Table 8

Annual Savings and Investment Justified for Peak Power Conservation

	Peak Power Conservation					
	2.4 Billion kWh/yr			5.0 Billion kWh/yr		
		Investment Amortized in 30 yrs ($ X 10^6)			Investment Amortized in 30 yrs ($ X 10^6)	
Peak to Offpeak Price Differential (cents/kWh)	Annual Savings ($ X 10^6)	@ 5%	@ 10%	Annual Savings ($ X 10^6)	@ 5%	@ 10%
1	24	369	226	50	769	471
2	48	738	452	100	1537	943
3	72	1107	679	150	2306	1414
4	96	1476	905	200	3074	1885
5	120	1845	1131	250	3843	2357

to accomodate the peak runoff during the spring. Thus, while they operate at near 100 percent capacity during the spring, they have extra capacity during the other seasons.

Table 9 gives a summary of generation capacity factors for the water projects. Most of the capacity is associated with the CVP and the SWP, both of which operate at relatively low capacity factors (note that 1973, the year on which data for the CVP are based, had relatively high runoff). Because the data in Table 9 aggregate all of the generating capacity for each project, a more detailed analysis on a facility-by-facility basis is required before definite conclusions can be reached on the opportunities for increased capacity. However, the data are sufficient to suggest that considerable flexibility does exist for on-peak generation.

One area where there may be some advantage in increasing the capacity is the recovery-generation plants on the California Aqueduct. Although these plants now operate at low capacity, Table 10 shows that some will have high capacity factors when the SWP reaches full development. If these plants could be reengineered to increase capacity, then more than 860 million kWh/year could be shifted to a 12-hour daily peak.

Power Contracts and Operating Schedules

The primary determinant of the scheduling of operations on the water projects is the demand of the water users; however, their needs do not require an entirely fixed operating schedule. Thus, there is flexibility to accommodate, to some extent, the second factor that influences scheduling: the contracts governing prices for the exchange of electricity among the water projects and the electric utilities. Over the years these contracts have developed into a fairly intricate network of agreements. A full exploration of this network would require a long and involved analysis, which has not been attempted here. Instead, an effort has been made to understand the basic structure of the CVP and SWP agreements, since these two projects are involved in most of the power transactions.

Table 9

Generation Capacity Factors for the Water Projects

Project Name	Annual Generation (millions of kWh)	Capacity (kWh)	Capacity Factor	Data Year
Central Valley[a]	6,289	1,106,880	0.65	1973
Hetch Hetchy	2,000	292,000	0.78	1975
Los Angeles Aqueduct	1,120	230,500	0.55	1975-6
Mokelumne	120	15,000	0.91	1975
Imperial Irrigation District	216 (est.)	74,000	0.34	1974
State Water Project[a]	2,343	798,350	0.33	1975

[a] Generation from primary storage facilities only. Recovery generation facilities operated at low capacity and produced relatively little power (see Table 4).

Table 10

Generating Plants and Shiftable Generation for the State Water Project at Full Development

	Total Design Flow (cfs)	Generator Capacity (kW)	Average Annual Energy Output (million kWh)	Capacity Factor	Generation Shiftable On-Peak (million kWh)[a]
Edward Hyatt	14,550	678,750	2,475	0.42	
Thermalito	16,900	119,600	383	0.37	
San Luis State Share	6,872	222,100	170	0.09	
Cottonwood	1,637	15,000	115	0.88	50
Devil Canyon	1,200	119,000	1,003	0.96	480
Pyramid	3,100	157,000	1,001	0.73	315
Castaic	3,092	--[b]	1,457	--[b]	
San Luis Obispo	111	5,900	41	0.79	15
Total.		1,317,350	6,645		860

Source: DWR 132-76, p. 209.

[a] This assumes a 12-hour daily peak year-round. The capacity factor above 0.50 is multiplied by the annual generation and divided by the capacity factor to obtain the potentially shiftable generation.

[b] The City of Los Angeles Department of Water and Power constructed and operates a 1,250,000 kilowatt Castaic Power Plant (850,000 kW operational as of June 1977) and will supply the Project with electrical power and energy equivalent to the generation from a 213,984 kilowatt power plant, which the State originally planned to construct.

Before describing these agreements, we define two terms: "firm power" and "dump energy." Firm power is that delivered according to a regular schedule over the period of a contract (typically five or more years).* Dump energy is delivered on an irregular schedule, i.e., both the amount and the time of delivery may vary from year to year. The amount of dump energy available from the water projects in a given year is dependent on runoff and on operational requirements imposed by water needs. The price of firm power is greater than the price of dump energy because the need for generating capacity is reduced when a utility has a firm supply, whereas dump energy reduces only the requirement for fuel. This price difference is sometimes called a "capacity credit."

The DWR has agreements for importing power from the Pacific Northwest and for both buying and selling power in California. Most of the power sales are from the Hyatt/Thermalito complex and are governed by a contract between Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas and Electric Company (collectively, the "Companies"), and DWR. Under this agreement DWR does not use any of the Hyatt/Thermalito power for its operations on the California Aqueduct; instead, the power is sold exclusively to the Companies which pay DWR a fixed fee of $16,500,000 per year. For this they receive 2.1 billion kWh of firm power and the use of the pumped-storage facilities. In addition, the Companies pay for dump energy in excess of the 2.1 billion kWh at 2.6 mills per kWh. (The actual provisions for dump energy are fairly complicated, but in most cases a 2.6-mill payment is the result.) The contract also contains provisions requiring the DWR to coordinate power deliveries with the requirements of the Companies and penalties for delivering power offpeak (i.e., only 0.77 kWh is credited for each 1 kWh of offpeak power delivered). Thus, there is incentive for on-peak operation at Hyatt/

---

*In some transactions, the sale of power does not include energy, i.e., the energy delivered must be returned at some other time. In such transactions, the power (in this context, capacity) is usually made available on-peak and the energy is returned offpeak. In this report, statements concerning the sale of power refer to transactions that include the sale of energy.

Thermalito; and most of the power is, in fact, delivered on-peak.

The contract between the Companies and DWR was made in 1967. It is to be renegotiated as of 31 March 1978, with new terms to become effective on 1 April 1983. The Draft Environmental Impact Statement for DWR's long-range energy program indicates a strong likelihood that DWR intends to discontinue sale of Hyatt/Thermalito power, which it will use instead for project pumping.

Intrastate purchases of power by DWR and transactions involving recovery generation are governed by a contract between the Companies and LADWP (collectively, the "Suppliers") and DWR. Under this contract which runs to 1983, DWR pays the Suppliers 3 mills per kWh for energy received for project pumping, In addition, DWR pays a demand charge based on the kW of generating capacity needed to supply power during on-peak periods. Because this demand charge more than doubles the cost of on-peak energy,* DWR has a strong incentive to confine its purchases to offpeak periods--which, for the most part, it does. However, some power is purchased on-peak; in 1977, for example, DWR planned to purchase about 88 million kWh of on-peak power (20 MW of capacity) from the Suppliers.

Most of the recovery generation from the SWP is used for project pumping. The contract does contain provisions for "banking" power from recovery generation (i.e., delivering power to the Suppliers in exchange for power to be received by the project at some future time), but the banked power must be used offpeak within two weeks or it is considered to have been sold to the Suppliers at 1.75 mills per kWh. The contract with the Suppliers contains no incentives to bank power on-peak for later offpeak use.

The DWR purchases both firm power and dump energy from the Pacific Northwest. The firm power comes from the "Canadian Entitlement": this

*The actual differential depends on the fraction of the time the capacity is used. The demand charge is set by the maximum capacity used during a given month even if the capacity is used only for a short period. The contract provisions governing the amount of the monthly demand charge are complicated; for example, the charge depends on how much notice the Suppliers had that capacity would be required, and also on the use of capacity in the preceeding 11 months.

is power generated in the Pacific Northwest that is earmarked for Canada as part of an agreement under which Canada releases water from its dams in a way that facilitates power production in the U.S. Canada has sold its Entitlement to an association of Northwest utilities. DWR, in turn, has purchased shares of the Entitlement from some members of the association. Under contracts running to 1983, 300 MW of capacity is available to the DWR for on-peak use. The price of Entitlement power is 3.9 mills/kWh. If the DWR does not want the power for an entire year, an arrangement exists whereby it can be sold to the Companies at cost.

Northwest dump energy is purchased primarily from the Bonneville Power Administration. The amount of dump energy available varies from year to year, depending on runoff. Prices for dump energy vary with market conditions, but in the past have typically been quite low (2-4 mills/kWh).

One consequence of the above agreements covering interstate power purchases and recovery generation is that a significant fraction of the pumping operations on the SWP are now conducted on-peak, even though pumping capacity is at this time sufficient to meet project needs almost entirely with offpeak operation (see Table 6). Since there are some advantages to continuous operation (e.g., the stress placed on pumps by start-up is reduced) and because there is little reason not to use recovery generation or the Canadian Entitlement for on-peak pumping, operations in 1977 will use 150-170 MW of on-peak power (30-50 MW recovery, 100 MW Canadian Entitlement, and 20 MW intrastate).*

In contrast to the SWP, the Central Valley Project sells much more power than it uses. The CVP generates approximately 6 billion kWh/year of electricity. In order to sell 5 billion kWh to preference agencies (rural electric cooperatives, municipalities, and other public and quasi-public agencies), 3 billion kWh to PG&E, and to use almost 1 billion kWh for project operations, the CVP imports an extra 3 billion kWh from the

---

*Because water shortages this year (1977) have reduced both the hydroelectric capacity available to PG&E and the level of operations on the SWP, these arrangements may be changed. PG&E and the DWR are attempting to reach an agreement on this.

Pacific Northwest. Since the CVP generates only hydroelectric power, its ability to supply firm power all year long is limited. By importing additional power, it is able to sell more firm power. The energy transfer among the various customers (CVP itself, preference agencies, and PG&E) is fairly complicated. The end result, however, is that the CVP can contract to sell 6 billion kWh of firm power rather than only the 2-3 billion kWh of firm CVP generation.

The operating practices of the CVP have not been investigated in any detail for this report. There is clearly an incentive not to schedule pumping in any way that compromises firm power commitments. Nonetheless, a significant fraction of the project pumping is conducted on-peak. Whether this is because of a lack of incentive to exchange on-peak dump energy for offpeak power or because of a lack of pumping capacity has not been determined.

While the above description of power contracts hardly does justice to the complexity of these arrangements, it does give an indication of the context in which operating decisions are made on the water projects. Clearly, the power contracts are critical to load management. Price differentials between peak and offpeak power set by these contracts will be a major determinant of the economic feasibility of load management strategies. Some idea of the future structure of the contracts is a necessary ingredient for load management planning. The two intrastate power contracts for the SWP expire in 1983, but they also contain provisions for renegotiation five years in advance of the termination (i.e. 1978). Thus, the next year could be a decisive period for load management on the SWP.

There are two changes which could be made, more or less within the existing contract structure, that would encourage load management. First, the renegotiated contracts could include graduated demand charges. The existing contracts provide for only one level of demand charges (or capacity credits) based on on-peak periods that are the same for each week of the year. The current on-peak schedule (7:00 a.m. to 10:00 p.m. on weekdays and 1:00 p.m. to 10:00 p.m. on Saturday) does not differentiate between the periods of greatest electricity demand (afternoons on weekdays) and periods of relatively lower demand. Division of the schedule into periods of "peak," "partial peak," and "offpeak" with different demand charges for each period would encourage more efficient use of generating capacity. Demand for electricity also varies seasonally with the highest demand for electricity in California occurring during the summer. Thus, seasonal adjustments to the demand charges (higher demand charges in the summer) could also encourage more efficient use of generating capacity.

Second, the renegotiated contracts could include graduated energy charges. The existing contract for energy supply has a single energy charge regardless of the time of delivery. In the contract for Hyatt/Thermalito, utilities pay less for energy delivered offpeak. Since fuel costs increase with increasing demand,* graduated energy charges would encourage more efficient fuel use. Such charges could be based on the same "peak," "partial peak," "offpeak," and seasonal schedules used for graduated demand charges. If the graduated energy charges applied to exchanges of energy as well as to purchases, the SWP would have an incentive to exchange on-peak recovery generation for offpeak power.

Graduated demand and energy charges are already in effect for a number of large power users in Northern California. Thus, including graduated charges in the DWR contracts would not be a departure from current pricing practices.

Graduated charges take account of regular daily and seasonal variations in demand, but they cannot reflect unsystematic fluctuations caused by extreme weather. (In the winter, very cold weather increases demand for electric heating; in summer, very hot weather increases demand for air conditioning.) In California, peak electricity demands caused by very hot weather may exceed the average peak demand for summer days by more than 1000 MW. One way of dealing with this is "interruptible power." In Northern California, some customers have power contracts which permit

---

*When a large fraction of the peaking power is supplied by hydroelectric plants, the average fuel costs may not always increase with demand. In this case, the argument for graduated energy charges is based on the marginal fuel cost (i.e., fuel costs for the least efficient generators, usually gas turbines).

the utility to interrupt service when the generating system is near maximum output. This reduces the need for generating capacity. In return, these customers pay reduced demand charges.

The existing supply contract for the SWP provides power to the project on demand. If provisions for interruptible power were included in the renegotiated contracts, then power delivery would be partly at the discretion of the Suppliers. This could require changes in the operating practices of the project. Still, since the SWP has a potential peak load of more than 1500 MW, provision for interrupting project pumping on a few peak days during the year could result in substantial savings. These savings might justify a departure from the current "power-on-demand" arrangements.

While graduated charges and interruptible power can encourage more efficient use of resources, it is difficult, within the context of a fixed schedule of rates, to construct agreements that will result in optimum operations for both the SWP and the Suppliers. In the future, optimum operating practices will be influenced by many factors including the demand for electricity, the demand for water, the climate, and the price of fuel. It is unreasonable to expect that these conditions can be fully anticipated in any fixed schedule.

A coordination agreement is an alternative to fixed schedules that could lead to more nearly optimum operations. Under such an agreement the Suppliers and DWR would both participate in the scheduling of operations. Project operations would be scheduled at times when the demand on the utilities' generating systems was lowest. Power for project pumping would be delivered from the utility that could supply it most economically. Project generation would be scheduled to supply power when it was most needed.

This type of coordination agreement is similar to "power-pool" agreements which now exist between some utilities in the eastern United States (see Kahn, 1977). The management practices and operating procedures that have been developed for these power pools could provide guidance for the establishment of a coordination agreement in California.

A reading of DWR's Draft Environmental Impact Report on its long-range energy program (DWR, 1976) indicates that the Department has recognized the advantages of a coordination agreement and is trying to provide for coordination in the renegotiated contracts. The potential economies of coordinated operations make this course of action well worth pursuing.

CONCLUSIONS AND RECOMMENDATIONS

The major conclusion of this study is that load management on the large water delivery systems in California is an important alternative to new generating capacity. Two complementary strategies for load management have been identified: increased pumping capacity and coordinated operations. Insuring that these strategies receive proper consideration and that the right mix of strategies is ultimately employed will require the concerted efforts of the water projects, the utilities and the regulatory agencies.

The ERCDC is mandated to examine alternatives to new generating capacity and to encourage those alternatives that can benefit the people of California. Thus, the ERCDC can and should involve itself in those operations of the water projects that have substantial energy impacts. The following three actions appear to be appropriate:

- The ERCDC should monitor power contract negotiations.
- It should determine the applicability of the power-pooling provisions of the proposed National Energy Act to water systems.
- It should encourage and support detailed studies of load management methods for specific water projects.

Power Contracts

Contracts for electricity supply between the water projects and the electric utilities have a substantial impact on the need for new generating capacity in California. Contracts for the SWP alone affect a potential peak load of more than 1500 MW.

The ERCDC should take steps to insure that provisions which encourage load management are considered when new contracts are negotiated. A thorough review of the existing contracts should be undertaken to determine what new provisions might be advantageous. Opportunities for changing contracts now in force should be explored. A schedule of upcoming negotiations should be maintained so that the ERCDC will have the opportunity to make timely recommendations.

Pursuant to Section 21100 of the Public Resources Code, the ERCDC should insist that energy impact statements be prepared for major new power contracts and that the alternatives of graduated prices, interruptible schedules, and coordination agreements be examined in these statements. A review of other statutes should be made to determine what other responsibility and authority the ERCDC has concerning power contracts.

Power Pooling

The most effective contractual arrangement for load management on the water projects is a coordination agreement. With flexible scheduling of pumping operations and hydroelectric generation, the utilities and the projects can jointly work to optimize system operations in a way that will take account of climatic variations and changing demands for water and power. Such arrangements would be similar to the "power-pools" which now exist to coordinate the operations of utilities in the eastern United States. The draft EIR for the SWP's long-range energy program indicates that the DWR is seeking a coordination agreement for the operation of the SWP. However, the report also expresses uncertainty as to whether the utilities will agree to a satisfactory arrangement.

President Carter's proposed National Energy Act contains provisions which may be applicable in the event that a satisfactory agreement cannot be reached. Section 521 of the Act would empower the Federal Power Commission (FPC) to order electric utilities to form power pools and would also allow the FPC to set the terms governing power-pool transactions. The Act appears (Section 502a) to define the DWR as an electric utility for the purposes of Section 521.

The ERCDC should undertake a careful study of the power-pooling provisions of the National Energy Act to determine if they are applicable to the operation of the water projects. The aim of the study would be to assist the DWR in preparing a motion to the FPC seeking an equitable arrangement if this becomes necessary.

Further Studies

Increased pumping capacity could greatly facilitate load management on the water projects. The analysis in this report suggest that very substantial investments (perhaps in the billions of dollars for the SWP) may be warranted for this purpose. However, detailed engineering studies and more sophisticated economic analyses are required before decisions can be made on whether to pursue this alternative.

The water agencies themselves are probably in the best position to undertake analysis of the technical feasibility and costs of additional pumping capacity since this analysis requires detailed knowledge of the engineering aspects of the water projects. On the other hand, analysis of the benefits of increased pumping capacity is an appropriate task for the ERCDC since such a study is largely dependent on analysis of the costs of other alternatives, including increased generating capacity and load management for other sectors of the economy.

Because the critical electricity supply decisions are being made now, the State Water Project presents the most immediate need for the analysis of increased pumping capacity. The ERCDC should encourage the Department of Water Resources to participate in a cooperative study of load management alternatives and should seek to secure resources for such a study which are adequate to conduct a thorough investigation. A careful analysis of the alternatives now could result in large future savings for all Californians.

ACKNOWLEDGEMENTS

Cliff Orloff participated in the planning of this study and provided helpful comments throughout the course of the work. Yvonne Howell edited the final report. Ed Kahn and Jayant Sathaye made additional helpful comments. A number of persons from USBR, local water agencies, and utility companies helped us to obtain data. We are grateful to all of these contributors.

BIBLIOGRAPHY

Berman, S. M.; Blumstein, C; Adams, V.A.; Clear, R.D.; Goldstein, D.B.; Greene, B.A.; Kahn, E.P.; Klein, W.; Krieg, E.L.; Schroeder, C.; and Wilms, W.W. Preliminary Report on the Assessment of Energy Conservation Strategies and Measures. Berkeley, California: Lawrence Berkeley Laboratory, October 1976.

California Statistical Abstract. Sacramento, California: State of California, 1975.

Cervinka, V.; Chancellor, W.J.; Coffelt, R.J.; Curley, R.G.; and Dobie, J.B. Energy Requirements for Agriculture in California. Davis, California: California Department of Food and Agriculture and the University of California, January 1974.

Copley International Corporation. The Market Structure of the Southern California Water Industry. Prepared for the Office of Water Resources Research, U.S. Department of the Interior. LaJolla, California: Copley International Corporation, June 1974.

Department of Water Resources. California State Water Project, Volume II, Conveyance Facilities. DWR Bulletin 200. Sacramento, California: DWR, November 1974.

Department of Water Resources. California State Water Project, Volume IV, Power and Pumping Facilities, DWR Bulletin 200. Sacramento, California: DWR, November 1974.

Department of Water Resources. The California State Water Project in 1966. DWR Bulletin 132-66. Sacramento, California: DWR, June 1966.

Department of Water Resources. The California State Water Project in 1974. DWR Bulletin 132-74. Sacramento, California: DWR, June 1974.

Department of Water Resources. The California State Water Project in 1975. DWR Bulletin 132-75. Sacramento, California: DWR, June 1975.

Department of Water Resources. The California State Water Project in 1976. DWR Bulletin 132-76. Sacramento, California: DWR, June 1976.

Department of Water Resources. The California Water Plan: Outlook in 1974. DWR Bulletin 160-74. Sacramento, California: DWR, November 1974.

Department of Water Resources. Contract between California Suppliers and the State of California for the Sale, Exchange and Transmission of Electric Capacity and Energy for the Operations of State Water Project Pumping Plants. DWR Contract No. 855503. November 18, 1966.

Department of Water Resources. Draft Environmental Impact Report - Long-Range Energy Program. Sacramento, California: DWR, 1976.

Department of Water Resources. Hydroelectric Energy Potential in California. DWR Bulletin 194. Sacramento, California: DWR, 1974.

Department of Water Resources. Water Conservation in California. DWR Bulletin 198. Sacramento, California: DWR, May 1976.

Department of Water Resources. Oroville-Thermalito Power Sale Contract. DWR Contract No. 860502. November 29, 1967.

Devanney, J.; Enholm, R.; and Witt, K. Electricity Pricing Policies for California. Sacramento, California: ERCDC, 1977.

Economic Sciences Corporation. A Review and Analysis of Resource Forecasts of California Electric Utilities. Prepared for ERCDC as ERCDC 4-0003. Berkeley, California: Economic Sciences Corporation, 1976.

Energy Resources Conservation and Development Commission. Load Management in California. Staff Report. Sacramento, California: ERCDC, 1976.

Energy Resources Conservation and Development Commission. Survey of Water Agencies in California. Staff Draft. Sacramento, California: ERCDC, June 1976.

Engle, Clair. Central Valley Projects Documents, Part Two: Operating Documents. Washington, D.C.: GPO, 1957.

Federal Energy Administration (FEA). Proceedings of the Conference on the Challenge of Load Management, Conservation Paper No. 24. Washington, D.C., 1975.

Gordian Associates, Inc. A Report on the Opportunities and Incentives for Electric Utility Load Management. New York, New York: Gordian Associates, Inc., 1975.

Harding, S.T. Water in California. Palo Alto, California: N-P Publications, 1960.

Hartman, L.M. and Seastone, Don. Water Transfers: Economic Efficiency and Alternative Institutions. Baltimore, Maryland: Resources for the Future, 1970.

Hundley, Norris. "The Politics of Reclamation: California, the Federal Government and the Origins of the Boulder Canyon Act—A Second Look," California Historical Quarterly, Volume II, Number 4, Winter 1973, pp. 292-326.

Imperial Irrigation District. Model "Greenhouse" for Desert Agriculture. Bulletin 1075. El Centro, California: Imperial Irrigation District.

Kahn, Edward P. An Assessment of the Potential for Full Coordination of the California Electric Utilities. LBL-5941. Berkeley, California: University of California, Lawrence Berkeley Laboratory, 1977.

Knutson, G.D.; Curley, R.G.; Roberts, E.B.; Hagan, R.M.; and Cervinka, V. Pumping Energy Requirements for Irrigation in California. Davis, California: California Agricultural Experiment Station, 1977.

Lasater, I. Backup Paper CD-5. Sacramento, California: ERCDC, August, 1976.

MacDiarmid, J.M. The California State Water Project: Development; Description; Current Conflicts. Paper presented to the 62nd Annual Conference of the National Council for Geographic Education, November 27, 1976, in San Francisco.

Metropolitan Water District of Southern California. Water from the Colorado. Los Angeles, California: MWD, October 1974.

Murray, C.R. and Reaves, E.B. Estimated Use of Water in the United States in 1970. USGS Circular 676. Washington, D.C.: GPO, 1972.

National Academy of Sciences, Committee on Technologies and Water. Potential Technological Advances and Their Impact on Anticipated Water Requirements. Washington, D.C.: National Academy of Sciences, 1971.

Roberts, E.B. and Hagan, R.M. Energy Requirements of Alternatives in Water Supply, Use and Conservation: A Preliminary Report. California Water Resources Center Contribution No.155. Davis, California: California Water Resources Center, December 1975.

Sales, D. Sacramento Municipal Utilities District. Personal Communication, June 25, 1976.

Smith, S.C. and Brewer, M.F. California's Man-Made Rivers: History and Plans for Water Transfer. Berkeley, California: University of California, Division of Agricultural Sciences, 1961.

Splinter, W.E. "Center-Pivot Irrigation," Scientific American. June 1976.

Stan, R.M. Economic Incentives for Efficient Energy Use. ERCDC Agreement No. 4-0161. Sacramento, California: Energy Resources Conservation and Development Commission, September 1976.

Todd, D.K. The Water Encyclopedia. Port Washington, New York: Water Information Center, 1970.

U.S. Bureau of the Census, 1969 Census of Agriculture: Volume IV, Irrigation. Washington, D.C.: GPO, 1972.

U.S. Bureau of Reclamation. Central Valley Project Annual Report 1973. Washington, D.C.: GPO, 1974.

U.S. Bureau of Reclamation. Informal Report, September 30, 1975, Meeting of CVP Reanalysis Team. Washington, D.C.: U.S. Department of the Interior, 1975.

U.S. Department of Agriculture. Water: The Yearbook of Agriculture. Washington, D.C.: GPO, 1955.

Warne, W.E. The Bureau of Reclamation. New York, New York: Praeger Publishers, 1973.

Water Resources Council. The Nation's Water Resources - First National Assessment. Washington, D.C.: GPO, 1968.

Watts, D. "Agricultural Water Supply." Paper presented at the Nebraska Water Resources Research Institute Conference, The Role of Water in the Energy Crisis, held 23-24 October 1973, in Lincoln, Nebraska.

APPENDIX A

DWR ALTERNATIVE FUTURES

The variables used to define each of the four DWR alternative futures are listed in Table A-1. Specific population numbers and irrigated crop acreages used in the analysis are in Tables A-2 and A-3.

Table A-1

Alternative Futures

	I	II	III	IV
Population Growth				
Fertility Rates [a]	2.8	2.5	2.5	2.1
Immigration	150,000	150,000	100,000	0
Agricultural Production				
National Population [b]	D	D	D	E
Foreign Trade [c]	High	Low	Low	Low
Crop Yields [d]	Modified	Modified	1968	Modified
Power Plant Cooling				
Energy Demand [e]	High	High	Low	Low
Inland Plants [f]	2/3	1/3	2/3	1/3

[a] Average number of children born per woman during her child-bearing years.

[b] U.S. Bureau of the Census series. Series D projects a population of 259 million in 1990 and 351 million in 2020; series E projects 247 million in 1990 and 298 million in 2020.

[c] Low estimate based on pre-1970 data; high estimate reflects 1972-74 events

[d] 1968 estimates used in Bulletin No. 160-70.

[e] High estimate based on California Public Utilities Commission projection and low estimate on Rand Corporation Case 3.

[f] Portion of new thermal plants requiring fresh cooling water.

Table A-2

Alternative Future Populations (in thousands)

	1972	1990				2020			
		I	II	III	IV	I	II	III	IV
Population:*									
Central Valley HSAs	3,100	3,100	4,390	4,290	4,200	7,500	6,780	6,320	4,570
South Coastal	11,240	11,240	14,620	14,260	13,930	22,510	20,300	19,140	13,790
San Francisco	4,630	4,630	5,940	5,800	5,680	8,670	7,920	7,350	5,700
Colorado Desert and South Lahontan	470	470	760	700	700	1,690	1,450	1,360	780
Other	1,060	1,060	1,690	1,650	1,590	1,400	2,650	2,430	1,660
	20,500	27,400	26,700	26,100	23,600	43,300	39,100	36,600	26,500

*DWR Bulletin 160-74, p. 47

Table A-3

Alternative Future Irrigated Crop Acreages (in thousands of acres)

	1972	1990				2020			
		I	II	III	IV	I	II	III	IV
Irrigated Acreage:*									
Central Valley HSAs	6,700	8,190	7,760	7,400	7,200	9,340	8,540	7,880	7,430
South Coastal	390	290	290	290	300	220	220	220	220
San Francisco	110	130	120	120	120	150	140	140	120
Colorado Desert and South Lahontan	710	710	710	710	710	720	700	700	700
Other	800	880	860	860	850	930	920	910	890
	8,780	10,200	9,740	9,380	9,180	11,360	10,520	9,850	9,360

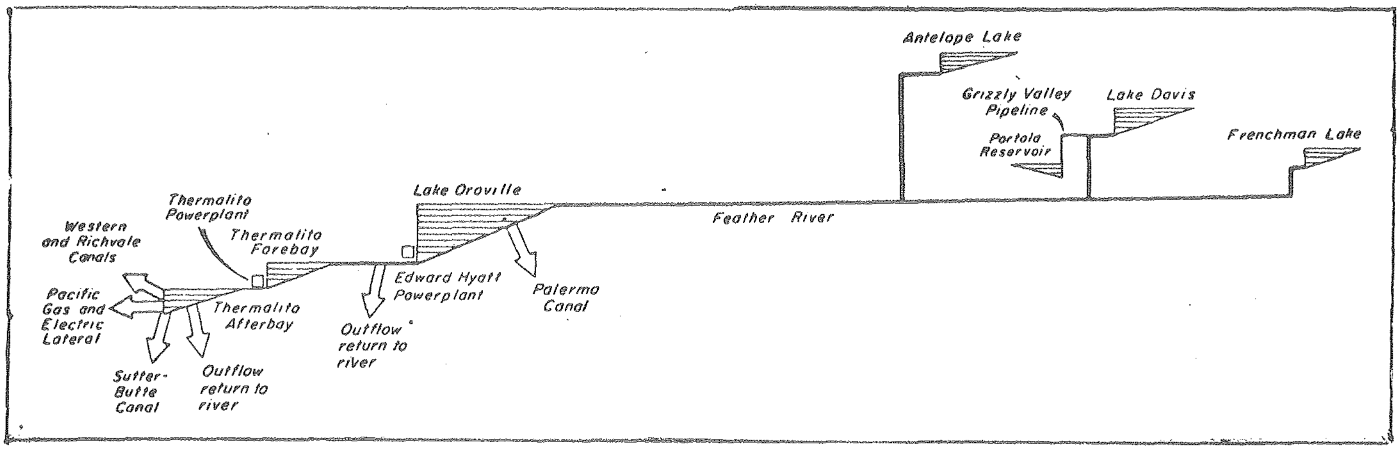
* DWR Bulletin 160-74, p. 55

APPENDIX B

THE STATE WATER PROJECT

The following tables present an overview of the State Water Project system and show the magnitude and rate of water flows. The information is summarized from the Department of Water Resources Bulletins 132-75 and 132-76.

Oroville Field Division (water operations during 1974 and 1975)



Outflow (acre-feet)

Deliveries	1974	1975	Annual Entitlement to Project Water at Full Development
Palermo Canal	8,468	8,635	
Western Canal	275,096	233,134	
Richvale Canal	106,228	100,233	
PG&E Canal	3,276	3,987	
Sutter-Butte Canal	494,415	499,804	
City of Yuba			9,600
County of Butte			27,500
Plumas County FC & WCD			2,700
River Outlet	5,992,252	2,952,114	
TOTAL	7,879,735	3,797,907	

Dams and Reservoirs

	Capacity (acre-feet)	Max Flow Rates (cfs)[a] In	Max Flow Rates (cfs)[a] Out
Frenchman Lake	55,477		165
Lake Davis	84,371		222
Antelope Lake	22,566		136
Lake Oroville	3,537,577	5,610[b]	5,400/16,900[c]
Thermalito Forebay	11,768	16,900/9,000[d]	16,900/9,000[e]
Thermalito Afterbay	57,041	16,900	17,000/9,000[f]

[a] Normal operations; this does not include flood conditions.

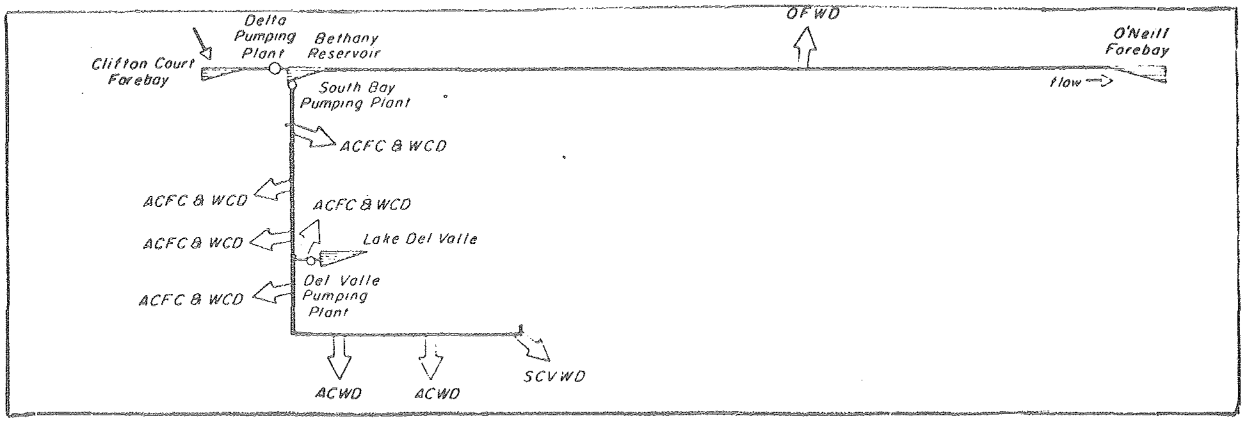
[b] From Thermalito Forebay, does not include Feather River inflow.

[c] River outlet/Thermalito Forebay.

[d,e] Edward Hyatt Power Plant/Thermalito Power Plant.

[f] Return flow to river does not include contract outlets/Thermalito Forebay.

Delta Field Division (water operations during 1974 and 1975)



Inflow (acre-feet)

	1974	1975
Pumped from Delta		
State	1,563,090	1,865,887
Federal	299,542	20,885
Natural Runoff into Lake Del Valle	4,608	5,126
TOTAL	1,867,240	1,891,898

Outflow (acre-feet)

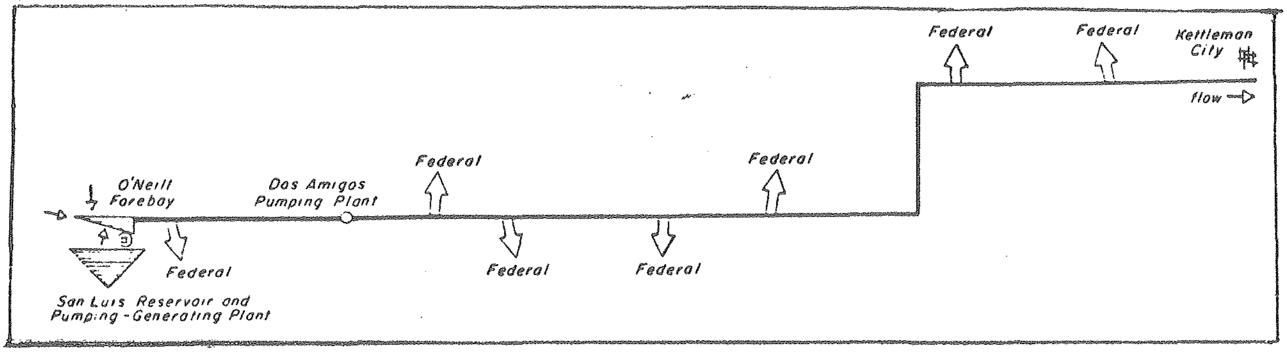
	Outflow 1974	Outflow 1975	Annual Entitlement to Project Water at Full Development
Deliveries			
Napa County FC & WCD			25,000
Solano County FC & WCD			42,000
Oak Flat WD	6,942	7,152	5,700
Tracy Golf and Country Club	11		
Alameda County FC & WCD Zone 7	1,314	4,618	46,000
Alameda County WD	4	986	42,000
Santa Clara Valley WD	90,934	106,470	100,000
Evaporation—Seepage Losses	-3,904	14,180	
to San Luis Field Division			
State	1,472,397	1,737,607	
Federal	299,542	20,885	
TOTAL	1,867,240	1,891,898	

Dams and Reservoirs

	Capacity (acre-feet)	Max Flow Rates (cfs)[a] In	Max Flow Rates (cfs)[a] Out
Clifton Court Forebay	28,653	10,300	10,300
Bethany Reservoir	4,804	10,300	330/10,000[b]
Lake Del Valle	77,106	120	120
O'Neill Forebay	56,426	14,200/13,200[c]	13,100/11,000[d]

[a] Normal operations; this does not include flood conditions.
[b] South Bay Pumping Plant/California Aqueduct.
[c] California Aqueduct and Delta-Mendota Canal/ San Luis Reservoir.
[d] Main California Aqueduct/San Luis Reservoir.

San Luis Field Division (water operations during 1974 and 1975)



Inflow (acre-feet)

	1974	1975
From Delta Field Division:		
State	1,472,397	1,737,607
Federal	299,542	20,885
From Federal O'Neill Pumping Plant	817,263	1,356,795
Net Decrease of San Luis Reservoir Storage	46,235	215,477
TOTAL	2,635,437	3,330,764

Outflow (acre-feet)

	1974	1975
Deliveries		
Federal Customers	1,121,747	1,361,573
Recreation Areas	10	19
Evaporation—Seepage Losses	94,033	108,801
Released through Federal O'Neill Pumping Plant	27,123	34,012
To San Joaquin Field Division		
State	1,392,524	1,814,659
Federal		11,700
TOTAL	2,635,437	3,330,764

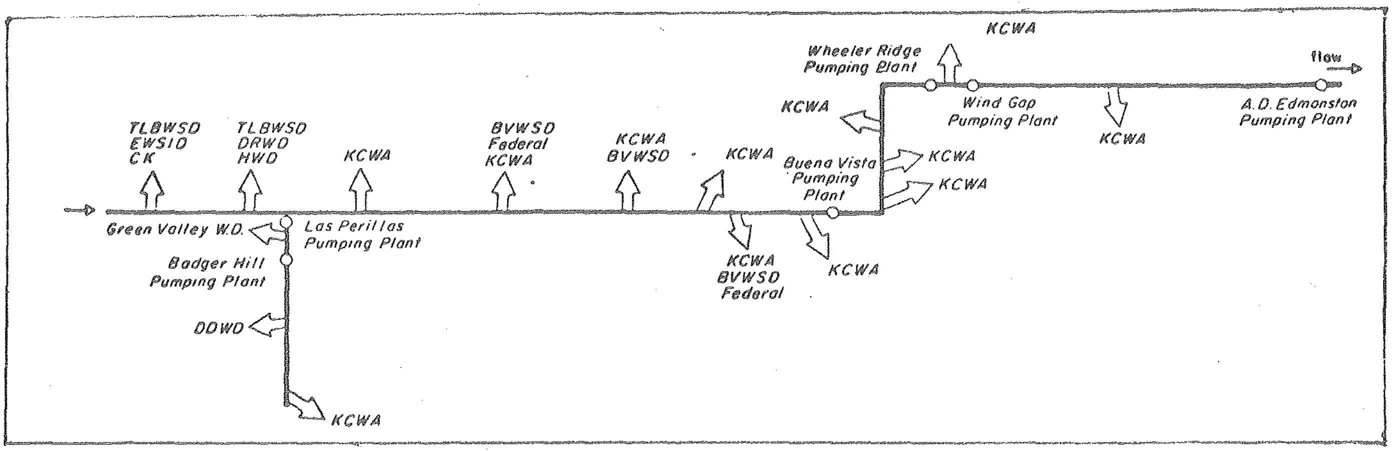
Dams and Reservoirs

	Capacity (acre-feet)	Max Flow Rates (cfs)[a] In	Max Flow Rates (cfs)[a] Out
O'Neill Forebay	*	*	*
San Luis Reservoir	2,038,771	11,000	13,120

* See Delta Field Division

[a] Normal operations; this does not include flood conditions.

San Joaquin Field Division (water operations during 1974 and 1975)



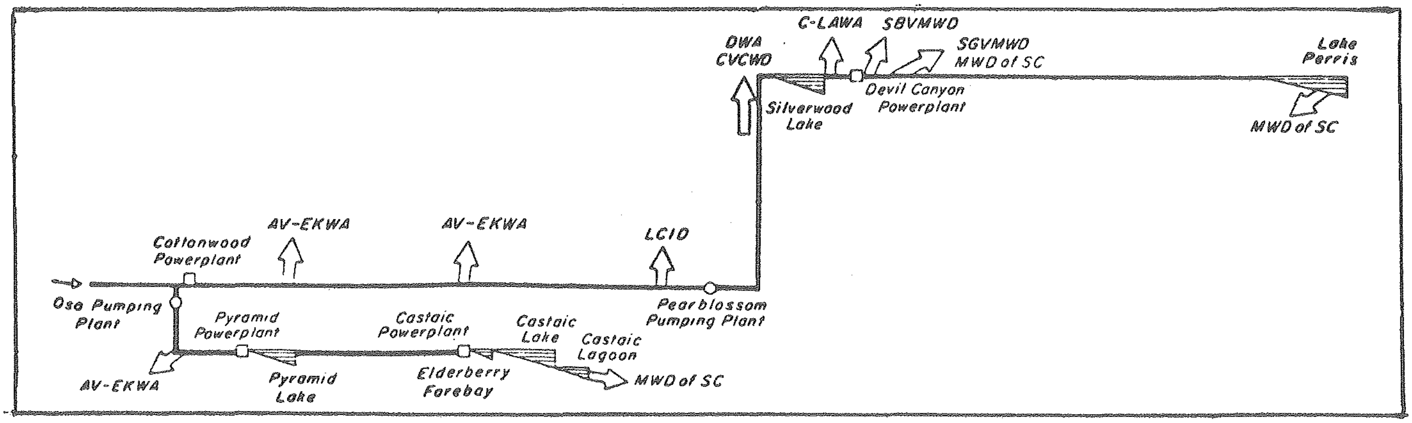
Inflow (acre-feet)

	1974	1975
From San Luis Field Division		
State	1,392,524	1,814,659
Federal		11,700

Outflow (acre-feet)

	1974	1975	Annual Entitlement to Project Water at Full Development
Deliveries:			
Federal		11,700	
San Luis Obispo County FC & WCD			25,000
Santa Barbara County FC & WCD			57,700
J.G. Boswell Company	2,500		
Buena Vista WSD	7,840	6,797	
County of Kings	1,500	1,600	4,000
Devil's Den WD	13,828	18,195	12,700
Dudley Ridge WD	66,781	81,110	57,000
Empire West Side ID	4,539	6,448	3,000
Green Valley WD	1,741	2,217	
Hacienda WD	5,272	7,517	8,500
Kern County WA	646,433		1,153,400
Tulare Lake Basin WSD	137,978		110,000
Evaporation—Seepage Losses	52,137		
To Southern Field Division	556,249	700,242	
TOTAL	1,392,524	1,826,359	

Southern Field Division (water operations during 1974 and 1975)



Inflow (acre-feet)

	1974	1975
From San Joaquin Field Division	556,249	700,242
Natural Runoff into Pyramid Lake	17,082	14,594
Natural Runoff into Castaic Lake	9,665	6,596
Natural Runoff into Silverwood Lake	10,385	6,272
TOTAL	593,381	727,704

Outflow (acre-feet)

	1974	1975	Annual Entitlement to Project Water at Full Development
Deliveries			
Antelope Valley-East Kern WA	1,259	8,068	138,400
Coachella Valley County WD	6,400	7,000	23,100
Crestline-Lake Arrowhead WA	627	825	5,800
Desert WA	10,000	11,000	38,100
Littlerock Creek ID	467	876	2,300
Mojave WA	14	--	50,800
San Bernardino Valley MWD	16,605	13,865	102,600
San Gabriel Valley MWD	612	5,450	28,800
The Metropolitan WD of SC	277,715	526,958	2,011,500
Castaic Lake WA			41,500
San Gorgorio Pass WA			17,300
Ventura County FCD			20,000
Recreation Areas	2,108	3,358	
Water Rights Entitlement	36,629	27,933	
Evaporative—Seepage Losses	38,169	33,075	
Net Increase of Reservoir Storage	202,776	89,296	
TOTAL	593,381	727,704	

Southern Field Division (continued)

Dams and Reservoirs

	Capacity (acre-feet)	Max Flow Rates (cfs)[a]	
		In	Out
Pyramid Lake	171,196	3,128/17,300[b]	18,400/1,000[c]
Elderberry Forebay	28,231	18,400	17,300/17,000[d]
Castaic Lake	323,702	17,000	3,788[e]
Castaic Lagoon	5,662	--[f]	--
Silverwood Lake	74,970	1,990	5,000/2,020[g]
Lake Perris	131,452	469	1,000

[a]Normal operations; this does not include flood conditions.

[b]Proposed inlet from Pyramid Power Plant; present is 850 CFS/Elderberry Forebay.

[c]Elderberry Forebay/stream maintenance.

[d]Lake Pyramid/Castaic Lake.

[e]Design deliveries; however, stream maintenance and reservoir drainage can be 6,000 and 11,000 CFS.

[f]Primarily recreation use.

[g]Stream maintenance at minimum storage/Lake Perris.