Title
Water Requirements for Future Energy production in California

Permalink
https://escholarship.org/uc/item/9hz9t8t8

Authors
Sathaye, Jayant A.
Ritschard, R.L.

Publication Date
1977-05-01

LBL-6872 c.2
UC-97e
TID-4500-R66

Energy and Environment Division

Water Requirements For Future Energy Production In California

Jayant A. Sathaye and
Ronald L. Ritschard

May 1977

Lawrence Berkeley Laboratory University of California/Berkeley
Prepared for the U.S. Department of Energy under Contract No. W-7405-ENG-48

WATER REQUIREMENTS FOR FUTURE ENERGY PRODUCTION IN CALIFORNIA

Jayant A. Sathaye and Ronald L. Ritschard

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

May 1977

Work supported by the U. S. Department of Energy.

Table of Contents

List of Tables

List of Figures

WATER REQUIREMENTS FOR FUTURE ENERGY PRODUCTION IN CALIFORNIA

Jayant A. Sathaye and Ronald L. Ritschard

INTRODUCTION

The Federal Water Resources Council (WRC) is conducting a 1975 National Water Assessment to regionally examine the nation's water resources. Part of this assessment is designed to estimate the impact of future national energy development on water resources. Energy development would include various types of electric power plants, production of synthetic fuels, coal and uranium mining, oil and gas extraction, and other conversion processes. The Energy Analysis Program at Lawrence Berkeley Laboratory has conducted this analysis for its assigned region, the states of California and Nevada.

The objective of this study is to determine water requirements of energy technologies and their implications, with emphasis on emerging technologies for aggregated subareas (ASA) in California. The first phase of this study provides energy supply projections and correponding demands for water resources as perceived by regional and state groups responsible for or involved in energy planning in California and Nevada.

The second phase of the study is designed to calculate the water requirements for the levels of energy development in California as specified by an Energy Research and Development Administration (ERDA) scenario for the year 2000 and by utility projections as reported by the Federal Power Commission (FPC) for 1985. The implications of these water requirements on competing water users are explored briefly.

The authors are grateful to those state and regional officials in California and Nevada, utility company representatives, and various other individuals who provided the data and information contained in this report.

PHASE I: SURVEY OF WATER REQUIREMENTS FOR FUTURE ENERGY PRODUCTION IN CALIFORNIA AND NEVADA: STATE'S PERSPECTIVE

CALIFORNIA WATER RESOURCES

Water availability in California varies geographically with northern California receiving almost 70 percent of the total runoff. However, nearly 80 percent of the water demand occurs south of the Sacramento-San Joaquin Delta area causing large geographic disproportionalities in the water supply and demand picture. To meet the large water demand in southern California, several aqueducts have been constructed to transport water from northern California to southern California. The state-owned California Aqueduct was designed to transport water from the Sacramento-San Joaquin Delta to southern California with Lake Perris being the ultimate sink. The Delta-Mendota Canal and the Friant-Kern Canal, the two major federally-owned canals in central California, transport water from north to south. Other major aqueducts include the Mokelumne Aqueduct and the Hetch-Hetchy Aqueduct supplying water to the San Francisco Bay Area, and the Los Angeles Aqueduct and the Colorado River Aqueduct which supply water to southern California.

Figure 1 shows the hydrologic study areas (hydrologic basins) in California whereas Figure 2 shows the aggregated subareas (ASA) in California as defined by the Federal Water Resources Council. The average annual runoff in California by hydrologic basins is included in Table 1. In addition, the State of California has an annual entitlement to the Colorado River of 4.4 million acre-ft, although the state has been drawing closer to 5 million acre-ft in recent years. Including these sources and the annual inflow from Oregon, the total average surface water supply available to California is about 76.6 million acre-ft/yr.[1] Annual runoff, however, varies from year to year. At the end of the driest weather year on record, California faced water shortages whose impacts were felt with progressive severity through 1977. Table 2 contains a comparison of the present water conditions to those of an average water year.

Table 1

Average Annual Runoff from Hydrologic Areas

Area	Millions of acre ft	Percent of total
North Coastal	27.2	38.5
San Francisco Bay	3.0	4.2
Central Coastal	2.5	3.5
South Coastal	1.2	1.7
Sacramento Basin	22.4	31.6
Delta-Central Sierra	1.5	2.1
San Joaquin Basin	6.4	9.0
Tulare Basin	3.3	4.7
North Lahontan	1.8	2.6
South Lahontan	1.3	1.8
Colorado Desert	0.2	0.3
State Total	70.8	100.0
Inflow from Oregon	1.4	
Colorado River Entitlement	4.4	
Total Water Supply	76.6	

Source: "Impact of Power Plant Siting on California's Water Resources," Association of California Water Agencies, July 1976.

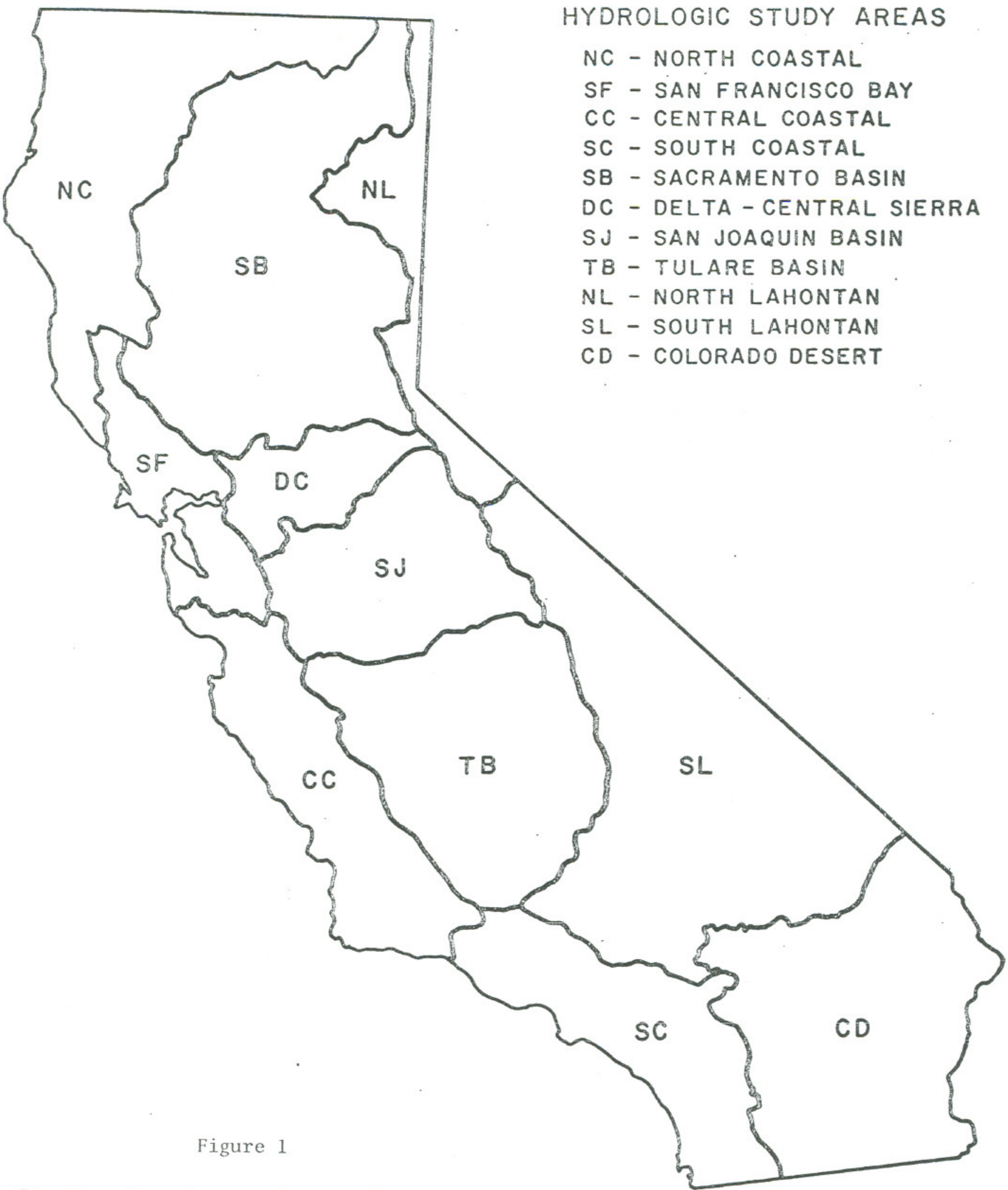

Figure 1

Source: Department of Water Resources
Bulletin No. 160-74
"The California Water Plan
Outlook in 1974"

Aggregated Subareas of California

XBL 776-8970

Figure 2

Table 2

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

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

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

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

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

Development potential for additional firm surface water supplies is limited due to environmental, economic and institutional constraints. The largest potential source of additional water supply is on the north coast; however, its development is precluded by the Wild and Scenic River Act of 1972.[2] However, the Act does allow possible reconsideration of development on the Eel River in 1985. The only other surface water streams with significant additional development opportunities are in the Sacramento Valley, although such development would be costly. Reclamation of waste water is a likely source which could provide water for industrial uses especially for power plant cooling in the future. Weather modification programs currently being carried out by several agencies hold some promise for additional runoff in the Sierra. Desalting of sea water and geothermal water supplies are the two novel sources which could be tapped; however, to this date they have not been proven economically or environmentally feasible.

The California Aqueduct will have excess capacity for several years that could be used to convey surplus water to recharge overdrawn ground water basins in southern California. This would require the construction of a trans-Delta facility to transport the water from the Sacramento River to the head of the Aqueduct. However, potential environmental problems may delay or prevent the construction of such a facility.

Ground water forms another major source of water in California. About forty percent, or some 15 million acre-ft, of the applied water requirement is now pumped from ground water basins. At present, there is an overdraft of about 2.2 million acre-ft/year of which the San Joaquin Valley (San Joaquin and Tulare basins) accounts for 1.5 million acre-ft/yr. Conjunctive operation of ground and surface water supplies could alleviate some of the overdraft. Furthermore, Sacramento, San Joaquin, and South Coastal and Colorado Desert basins offer significant opportunities for development and use of ground water.[3]

Water Demand

Table 3 summarizes the projected water supply picture in California by ASA. The information was interpreted from data presented in DWR

Table 3

Projected Water Supply in California*
(10^6 acre-feet)

ASA	1975	1985	2000
1801	.963	.974	.991
1802	7.726	8.304	8.744
1803	12.342	13.197	13.647
1804	2.042	2.309	2.529
1805	.850	.917	.950
1806	7.416	8.320	8.777
1807	.215	.280	.314
TOTAL	31.554	34.301	35.952

* Interpolated from data in DWR Bulletin 160-74, Table 27, pp. 146-47 and adjusted from hydrologic study areas to aggregated subareas.

Bulletin 160-74 using Alternative II. Since the information in the bulletin is reported by HSA rather than ASA, certain areal correlations are assumed. Table 4 contains the correlations that are used by DWR in relating HSA to ASA.

Table 5 shows the projected net water demand for agricultural and urban use by ASA in 1975, 1985 and 2000. Agriculture accounts for 85 percent of this demand in California. Net water demand for agriculture in 1975 was 24.5 million acre-ft. This demand is expected to increase to 31.8 million acre-ft by 2000.[1] In contrast to the agricultural demand, urban net water demand was about 4.4 million acre-ft in 1975, and it is expected to grow to about 7 million acre-ft by 2000.[1]

In-stream water uses such as recreation, fish, wildlife and water quality maintenance have received increasing attention in recent years. These uses in the future may require higher minimum water levels in the streams thus affecting firm water commitments for other uses.

Demand for power plant cooling constitutes a very small fraction (approximately 32,000 acre-ft) of the total fresh water demands since most of this demand is met by sea water. Coastal siting restrictions may substantially increase this fresh water demand for cooling in the future.

Supply-Demand Relationships

Water demands now exceed the available water supplies in some areas of the state. At present the deficiency is supplied for the most part by ground water overdraft.

Table 6 shows the deficiency in water supply required to meet urban and agricultural water requirements. This does not constitute the entire water demand which would be larger by the quantity of water required for in-stream uses and for power plant cooling. So any additional water requirements for power plants as estimated in latter sections of this report would add to this water demand burden.

Table 4

Correlations of Hydrologic Study Areas to Aggregated Subareas in California

ASA (Aggregated Subarea)	HSA (Hydrologic Study Area)	Planning Subareas
1801	North Coastal	All
1802	Sacramento	All
	North Lahontan	Lassen Group; Alpine Group-Tahoe and Truckee Basin
	Delta Central Sierra	30% Delta service area
1803	San Joaquin	All
	Tulare	All
	Delta Central Sierra	Foothill and uplands; Eastern Valley Floor; 50% of Delta service area
1804	San Francisco Bay	All
	Delta Central Sierra	Western uplands; 20% of Delta service area
1805	Central Coast	All
1806	South Coastal	All
	Colorado Desert	All
	South Lahontan	Mohave River, Antelope Valley
1807	South Lahontan	Mono-Owens area; Death Valley
	North Lahontan	Alpine Group; Canyon and Walker Basins

Source: California Department of Water Resources, 1975 National Assessment: State-Regional Future, Technical Memorandum No. 2, July 1976.

Table 5

Projected Net Water Demands in California*
(10^6 acre-feet)

ASA	1975			1985			2000		
	Agri-culture	Urban	Total	Agri-culture	Urban	Total	Agri-culture	Urban	Total
1801	.556	.392	.948	.549	.427	.976	.535	.468	1.003
1802	6.526	.529	7.055	7.281	.676	7.957	7.967	.866	8.833
1803	12.989	.416	13.405	14.380	.522	14.902	15.563	.716	16.279
1804	.860	.970	1.830	.976	1.207	2.183	1.105	1.527	2.632
1805	.889	.103	.992	.994	.137	1.131	1.098	.195	1.293
1806	5.406	2.009	7.415	5.364	2.467	7.831	5.266	3.173	8.439
1807	.236	.016	.252	.245	.024	.269	.273	.023	.296
TOTAL	27.462	4.435	31.897	29.789	5.460	35.249	31.807	6.968	38.775

* Interpolated from data in DWR Bulletin 160-74, Table 27, pp. 146-47 and adjusted from hydrologic study areas to aggregated subareas.

Table 6

Projected Deficiency in Water Supply
to Meet Agricultural and Urban Demand
(10^6 acre-feet)

	1975			1985			2000		
ASA	Supply	Net Demand	Deficit	Supply	Net Demand	Deficit	Supply	Net Demand	Deficit
1801	.963	.948	--	.974	.976	--	.991	1.003	.012
1802	7.726	7.055	--	8.304	7.957	--	8.744	8.833	.089
1803*	12.342	13.405	1.063	13.197	14.902	1.705	13.647	16.279	2.632
1804	2.042	1.830	--	2.309	2.183	--	2.529	2.632	.103
1805*	.850	.992	.142	.917	1.131	.214	.950	1.293	.343
1806	7.416	7.415	--	8.320	7.831	--	8.777	8.439	--
1807	.215	.252	--	.280	.269	--	.314	.296	--
TOTAL	31.55	31.90		34.30	35.25		35.95	38.77	

Energy Supply

Natural gas, oil and electricity form the major sources of energy supply to California. Natural gas supply for California at present comes from California, Texas, the Rocky Mountain states and Canada. As existing onshore sources are depleted, additional future gas supplies are expected to come from Alaska, Indonesia and offshore wells and as synthetic natural gas from Rocky Mountain states. Natural gas supplies are currently inadquate to meet the demand for gas and are likely to remain inadequate in the future. Crude oil, the second major source of supply, is available from onshore and offshore wells in limited quantities and from imports. Onshore crude oil production is expected to decline over the next twenty-five years whereas California offshore production is expected to peak in 1990. Additional oil requirements would be met by Alaskan oil supplies and foreign imports.

Electricity accounts for the rest of the energy supply to California. In 1975 electricity production consumed approximately one fifth (124×10^{12} Btu) of the total energy (5670×10^{12} Btu) consumed in California.[4] This proportion will rise in the future as electricity is used as a substitute for natural gas and fuel oil. It is estimated that by 1995 almost half of the total energy consumed would be available in the form of electricity. Table 7 shows the electricity generating capacity planned by the utilities until 1995. The utilities are required to submit these plans to the California Energy Resources Conservation and Development Commission (CERCDC) every two years. We obtained these projections from the CERCDC. Figures for the year 2000 are derived from the utility projections by linearly extrapolating from 1995. As the table shows, the proportion of baseload power plants (nuclear, coal and part of oil) in 1995 is far larger than that in 1975. As a result the growth in electricity generation is faster than the growth in electrical capacity. Electricity generation would increase from approximately 1300×10^{12} Btu's in 1975 to approximately 4500×10^{12} Btu's[3] by 1995, whereas capacity would grow from approximately 36,000 MWe to approximately 85,000 MWe.

Table 7

Utility Supply Plans Capacity Projections
(in megawatts)

	1975	1985	1995	2000**
Coal	2287	5719	8656	10124
Combined Cycle	24	2458	3526	4060
Gas Turbine	1047	3426	6068	6421
Geothermal	502	1978	3458	4198
Hydro	8737	8582	9070	9314
Nuclear	1379	7823	30827	42329
Oil	21361	21283	17448	15531
Pumped Storage	1054	2923	5323	6523
Other*	-79	118	504	697
TOTAL	36312	54310	84880	99197

Source: "Electricity Forecasting and Planning," Staff Proposed Preliminary Report, Energy Assessment Division, CERCDC, p. IV-11.

*Includes off main system losses and fuel cell, wind and solar resources.

**Figures in this column were projected using linear extrapolation from 1995.

Table 8

Total Sales Forecast

	1975	1980	1985	1990
Sales (10^6 kwh)	141,574	170,416	200,487	236,438

Source: "Electricity Forecasting and Planning," Staff Proposed Preliminary Report, Energy Assessment Division, CERCDC, p. II-3.

Table 7 shows the electricity capacity projections as submitted by the five major utilities in California. These utilities are 1) Pacific Gas and Electric, 2) Southern California Edison, 3) San Diego Gas and Electric, 4) Sacramento Municipal Utility District, and 5) Los Angeles Department of Water and Power.

In addition to the utilities forecast, the CERCDC has published a staff-recommended demand forecast for electricity growth. This forecast is shown in Table 8. The overall projected growth rate of electricity consumption is 3.4 percent. Conversations with CERCDC staff indicate that to meet this demand, more than one electricity supply mix may be examined. The development of one such supply mix may also be left up to the utilities.

The CERCDC staff has not yet made any evaluation of the level of impacts arising due to the power plants that would be needed to meet the 3.4 percent growth in electricity consumption. The Department of Water Resources (DWR) has indicated that it will follow the projections made by CERCDC for electricity capacity growth and for the resulting impacts on water resources.[5] Since oil and gas extraction in California is expected to decrease, water requirements for these would decrease over the next twenty-five years.

Water Requirements and Impacts

Table 9 shows the water requirements for fuel extraction and refineries by aggregated subareas (ASA) for 1975, 1985 and 2000. The water requirements for fuel extraction drop as crude oil and natural gas resources are depleted. Increase in water requirements for refineries by 1985 is mainly due to the expected supply of a large amount of Alaskan and foreign oil. Environmental concerns may, however, delay or limit the construction of these new refineries in California. Within ASA 1806 the refineries would most probably be located in the south coastal area, creating additional water demands on limited supply sources.

Table 10 shows the fresh water requirements by aggregated subareas for inland power plant cooling. These requirements are based on

Table 9

Water Requirements (Consumptive Use) for Fuels Extraction and Refineries
(10^6 gallons/day)

ASA No.	1975		1985		2000	
	Fuels	Refineries	Fuels	Refineries	Fuels	Refineries
1801	0	0	0	0	0	0
1802	0.6	--	0.6	--	0.3	--
1803	6.0	3.2	5.4	2.8	5.4	1.8
1804	0.6	8.1	0.6	7.6	0.9	8.9
1805	1.5	--	1.5	--	1.5	--
1806	7.5	12.3	7.5	30.1	7.5	34.3
Total*	16.2	23.6	15.6	40.5	15.6	45.0

Source: "1975 National Assessment, State Regional Future," James L. Welsh, State of California, July 1976.

*Total: Figures were added for this report.

Table 10

Inland Cooling Water Demands (makeup water)[a,b]
(10^3 acre-ft/yr)

	1975	1985	1995
1801	--	--	--
1802	9.61	21.14	46.17
1803	--	23.52	173.66
1804	6.62	23.45	18.15
1805	--	--	--
1806	16.01	47.77	356.91
1807	--	--	--
Unsited	--	--	212.25
Total In-State	32.25	120.58	807.14
Total Out-of-State	50.25	195.12	204.66
TOTAL	82.50	315.70	1011.80

Source: CERCDC, Staff Proposed Preliminary Report on Electricity Forecasting and Planning, Energy Assessment Division, September 24, 1976 (converted from hydrologic areas to aggregated subareas).

[a]Figures based on utility projections, Table 7.

[b]Figures represent cooling water requirements for entire facilities, not just for the portion owned by California utilities.

NOTE: These demands are based on the use of wet cooling towers for inland power plants.

the mix of power plants projected by the utilities (Table 7). By 1995 the California water requirements would increase from approximately 32,000 acre-ft/yr to approximately 800,000 acre-ft/yr, almost a twenty-five-fold increase. The low demand for cooling water in 1975 reflects the sizable use of sea water for cooling purposes. However, stricter coastal zoning regulations may cause the majority of the future power plants to be sited inland.

Colorado Desert, Tulare and San Joaquin basins show the largest increase for cooling water requirements. The Tulare and San Joaquin basins (ASA 1803) had deficient water supply with major ground water overdraft in 1975 (see Table 5). This deficiency will continue to increase in both basins due to increased future urban and agricultural demand. The cooling water demand would therefore pose an additional burden on water supplies in these basins. Cooling water requirements in the Colorado Desert basin (ASA 1806) represent almost 45 percent of the potential statewide freshwater cooling demand. The basin is a water-poor area with the developed supply of 4 million acre-ft/yr being barely enough to meet current water requirements. In addition, these developed supplies are not expected to increase sufficiently enough to meet the projected cooling water demand. So the demand may have to be met by alternative means or by shifting water supplies to the utilities from existing users. The area also has several ground water basins with a useable storage capacity of 10.3 million acre-ft.[3] Additional ground water could be drawn from these basins to meet the cooling water demand. However, the natural recharge would have to be supplemented by water transfer from other areas to replenish the basins. The development required to provide water transfers will have an impact on the environment and impose an additional burden on water-rich areas.

The Department of Water Resources (DWR) expects that the utilities would be able to pay more for water and thus would be in a position to buy the water from existing water users.[5] Most of the California water is currently appropriated to several users or groups of water users. These users pay anywhere between $3 to $25 an acre-foot. The utilities, however, could afford to pay a higher price per acre-foot for the same water. Unless legislative or other constraints prevent the current users from selling the water, DWR expects the users to sell the water to the utilities as it would be in their best economic interests. Increased cooling water demand could therefore have an adverse impact on irrigated agriculture.

As regards the question of power plant siting and the use of ocean water for cooling, different state agencies have different priorities. The DWR favors coastal siting over inland due to fresh water availability problems. It also favors brackish water over fresh water for cooling.[5] The State Water Resources Control Board (SWRCB) policy is a five-part system ranging from the use of ocean water to that of fresh water.[6] They, too, favor coastal siting to the maximum extent. The CERCDC currently has no policy on the use of inland water for power plant cooling but is attempting to develop such policies and plans as required by its enabling legislation in an effort to avoid case-by-case decision-making.[7] The DWR and SWRCB policies are in conflict with the California Coastal Commission's policy which requires examination of inland sites prior to coastal siting. This conflict may have to be resolved in the courts. However, it is possible that the utilities may decide to go out-of-state to avoid such litigation. Sea water could be used as cooling water for power plants located inland beyond the jurisdiction of the Coastal Commission. DWR, however, believes that the transport of sea water inland for once-through cooling would not be economical.

The CERCDC expects the water quality problems to be largely site-specific. However, increased demands in southern California would require additional water from the Delta, thus affecting the fish, wildlife and agricultural production in the Delta area. The geothermal development in Imperial Valley could pose a major threat to water quality. DWR believes that problems of subsidence and reinjection as well as water quality issues will delay development of hot brine geothermal resources in the Imperial Valley (ASA 1806).

Mitigation Measures

Several measures have been proposed to mitigate the potential adverse impact on water requirements. Among these are use of wet/dry and dry cooling towers, water conservation, use of agricultural waste water and new development of surface streams and ground water basins.

Wet/dry cooling towers have the potential of reducing cooling water demands to 25 percent of the water that a wet tower would use. Disadvantages to this method include higher capital costs and decreased efficiency at high temperatures. DWR does not see the possibility of using dry cooling towers by 2000.

DWR estimates that by the year 2000, over 3.6 million acre-ft/yr of water could be conserved from urban and agricultural uses through more efficient water use, metering, pricing and other incentives. These savings could easily meet the power plant demands.[8]

DWR believes that agricultural waste water, if properly treated, could form a major part of power plant cooling water, especially in the San Joaquin Valley and Colorado Desert areas. The quantity of waste water generated in the San Joaquin Valley is projected to increase from 125,000 acre-ft/yr in 1980 to about 440,000 acre-ft/yr by 2000.[8] The major constraint is a lack of a collection and storage system. The Colorado Desert has two areas of high agricultural waste water availability, the Palo Verde Valley which currently returns 400,000 acre-ft/yr of waste water to the Colorado River and the Imperial and the Coachella valleys with waste water flows of about 1 million acre-ft/yr to the Salton Sea. These sources could be tapped for power plant cooling although they may have adverse impacts on air quality and may have solid waste problems of their own. Waste waters from urban and municipal areas along the south coast would amount to 4.2 million acre-ft/yr. Part of this water, 2.5 million acre-ft/yr could be reclaimed and used for cooling. Costs for reclamation could range from \$2 to \$100 an acre-foot depending on quantity and quality of waters to be treated.

Staff members of DWR stressed the importance of a trans-Delta facility and the questions of getting water across the Delta while maintaining water quality standards. The CERCDC does not have a policy on the need for a trans-Delta facility, but the CERCDC staff recognizes the importance of such a facility. Metropolitan Water District (MWD) gets 575,000 acre-ft/yr of water from the California Aqueduct (trans-Delta facility would be linked to this aqueduct) which provides 20 percent of the south coast demand. The construction of a trans-Delta facility involves environmental and water rights problems. The fact that industrial interests in the Bay Area need the high quality water and are siding with the environmentalists makes the implementation of the Delta diversion even more difficult. If such a facility were built, it would provide additional water to MWD which in turn could sell the water to the utilities, thus meeting their cooling water demands.

MWD has made available up to 100,000 acre-ft/yr of its allotment from the Colorado River for power plant use in desert sites. In 1974 the Lanterman Act (AB 3140) was enacted in order to allow this type of transaction. MWD has executed letters of intent for the allocation of water with several southern California utilities.

Development of new sources of water, both surface and underground, could meet some of the water requirements. However, most of the new streams are currently protected by the Wild and Scenic Rivers Act[2] and are therefore not available for further development. Several as yet undeveloped ground water basins have been identified in the Colorado Desert Basin.[3] These basins in conjunction with surface supplies could be used to store water for power plant cooling. Surface supplies would have to be obtained from northern California or from agricultural waste waters.

Summary

To summarize, energy development in California could require almost 800,000 acre-ft/yr of fresh water for power plant cooling by 1995. Based on the utilities' anticipated fuel mix, for the rest of the fuel cycle (i.e., other than power plants) the water requirements would not increase significantly. Major impacts of water requirements for power plant cooling would be felt in the San Joaquin, Tulare and

Colorado basins. The first two basins are at present water-deficient while the last basin is presently a water-poor area. Use of agricultural waste waters and/or wet/dry cooling could help in meeting the water requirements although these measures could create new environmental quality problems. Development of new supplies could also be undertaken to meet the cooling water demand.

NEVADA WATER SUPPLIES

Water is one of Nevada's most precious resources which plays a major role in the state's economy and general welfare and is necessary for the various energy technologies. Due to its natural mountain barriers, Nevada's average precipitation (slightly greater than 9 inches per year) is less than any other state.

Nevada possesses a unique water resources characteristic since about 85 percent of the state's nearly 71 million acres of land lie within the Great Basin region with no outlet to the sea. The remaining portion is found in the Snake River and Colorado River drainages. About 3.3 million acres in the north central part of the state, mostly in Elko County, is in the Snake River drainage. Similarly, about 7.9 million acres in the southeast corner of the state, mostly in Clark and Lincoln counties, is in the Lower Colorado River drainage. Therefore, the majority of the precipitation and surface water inflow is retained, utilized and evaporated within the state.

Another unique characteristic is that some of the stream systems in western Nevada, notably the Walker River Basin and the Carson-Truckee River Basin, end in terminal inland lakes, which creates a condition of gradual salinity buildup and potential ecosystem degradation.

The Water Resources Council has divided Nevada into three aggregated subareas (ASA). ASA 1603 of the Great Basin region includes the counties of Elko, Esmeralda, Eureka, Humboldt, Lander, Nye, Pershing, and White Pine, while ASA 1604 approximates the following counties: Carson City, Churchill, Douglas, Lyon, Mineral, Storey and Washoe. The remaining region is ASA 1502 of the Lower Colorado River Basin and includes Clark and Lincoln counties (Figure 3).

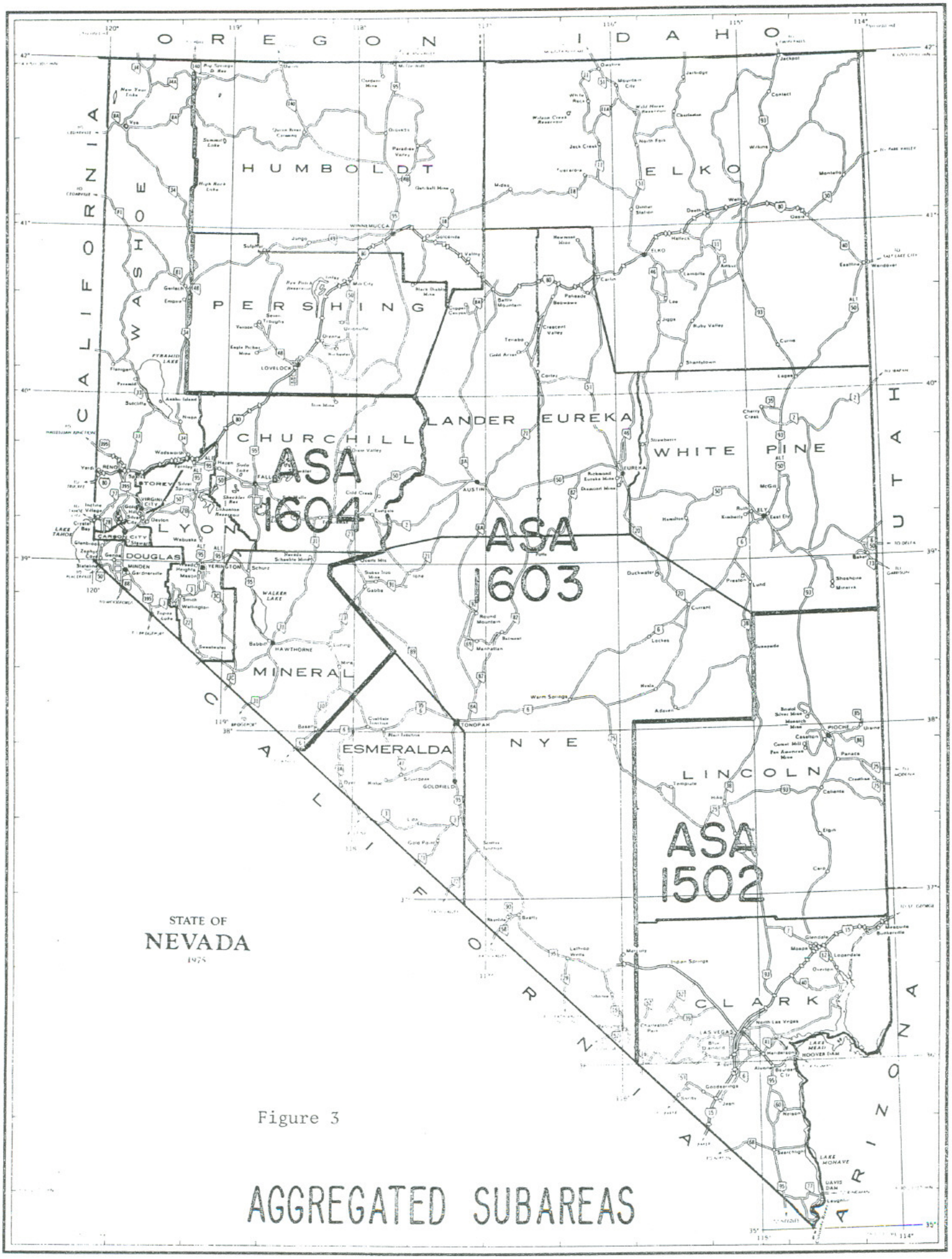

Figure 3

AGGREGATED SUBAREAS

Water sources for Nevada include surface water which is water taken from lakes, reservoirs, rivers, springs and streams and waste water from industrial and municipal effluents, and ground water from wells. According to information provided by the Nevada Division of Water Resources, there are no areas with significant amounts of uncommitted surface water.[9]

In the Walker River Basin, it is reported that there is not sufficient water in the system to satisfy present and projected requirements upstream and, in turn, maintain its terminal lake, Walker Lake, as a viable fishery.[9] Within the Carson-Truckee River Basin, the right to use the water supplies of these streams are subject to pending litigation. There are occasional "surplus" waters in the Humboldt River System and several potential storage projects are in the planning stages.[10] The Humboldt River Project includes Hylton Dam and Reservoir on the south fork, Devil's Gate on the north fork and Vista on Mary's River, a tributary of the Humboldt River. Whether or not these facilities will be completed is uncertain at this time.

Nevada has an annual allocation of 300,000 acre-ft of Colorado River water. Most of this allocation in the past was not utilized by the state because the water needs of southern Nevada were being supplied by ground water withdrawals. However, the rapid expansion of population that has occurred in the Las Vegas area in recent years has forced the state to implement measures by which the full allocation will be made accessible for various beneficial uses. The first phase of the southern Nevada project, sponsored by the Bureau of Reclamation, was completed in 1971 and will provide 132,000 acre-ft from Lake Mead. The second stage, which is essentially an enlargement of the system, is scheduled to be operational by 1981.[11]

In view of the southern Nevada water project, Nevada's annual Colorado River allocation of 300,000 acre-ft will be fully utilized by the early 1990's. In addition, there are two tributaries of the Colorado River in Nevada (Virgin and Muddy rivers) which could provide some additional unallocated surface water. However, it is unlikely that they will contribute any significant amount of surface water in the near future.

According to Bureau of Reclamation estimates, there will be an annual surplus of water on the Colorado River before 1980.[11] This condition will last until implementation of the Central Arizona Project, which is scheduled for 1985, or until further development occurs in the upper Colorado River Basin. It is anticipated that the surplus water will be available in 1977. The first allocation will probably be granted to Mexico with the remaining water being distributed to the neighboring states in the same proportions as now. The actual amount of surplus and the number of years into the future that it will be available are important factors to energy resource development in this area.

Industrial and municipal sewage effluents provide another potential source of surface water. The Harry Allen coal-fired facilities proposed for a site near Las Vegas will use about 37,000 acre-ft/yr of municipal and industrial effluent from the Las Vegas Valley. This quantity of sewage effluent represents only about one-half of the total available from the system. The remainder will probably be returned to the Colorado River system as credit against Nevada's compact allocation.

Since the surface water resources in Nevada are limited and almost completely appropriated and water supplies from outside Nevada are not readily available, additional agricultural, municipal and industrial expansion in the state will rely on the development of available ground water supplies. Future increases in water availability for the development of energy technology in Nevada will probably come from pumping ground water.[12] The Division of Water Resources has tentatively identified several hydrographic areas where ground water exists in sufficient quantity (at least 15,000 acre-ft of perennial ground water yield) to support an expansion of electric generating capacity.[13]

In recent years, development of large areas of arid land as well as increased water requirements for municipalities has led to extensive pumping of ground water aquifers. In particular ground water withdrawal in Clark County has begun to deplete the aquifer system underlying Las Vegas Valley.[14] Following the provisions of Nevada water law, the State Engineer has restricted ground water pumping to 50,000 acre-ft/yr.

State Water Problems

The Department of the Interior's Westwide study report[15] on critical water problems of the western states identified several specific problems for Nevada. The statewide water picture as expressed in the Division of Water Resources publications as well as through personal contacts has re-emphasized some of these problems.

The first problem area relates the conflict of water rights to fluctuating levels of two terminal lakes, Walker and Pyramid lakes. Allocation between Nevada and California of waters in the Carson, Truckee and Walker rivers has been addressed by an interstate compact, which is currently under consideration by Congress. Several suits have been filed in Federal Court for purposes directly or indirectly related to determination of water rights and use. The problem of declining lake levels and increases in salinity downstream are due to changing climate and upstream development. Competition for available water supplies is indicated in these three basins. Walker Lake, for example, will probably cease to be a fishery around 1990-2000 if recent trends are not changed.[9] The situation at Pyramid Lake is less critical and is currently being addressed in suits before the Federal Courts. Existing and future developments on the Carson-Truckee systems are constrained until decisions are reached by Congress and the Courts.

A second area of conflict is increasing water needs with respect to water supplies in the Humboldt and Colorado River basins. As mentioned previously, there are at least two potential water projects in Nevada. The Upper Humboldt River project of the Corps of Engineers has advanced to the preconstruction planning phase and includes the Hylton, Devil's Gate and Vista reservoirs. The other major project is the Southern Nevada Water System (Bureau of Reclamation and the State of Nevada) which enlarges the existing Colorado River diversion system to southern Nevada. Phase 1 of the Southern Nevada System has been completed. Phase 2 is scheduled to be completed by 1981.

Another potential problem is the presence within the state of several critical water areas in which water demands will exceed supply, especially for municipal and industrial uses. Nevada does not allow overdraft drainage basins except under unusual circumstances. In the past, the legislature has provided for issuing temporary permits on a case-by-case basis.

Examples of such overdraft areas are the Las Vegas Valley, Pahrump Valley and Diamond Valley. The Las Vegas Valley, in particular, due to its expanding population has become dependent upon diminishing ground water sources to meet the needs of the municipalities. In addition, as the new federal water quality standards are being met by the mid-1980's, possible state-federal water control conflicts may arise.[9] The overall picture expressed by the various state representatives is one of water shortages.

Energy Futures

The final general problem area and the major topic of this report is the question of water requirements for the development of the energy technologies. Portions of Nevada and especially those in the southern part of the state are being viewed as potential sites for electricity-generating facilities in the future. Southern Nevada is in close proximity to coal deposits in Arizona and Utah, and to the well-established transmission corridor through which power could be conveyed to the load centers of southern California.

Hydroelectric plants were historically favored over thermal-electric plants because of the high installation cost and fuel consumption of thermal plants. As high efficiency steam-electric generating plants became possible and fossil fuels such as coal, natural gas and oil became increasingly available, the steam-generating facilities began to outnumber the hydroelectric plants.

Today there are two major electric utilities operating within Nevada which serve about 95 percent of the State's customers. The utility with the largest sales is Nevada Power Company whose service area approximates Las Vegas and most of Clark County as well as Elko in the northeastern part of the state. The other major company is Sierra Pacific Power with sales in Carson City, Reno, Sparks and several other communities in northern and western Nevada.

Historically, both companies had a modest beginning. Sierra Pacific Power Company began operations in the Reno area with small hydroelectric developments, which were supplemented in the early 1960's by steam plants utilizing natural gas and oil (Table 11).

Nevada Power Company began in 1906 with a system of internal combustion plants. By 1964 they had added several units of gas- or oil-fired capacity. Since that time all of Nevada Power Company's steam-electric additions have been coal-fired (Table 12).

According to a recent Public Service Commission report, future electrical capacity additions planned by Nevada's utilities are expected to be exclusively coal-fired.[16] Two major projects involving coal combustion are presently being considered. Sierra Pacific has planned addition of two 250 MWe units near Valmy in northern Nevada. Nevada Power in conjunction with Los Angeles' Department of Water and Power is planning four 500 MWe coal-fired units (called the Harry Allen project) at a site northeast of Las Vegas (Tables 11, 12). The water requirements for these proposed additions as well as estimates of water withdrawals for present electric power generation in Nevada will be presented in a subsequent section of this report.

Another source of electric energy for Nevada is energy purchased from out-of-state. Purchased power supplies a significant portion of the state's peak demands. The Public Service Commission (PSC) reported that in 1975 as much as 37.1 percent of the total load was purchased from outside of Nevada.[16] In addition to the total flows of electrical energy into the state, over half of the energy generated was exported out of Nevada. The major portion of this export is the energy flowing from Hoover Dam and the Mohave Generating Station. Southern California Edison Company owns 86 percent of the total capacity at Mohave, with the balance being owned by Nevada Power Company. According to the Nevada PSC Report, future additions in coal-fired capacity mentioned above will add further to the amount of exported energy. The Harry Allen project is expected to supply California utilities with as much as 1600 MWe of the proposed 2000 MWe capacity.[16] Idaho has shown interest in Nevada-based generation as well as with Sierra Pacific's Valmy project.

Table 11

Steam-Electric Generating Plants - Sierra Pacific Power Company

Date in Service	Plants	Unit No.	Capacity MWe	Fuel Type	Water Source	Cooling Type	Estimated Annual Coal Consumed
1963	Tracy	#1	53.0	Gas/Oil	Truckee River	Once through	--
1965	Tracy	#2	83.0	Gas/Oil	Truckee River	Once through	--
1974	Tracy	#3	105.0	Gas/Oil	Truckee River	Once through	--
1968	Fort Churchill	#1	105.0	Gas/Oil	Wells	Cooling Ponds	--
1971	Fort Churchill	#2	105.0	Gas/Oil	Wells	Cooling Ponds	--
	(PLANNED ADDITIONS)						
1981	Valmy	#1	250	Coal	--	--	830,606
1983	Valmy	#2	250	Coal	--	--	830,606

Table 12

Steam-Electric Generating Plants - Nevada Power Company

Date in Service	Plant	Unit No.	Capacity MWe	Fuel Type	Water Source	Cooling Type	Water Consumed (acre ft/yr)*	Estimated Annual Coal Consumed (tons)
1955	Clark	#1	50.0	Gas/Oil	Sewage effluent	Cooling towers		--
1957	Clark	#2	65.28	Gas/Oil	Sewage effluent	Cooling towers	2,009	--
1961	Clark	#3	75.00	Gas/Oil	Sewage effluent	Cooling towers		--
1964	Sunrise	#1	81.6	Gas/Oil	Sewage effluent	Cooling towers	997	--
1965	Reid-Gardner	#1	113.6	Coal	Muddy River	Cooling towers	3,462	618,280
1968	Reid-Gardner	#2	113.6	Coal	Muddy River	Cooling towers		
1976	Reid-Gardner	#3	113.6	Coal	Muddy River	Cooling towers	--	--
1971	Mohave	#1	818.1	Coal	Colorado River	Cooling towers	11,859.5	3,268,280
1971	Mohave	#2	818.1	Coal	Colorado River	Cooling towers		
	(PLANNED ADDITIONS)							
1983	Harry Allen	#1	500	Coal	Sewage Effluent	Cooling towers	--	2,281,100
1985	Harry Allen	#2	500	Coal	Sewage Effluent	Cooling towers	--	2,281,100
1986	Harry Allen	#3	500	Coal	Sewage Effluent	Cooling towers	--	2,281,100

*As reported by utility company to Federal Power Commission 1973. (Reference 16)

A representative listing of present and projected estimates of Nevada's electrical energy trends including flows of electrical energy into- and out-of-state as well as total in-state sales is given in Table 13. The Public Service Commission data as presented in this table show an increase in flows out of Nevada which average over 50 percent of the total annual sales. Imports, in turn, during this period are forecast to decline slowly.

Nevada has been, therefore, a net exporter of electrical energy since 1971 with the startup of the Mohave power plant and is expected by the Nevada PSC to continue this trend well beyond the year 2000. Large exports of electrical energy will have a substantial effect on Nevada's total energy picture. The implications of such impacts will be discussed below.

An important point is that even though Nevada can be characterized as a net exporter of electrical energy, essentially all the coal, natural gas and petroleum used to fire its generating facilities are imported from surrounding states and from foreign countries. Therefore, Nevada must be considered as a net energy importer.

The demand for electrical energy in Nevada has grown at an average annual rate of about 8.4 percent. According to the Public Service Commission, future electrical energy demand is expected to increase but at a reduced rate.[16] This prediction of a reduced rate of growth is due to an expected slowing of the population growth rate and future energy conservation efforts by consumers.

Division of Water Resources' publication on future forecasts of electric energy predicted a different picutre from that of the PSC for electrical energy growth. The level of projected load growth between 1985 and 2000 declined at a slower rate indicating a cessation of net electrical energy export before 1980.[13] The differences between these estimates resulted from the methodologies employed for forecasting both population and per capita energy consumption. There is a difference also in the distribution of population between northern and southern Nevada. Both forecasts, however, suggest new energy-generating facilities in the future to satisfy Nevada needs, independent of net export or import status.

Alternative energy technologies (e.g. geothermal, solar, pumped storage, etc.) do not yet contribute significantly toward meeting the

Table 13

Electrical Energy Summary*
(10^6 Megawatt-hours)

Year	Total Nevada Generation	Total Flows into Nevada	Total Flows out of Nevada	Total Sales	Total Losses Unaccounted
1975	13.86	2.83	7.28	7.62	1.79
1985	24.58	4.14	18.23	12.39	3.09
2000	36.12	37.04	18.24	18.52	37.18

*Data taken from "Energy in Nevada" (Draft Report) for Nevada Public Service Commission, September 1976.. (Reference 16) demand for energy in Nevada. The potential for using resources is great, but currently there are many technological problems and the cost is too high to make them competitive.

The U.S. Geological Survey has identified 13 Known Geothermal Resource Areas (KGRA) in Nevada. About 13.5 million acres in these KGRA's is believed to be valuable for future geothermal development.[13]

Use of Nevada's geothermal resources up to this time has been for heating of houses, domestic water supplies and swimming pools. Most of these uses are concentrated in the Truckee Meadows of Washoe County in northwestern Nevada. Outside of this area there are only a few limited applications including the use of geothermal heat in greenhouses and in resorts with pools and mineral baths.

Most forecasts of geothermal energy production in Nevada do not show significant contributions before 1985. The Division of Water Resources has projected that there will be at least two geothermal power plants (total of 160,000 MWe hours electricity annually) in 1980 and as many as seven of larger capacity (total of 724,000 MWe hours) by the year 2000.[13]

If a reliable and cost-competitive technology can be developed within the next decade, Nevada may be in a position to meet much of its future energy demands with geothermal power plants. At least the geothermal resources should provide supplemental energy to the residential and commercial heating sectors.

Pumped storage generation appears to be a possible alternative for supplying peak power needs, especially where the peak loads are large. Highly urbanized areas in Nevada such as the Las Vegas Valley might provide enough demand to justify pumped storage facilities in the future. Several potential pumped storage sites have been identified in Nevada.

Solar energy has a great potential in Nevada. It is believed that solar energy will provide a substantial input to non-electric heating and cooling systems in the future, which would relieve some of the demand for electrical power.[17] At the present time, however, direct conversion of solar radiation into electricity is limited by the problem of developing cost competitive equipment and systems. Like geothermal resources, the state's potential for solar energy utilization relies on the continued experimental efforts by the federal government and the private sector.

According to the state representatives contacted, nuclear power generation has a poor future in Nevada until a conglomeration of utilities comes forth or the largest utilities expand enough in size to support the capital expenditures in installing nuclear generation.[16,17] Present minimum economical capacities for nuclear power plants are estimated to be about 1000 MWe and greater, which is nearly all the peak load of Nevada's largest utility, Nevada Power Company. There have been no announced plans at this time for future nuclear generation in Nevada.[16]

Uranium and thorium resources, which are an important part of the nuclear fuel cycle, have been identified within the State. Significant quantities of uranium ore have been produced in the past, and future production depends upon future demands for a uranium economy. Whether conditions in the future will be conducive to profitable mining of these products in Nevada is uncertain.

In summary, from the State's point of view, it appears that more electrical energy facilities will be required in the future to supply Nevada's demand and possibly to supply a portion of the demand in surrounding western states. At the present time additions are expected to come exclusively from coal-burning facilities. In addition, even though emerging energy technologies such as geothermal and solar have great potential in Nevada, they will probably not contribute significantly before the year 2000. There are many factors that will determine whether Nevada is able to meet its future demands for electric energy or is a significant net exporter.

Water Requirements

Water is used in many aspects of energy production, including mining and reclamation, processing, transportation and conversion to electrical energy. By far the largest category of water use in the energy industry is withdrawal for cooling of the steam-electric power plant. Various cooling technologies are available to achieve maximum economy in combination with acceptable environmental effects. Consumptive use of water for cooling becomes a serious consideration where it is in competition with other beneficial water uses. This is the case in Nevada where fresh water has high value for alternative use (e.g. irrigation, industrial and public needs).

The Division of Water Resources in several publications has made estimates of coolant water needs for future electrical energy generation in Nevada.[13] Withdrawals for hydroelectric power plants are returned to natural sources and are subsequently withdrawn again for other purposes. Therefore virtually none of the water used is consumed. The steam-electric facilities in Nevada with the exception of those on the Truckee River consume water for condenser cooling process. The water that is used comes from several sources including the Colorado River and its tributary, the Muddy River, underground wells, and treated sewage effluent in the Las Vegas area. The electrical power stations on the Truckee River employ once-through cooling so that nearly all the water withdrawn is returned to the river. A summary of the steam-electric generating plants for each major Nevada utility company was presented in Tables 11 and 12. The tables also contain the various characteristics such as plant capacity, fuel type, water source, condenser cooling type, and average rate of water consumed (1973 data) as reported by the companies.[18]

Table 14 summarizes the 1969 water requirements by water basin, not including water withdrawn at the Hoover and Davis dams. Included in the table are water withdrawals for both hydroelectric power generation and steam-electric generation. It can be seen in Table 14 that the overwhelming majority of water that is withdrawn is involved with the hydroelectric cycle, which is essentially a non-consumptive use. If we exclude the once-through cooling system on the Truckee River, about 87 percent of the water withdrawn for power generation in 1969 (approximately 1.021 million acre-ft), the major portion is from surface sources (about 1.015 million acre-ft) and less than one percent (8,300 acre-ft) of this was consumed.[19]

In relation to the estimated annual water withdrawals for all uses in the state (Table 15), electric power generation amounted to about 1.0 percent. Water demands for irrigation accounted for

Table 14

Estimated Water Requirements for Electric Power Generation in 1969*

(10^3 acre ft/yr)

Region	Hydroelectric Generation Withdrawals	Steam-electric Generation Withdrawals	Steam-electric Generation Consumed	All Power Generation Withdrawals	All Power Generation Consumed
Carson River Basin	260	--	--	260	--
Central Region	0.4	--	--	0.4	--
Colorado River Basin**	--	5.2	4.7	5.2	4.7
Humboldt River Basin	7.5	--	--	7.5	--
Truckee River Basin	690	54	--	744	--
Walker River Basin	--	4.3	3.6	4.3	3.6
State Total	958	64	8.3	1,021	8.3

*Source: "Water for Nevada: Estimated Water in Nevada," Report No. 2, January 1971. (Reference 19)

**Does not include water used for power generation of Hoover and Davis Dams.

Table 15

Estimated 1975 Water Supplies & Demands in Nevada*
(10^3 acre ft/yr)

Region/ Subregions	Estimated Imports	Total Water Supply	Irrigation	Municipal Industrial	Minerals	Electric Power	Other[b]	Reservoir Evaporation	Total Estimated Depletions
Great Basin									
Great Salt Lake	--	80	28	--	--	--	--	16	44
Humboldt	--	1160	615	5	--	--	1	112	733
Central Lahontan	--	1540	518	29	--	4	2	905	1458
Tonopah	--	900	179	26	--	--	1	41	900
Total Region	0	3680	1340	60	0	4	4	1074	2482
Columbia-No.Pacific									
Upper Snake	--	160	26	--	--	--	--	4	30
Central Snake	--	520	102	--	--	--	--	9	111
Total Region	0	680	128	0	0	0	0	13	141
Lower Colorado									
Total Region	107[a]	427	151	77	2	30	39	12	311
Total Summary	107	4787	1619	137	2	34	43	1099	2934[c]

*Source: Modified from Tables VI-24 and VI-25, "Critical Water Problems Facing the Eleven Western States," U.S. Department of Interior, April 1975. (Reference 15)

a. Expected use of Colorado River allotment (1975).

b. Includes recreation,fish and wildlife uses.

c. Surface water depletions = 2598; ground water depletions = 336.

over 50 percent of the total annual withdrawals followed by industrial demands, public supply needs, electric power, and recreation uses. Nonetheless, Nevada's scarce water and related land areas suitable for use in electric energy generation are under increasingly competitive demand for other uses, particularly in urbanized areas. Consequently, an assessment of the water withdrawals and uses is made periodically to help the state in its long-range planning process.

Estimates derived by the Division of Water Resources of future water requirements for electric energy production in Nevada are shown in Table 16.[13] These projections were made assuming no net import or export of electric energy or balance of production and use, which as mentioned previously does not seem likely in the near future. Water use data were based upon present technology, which uses about 0.7 gallons per kilowatt-hour of electricity produced, and were derived by techniques described in a Division of Water Resources publication.[13] The corresponding electrical energy use in megawatt-hours per year, that was estimated in order to derive the coolant water needs, is also presented in the table.

In comparing the electrical energy use figures shown in Table 16 with the forecasts provided by the Public Service Commission[16] (Table 13), there is a range which widens with time between the estimates of the Public Service Commission and the Division of Water Resources. Therefore the projected cooling water needs as presented in Table 16 represent the range of planning efforts by the state. There may be some projected differences with regard to which regions in the state will actually develop further electrical energy capacity. According to the Division of Water Resources estimates, over 70 percent of electric energy use and water needs for electrical energy generation will be localized in the southeast corner of the state corresponding to ASA 1502 of the Lower Colorado Basin.[13]

Implications

Under Nevada water law, the state adheres to the doctrine of prior appropriation. Water may be appropriated for any beneficial use subject to its supply and existing rights. The State Engineer is required to approve a new appropriation if it does not infringe on

Table 16

Estimated Future Water Requirements for Electrical Energy Generation*

	1970	1975	1980	1985	2000
Water Needs (10^3 acre ft/yr)	12.55	18.50	26.45	35	172.85
Electrical Energy Use (10^4 MWH)	584	0.76	1230	1.75	3390

*Source: "Water for Nevada: Forecasts for the Future, Electric Energy," Report No. 9, August 1974. (Reference 19) existing rights or is otherwise detrimental to the public interest. As mentioned earlier, most of the available surface water has been appropriated and used for irrigation. Future increases in supply to meet water demands will probably come from ground water sources. It is general policy of the State Engineer to limit ground water withdrawals from any basin in Nevada to an amount equal to that naturally recharged. Since Nevada water law now prohibits mining of ground water, legislative changes would be required to use the apparent large quantities of ground water.

The Tonopah Basin of the Central Nevada Desert is a potential site for thermal generating plants utilizing ground water for cooling purposes possibly suplemented by surface water.[9] Several other water basins in the southeastern and central portions of Nevada were discussed as potential sites for a steam-electric plant, particularly the three valleys of eastern White Pine County.[14] The Division of Water Resources, as well, has identified various areas where there is sufficient ground water to support additional electrical generating capacity.[13]

In addition to water demands for energy resource development there are larger competing uses. Agricultural and municipal industrial users are important to Nevada's economy and consume the largest quantities of water. Recent assessments suggest a general need for more water-based recreation in Nevada.[15] Maintenance of selected Lower Carson River Basin wetlands, which are some of the most important wildlife habitats in the state, requires resolution. Potential agricultural development is severely limited in many areas of the state as well due to the lack of ample water supplies. Finally, the State's rapid population expansion has resulted in increased water requirements for municipal or public supply needs. It is estimated that in the Lower Colorado River region there will be a series of step-by-step choices between water for power production and water for municipal uses between the present and the decade between 1990 and 2000. Since water is a scarce resource to begin with in Nevada, water conservation practices have been employed for many years, and shall continue to be an important feature.

The consensus of the State representatives contacted was that Nevada can support its per capita electrical energy use, which is still accelerating.[9,17,20] It has enough water to support planned fossil fuel plants as well as perhaps two to three additional power generating facilities.

The focus in Nevada's energy and water future seems to be in the import-export areas. Nevada could continue and even expand its present, short-term role as a net electrical energy exporter if it was decided to be in the best interests of the state and sufficient capital were available. The Utility Environmental Protection Act of Nevada (NRS 704.892) grants discretionary authority to the State Public Service Commission in issuing construction permits to the effect that any interstate power projects using the natural resources of Nevada may be required to sell within the state an amount of power not to exceed that which is exported.[14] Exporting electrical energy is in a sense like exporting water resources. Large exports could have a substantial effect on Nevada's total water and energy market, the state's economy and its environment. Under Nevada water law (NRS 533.370), when energy for export is generated using Nevada water sources, a recovery provision for energy may be exercised. The State Engineer may issue permits for the use of water, expressly subject to the recapture, as the need arises in Nevada, of capacity and associated energy resulting from use of water under these permits.

PHASE II: WATER REQUIREMENTS FOR FUTURE ENERGY PRODUCTION IN CALIFORNIA

This phase of the study was designed to estimate the future water requirements for energy development in California. In contrast to the first phase of the study, future energy development levels were determined by an Energy Research Development Administration (ERDA) scenario for 2000 and by activity projections as reported by the Federal Power Commission (FPC) for 1985. Development of these scenarios for California and the resulting water requirements and their impacts are described in the following sections. Unit water requirements, used to determine the total water requirement, are shown in Table 17.

Table 17

Unit Water Requirements[a]

Type of Power Plant	Assumed Plant Factor	Wet Tower Water Requirements acre-ft/MWe-yr.
Nuclear	.65	17.90
Oil	.40	7.50
Coal	.65	13.36
Combined Cycle	.68	15.64
Geothermal (hydrothermal)	.70	52.50
Solar Central Receiver	.40	12.60

[a]Sources: Teknekron, Inc., Fuel Cycles for Electric Power Generation, Report No. EEED 101, 1975. (Reference 23)

Western States Water Council, Western States Water Requirements for Energy Development to 1990, November 1974. (Reference 24)

ENERGY PROJECTIONS FOR 1985 AND 2000

California electricity demand projections by each ASA for 1985 were supplied by Oak Ridge National Laboratory (ORNL). These figures are based on a set of energy supply and demand calculations specified by ERDA. The total electricity generation for California amounted to $.718 \times 10^{15}$ Btu's, assuming transmission losses of 10 percent. The utilities' projections as reported by the FPC were used to estimate the specific types of electrical capacity needed to meet this demand. Appropriate load factors used in the estimation were derived from utilities data or the energy demand projections. Table 18 contains the electricity generation and capacity figures for 1985.

California electricity demand projections for 2000 were arrived at by disaggregating the Pacific scenario for 2000 developed by Brookhaven National Laboratory (BNL). This scenario is based on a set of energy demand and supply figures provided by ERDA. Table 19 illustrates the electricity demand and supply figures for the Pacific region and California. Figures for energy demand by each ASA in the Pacific region were supplied by ORNL. Assuming 10 percent transmission losses, the total electricity generation for California was estimated at 1.391×10^{15} Btu's. Projections of individual types of electrical capacity for 2000 to meet this energy demand were estimated by a process of successive elimination. The Pacific fuel mix scenario provided by BNL served as a guideline constraint on the capacities of individual types of power plants.

Due to the projected shortage of natural gas, power plants currently burning gas would be permitted to burn only oil for electricity generation from 1980. The 5980 MWe of gas-burning power plants in the Pacific scenario were therefore converted to fuel oil. The total oil-fired capacity then amounted to 11,570 MWe. Since utilities in California are planning construction of the more efficient combined cycle power plants, these plants account for 3000 MWe of the oil-fired capacity in the 2000 scenario. The fraction of hydro capacity (9500 MWe) and pumped storage capacity (3150 MWe) in the scenario is based on the California utilities' projections. The geothermal capacity is based on the maximum resource availability projected in a U.S. Geological Service publication.[21] As such the projection ignores technical,

Table 18

Electricity Generation and Capacity in California for 1985

Power Plant Type	Electricity Generation (10^{15}BTU)	Electrical Capacity (MWe)
Coal	.063	800+3850*
Oil - Conventional	.296	21,050
Combined Cycle		1,432
Gas Turbine	.005	1,594
Hydro - Conventional	.147	8,480
Hydro - Pumped	.009	3,150
Hydro - Northwest	.02	1,193
Nuclear	.147	6657+381**
Geothermal	.032	1,528***
Solar	.001	50
Losses	-.002	
TOTAL	.718	50,115

*Out-of-state coal capacity

**Out-of-state nuclear capacity

***Includes 400 MWe of hydrothermal capacity.

Table 19

Electricity Generation and Capacity for 2000

Power Plant Type	Electrical Capacity ERDA-2 Pacific GWe	Resource Consumption ERDA-2 Pacific 10^{15}BTU	Electricity Generation ERDA-2 Pacific 10^{15}BTU	Electricity Generation LBL California 10^{15}BTU	Electrical Capacity LBL California MWe
Coal	11.57	.435	.157	.157	10,000*+5570
Gas Turbine	6.78	.066	.020	.020	7265
Oil	5.59	.189	.067	.138	8570
Combined Cycle					3000
Nuclear(LWR+HTGR)	24.72+1.92	1.413+.093	.48+.037	.48+.017†	24339+880†+381**
Gas	5.98	.026	.071		
Hydro	50.64	2.372	.833	.156	9500
Hydro Pumped	2.68	.033	.008	.008	3150
Geothermal	32.02	1.972	.671	.369+.031	17,585 hydrothermal + 1,500 vapor
Solar	1.49	.052	.018	.018	1490
Losses			-.003	-.003	
TOTAL	143.39	6.831	2.366	1.391	93,230

*Out-of-state coal capacity

**Out-of-state LWR capacity

†Out-of-state HTGR capacity

social, institutional and other constraints that may limit the development of this resource. The projected 17,585 MWe of geothermal (hydrothermal) resource development may therefore be well above the actual development of this resource. All of the projected solar and nuclear generation of electricity in the scenario is assumed to occur in California. The remaining generation is supplied by coal with 10,000 MWe of coal-fired generation occurring in the Rocky Mountain states.

Table 20 shows the electrical generating capacity by fuel type for 1975, 1985 and 2000. These figures include both in-state and out-of-state power plants. Table 21 shows the water consumptive electrical capacity by California water subareas and by type for 1975, 1985 and 2000. Hydroelectric, pumped storage, gas turbines and vapor-dominated geothermal facilities are not included in this table since these have no cooling water requirements. Water consumptive electrical capacity increases from 23,000 MWe to 61,000 MWe by 2000 whereas the non-water consumptive capacity in California increases from 11,000 MWe to 23,000 MWe. Clearly a higher proportion of future power plants will require cooling water than in 1975.

WATER REQUIREMENTS FOR 1975, 1985 AND 2000

Table 22 illustrates the water requirements for power plant cooling by aggregated subarea within California for 1975, 1985 and 2000. Assuming all power plants use wet cooling towers, the enormous increase in cooling water requirement between 1975 and 2000 is accounted for by three major factors:

1. inland siting of most of the new power plants;
2. higher proportion of water consumptive electrical capacity by 2000, and
3. high fraction of hot water geothermal electrical capacity in 2000.

Most of the large fossil-fueled power plants are currently located along the California coast and use sea water for once-through cooling. However, due to the California Coastal Commission's policy which requires examination of inland sites prior to coastal siting, the utilities may opt for inland siting of power plants. As a result

Table 20

Electrical Capacity by Type of Generation
MWe

	1975	1985	2000
Coal	2276*	800+3580*	5570+10,000*
Oil Conventional	21361	21050	8570
Gas Turbine	1083	1594	7265
Combined Cycle	24	1432	3000
Nuclear	1379	6657+381**	24339+880†+381**
Geothermal	502	1528=1128 vapor + 400 hydrothermal	17585 hydrothermal + 1500 vapor
Solar	0	50	1490
Hydro Conventional	7385	8480	9500
Hydro Pumped Storage	1055	3150	3150
Hydro Northwest	1193	1193	0
TOTAL	36258	50115	93230

*Out-of-state coal capacity

**Out-of-state nuclear (LWR) capacity

†Out-of-state HTGR capacity.

Table 21

Electrical Capacity by Aggregated Subarea*
(MWe)

Subarea	Type of Capacity	1975	1985	2000
1801	Nuclear	63	63	63
	Oil	105	105	0
1802	Nuclear	886	886	1,986
	Coal	0	800	2,400
	Geothermal	0	0	2,123
1803	Nuclear	0	0	7,400
	Oil	180	180	0
1804	Oil	4,141	4,033	1,370
	Combined Cycle	0	360	702
1805	Nuclear	0	2,240	2,271
	Oil	3,062	3,062	1,478
1806	Nuclear	430	3,588	12,620
	Oil	14,053	13,677	5,756
	Coal	0	0	3,170
	Combined Cycle	0	1,072	2,264
	Solar	0	50	1,490
	Geothermal	0	400	4,846
1807	Geothermal	0	0	10,616
Total in California		22,290	30,516	60,555

*Excludes out-of-state hydro, coal and nuclear and in-state hydro, pumped storage, gas turbines, and vapor-dominated geothermal since these facilities have no water requirements.

Table 22

Fresh Water Requirements
(acre-feet)

Aggregated Subarea	Power Plant Type	1975	1985	2000
1801	Nuclear	0	0	0
	Oil	0	0	0
1802	Nuclear	9,613	15,837	35,500
	Coal	0	10,686	32,058
	Geothermal	0	0	111,457
1803	Nuclear	0	0	132,275
	Oil	*	1,350	0
1804	Oil	6,624	8,700	5,625
	Combined Cycle	0	5,630	10,479
1805	Nuclear	0	0	0
	Oil	0	0	0
1806	Nuclear	0	16,981	178,428
	Oil	15,822	11,302	1,357
	Coal	0	0	42,343
	Combined Cycle	0	8,915	27,558
	Solar	0	630	18,774
	Geothermal	0	21,000	254,415
1807	Geothermal	0	0	558,340
California Summary				
	Nuclear	9,613	32,818	346,203
	Oil	22,446	21,352	6,982
	Coal	0	10,686	74,401
	Combined Cycle	0	14,545	38,537
	Geothermal	0	21,000	923,212
	Solar	0	630	18,774
	TOTAL	32,059	101,031	1,408,109

*Less than 1 acre-foot

all future water consumptive electrical capacity was assumed to be located inland.

Hydroelectric capacity has so far formed almost 25 percent of the total in-state capacity. Further development of this resource is precluded, largely due to the Wild and Scenic Rivers Act of 1972. The Act, however, does allow for possible reconsideration of development on the Eel River in 1985. Steam-fired electric capacity will therefore form a larger portion of the future capacity, electric thus increasing the cooling water requirements.

The ERDA scenario for 2000 used in this study calls for 17,585 MWe of geothermal (hydrothermal) capacity. Water requirements per unit of this type of geothermal capacity are almost six times those for fossil power plants. The consequences are clearly evident in Table 22 where an increase of 8000 MWe from 1975 to 1985 leads to 69,000 acre-ft/yr increase in water requirements whereas an increase of 30,000 MWe from 1985 to 2000 leads to 1,307,000 acre-ft/yr increase in water requirement.

The effect of the three factors can be deduced from an examination of the figures in Table 22. Calculations show that 8.8 million acre-ft/yr of saline water were used for once-through cooling of power plants located along the coast in 1975. Fresh water requirements at the same time averaged roughly 32,000 acre-ft/yr. By 1985 estimated saline water and fresh water requirements increase to 12.0 million acre-ft/yr and 101,000 acre-ft/yr, respectively. The increase in saline water requirements is due to coastal plants that have already been approved or are already under construction. By 2000, however, the effects of these three factors is apparent as saline water requirements decrease to 8.1 million acre-ft/yr while fresh water requirements increase to 1.4 million acre-ft/yr.

IMPACTS ON WATER RESOURCES BY ASA

Overall the 1.4 million acre-ft/yr cooling water requirement would form a small fraction of roughly 35 million acre-ft/yr of net water supplies expected to be available by 2000. However, California is currently a water-deficient state. This deficiency is largely confined to inland ASA regions some of which have a potential for siting power plants. Availability of future fresh water supplies to these regions is contingent upon construction of certain key water development projects such as the trans-Delta facility and the New Melones and Auburn reservoirs. The future of these projects is, however, uncertain. Introduction of power plants in these regions could therefore lead to a further burden on these water-deficient areas.

The estimates of water requirements by individual types of power plants were aggregated by subareas as designated by the Water Resources Council. However, the hydrological conditions in California vary considerably even within subareas. As a result each area has several sources of supply such as natural streams or rivers, developed surface water supplies, ground water, and agricultural waste waters. Water demands and their possible sources of supply are therefore analyzed individually for each type of power plant within a subarea.

Since it is projected that existing and planned supplies are adequate to meet water demand in most areas of the State in 1985, there will probably be few water use impacts. Therefore fresh water requirements and their possible sources of supply for 1985 are discussed only for those subareas where there is a significant change from the current water usage.

In accordance with the scenario for California, only one coal-fired power plant (800 MW) was sited within the state for 1985. This facility was sited in the Sacramento Basin (ASA 1802) on the west side of the Sierra. Most of the surface water supplies of this ASA are already committed. Since little or no agricultural drainage water exists, arrangements for purchase of fresh water would be neccessary. Currently, the Rancho Seco Nuclear Plant located in ASA 1802 receives water from the Folsom South Canal through an agreement with the Bureau of Reclamation. Similar arrangements might be possible for other facilities. Potential ground water sources exist in the subarea. The Sacramento Valley is reported to be one of the only major water basins that has the capability of a safe ground water yield greater than its present use.[3]

ASA 1806 is comprised of the south coastal and Colorado Desert regions. A majority of the nuclear and oil capacity in this subarea will use sea water for once-through cooling. The remaining capacity will require fresh water sources.

The Metropolitan Water District of Southern California (MWD) has allocated up to 100,000 acre-ft/yr of its Colorado River water supplies for power plant use at facilities to be constructed in the desert area. Forty percent (40,000 acre-ft/yr) of this amount is allocated to the Southern California Edison Company (SCE). The remaining 60 percent (60,000 acre-ft/yr) is allotted to the following utilities:

1) San Diego Gas and Electric Company (SDGE) - 17,000 acre-ft/yr
2) Los Angeles Department of Water and Power (LADWP) - 33,000 acre-ft/yr

This 60,000 acre-ft of water will be available from the Palo Verde outfall drain.

The only nuclear power plant sited in ASA 1806 by 1985 is SDGE's proposed Sun Desert facility. The Sun Desert project will receive 17,000 acre-ft/yr of water from the Palo Verde drain for cooling its first unit (950 MW), while MWD will forebear from diverting an equivalent amount into the Colorado River Aqueduct at Parker Dam.

New combined cycle capacity of 1072 MW is sited in ASA 1806 by 1985. This increased combined cycle capacity is added to existing facilities. Both of the sites involved are currently using ground water as a source for cooling water. It is anticipated that the additional water requirement (about 9,000 acre-ft/yr) will come from ground water sources.

Since solar power plants represent only a small fraction of the electrical capacity in 1985 (50 MW), the concomitant water requirements are minimal. Solar central receivers will probably be sited in the Colorado Desert area of ASA 1806. The cooling water could come from several potential sources including agricultural drainage water, ground water or transfer of surface water rights.

Development of geothermal resources (hydrothermal) is projected for the Imperial Valley by 1985 (400 MW). The unit water requirements of geothermal facilities using hydrothermal resources is several times greater than those for conventional energy sources (see Table 17). The cooling water required for the projected geothermal capacity (about 21,000 acre-ft/yr) could be obtained from the New and Alamo rivers, which consist primarily of agricultural waste water. It has been reported that these two rivers have a combined minimal yearly flow of more than 600,000 acre-ft.[22] The water supplies therefore appear adequate for geothermal development in this subarea without any impact on competing users.

By 2000 nuclear and coal-fired power plants would account for 4380 MWe of electric capacity in area 1802 (see Figure 2). These facilities would be located in the Sacramento Basin on the western side of the Sierra. Agriculture is a major economic activity in this area. Reclaimed agricultural waste waters therefore form a potential source of supply for cooling water. Geothermal facilities, on the other hand, would be located in the northeast corner of the state outside the Sacramento Basin. Most of the surface water supplies in this area are already developed but potential additional ground water sources exist. Knowledge of ground water sources in this area is superficial, however, and basin perennial yields are not known. Development of geothermal resources therefore may be constrained by lack of sufficient water.

Area 1803 forms the Central Valley. Virtually all the existing supplies are committed in these areas. Agriculture is again the major water user in the Valley. The area is currently water-deficient with a ground water overdraft. Conjunctive operation of surface and ground water sources may provide some additional water supplies. For power plant cooling, however, agricultural waste waters could form the major source of supply. It has been estimated that as much as 200,000 acre-ft/yr of agricultural drainage water would be available in the southern San Joaquin Valley by 2000.[24] Several potential problems exist that must be solved before power plants can use this brackish water for cooling. The problems include seasonal variation in flow, water quality and costs of collection, transport, storage and treatment. The nuclear- and oil-fired plants in Area 1805 are located along the coast and use sea water for cooling.

Area 1806 is comprised of the southern coastal and Colorado Desert region. Part of the nuclear and oil capacity in this area (2638 MWe and 5575 MWe, respectively) will use sea water for cooling. The rest of the capacity will require fresh water for cooling. Ground water and developed supplies from the Colorado River and northern California form the major sources of supply in this water-critical area. Ground water sources are well known and inventoried in this area and could provide some water. The area, however, is already water-deficient and utilities may resort to dry or wet/dry cooling towers. The dry towers would reduce the water requirements to virtually nil whereas the wet/dry towers would reduce it to 25 percent of normal requirements for wet towers.

A specific example of how utilities are addressing the water source problem in this subarea involves the second unit (950 MW) of the proposed Sun Desert nuclear plant. In order to provide fresh water for the second unit, SDGE has purchased three ranches within the Palo Verde Irrigation District and the attendant water rights. By taking some of this land out of production, an additional 17,000 acre-ft/yr will become available for use in the cooling system. The water will again be diverted from the Palo Verde outfall drain. It is uncertain at this time whether other proposed projects will use a similar strategy for acquiring cooling water. It is also unclear what long-term impacts might develop due to water tradeoffs between agriculture and energy development.

Development of geothermal resources in the Colorado Desert (Area 1806) would not have a major impact on the water resources. This area is currently a major agricultural region in the country with agricultural waste water flows of 1 million acre-ft/yr to the Salton Sea and 400,000 acre-ft/yr to the Colorado River. The New and Alamo rivers carry the 1 million acre-ft/yr flow to the Salton Sea. These are good water quality supplies and could be easily tapped for power plant cooling.[22] The water supplies therefore appear adequate for geothermal development.

The scenarios postulate 10,600 MWe of geothermal development in Area 1807. This area is on the eastern side of the Sierra and receives comparatively little rainfall. Surface water resources in the area are already well-developed with exports of 50,000 acre-ft/yr of water to Los Angeles via the Los Angeles Aqueduct. Knowledge of ground water is at best superficial with practically nothing known about deep ground water (600' depth). Since ground water would form the only major potential source of supply, it is unclear if 560,000 acre-ft/yr of water required for cooling 10,600 MWe of capacity would be available. Part of the water exported to Los Angeles could be used for power generation, but considering current contracts and the requirements for water in Los Angeles, that appears unlikely. Water availability would seem to be a major constraint to development of geothermal resources in this area.

SUMMARY

Cooling water for electricity generation will form the major portion of water requirements for future energy development in California. Since almost all the power plants in 1975 were located along the coast, fresh water requirements for cooling amounted to only 32,000 acre-ft/yr. Coastal siting restrictions and development of geothermal resources located inland will increase these water requirements to 1.4 million acre-ft/yr by 2000. The diminishing potential for future water development along with overcommitted water resources could pose a serious constraint to siting electrical capacity of this magnitude in California by 2000.

Coastal siting restrictions may require new power plants to be sited inland. As a result very little new capacity is added in coastal water subareas 1801, 1804 and 1805. Capacity additions in subarea 1806, which has a coastal zone, will occur inland in the desert region, resulting in 230,000 acre-ft/yr of additional water requirements. Currently almost 85 percent of the water to this area is imported from the Colorado River and from northern California.

Therefore the cooling water requirement may have an adverse impact on competitive water users. Utilities may resort to deep ground water supplies or to dry or wet/dry towers to reduce water requirements. Water requirements for fossil- and nuclear-fueled plants in subareas 1802, 1803 and 1804 are not as high. Water supplies although limited are more easily accessible to these areas, as compared with subarea 1806. Additional water supplies would primarily come from conjunctive use of surface and ground water sources and agricultural waste waters. In some instances it may also prove more economical for the farmer to transfer water from agricultural uses to the utilities.

Geothermal capacity by the year 2000 accounts for nearly 925,000 acre-ft/yr of the total 1.4 million acre-ft/yr water requirement. Extensive development of geothermal resources (∿17,600 MWe) coupled with high cooling water requirements lead to this estimate. Water supplies appear adequate in the Imperial Valley (subarea 1806) to meet the requirements. These supplies could come from two rivers, the New and Alamo, which are fed by agricultural waste waters. In the Mono Lake area (subarea 1807) and Surprise Valley (subarea 1802), substantial development of surface water supplies has occurred in the past. Future water supplies would depend primarily on development of ground water basins. Data on ground water basins in these regions are superficial, and safe yields from the ground water basins are therefore not known.

REFERENCES

1. Association of California Water Agencies, The Impact of Power Plant Siting in California's Water Resources, July 1976.

2. California Wild and Scenic Rivers Act, SB-107, Chapter 1259, 1972.

3. California Department of Water Resources, "California's Ground Water," Bulletin No. 118, September 1975.

4. Sathaye, J.A. et al., Analysis of the California Energy Industry, LBL-5928, January 1977.

5. Conversations with James L. Welsh, Planning Division, Department of Water Resources, Sacramento, California.

6. California State Water Resources Control Board, Water Quality Control Policy on Use and Disposal of Inland Water Used for Power Plant Cooling, June 1975.

7. Conversations with staff, California Energy Resources Conservation and Development Commission, Sacramento, California.

8. California Department of Water Resources, "Water Conservation in California," Bulletin No. 198, May 1976.

9. Personal Communication with Victor Hill, Division of Water Resources, Carson City, Nevada, September 28, 1976.

10. Division of Water Resources, "Preliminary State-Regional Future Document," Carson City, Nevada, June 1976.

11. Personal Communication with Alden Briggs, U.S. Bureau of Reclamation, Boulder City, Nevada, October 6, 1976.

12. Personal Communication with Reeve Fagg, Sierra Power Company, Reno, Nevada, September 28, 1976.

13. Nevada State Engineer's Office, Water for Nevada: Forecasts for the Future, Electric Energy, Report No. 9 and Appendices, August 1974.

14. Gertsch, W.D., An Assessment of Water Resources in Utah and Nevada for a Proposed Electric Power-Generating Station, Los Alamos Scientific Laboratory, July 1976.

15. Department of the Interior, Critical Water Problems Facing the Eleven Western States, April 1975.

16. Mendive, D.L., Energy in Nevada: A Summary of Historical Energy Consumption and Projections of Future Energy Consumption, Draft Report for Nevada Public Service Commission, September 1976.

17. Personal Communication with Noel Clark, Chairman of Nevada Public Service Commission, Carson City, Nevada, September 28, 1976.

18. Federal Power Commission, Steam-Electric Plant Air and Water Quality Control Data (Summary Report), January 1976.

19. Nevada State Engineer's Office, Water for Nevada: Estimated Water Use in Nevada, Report No. 2, January 1971.

REFERENCES (continued)

20. Personal Communication with Bruce Ardell, Nevada State Planning Coordinator, Carson City, Nevada, September 28, 1976.

21. U.S. Geological Survey, Assessment of Geothermal Resources of the United States—1975, Circular 726, 1975.

22. Goldsmith, Martin, Engineering Aspects of Geothermal Development in the Imperial Valley, California Institute of Technology, EQL, Memorandum No. 20, December 1976.

23. Teknekron, Inc., Fuel Cycles for Electric Power Generation, Report No. EEED 101, 1975.

24. Western States Water Council, Western States Water Requirements for Energy Development to 1990, November 1974.