CALFED

TECHNICAL REPORT
AFFECTED ENVIRONMENT

POWER PRODUCTION & ENERGY

DRAFT

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CALFED
BAY-DELTA
PROGRAM

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LIST OF ACRONYMS

AB	Assembly Bill
AFB	Air Force Base
CALFED	CALFED Bay-Delta Program
CEC	California Energy Commission
cfs	cubic foot per second
CPUC	California Public Utilities Commission
CVP	Central Valley Project
CVPIA	Central Valley Project Improvement Act
DOE	U.S. Department of Energy
DWR	California Department of Water Resources
EBMUD	East Bay Municipal Utility District
EIR	environmental impact report
EIS	environmental impact statement
FERC	Federal Energy Regulatory Commission
Gwh	gigawatt hour
ISO	Independent System Operator
kW	kilowatt
kWh	kilowatt hour
hp	horsepower
LADWP	Los Angeles Department of Water and Power
M&I	municipal and industrial
MW	megawatt
MWh	megawatt hour
NASA	National Aeronautics and Space Administration
PG&E	Pacific Gas and Electric Company
Reclamation	U.S. Bureau of Reclamation
SCE	Southern California Edison Company
SDG&E	San Diego Gas and Electric Company
SMUD	Sacramento Municipal Utility District
SWP	State Water Project
Western	Western Area Power Administration
WSCC	Western Systems Coordinating Council

POWER PRODUCTION & ENERGY

INTRODUCTION

This technical report describes characteristics of power production and energy resources that could be affected by implementation of the CALFED Bay-Delta Program (CALFED). This report focuses on the following major power and energy assessment variables:

- Available power capacity and energy generation at Central Valley Project (CVP) and State Water Project (SWP) hydroelectric power plants,
- SWP and CVP project energy use,
- SWP and CVP capacity energy sales,
- SWP and CVP power production and replacement costs, and
- SWP and CVP power rates.

SOURCES OF INFORMATION

The system operations models (DWRSIM and the power module of PROSIM, a CVP water and power simulation model) used during this study define available capacity, energy generation, and project energy use (primarily pumping requirements) for each major SWP and CVP power generation and pumping facility under different model scenarios. The model results for existing conditions model scenarios were the sources of information for the following types of existing conditions data included in this report: system-wide available capacity, energy generation, project energy use, Western Area Power Administration (Western) energy sales, and net SWP energy requirements. These data are reported separately for the SWP and CVP.

U.S. Bureau of Reclamation (Reclamation), Western, and California Department of Water Resources (DWR) documents and staff were the sources of information for historical data on power facilities, regulatory background information, power prices, power and energy sales, and power customer names and locations.

Various documents related to electric utility industry restructuring and deregulation were used to prepare the regulatory context section. Sources for these documents included the Federal Energy Regulatory Commission (FERC), California Public Utilities Commission (CPUC), California Energy Commission (CEC), and Western Systems Coordinating Council (WSCC).

ENVIRONMENTAL SETTING

Regulatory Context

Reclamation Law. CVP facilities have been constructed and are operated under Reclamation Law and the authorizing legislation for each facility. Initially, Reclamation projects were authorized under the Reclamation Act of 1902.

In 1906, Reclamation Law was amended to include power as a project purpose if power was necessary to operate the irrigation water supply facilities, or if power could be developed economically in conjunction with the water supply projects. The 1906 Act allowed the sale of surplus power, described as power that exceeds the capacity and energy required to operate Reclamation facilities (project energy use). The 1906 Act included the "preference clause." This clause stipulated that surplus power would be sold with "preference" to municipalities and public corporations or agencies. The CVP's preference power customers include irrigation, water and reclamation districts, rural electric cooperatives, public utility districts, municipalities, state agencies, federal agencies, and local public transportation districts. If additional power is available after the needs of preference power customers loads are met, additional power can be sold to private industries or utilities.

Power supply first was authorized as a purpose for some CVP facilities in the Rivers and Harbors Act of 1937, which included authorization for federal funding of the initial CVP facilities.

Until 1977, Reclamation operated the CVP power generation and transmission facilities and marketed the power generated by CVP facilities. In 1977, Western was established as part of the U.S. Department of Energy. Western operates, maintains, and upgrades the transmission grid that was constructed as part of the CVP. Western also dispatches and markets CVP power to the CVP preference power customers and other utilities. Western, as part of its marketing function, ensures that CVP project use loads are met at all times by using a mix of generation resources, including CVP generation and other purchased resources.

State Water Project. In 1951, the California Legislature authorized construction of the SWP. In addition to providing approximately two-thirds of California residents with at least part of their drinking water, and irrigation water to 600,000 acres of farmland, the SWP was designed and built to control floods, generate power, provide recreational opportunities, and enhance habitats for fish and wildlife. The development of the SWP provides the managing agency, DWR, with the ability to fund the project through the sale of water and power. DWR has developed a power resources program to guide the development and use of SWP power resources.

The goals of the SWP power resources program are to:

- Obtain reliable, environmentally sensitive, and competitively priced power sources and transmission services sufficient for operating the SWP.
- Develop and manage power resources to minimize the cost of water deliveries to SWP contractors.
- Minimize impacts on the SWP when major contractual power arrangements begin to expire in 2004.
- Meet responsibilities and criteria of the WSCC.
- Conform with regulations of the CEC and FERC.

To achieve these goals, DWR developed a power resources program to guide the development and use of SWP power resources. DWR constructed its own power facilities and contracted for long-term power resources with many electric utilities. In addition, DWR arranged for transmission service between the SWP power resources and pumping loads and interconnected utilities. The power resources program also takes advantage of the SWP water storage and conveyance capacities that allow DWR to operate pumps somewhat independently of water delivery needs. This pumping load and generation control enables DWR to enter into advantageous agreements with other electric utilities. Those agreements complement the use of SWP generation to meet SWP power requirements.

The electric industry in California is undergoing a comprehensive restructuring, the objective of which is to reduce electric rates and provide electric consumers with more choices. This process has significant implications for future power values relevant to the evaluation of the CALFED alternatives. The following description of the elements of this restructuring are provided as background.

Open Access Transmission. At the federal level, the Energy Policy Act of 1992 initiated the restructuring process by mandating that access to electric transmission service at the wholesale level be available to all eligible customers. The FERC, which regulates wholesale power and transmission transactions, issued Order No. 888, which provides for "open access" transmission service and the recovery of wholesale "transition" costs or "stranded" costs.

With open access transmission, low-cost power suppliers have access to new customers, thereby increasing wholesale competition and creating an opportunity for reduced power costs.

California Restructuring Legislation (Assembly Bill 1890). At the state level, retail electric service is regulated by the CPUC, which has been pursuing electric restructuring for 3 years. Assembly Bill (AB) 1890 was signed into law in September 1996 and largely confirmed the policies proposed by the CPUC. Under the AB 1890 plan, Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric Company (SDG&E) will continue to own their transmission facilities, but will turn operation of these facilities over to an Independent System Operator (ISO), which will be regulated by the FERC. The ISO, functioning like an air traffic controller for energy, will operate the state's transmission system to ensure that all parties have equal access to transmission, and that the transmission grid and bulk power system are operated reliably.

AB 1890 ensures that an ISO has centralized control of the statewide transmission grid. Toward that end, the legislation directed PG&E, SCE, and SDG&E to transfer operating control of their transmission facilities to the ISO. Although Western, many of Western's preference power customers, and DWR are actively participating in the development of tariffs, protocols, and agreements related to the implementation of AB 1890, none of these customers are required by AB 1890 to transfer operating control of their transmission facilities and contractual rights to the ISO. (If a local publicly owned utility, such as DWR or one of Western's preference power customers, relies on AB 1890 for authority to recover above-market generation costs through a non-bypassable charge on distribution services, then transfer of operating control is required.) AB 1890 provided, and the FERC has reaffirmed, that the terms of existing contracts held by Western, Western's preference power customers, and DWR must continue to honored by the ISO. (FERC 1997)

The restructuring of the California electric industry will significantly affect the value of power resources. Historically, rates have reflected dependable (also referred to as "firm") capacity and energy. Although the dependable capacity of hydroelectric resources potentially affected by the CALFED alternatives during critical dry years will remain a relevant indicator of value, the pricing of power resources, by which the capability of a hydroelectric resource might be measured, will be changed.

CVP Restoration Fund. Section 3407 of the Central Valley Project Improvement Act (CVPIA) established the Central Valley Project Restoration Fund to assist the Secretary in carrying out the programs, projects, plans, and habitat restoration, improvement, and acquisition provisions of the CVPIA. Revenues for the Restoration Fund are derived through collections of pre-renewal charges, tiered water rates, transferred water rates, Friant surcharges, municipal and industrial (M&I) surcharges, and mitigation and restoration payments by water and power beneficiaries.

Total annual collections from all these sources are required to average $50 million annually (October 1992 price levels) on a 3-year rolling average. Annual collections from CVP water and power contractors are not to exceed $30 million (October 1992 price levels) on a 3-year rolling average. The amount of the mitigation and restoration payments made by CVP water and power users is intended to be assessed, to the greatest extent practicable, in the same proportion (measured over a 10-year rolling average) as water and power users' respective CVP repayment allocations.

The CVP Restoration Fund is funded by the following sources:

- payments from CVP water users;
- payments from CVP power users;
- surcharges on M&I water users;
- surcharges on water sales to Friant Project water users; and
- non-federal contributions.

The CALFED alternatives could potentially affect the contributions of CVP power and water users to the fund. According to the CVPIA, the annual collections from CVP water and power users are not to exceed $30 million on a 3-year rolling average. Western estimates the annual contribution by power customers to be approximately $7.5 million, therefore leaving approximately $22.5 million to be contributed each year by CVP water contractors. The contributions by water users are subject to the payment caps described in the Supplement. There are no payment caps that apply to the contributions by power users.

All Regions

The interrelated nature of the power facilities within the SWP and CVP prevents the development of useful analyses on a regional basis. This section, and subsequent sections, provides quantitative analyses of power production and energy resources associated with the SWP and CVP on a system-wide basis only. A system-wide perspective is appropriate and consistent with the regional approach used by the operators of power systems. Therefore, this report does not describe SWP and CVP facilities, rates, and customers on a region-by-region basis. Although the potential power and energy impacts of the CALFED alternatives have been assessed on a system-wide basis, individual hydroelectric and pumping facilities would be impacted. Figure 1 shows these individual SWP and CVP facilities as well as the study area.

HISTORICAL PERSPECTIVE

This section provides a brief description of historical SWP and CVP system-wide available capacity and energy generation, system-wide power and energy sales, and power rates and project energy use from 1960 through 1995.

CVP power generation facilities initially were developed based on the premise that power could be generated to meet project use loads. Reclamation law provides for surplus power to be sold first to preference power customers. Preference power customers include irrigation and reclamation districts, cooperatives, public utility districts, municipalities, California educational and penal institutions, and federal defense and other institutions. Surplus commercial firm power may be sold to non-preference utilities. The first commercial power generated by the CVP (at the Shasta Power Plant) was sold to PG&E in 1945. The initial preference power customers began to take delivery in the late 1940s.

CVP power is not necessarily generated at the appropriate times to meet peak power needs of project use and preference customers. In addition, power generation frequently is reduced due to droughts and changes in minimum stream flow requirements. To maximize the beneficial use of CVP power, Western frequently exchanges, or banks, power with PG&E and purchases power from PG&E and other entities (such as suppliers in the Pacific Northwest) to meet project use and preference customer loads.

Power rates for preference customers are determined by Western. Western completes an

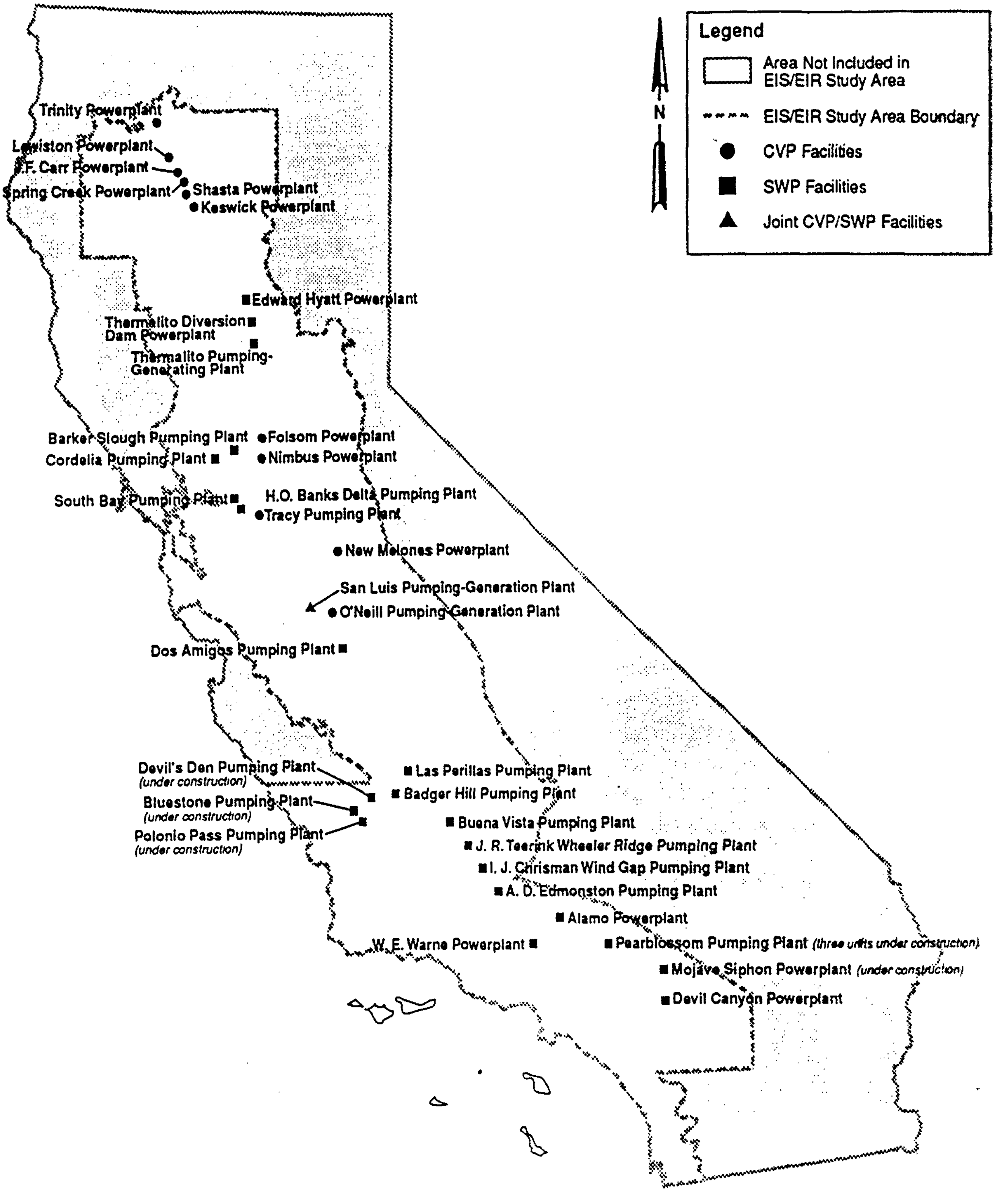


Figure 1. Potentially Affected Power and Energy Resources

annual Power Repayment Study to determine whether revenues from power sales will be sufficient to pay all costs assigned to CVP power purposes, including operation and maintenance and interest expenses. The revenues also must be sufficient to recover the investment of the CVP facilities within a 50-year period after the facilities become operational or as provided by federal law. The revenues also must be sufficient to recover the investment in federal transmission facilities, and the cost of replacement of all power facilities, within the service life of the facilities up to a maximum period of 50 years.

Water deliveries from the SWP initially were provided in 1962 to Alameda and Santa Clara counties through the South Bay Aqueduct. In 1966, DWR entered an agreement with the Los Angeles Department of Water and Power (LADWP) for the joint development of the West Branch of the California Aqueduct. The facilities constructed under this agreement include the Castaic Power Plant, owned and operated by LADWP, from which DWR receives capacity and energy. Power generation from SWP facilities began in 1968 with the operation of the Hyatt-Thermalito facilities downstream of Lake Oroville. The primary purpose of the SWP power generation facilities is to meet the energy requirements of the SWP pumping plants.

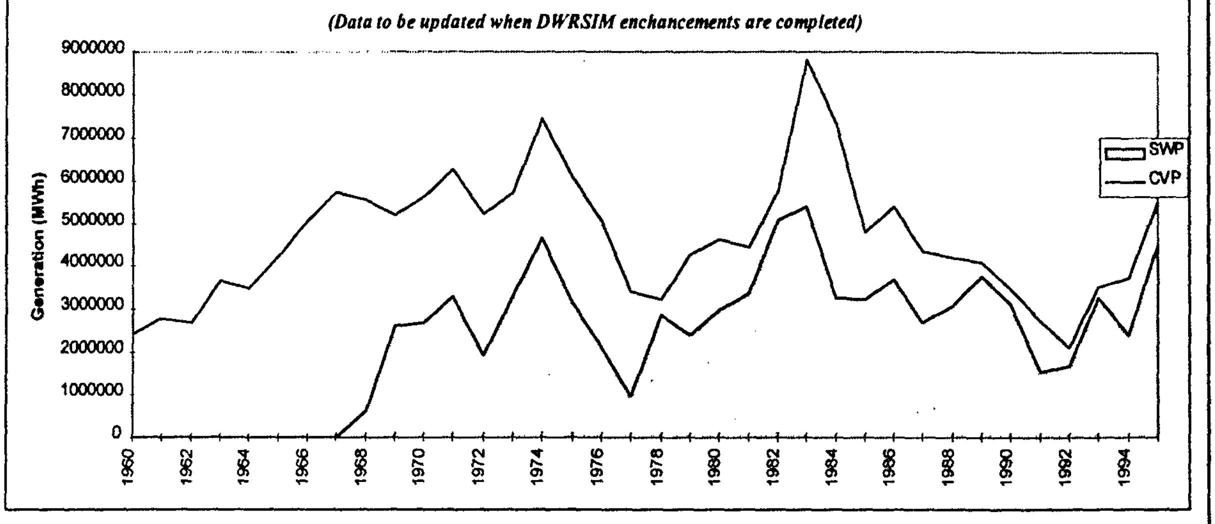
SWP power is not necessarily generated at the appropriate times to meet peak power needs of project use. Conversely, power generation at off-peak periods of project use can exceed project use power needs and provide an opportunity for the sale of excess power. Starting in 1968, SWP power was provided to the power grid of California's large investor-owned utilities, with whom DWR has agreements to provide and receive power. SWP net generation was provided to the utilities and "banked" so that the SWP received an in-kind credit from the utilities for power to be used at project pumping plants during times of peak project use.

Despite the economical exchange arrangements that DWR has entered, the SWP remains energy deficient, with pumping energy requirements that exceed the energy generated by the SWP hydroelectric facilities. Consequently, DWR has entered several long-term agreements for additional power supplies, and purchased an ownership interest in the Reid Gardner Unit 4 from Nevada Power Company. DWR's total energy resources, considering the SWP generation and exchange arrangements, long-term power purchase agreements, and Reid Gardner Unit 4, historically have provided more than enough energy to meet SWP pumping requirements. When DWR has surplus power, it is sold to various utilities, with the objective of maximizing revenue from such sales to offset power costs.

Most costs of SWP operation, including net power costs, are collected from the SWP water customers under long-term water supply contracts. A constant "system energy rate" is defined based on the net cost of energy and capacity, after revenues from surplus sales. Power costs are assigned to water deliveries at the system energy rate based on the amount of energy required to deliver water to each reach on the California Aqueduct. To the extent that a CALFED action alternative results in a decrease in the value of SWP hydroelectric generation, the system energy rate will be increased, and the cost of water delivered to all water customers of the SWP will be increased in proportion to the energy required to deliver SWP water to each contractor. Similarly, if a CALFED action alternative causes an increase in the value of SWP hydroelectric generation, then the system energy rate would be reduced, and all SWP water customers would benefit proportionately.

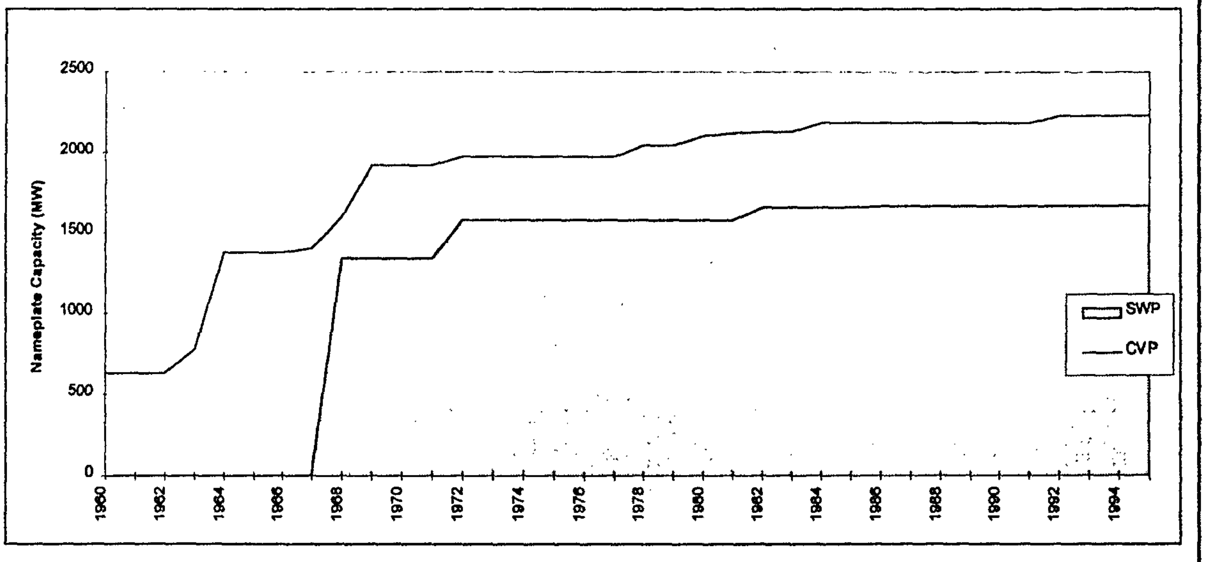
SWP AND CVP CAPACITY AND ENERGY GENERATION

Figure 2 summarizes the historical energy generated by the SWP and CVP power systems. Figure 3 summarizes the total historical nameplate capacity (design capacity specified by the manufacturer representing approximate



SWP - Totals are net of station service.
CVP - Totals include station service.
Sources: Reclamation Power Program
Western, Sierra Nevada Regional Office
DWR, Bulletin 132

Figure 2. Historical SWP and CVP Energy Generation



SWP - Capacity is estimated based on current nameplate capacity and year of initial service.
Sources: Reclamation Power Program
Western, Sierra Nevada Regional Office
DWR, Bulletin 132

Figure 3. Historical SWP and CVP Nameplate Capacity

maximum sustainable level of output) ratings of the SWP and CVP power systems.

SWP AND CVP PROJECT ENERGY USE

Figure 4 summarizes historical SWP and CVP project energy use.

WESTERN ENERGY SALES

Figure 5 summarizes the historical hydroelectric energy sales (in megawatt hours [MWh]) by Western (Fout pers. comm.). Figure 6 summarizes historical revenue from the Western hydroelectric energy sales (Fout pers. comm.).

NET SWP ENERGY REQUIREMENTS

The SWP is a net energy consumer; in other words, SWP project energy use exceeds SWP energy generation. The difference is referred to as net SWP energy requirements and is the amount of energy DWR must meet with energy provided by existing capacity exchange arrangements, off-aqueduct power resources, or purchases from other sources. Figure 7 shows the SWP's historical net energy requirements.

WESTERN AND DWR POWER RATES

Table 1 summarizes the historical system-wide power and energy rates for Western (CVP) and DWR (SWP). Because the SWP is a water delivery project, DWR does not include a calculation of capacity payments to its customers. Since DWR does not charge for capacity in the traditional sense, no capacity rate is calculated.

The system energy rate, including off-aqueduct costs, reflects the net variable cost of energy required to meet the pumping energy requirements of the SWP. This value considers the amount of energy generated at SWP hydroelectric projects, energy returned under DWR's capacity exchange agreements, the value of sales of surplus energy, and the cost of additional energy purchases.

Hydroelectric power plants that are within the study area but are not operated as part of the CVP or SWP may be affected by changes in operation of water flows in the study area. Potentially affected plants are discussed by region.

CURRENT RESOURCE CONDITIONS

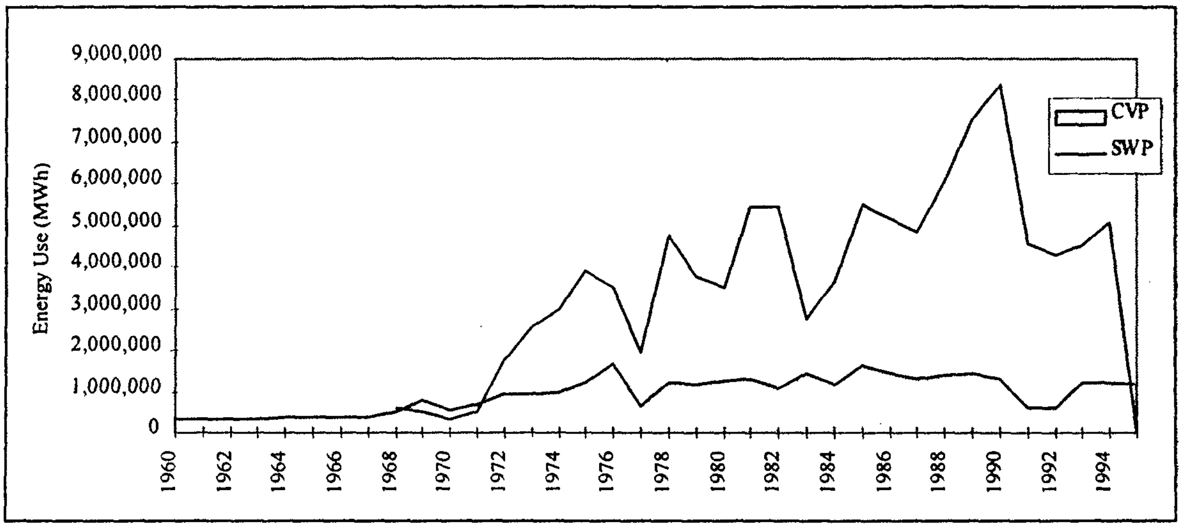
AVAILABLE CAPACITY AND ENERGY GENERATION AT SWP AND CVP HYDROELECTRIC POWER PLANTS

SWP and CVP hydroelectric generation facilities have a total nameplate capacity rating of approximately 3,678 megawatts (MW). As shown in Table 2, the CVP has a nameplate rating of 2,220 MW and the SWP has a nameplate rating of 1,458 MW. Under current conditions (1995 level of development), 1,679 MW of the CVP capacity is available on average (over the 73-year hydrologic record used for this Programmatic EIS/EIR) and 1,427 MW is available during dry conditions. For the SWP, 1,490 MW of capacity is available on average during the summer and 1,357 MW of capacity is available during dry conditions.

The CVP generates an annual average of 5,265 gigawatt hours (GWh) under existing conditions (see Table 2). The SWP generates an annual average of 4,362 GWh under existing conditions (see Table 2).

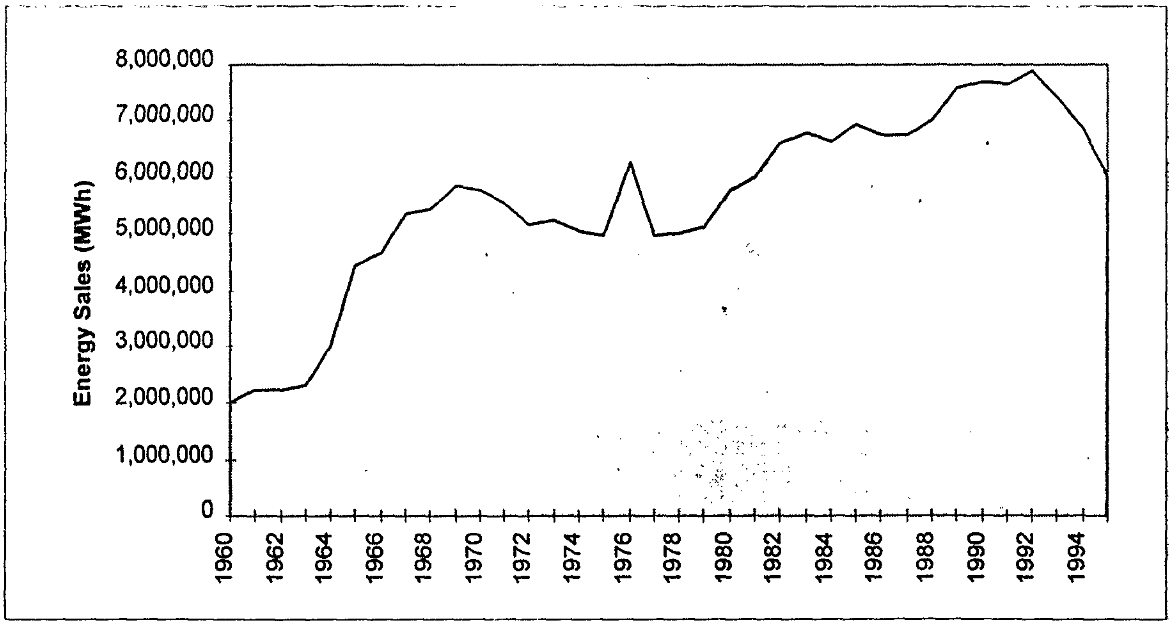
SWP AND CVP PROJECT ENERGY USE

Current annual CVP project energy use averages 1,563 GWh, and annual SWP project energy use averages 8,412 GWh (see Table 2). Most of this energy is used to power the surface water pumping facilities of these projects.



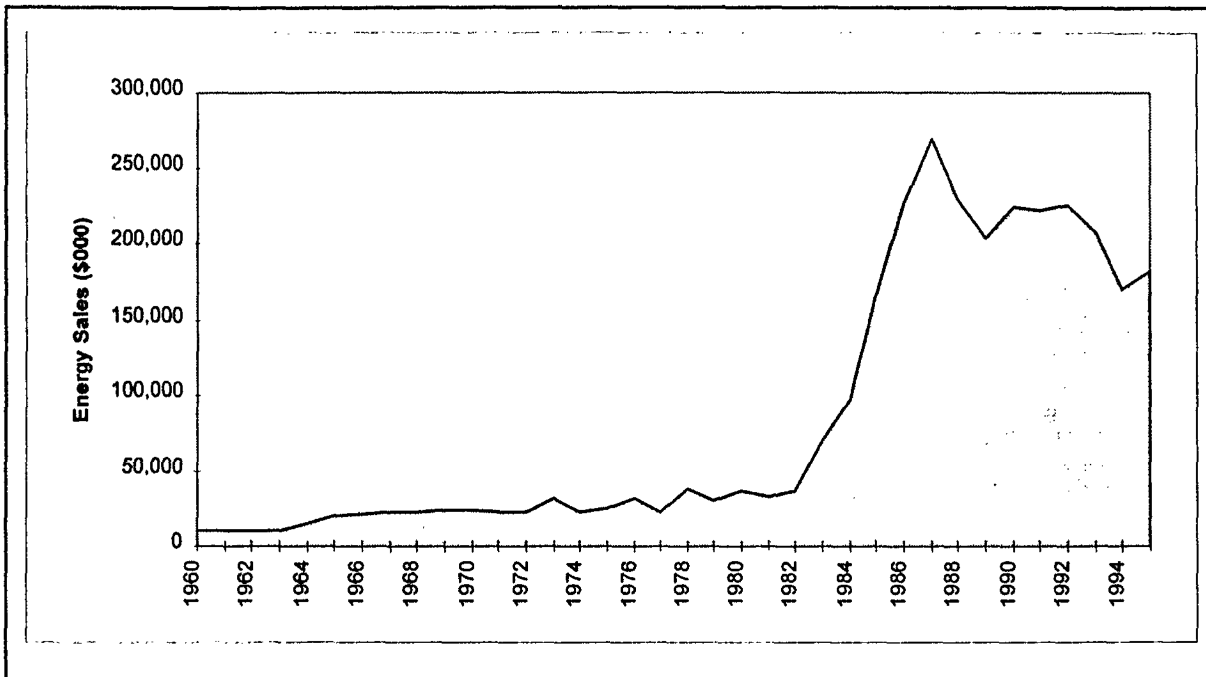
Sources: Western, Sierra Nevada Regional Office
DWR, Bulletin 132

Figure 4. Historical SWP and CVP Project Energy Use



CVP - Energy sales are for firm commercial only. Prior to 1965, some CVP energy was sold as non-firm. These sales are not reflected here.
Sources: Western, Sierra Nevada Regional Office

Figure 5. Historical Western Energy Sales (in MWh)



CVP - Energy sales are for firm commercial only. Prior to 1965, some CVP energy was sold as non-firm. These sales are not reflected here.
Sources: Western, Sierra Nevada Regional Office

Figure 6. Historical Western Power Sales Revenue (in $)

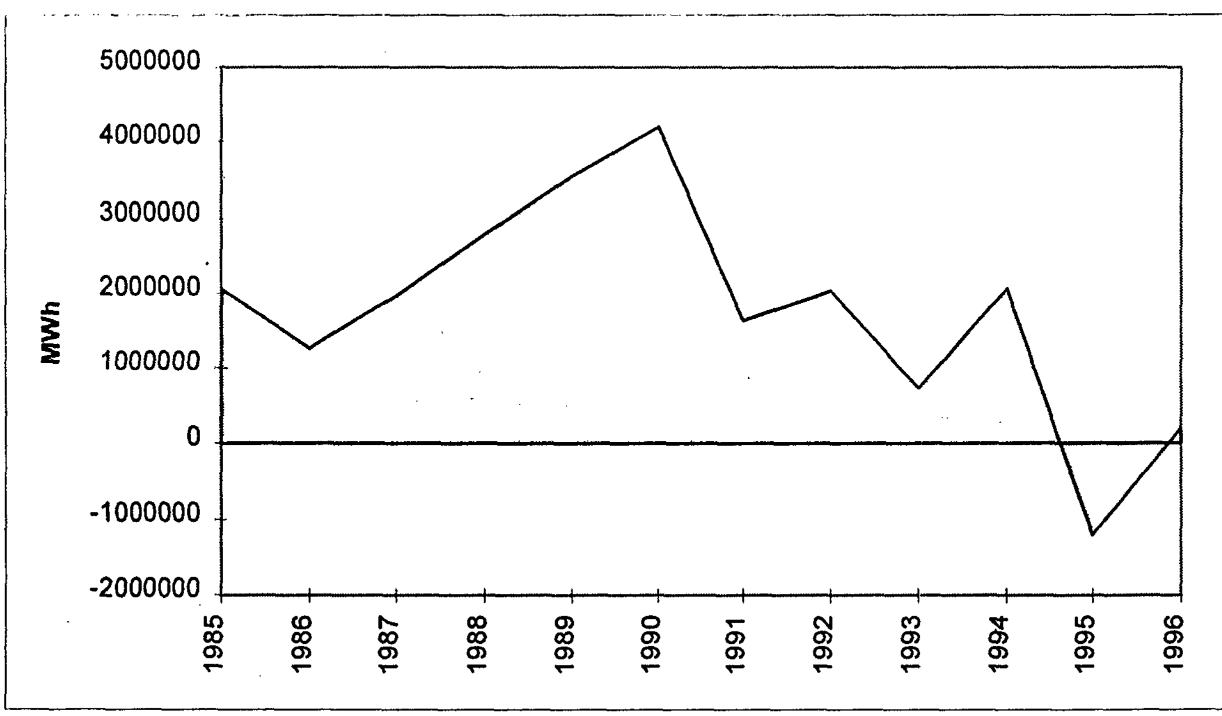


Figure 7. Historical Net SWP Energy Requirements (in MWh)

Year	Western (CVP) Capacity Rate ($/MW-month)		Western (CVP) Energy Rate ($/MWh)		DWR (SWP) Energy Rate[a] ($/MWh)
1960-1973		750		3.00	
1974	1/1-3/31	750		3.00	
	4/1-12/31	1,150			
1975-1977		1,150		3.00	
1978	1/1-5/24	1,150	1/1-5/24	3.00	
	5/25-12/31	2,000	5/25-12/31	4.20	
1979		2,000	1/1-10/31	4.20	
			11/1-12/31	5.11	
1980-1982		2,000		5.11	
1983	1/1-5/24	2,000	1/1-5/24	5.11	17.02
	5/25-12/31	3,750	5/25-12/31	8.53	
1984		3,750	1/1-9/30	13.74	26.35
			10/1-12/31	18.95	
1985		3,750	1/1-10/31	18.95	31.38
			11/1-12/31	27.97	
1986		3,750	1/1-9/30	27.97	19.08
			10/1-12/31	31.44	
1987		3,750		31.44	19.68
1988	1/1-4/30	3,750	1/1-4/30	31.44	21.61
	5/1-12/31	6,860	5/1-12/31	14.43	
1989	1/1-9/30	6,860	1/1-9/30	14.43	26.48
	10/1-12/31	7,490	10/1-12/31	15.76	
1990		7,490		15.76	24.58
1991	1/1-9/30	7,490	1/1-9/30	15.76	22.25
	10/1-12/31	7,740	10/1-12/31	16.30	
1992		7,740		16.30	24.57
1993	1/1-4/30	7,740	1/1-9/30	16.30	22.39
	5/1-9/30	6,450	10/1-12/31	17.97	
	10/1-12/31	6,220			
1994		6,220	1/1-4/30	17.97	23.23
			Base	16.99	
			Tier	30.87	
1995	1/1-9/30	6,220	Base	14.83	12.27
	10/1-12/31	4,030	Tier	25.90	

NOTE:

[a] Calculated based on total energy sales in dollars and MWh.

SOURCES:
Dang pers. comm., DWR Series 1986-1996.

Table 1. Historical System-Wide Power and Energy Rates for Western (CVP) and DWR (SWP)

Table 2. Summary of Existing Power Production and Energy Conditions for SWP and CVP

Assessment Variables	CVP Existing Conditions	SWP Existing Conditions	CVP and SWP Combined Total
Total Nameplate Capacity Rating (MW)	2,200	1,458	3,678
Total Available Summer Capacity (MW) - Average Conditions - Dry Conditions	 1,679 1,427	 1,490 1,357	 3169
Total Annual Energy Generation (Gwh) - Average Conditions - Dry Conditions	 5,265 2,875	 4,362 2,853	 9,627
Total Annual Project Energy Use (Gwh) - Average Conditions - Dry Conditions	 1,563 1,252	 8,412 6,212	 9,975
Total Annual Energy[1,2] (GWh) - Average Conditions - Dry Conditions	Available for sale[1] 3,702[1] 1,723	Net Requirements[2] 4,050 3,359	 - -
Energy Rate[3] (mills/kWh)	Western's Composite Rate (mills/kWh) $20.6	System Rate (mills/kWh) $23.8	Average Energy Rate ($/MWh) $21.48

NOTES:

[1]Western's total annual energy available for sale is equal to CVP maximum project generation minus CVP maximum project energy use. negative values represent a net energy requirement.
[2]The SWP's net energy requirement is equal to SWP maximum project energy use minus SWP maximum generation.
[3]For CVP uses Western's Composite Energy Rate; for SWP uses System Energy Rate; for Combined CVP and SWP uses Average Energy Rate

WESTERN ENERGY SALES AND NET SWP ENERGY REQUIREMENTS

Western's net energy available for sale under existing conditions average 3,702 GWh per year (Table 2). As with the other CVP-related data in this section, this number is projected using the DWRSIM output based on 1995 level of development conditions, and is the average sales volume over the entire 73-year hydrologic record used in this analysis. Western sells available capacity and energy after all CVP project energy use requirements are met.

The SWP is a net consumer of power because its project energy use exceeds the amount of energy generated at its hydroelectric facilities. Therefore, the SWP's net energy requirement, before considering DWR's unrelated long-term agreements and off-aqueduct power resources, is the appropriate assessment variable to measure. The SWP's net energy requirement under existing conditions is estimated to average 4,050 GWh over the 73-year hydrologic record. DWR meets its net energy requirement by purchasing energy from a variety of sources.

WESTERN AND DWR POWER RATES

Western's current composite power rate is $20.6 MWh. DWR's existing system energy rate is 23.8 mills/kWh.

DELTA REGION

CURRENT RESOURCE CONDITIONS

This section provides a description and qualitative discussion of the SWP and CVP pumping and power plants that are physically located within the defined Delta Region. These facilities are shown in Figure 1.

There are 75 CVP preference power customers (not including Reclamation customers). After their power needs are met, Western can sell the remaining power and energy to other customers. The major customers of surplus/commercial sales include Pacific Gas and Electric Company and the City and County of San Francisco.

CVP Surface Water Pumping

Tracy Pumping Plant

The Tracy Pumping Plant is located in Alameda County near the town of Byron. The plant moves water from the Delta Region into the San Joaquin River Region by pumping Delta water into the Delta-Mendota Canal.

SWP Surface Water Pumping

Barker Slough Pumping Plant

In the northern section of the Delta, the Barker Slough Pumping Plant diverts water for delivery to Napa and Solano counties through the North Bay Aqueduct, which was completed in 1988 (Figure 1). Barker Slough has nine units with a total motor rating of 4,800 horsepower (hp), providing a total flow at design head of 228 cubic feet per second (cfs).

Banks Pumping Plant

In the southern Delta, water is diverted to the Clifton Court Forebay for delivery south of the Delta. The Harvey O. Banks Delta (Banks) Pumping Plant is located in San Joaquin County, just south and west of the CVP's Tracy Pumping Plant (Figure 1). The plant lifts water from Clifton Court Forebay into Bethany Reservoir. Most of the water from Bethany Reservoir flows into the Governor Edmund G. Brown California Aqueduct, delivering water to the San Joaquin River Valley and southern California. Banks has 11 units with a total motor rating of 333,000 hp, providing a total flow at design head of 10,668 cfs.

South Bay Pumping Plant

The South Bay Pumping Plant lifts some water from Bethany Reservoir to the South Bay Aqueduct (Figure 1). Water in the South Bay Aqueduct is supplied to Alameda and Santa Clara counties. South Bay has nine units with a total motor rating of 27,800 hp providing a total flow at design head of 330 cfs.

CVP Power Customers

Eight CVP preference power customers have a service area located wholly or partially within the Delta Region. These customers make up 37.4% of total CVP preference customer energy sales. The following preference power customers have service areas located wholly or partially in the Delta Region:

- Sacramento Municipal Utility District
- Travis Air Force Base (AFB), David Grant Medical Center
- Travis AFB, Wherry Housing
- California Medical Facility, Vacaville
- Tracy Defense Distribution Depot
- University of California at Davis
- Naval Radio Station, Dixon
- City of Lodi

In addition, PG&E purchases CVP non-preference power.

SWP Power Customers

The two SWP power customers with a service area located wholly or partially within the Delta Region make up 29% of total SWP energy sales. These customers are:

- PG&E
- SMUD

BAY REGION

<u>CURRENT RESOURCE CONDITIONS</u>

This section provides a description and qualitative discussion of the facilities that are physically located within the defined Bay Region.

No CVP or SWP generation facilities are located in the Bay Region, and no CVP surface water pumping facilities are located in the Bay Region.

SWP Surface Water Pumping

Cordelia Pumping Plant

The Cordelia Pumping Plant is located on the North Bay Aqueduct and moves water diverted from the Delta to destinations in Napa and Solano counties (Figure 1). Cordelia has 11 units with a total motor rating of 5,600 hp, providing a total flow at design head of 138 cfs.

Del Valle Pumping Plant

The Del Valle Pumping Plant is located on the South Bay Aqueduct and moves water diverted from the Delta to destinations in Alameda and Santa Clara counties (Figure 1). Del Valle has four units with a total motor rating of 1,000 hp, providing a total flow at design head of 120 cfs.

CVP Power Customers

Twenty CVP preference power customers with a service area located wholly or partially within the Bay Region make up 32.7% of total CVP preference customer energy sales. These customers are:

- City of Alameda
- Naval Shipyard, Mare Island
- City of Palo Alto
- Naval Weapons Station, Concord
- City of Santa Clara

- East Contra Costa Irrigation District
- East Bay Municipal Utility District (EBMUD)
- Onizuka AFB
- Santa Clara Valley Water District
- U.S. Department of Energy (DOE), Lawrence Berkeley National Laboratory
- West Side Irrigation District
- DOE, Lawrence Livermore National Laboratory
- Bay Area Rapid Transit District
- DOE, Site 300
- Ames Research Center, National Aeronautics and Space Administration (NASA)
- DOE, Stanford Linear Accelerator
- Moffett Federal Airfield, NASA
- Parks Reserve Forces Training Area
- Naval Station - Treasure Island
- Oakland Army Base

In addition, PG&E and the City of San Francisco purchase CVP non-preference power.

SWP Power Customers

Three SWP power customers with a service area located wholly or partially within the Bay Region make up 8.7% of total SWP energy sales. These customers are:

- Hetch Hetchy Water and Power
- PG&E
- City of Santa Clara

SACRAMENTO RIVER REGION

CURRENT RESOURCE CONDITIONS

This section provides a description and qualitative discussion of the facilities that are physically located within the defined Sacramento River Region.

No CVP pumping facilities are located in the Sacramento River Region.

CVP Generation Facilities

Shasta Power Plant

The Shasta Power Plant is located on the western bank of the Sacramento River below Shasta Dam, 9 miles northwest of Redding, California. The power plant contains seven generating units, including two station service units. The power plant, initially operated in 1944, has been expanded from the original nameplate capacity of 379 MW to a current installed capacity of 539 MW provided by five main generation units. The power plant is a peaking plant (a power plant used to generate energy during peak-periods when demand is highest).

Keswick Power Plant

The Keswick Power Plant at Keswick Dam was constructed 9 miles downstream of the Shasta Power Plant as an afterbay (a small reservoir downstream of the power plant). The afterbay regulates, or dampens, the rapid flow fluctuations that occur when Shasta Power Plant operations change suddenly to meet changing power loads. The power plant, initially operated in 1949, was expanded (in 1992) from the original nameplate capacity of 75 MW to a current installed capacity of 117 MW. The power plant is a run-of-the-river plant, with no ability to regulate flows for power purposes.

Trinity Power Plant

The Trinity Power Plant at Trinity Dam is located on the Trinity River, 9 miles upstream from Lewiston. The power plant has two units, and utilizes different turbine designs to maximize efficiency as reservoir levels change. The power plant, initially operated in 1964, was expanded (in 1984) from the original nameplate capacity of 100 MW to a current installed

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capacity of 140 MW. The power plant is a peaking plant. Trinity County has priority on the power from the Trinity, Judge Francis Carr, and Spring Creek power plants.

Lewiston Power Plant

After flowing through the Trinity Power Plant, water empties into Lewiston Reservoir (Figure 1). Water released from Lewiston Reservoir flows through the Lewiston Power Plant and into either the Trinity River or the Clear Creek Tunnel. Initially operated in 1964, the power plant has an installed capacity of 350 kilowatt (kW). The power plant is a run-of-the-river plant and provides station service to Trinity Power Plant and power to local fish hatchery loads. Energy in excess of hatchery loads is sold to PG&E.

Judge Francis Carr Power Plant

Water diverted from the Clear Creek Tunnel passes through the Judge Francis Carr Power Plant before entering Whiskeytown Lake (Figure 1). The power plant is located on Clear Creek, at the outlet of Clear Creek Tunnel on the northwestern extremity of Whiskeytown Lake.

The power plant, initially operated in 1963, was uprated (in 1984) from the original nameplate capacity of 143.68 MW to a current installed capacity of 154.4 MW. The actual operating capability is limited by operating conditions of the Clear Creek Tunnel. Mineral deposits in the tunnel reduce the capacity of the tunnel and the related generation capability. Tunnel operations are suspended periodically in spring to allow the mineral deposits to be removed naturally. Generation capabilities are restored as the tunnel is self-cleaned. The average generation capabilities range from 147 to 158 MW. The power plant is a peaking plant. Trinity County has first preference to the power benefit to the CVP from this power plant.

Spring Creek Power Plant

The Spring Creek Power Plant is located on the Spring Creek arm of Keswick Reservoir (Figure 1). The power plant, initially operated in 1964, was uprated (in 1981 to 1982) from the original nameplate capacity of 150 MW to a current installed capacity of 180 MW. The actual operating capability is determined by hydraulic capacity of the Spring Creek Tunnel. In a manner similar to the Clear Creek Tunnel, tunnel operations become limited due to mineral deposits and periodic cleaning operations. Power plant operation is tied to flow regimes aimed at minimizing the build up of metal concentrations in the Spring Creek arm of the Keswick Reservoir. The power plant is a peaking plant. Trinity County has first preference to the power benefit to the CVP from this power plant.

Folsom Power Plant

The Folsom Power Plant is located on the north bank of the American River at the foot of Folsom Dam (Figure 1). The power plant, initially operated in 1955, was uprated (in 1972) from the original nameplate capacity of 162 MW to a current installed capacity of 198.72 MW. The power plant is a peaking plant. The power plant also provides power for the pumping plant, which supplies the local domestic water supply. Folsom Power Plant is being increasingly relied upon to support local loads during system disturbances.

Nimbus Power Plant

The Nimbus Power Plant was initially operated in 1955 as an afterbay for the Folsom Power Plant. The power plant is located on the right abutment of Nimbus Dam on the north side of the American River, about 7 miles downstream from Folsom (Figure 1). The installed capacity of the power plant is 13.5 MW. The power plant is a run-of-the-river plant and provides backup power service for essential systems at the Folsom Power Plant. Nimbus Dam also includes a diversion structure to convey water to the Folsom South Canal.

SWP Generation Facilities

Hyatt-Thermalito Plant Complex

The Edward Hyatt Pumping-Generating Plant, the Thermalito Pumping-Generating Plant, and the Thermalito Diversion Dam Power Plant are located along the Feather River below Oroville Dam (Figure 1). The plants, initially operated in 1968, have a total installed capacity of 903 MW. In addition to generation, the Hyatt Plant pumps water to the Thermalito Diversion Dam Reservoir. After passing through the Thermalito Diversion Dam Power Plant, water flows through the Thermalito Pumping-Generating Plant and is pumped to the Thermalito Afterbay for release into the Feather River. The primary purpose of the facility is to generate power for project use. Remaining energy is marketed primarily to customers in the Pacific Northwest and northern California.

SWP Surface Water Pumping

Hyatt-Thermalito Plant Complex

The SWP operates two pumping-generating plants in the Sacramento River Region, the Edward Hyatt Pumping-Generating Plant and the Thermalito Pumping-Generating Plant (Figure 1), as described above for "SWP Generation Facilities."

The pumping component of the Hyatt Pumping-Generating Plant has three units with a total motor rating of 519,000 hp, providing a total flow at design head of 5,610 cfs. The pumping component of the Thermalito Pumping-Generating Plant has three units with a total motor rating of 120,000 hp, providing a total flow at design head of 9,120 cfs.

CVP Power Customers

Twenty CVP preference power customers with a service area located wholly or partially within the Sacramento River Region make up 53.4% of total CVP preference customer energy sales. These customers are:

- City of Biggs
- City of Gridley
- City of Healdsburg
- City of Redding
- City of Roseville
- City of Shasta Lake
- Plumas-Sierra Rural Electric Cooperative
- City of Ukiah
- Beale AFB
- Sonoma County Water Authority
- Trinity County Public Utility District
- Glenn-Colusa Irrigation District
- Provident Irrigation District
- Lassen Municipal Utility District
- Tuolumne Public Power Agency
- McClellan AFB
- California Parks and Recreation Department
- California State Prison, Folsom
- San Juan Water District
- California State University, Sacramento

In addition, PG&E purchases CVP non-preference power.

SWP Power Customers

Four SWP power customers with a service area located wholly or partially within the Sacramento River Region make up 38.2% of total SWP energy sales. These customers are:

- Lassen Municipal Utility District
- Northern California Power Agency
- PG&E
- SMUD

SAN JOAQUIN RIVER REGION

CURRENT RESOURCE CONDITIONS

SWP and CVP Generation and Surface Water Pumping Facilities

William R. Gianelli Pumping-Generating Plant

The William R. Gianelli Pumping-Generating Plant is located on San Luis Creek (Figure 1) and is a joint CVP/SWP facility that is operated and maintained by the state under an operation and maintenance agreement with Reclamation. The facility lifts water by pump turbines from the O'Neill Forebay into the San Luis Reservoir. During the irrigation season, water is released from San Luis Reservoir back through the pump turbines to the forebay and energy is reclaimed.

Each of the eight pumping-generating units has a capacity of 63,000 hp as a motor and 53 MW as a generator. As a pumping station to fill San Luis Reservoir, each unit lifts 1,375 cfs at 290 feet total head (head is the difference in elevation between water levels above and below a power plant). As a generating plant, each unit passes 1,640 cfs at the same head. The power plant, initially operated in 1968, has an installed capacity of 424 MW, of which 202 MW are apportioned as Reclamation's share. The remaining 222 MW are apportioned to DWR. The primary purpose of the facility is to pump CVP water for off-stream storage.

O'Neill Pumping-Generating Plant

The O'Neill Pumping-Generating Plant is located on San Luis Creek, 2.5 miles downstream from San Luis Dam (Figure 1). The plant consists of an intake channel leading off the Delta-Mendota Canal and six pump-generating units. Normally, these units operate as pumps to lift water from 45 to 53 feet into the O'Neill Forebay. Water occasionally is released from the forebay to the Delta-Mendota Canal, and these units then operate as generators. When operating as pumps and motors, each unit can discharge 700 cfs and has a rating of 6,000 hp. The power plant, initially operated in 1967, has an installed capacity of 25.5 MW. The primary purpose of the facility is to pump CVP water for off-stream storage; the plant generates only part of the year. The authorizing legislation for O'Neill states that power generated at the facility cannot be used for commercial purposes. The generation produced at O'Neill is allocated as project use power for the CVP.

CVP Generation Facilities

New Melones Power Plant

The New Melones Power Plant is located on the Stanislaus River (Figure 1). The power plant, initially operated in 1979, has an installed capacity of 300 MW. It is a peaking plant.

Dos Amigos Pumping Plant

The Dos Amigos Pumping Plant is located on the California Aqueduct, south of the Gianelli Pumping-Generating Plant, and raises water in the aqueduct as it flows south through the San Joaquin Valley (Figure 1). Dos Amigos has six units with a total motor rating of 240,000 hp, providing a total flow at design head of 15,450 cfs.

Las Perillas Pumping Plant

The Las Perillas Pumping Plant is located at the juncture of the California Aqueduct and the Coastal Branch Aqueduct (Figure 1). The Las Perillas Pumping Plant diverts water from the California Aqueduct to the Coastal Branch Aqueduct. The Coastal Branch Aqueduct currently serves agricultural areas west of the California Aqueduct and is being extended to serve municipal and industrial water users in San Luis Obispo and Santa Barbara counties. Las Perillas has six units with a total motor rating of 4,000 hp, providing a total flow at design head of 461 cfs.

Badger Hill Pumping Plant

The Badger Hill Pumping Plant is located on the Coastal Branch Aqueduct and currently serves agricultural areas west of the California Aqueduct (Figure 1). Badger Hill has six units with a total motor rating of 11,800 hp, providing a total flow at design head of 454 cfs.

Buena Vista Pumping Plant

The Buena Vista Pumping Plant is located on the California Aqueduct, at the south end of the San Joaquin Valley, and is the northernmost of three successive pumping plants that raise water in the aqueduct as it nears the foot of the Tehachapi Mountains (Figure 1). Buena Vista has 10 units with a total motor rating of 144,500 hp, providing a total flow at design head of 5,405 cfs.

J. R. Teerink Wheeler Ridge Pumping Plant

The J. R. Teerink Wheeler Ridge Pumping Plant is located on the California Aqueduct, at the south end of the San Joaquin Valley, and is the second of three successive pumping plants that raise water in the aqueduct as it nears the foot of the Tehachapi Mountains (Figure 1). Wheeler Ridge has nine units with a total motor rating of 150,000 hp, providing a total flow at design head of 5,445 cfs.

I. J. Chrisman Wind Gap Pumping Plant

The I. J. Chrisman Wind Gap Pumping Plant is located on the California Aqueduct, at the south end of the San Joaquin Valley, and is the last and southernmost of three successive pumping plants that raise water in the aqueduct as it nears the foot of the Tehachapi Mountains (Figure 1). Wind Gap has nine units with a total motor rating of 330,000 hp, providing a total flow at design head of 4,995 cfs.

A. D. Edmonston Pumping Plant

The A. D. Edmonston Pumping Plant is located on the California Aqueduct, at the northern foot of the Tehachapi Mountains (Figure 1). Remaining water in the aqueduct at this point must cross the Tehachapi Mountains to be delivered to southern California. The Edmonston Pumping Plant lifts the water in the aqueduct 1,926 feet, the highest single lift of any pumping plant in the world. The pumping plant has 14 units with a total motor rating of 1,120,000 hp, providing a total flow at design head of 4,480 cfs.

CVP Power Customers

Fifteen CVP preference power customers with a service area located wholly or partially within the San Joaquin River Region make up 3% of total CVP preference customer energy sales. These customers are:

- City of Avenal
- Northern California Youth Center
- Naval Communication Station, Stockton
- Byron-Bethany Irrigation District
- Sharpe Defense Distribution Depot
- Deuel Vocational Institute
- Calaveras Public Power Agency
- Sierra Conservation Center
- Patterson Water District
- West Stanislaus Irrigation District
- Banta-Carbona Irrigation District
- San Luis Water District
- Modesto Irrigation District
- Reclamation District 2035
- Turlock Irrigation District

In addition, PG&E purchases CVP non-preference power.

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SWP Power Customers

Three SWP power customers with a service area located wholly or partially within the San Joaquin River Region make up 13.1% of total SWP energy sales. These customers are:

- PG&E
- Modesto Irrigation District
- Turlock Irrigation District

SWP AND CVP SERVICE AREAS OUTSIDE THE CENTRAL VALLEY

CURRENT RESOURCE CONDITIONS

No CVP generation or pumping facilities are located outside the Central Valley.

SWP Generation Facilities

Alamo Power Plant

The Alamo Power Plant is located in the northwest corner of Los Angeles County, south of the Tehachapi Mountains (Figure 1). The power plant, initially operated in 1986, has an installed capacity of 15 MW and is dedicated first to project use. The remaining energy is marketed to customers in the Los Angeles Basin area.

W. E. Warne Power Plant

The Warne Power Plant is located in the northwest corner of Los Angeles County, downstream of the Alamo Power Plant (Figure 1). The power plant, initially operated in 1982, has an installed capacity of 78 MW and is dedicated first to project use. The remaining energy is marketed to customers in the Los Angeles Basin area.

Devil Canyon Power Plant

The Devil Canyon Power Plant is located in San Bernardino County (Figure 1). The power plant, initially operated in 1972, has an installed capacity of 240 MW and is dedicated first to project use. The remaining energy is marketed to customers in southern California and the Desert Southwest.

Mojave Siphon Power Plant

The Mojave Siphon Power Plant is under construction on the East Branch Aqueduct in San Bernardino County (Figure 1), upstream of Silverwood Lake. The power plant will have an installed capacity of 28 MW and will be dedicated first to project use. The remaining energy will be marketed to customers in southern California and the Desert Southwest.

SWP Surface Water Pumping

Oso Pumping Plant

The Oso Pumping Plant is located at the juncture of the California Aqueduct and the West Branch Aqueduct, which delivers water primarily to users in Los Angeles County (Figure 1). The Oso Pumping Plant diverts water from the California Aqueduct to the West Branch Aqueduct. Oso has eight units with a total motor rating of 93,800 hp, providing a total flow at design head of 3,252 cfs.

Pearblossom Pumping Plant

Water not diverted to the West Branch Aqueduct from the California Aqueduct flows to the East Branch Aqueduct. The Pearblossom Pumping Plant is located on the East Branch Aqueduct, which delivers water primarily to users in San Bernardino and Riverside counties (Figure 1). Pearblossom pumps water from Antelope Valley into Silverwood Lake in the San Bernardino Mountains. Pearblossom has nine units with a total motor rating of 203,200

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hp, providing a total flow at design head of 2,575 cfs.

Devil's Den Pumping Plant

The Devil's Den Pumping Plant is under construction on the Coastal Branch Aqueduct, west of the Badger Hill Pumping Plant (Figure 1). The plant will serve M&I water users in San Luis Obispo and Santa Barbara counties. Devil's Den will have six units with a total motor rating of 10,500 hp, providing a total flow at design head of 150 cfs.

Bluestone Pumping Plant

The Bluestone Pumping Plant is under construction on the Coastal Branch Aqueduct, west of the Devil's Den Pumping Plant (Figure 1). The plant will serve M&I water users in San Luis Obispo and Santa Barbara counties. Bluestone will have six units with a total motor rating of 10,500 hp, providing a total flow at design head of 150 cfs.

Polonio Pass Pumping Plant

The Polonio Pass Pumping Plant is under construction on the Coastal Branch Aqueduct, west of the Bluestone Pumping Plant (Figure 1). The plant will serve M&I water users in San Luis Obispo and Santa Barbara counties. Polonio Pass will have six units with a total motor rating of 10,500 hp, providing a total flow at design head of 150 cfs.

CVP Power Customers

Twelve CVP preference power customers with a service area located wholly or partially within SWP and CVP Service Areas Outside the Central Valley make up 4% of total CVP preference power sales. These customers are:

- Broadview Water District
- James Irrigation District
- Naval Air Station, Lemore
- Cawelo Water District
- Lindsay-Strathmore Irrigation District
- Lower Tule River Irrigation District
- Rag Gulch Water District
- Kern-Tulare Water District
- Terra Bella Irrigation District
- Delano-Earlimart Irrigation District
- Arvin Edison Water Storage District
- City of Lompoc

SWP Power Customers

Seven SWP power customers with a service area located wholly or partially within the SWP and CVP Service Areas Outside the Central Valley make up 1.2% of total SWP energy sales. These customers are:

- SCE
- LADWP
- City of Burbank
- City of Glendale
- City of Pasadena
- City of Riverside
- City of Vernon

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CALFED

TECHNICAL REPORT
AFFECTED ENVIRONMENT

SUPPLEMENT TO POWER PRODUCTION & ENERGY

DRAFT

March 1998

CALFED
BAY-DELTA
PROGRAM

SUPPLEMENT TO POWER PRODUCTION & ENERGY

California Restructuring Legislation (AB 1890)

In the new market structure, energy suppliers will bid into "day-ahead" and "hour-ahead" markets. Rather than long-term contracts for unit-contingent or "firm" capacity supported by system resources, markets for "ancillary" services will be conducted. These ancillary services include regulation, operating reserves (including "spinning" and "non-spinning" reserves), replacement reserves, black start capability, and voltage support.

Of these ancillary services, only "replacement reserves" represents a new product. The WSCC requires that its members maintain operating reserve (which must be available to serve load within 10 minutes) to assure reliable service as customer loads fluctuate (WSCC MORC). In the new market structure, utilities will be able to procure operating reserve and the other ancillary services from the ISO.

Another significant difference arises due to the operation of the transmission grid by the ISO. Most energy transactions that market participants would like to schedule will be accepted by the ISO; however, transmission is a limited resource and, under certain conditions, some transmission paths will be congested. If two "zones" are separated by a congested transmission path, the ISO will assign the limited available transmission capacity to those who place the highest value on its use.

The CVP Restoration Fund

Certain payment caps are in effect for CVP water users. Annual payments for agricultural water sold and delivered by the CVP are not to exceed $6.00 per acre-foot (October 1992 price levels). Annual payments for municipal and industrial water sold and delivered by the CVP are not to exceed $12.00 per acre-foot (October 1992 price levels). The charge on agricultural water may be further reduced by the Secretary of the Interior (Secretary) to an amount within the probable ability of the users to pay. This adjustment will be made by the Secretary no less than every 5 years. Also, an additional annual charge of $25.00 per acre-foot (October 1992 price levels) will be imposed on CVP water sold or transferred to any state or local agency or other entity that has not previously been a CVP customer and that contracts with the Secretary or any other individual or district receiving CVP water for its own municipal and industrial use. If the average annual payment of $30 million (October 1992 price levels) eannot be met, and given the water payment caps, revenue shortfalls must be met by power users if new funding sources are not found.

CALFED

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LIST OF ACRONYMS

CALFED	CALFED Bay-Delta Program
CEC	California Energy Commission
cfs	cubic foot per second
CPUC	California Public Utilities Commission
CTC	Competition Transition Charge
CVP	Central Valley Project
CVPIA	Central Valley Project Improvement Act
DWR	California Department of Water Resources
ER-96	1996 Electricity Report
GWh	gigawatt hour
ISO	Independent System Operator
MAF	million acre-feet
M&I	municipal and industrial
MCP	market clearing price
mills/kWh	mills per kilowatt hour
MW	megawatt
O&M	operations and maintenance
PG&E	Pacific Gas and Electric Company
PX	Power Exchange
Reclamation	U.S. Bureau of Reclamation
SWP	State Water Project
SWRCB	State Water Resources Control Board
Western	Western Area Power Administration

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POWER PRODUCTION & ENERGY

INTRODUCTION

This technical report discusses impacts on power production and energy associated with implementing the CALFED Bay-Delta Program (CALFED).

CALFED alternatives could cause different types of impacts on power and energy resources. Some of the storage projects included in the CALFED alternatives would include the addition of new hydroelectric generating capacity, and could disrupt existing hydroelectric generation during construction. Once CALFED has been implemented, hydroelectric generation and capacity at existing Central Valley Project (CVP), State Water Project (SWP), and other hydroelectric plants would be affected as the operation of these projects change. Energy use at CVP and SWP surface water pumping plants (referred to as project energy use) would change, as would energy use at groundwater pumping plants and water treatment plants. Energy would be needed to construct and implement all of the components of the CALFED alternatives.

The potential physical impacts described above could lead to power economics impacts on power providers and customers. Western Area Power Administration (Western) and California Department of Water Resources (DWR) power production and replacement costs would change as they experience capacity, energy generation, and project energy use impacts and attempt to meet the power supply needs of their customers. Changes in these types of costs would affect the net cost of pumping energy to DWR, or the power rates Western charges its customers. These potential power economics impacts could in turn cause agricultural, municipal and industrial, and regional economics impacts. (Refer to the technical reports for these resource topics for more information.)

Finally, if the CALFED alternatives change CVP water deliveries or Western power deliveries, or impact Western power rates, they have the potential to affect the amount of power revenue received by the CVP Restoration Fund. Changes in the power revenue requirement of the fund could affect Western power rates and customers.

The following assessment variables are discussed in this report:

- Available capacity and energy generation at CVP and SWP hydroelectric power plants;
- CVP project energy use and SWP pumping energy requirements;
- SWP and CVP capacity and energy generation;
- Net CVP energy available for sale and net SWP energy requirements;
- SWP and CVP power production value and replacement costs;
- Western composite energy rate and DWR system energy rate;
- Power payments to the CVP Restoration Fund;
- Impacts on Western and DWR power customers; and
- Capacity and energy impacts at other hydroelectric power plants.

Changes in energy use caused by construction of facilities, water treatment energy requirements, and energy use associated with water use efficiency and traffic and navigation impacts cannot be evaluated with the information available at a programmatic level of analysis.

ASSESSMENT METHODS

Ranges of impacts were defined to represent the types of impacts that could result from the CALFED alternatives. Examples of potential alternative components were used to develop representative ranges of impacts because the specific components of the CALFED alternatives have not been defined for this programmatic review.

No assumptions were made in this report regarding the way in which changes in energy generation and project energy use (and related costs) eventually would be allocated between the SWP and CVP. Ranges were used to describe the potential energy generation and pumping impacts on both the SWP and the CVP. For a particular CALFED alternative, that range is equal to the total change from No Action Alternative conditions. For example, the maximum potential impact on energy generation would occur to either the CVP or the SWP and is equal to the total change in energy generated between a CALFED alternative and the No Action Alternative at all SWP and CVP facilities. The range in potential impacts is bounded by two extremes. At one extreme, the entire change in generation and pumping energy was assumed to be assigned to the SWP, with none of the change assigned to the CVP. At the other extreme, the entire change in generation and pumping energy was assumed to be assigned to the CVP, with none of the changes affecting the SWP. As the assignment of costs and operational changes between the SWP and CVP become better defined in subsequent studies, this range will be narrowed.

The analysis summarized in this technical report does not address the issue of CALFED-related power cost allocations to the SWP and CVP. Decisions eventually will be made by the agencies involved in CALFED on how to allocate power-related costs to the SWP and CVP. These costs include such items as the cost of adding new hydrogeneration capacity to existing and proposed storage projects, costs of modifying and constructing new power transmission and distribution facilities, and pumping costs that are necessary to implement CALFED alternatives. The eventual allocation of these costs to the SWP or CVP will change the power production cost and rate estimates presented in this report.

The power production and energy analysis was conducted for the overall study area. Assessment of potential power production and energy impacts on SWP and CVP was more appropriate on a system-wide basis than by CALFED region. Power facilities and customers in a given region would be affected by CALFED-related actions occurring in many different regions. For example, changes in water supply operations and environmental restoration activities throughout the CALFED study area would affect the amount of water available for hydroelectric generation at SWP and CVP power plants. These same widespread changes in operation and restoration activities also would affect how much energy is needed for pumping water at SWP and CVP pumping plants. Furthermore, potential impacts such as changes in rates or CVP Restoration Fund charges on power customers would be system-wide impacts, and customer impacts would not vary by CALFED region. Some region-specific capacity and energy impacts (such as energy use during construction) will be assessed in subsequent project-level studies before the program is implemented.

Hydroelectric Capacity and Energy Generation

The CALFED alternatives would change reservoir levels and the available capacity of state and federal hydroelectric power plants in the study area as well as the amount of energy generated at such facilities. Impacts on hydroelectric facilities in the Sacramento and San Joaquin River basins that are not part of the SWP and CVP also may result. The methods used to assess potential impacts on power facilities and operation are described below.

PHYSICAL IMPACTS ON POWER PLANTS

CALFED alternatives include adding offstream storage with the construction of new hydroelectric power plants. The impacts of these potential changes were identified by first defining representative facilities that may be constructed under each alternative. The nameplate capacity ratings or design output of these power plants were defined in megawatts (MW), and coordinated operation of these facilities with existing SWP and CVP facilities was analyzed.

CAPACITY AND ENERGY GENERATION IMPACTS DURING OPERATION

The next step of the analysis consisted of defining how the operation of SWP and CVP hydroelectric power facilities would change in the future after (1) the CALFED-related physical modifications to power plants were completed, (2) the projects included in the No Action Alternative scenario were implemented, and then (3) the proposed system operational changes included in the CALFED alternatives were fully implemented. These proposed system operational changes primarily consist of operating new storage and conveyance facilities, and changing releases from state and federal reservoirs to meet Ecosystem Restoration Program and Water Quality Program objectives.

The following types of potential impacts were assessed for both the SWP and CVP:

- Changes in average and dry year capacity;
- Changes in average and dry year energy generation;
- Changes in annual and monthly project energy use; and
- Changes in the potential to provide ancillary services, such as regulation and reserves.

The DWR's system operational model (DWRSIM), in coordination with the power module of the U.S. Bureau of Reclamation's (Reclamation's) project simulation model (PROSIM), was used to define changes in available capacity, energy generation at affected state and federal hydroelectric facilities, and project energy use at state and federal facilities. Specifically, the DWRSIM output analysis system provides CVP power operation tables and SWP power operation tables. These output exhibits provided estimates of average monthly energy generation and pumping energy requirements at SWP and CVP facilities. Pumping energy requirements at certain facilities, including the South Bay Pumping Plant, CVP Dos Amigos, and O'Neill Pumping Plant, were estimated separately based on DWRSIM projected flows and diversions. Average monthly storage by reservoir also was used, together with estimated power output by reservoir level, to estimate the average maximum potential capacity output in each month.

Reservoir levels, diversions, and releases from DWRSIM were used directly in the PROSIM power module to enhance the DWRSIM results by including estimates of the capacity and energy impacts of CALFED alternatives on CVP facilities that mirror the results PROSIM would provide. (Note: The integration of the PROSIM power module into DWRSIM has not been completed at the time of this draft. As an alternative, a spreadsheet post-processor was used to accomplish the analysis. The post-processor replicates the intended analysis using DWRSIM output together with the PROSIM input data regarding energy and capacity output by rate of flow and reservoir level. However, the PROSIM module was not directly used.)

Eight operational scenarios were defined to characterize the range of operational results for

CALFED alternatives. The DWRSIM output was relied on to establish a range of operational impacts for each alternative. Table 1 describes the relationship between the operational scenarios used in this analysis, the corresponding DWRSIM case numbers, and CALFED alternative configurations that correspond to the scenarios.

Operational Scenario	DWRSIM Case #	CALFED Alternatives
---	469	Existing Conditions
---	472	No Action
1	472	1A, 1B
2	510	1C
3	472B	2A
4	510	2B, 2E
5	498	2D
6	475	3A
7	500	3B, 3H
8	500	3E, 3I

Table 1. Relationship of Operational Scenarios, DWRSIM Case Numbers, and CALFED Alternative Configurations

The analysis of average annual conditions and impacts was based on the 73-year hydrologic record from 1922 through 1994. The hydrology represented by water years 1929 through 1934 was used to estimate power production and energy impacts under dry conditions.

The impacts of CALFED alternatives on SWP and CVP capacity, energy generation, and project energy use were defined by following the steps listed below.

The monthly maximum available capacity was estimated based on average reservoir levels by month, by facility, for each of the SWP and CVP hydroelectric power plants. Capacity was estimated under dry conditions, and the average capacity over the entire 73-year hydrologic record was defined. Monthly and annual energy generation was estimated by facility for the SWP and the CVP. Average energy generation over the entire hydrologic period of record and generation under dry conditions were defined. SWP and CVP project energy use was estimated on a monthly and annual basis. Project energy use was defined for each scenario under dry conditions, and the average over the entire hydrologic record also was defined.

The incremental impacts of CALFED alternatives were determined by comparing the average and dry year model results under each of the CALFED alternative configurations to related conditions under the No Action Alternative. Tables and graphs were prepared to display the results of the analysis for each Alternative Configuration.

Potential impacts on locally owned hydroelectric facilities downstream of state and federal reservoirs also were considered. This analysis was conducted in much less detail because such impacts will be assessed in subsequent project-level studies when more information regarding specific operational changes is available.

SWP and CVP Project Energy Use and Other Pumping Energy Impacts

Changes in pumping energy requirements at affected surface water pumping plants was assessed using the related output of DWRSIM and the PROSIM energy module. These models define changes in pumping at the major surface water pumping plants of the SWP and CVP. Typical operational scenarios and representative examples of groundwater projects were used to describe potential changes in regional groundwater pumping requirements.

Energy use impacts during the operation of major treatment plants were broadly defined by determining what types of potential changes in water deliveries to municipal and industrial (M&I) customers could occur, and thus the amount of water requiring treatment.

Potential surface water and groundwater pumping and treatment-related energy impacts will be assessed in more detail in subsequent project-level studies.

CVP Net Energy Available for Sale and SWP Net Energy Requirements

Power generation from the CVP is used to meet CVP pumping requirements (CVP project energy use), and for sales to preference customers at power rates established by Western. The CVP is a net energy producer, with capacity and energy resources that substantially exceed those required for CVP project energy use. The difference between the estimated CVP generation and the project use energy requirements represents the net energy available for sale. Conversely, the SWP is a net power consumer, and requires power resources in addition to those hydroelectric resources available on the SWP system to meet pumping energy requirements. The difference between such SWP energy generation and SWP pumping energy requirements is the SWP net energy requirement.

SWP and CVP Power Production and Replacement Costs

The direct impact of CALFED alternatives on the production costs of the SWP and CVP was estimated based on available information regarding variable costs of operation and maintenance, and operating costs of facility modifications required due to the CALFED alternatives. The production costs of new facilities were estimated based on available cost information and typical allowances for operation and maintenance. Pending decisions regarding cost allocation between water, power, and other users, the costs of new pump-generator facilities are not included in the analysis.

Reductions in capacity and energy available from hydroelectric facilities as a result of CALFED alternatives requires consideration of the need to obtain replacement capacity and energy. The operation of the CVP power resources presently is integrated with Pacific Gas and Electric Company (PG&E) by agreement (Contract 2948A). This agreement provides for the sale, interchange, and transmission of capacity and energy between Western and PG&E. DWR has a number of existing power purchase, transmission, and exchange agreements through which the pumping energy requirements of the SWP are met.

Western's existing contracts with preference power customers and its Contract 2948A all expire on December 31, 2004. Western has developed a Post-2004 Marketing Plan that describes the terms under which service to existing and new customers will be provided. Under that plan, a "Base Resource" will be defined and allocated to customers. The Base Resource will vary annually, monthly, weekly and daily based on hydrology and other constraints relevant to CVP operations. This plan recognizes electric industry restructuring and is intended to maximize the value of available CVP resources to Western's customers.

Given the long-term perspective of the CALFED process and that all these agreements have specific termination dates, the value of replacement power was estimated based on market prices that are expected under a deregulated market. Consequently, the terms of the existing agreements were not considered in the impact analysis.

The estimated changes in dry year available capacity and average annual energy were analyzed. Future power rates in the California power market after electric industry restructuring were estimated to assess the value of those impacts. These power rates are important because they will determine the cost of potential replacement sources for power providers and power customers. Future power rates in the market as a whole also may affect the willingness of Western's customers to pay the rates that Western is required to charge for CVP power.

Both the SWP and CVP systems are operated to maximize value of the available power resources, subject to minimum stream flow releases and export limits defined by environmental requirements. This is accomplished by seeking to shift energy generation to on-peak periods, when power values are highest, and pumping energy requirements to off-peak periods, when power values are lowest.

The following steps were taken to project the future price of power in California's power markets. First, publicly available analyses of future power values in the restructured industry were evaluated, together with market power analyses prepared by the California investor-owned utilities and the California Energy Commission (CEC), to develop an estimated range of values for the Power Exchange (PX). The forecast market value of power is the sum of the value of energy and any additional value attributed to ancillary services.

Among the numerous changes associated with electric restructuring is a change in the determination of transmission losses. Losses will be assigned based on the generator location, and that assignment will be revised frequently as loads change. Consequently, it is speculative to estimate the effect of transmission losses on power production and energy impacts of CALFED alternatives. Incremental transmission losses among CALFED alternatives are expected. Transmission losses are expected to cause similar differences in the estimated impacts of the alternatives. These effects would vary minimally among the CALFED alternatives.

Forecast power rates were defined, and the rates were used to determine impacts on power revenues for Western and DWR by multiplying the relevant rates by the different types of capacity and energy available for sale from facilities affected by CALFED alternatives.

ANCILLARY SERVICES

The California market under the Independent System Operator (ISO) will separately procure ancillary services, such as regulation, operating, and replacement reserves, and other services. These will be procured at cost-based rates or at market rates, if a competitive market is determined to be operating.

The unique characteristic of hydroelectric projects to quickly increase energy output and generally supply additional capacity for some period when needed makes them exceptionally valuable for ancillary service purposes. Hydroelectric project capacity that is not scheduled to provide energy can be used to provide regulation and reserves.

Reoperation of the affected hydroelectric facilities may result in changes to peak project capabilities; the annual quantity of electric energy produced; and the distribution of energy on a seasonal, monthly, and daily basis. The relationship between energy generation and the ability to provide ancillary services may also change. Figure 1 conceptually illustrates the variables that may be affected by hydroelectric project reoperation. Reoperation will affect reservoir levels, which will change the peak capability (in MW) of those hydroelectric projects with storage. Reoperation also will affect the timing of energy generation. Potential to provide ancillary services is represented by the difference between the peak capability (adjusted for reservoir storage levels) and actual energy generation. As the profile of energy generation changes (represented by the curve in Figure 1), the ability to provide ancillary services will be affected.

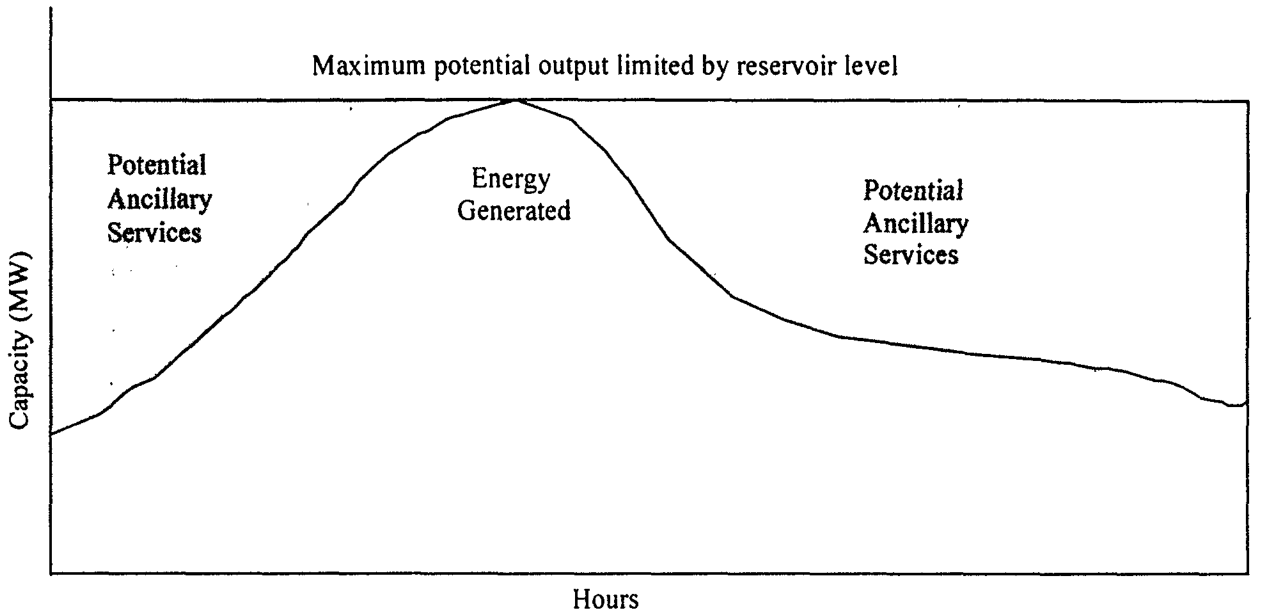

Figure 1. Conceptual Illustration of Real Time Factors Affected by Hydroelectric Project Reoperation

The potential to provide operating and replacement reserves (the shaded area in Figure 1) increases as the capacity used to generate energy decreases. However, the value of that potential depends, in large part, on the amount of energy available and on the discretion that exists with regard to scheduling that energy. Revenue still may be earned for regulation and reserves even if little energy is available to support such regulation and reserves. This is because energy is separately bid in the new market structure, and an operator can bid a competitive price for providing the capacity required to deliver operating or replacement reserves but bid a very high price for energy. If the associated energy bid is very high, only if other energy resources at lower prices are unavailable will that capacity be required to deliver energy. In summary, each generator must address complex questions in devising strategies for realizing maximum value from available energy and capacity. The answers to these questions will depend on the location of the resources, price and availability of other resources, level of demand, water-year type, time of day, season, and skill and risk preferences of the bidder. As a result, it would be speculative to undertake to assign specific values to impacts of the CALFED alternatives on the value of ancillary services that might be provided by SWP and CVP facilities. The change in revenues from power sales, and the change in costs to the consumer, result from the change in project operations and the value of the power purchased or sold. Power plant operators will seek to recover their fixed and variable costs from the competitive market for energy and ancillary services. Transmission, distribution, and related costs will continue to be recovered through regulated cost-of-service rates.

A range in long-run, competitively determined energy prices or market clearing prices (MCPs) was developed to evaluate impacts of the CALFED alternatives. One end of this range was based on the cost of a new combined cycle facility. The other end of the range was based on an administratively determined projection of the wholesale MCPs for energy developed through proceedings before the California Public Utilities Commission (CPUC) on electric restructuring.

POWER VALUES IN THE RESTRUCTURED CALIFORNIA MARKET

Power value is measured by the price a seller will receive for energy sold into the wholesale market. The California wholesale power market under the PX will operate using energy prices bid by generators and loads. Generators will recover their fixed costs from the difference between their variable costs and the MCPs, as adjusted for losses together with any revenue from ancillary services.

Hydroelectric projects are expected to be price takers, with variable production costs significantly less than the MCPs. This impact assessment assumed that reoperation will not itself affect the short-run MCPs, although in the aggregate, the presence or absence of hydroelectric energy or the configuration in available energy due to varying water conditions will affect the short-run MCPs.

In the long run, the competitive market must permit recovery of both fixed and variable costs. For the market to support new or re-powered baseload or intermediate load facilities, the long-run average market price can fall no lower than the "all-in" cost of constructing, owning, and operating such facilities. New power plants must be built to support load growth and retirement of existing facilities as they reach the end of their useful lives.

Power values will continue to vary by season and by time of day. Electric restructuring is likely to change the relationship between on-peak and off-peak energy prices, however, which is influenced by numerous factors, including the prevailing load profiles, reserve margins, the amount and type of available generation, transmission constraints, and the rate at which real-time or hourly meters are installed and time-of-use pricing is implemented. Hourly prices will be seen by an increasing proportion of the total load in California. Even if the customer response to hourly prices is small, some narrowing in the average differential between on-peak and off-peak energy prices is likely to result from increased time-of-use pricing.

Although the *average* differential between on-peak and off-peak pricing may narrow with increased time-of-use pricing, other factors may tend to cause substantially higher prices during some peak hours. These conditions may arise during very high load periods, or when there are a large number of unplanned outages, resulting in a greater degree of market power by generators as they raise prices to what the market will bear. Concerns about abuse of market power underlie the proposed use of an active market power monitoring program by both the ISO and the PX, and administratively determined pricing caps that will be imposed under emergency conditions. These conditions are expected to arise infrequently.

NEED FOR NEW CAPACITY

The Proposed Final 1996 Electricity Report (ER-96) issued by the CEC (October 1997) forecasts a physical need for new capacity to serve the California market of up to 6,737 MW by 2007. The CEC proposes to let the market decide when that capacity should be built. (In fact, additional capacity may be economic beyond that which the CEC identifies. The CEC estimate is based solely on reserve margin criteria.)

Current expectations are that simple-cycle combustion turbines or gas-fired combined cycle facilities will provide the bulk of the new or repowered capacity for the foreseeable future. Environmental restrictions, fuel price forecasts, continuing gas pipeline availability, and further technological improvement all suggest that gas-fired capacity will continue to be the preferred alternative for new California central station generating capacity.

POWER VALUE FORECAST

The precise timing and technology (simple or combined cycle) of new resource additions will be market driven. The long-run marginal cost will not be exceeded on average by the sum of the value obtained by average market participants from the energy and ancillary service markets. As a result, the estimated composite energy cost of a combined cycle plant is a reasonable proxy for the full energy and ancillary services value of the marginal power resource. Combined-cycle facilities, which are very fuel efficient, will be built by market participants that intend to operate as intermediate of baseload resources, while other market participants that intend to focus on the opportunities to provide for peaking energy and ancillary services will construct simple-cycle combustion turbines. Combined-cycle plants also would be cost effective in the near term as replacement for existing capacity. The long-term forecast of the value of energy and ancillary services was, therefore, assumed to be the full, all-in cost of a modern combined-cycle facility.

With existing technology, combined-cycle facilities range in cost from 25 to 35 mills per kilowatt hour (mills/kWh), including fuel, operations and maintenance (O&M), and debt service and capital recovery. The range derives from differing assumptions regarding fuel, fuel transportation price, and cost of debt and equity. For example, the capital and O&M costs of a combined-cycle facility in 1997 dollars is approximately 15 mills/kWh with fuel costs, including transportation in the PG&E service territory representing another 17 mills/kWh, for a total of 32 mills/kWh. (This amount assumes a baseloaded facility with a $550/kW capital cost, and private financing. Energy costs are based on a 6,900 heat rate and a 2.42 burner tip gas price per the August 1997 CEC Revised Fuels Report (CEC 1997).

The CPUC has adopted a proxy MCP of 24 mills/kWh for use in determining Competition Transition Charge (CTC) balances in 1998. This 24 mills/kWh value reflects an expectation about the nature of the market in 1998, and provides a reasonable basis for establishing the estimated lower range of power values. A range of value of approximately 15% has been established based on the historical relationship between on-peak and off-peak incremental heat rates for PG&E.

Another consideration in the value of power is the timing of energy generation or demand. Energy MCPs likely will be higher during on-peak periods and lower during off-peak periods. Historically, the SWP and the CVP have been operated to schedule pumping demands during off-peak periods and generation during on-peak periods, as limited by environmental operating constraints and limits of conveyance and storage.

DWRSIM and the PROSIM power module are based on a monthly time step, which means that these tools cannot be used to analyze operations within a month. Much more detailed information is required to develop unbiased estimates of operations on a weekly, daily, or hourly basis, including the specific criteria by which the weekly, daily, and hourly operations of all affected hydroelectric and pumping facilities would be changed under each alternative, distinguished by season, water-year type, and environmental conditions in the Bay-Delta system. Such details are not available, making speculative any rigorous analysis of the impacts of the CALFED operations on a time step of shorter duration than 1 month. Despite these limitations in data, it is reasonable to expect that the scheduling discretion available to the SWP and the CVP will be exercised to maximize the value of generation and minimize the value of pumping, to the extent possible. Consequently, the power value forecast used in this analysis assumed that generation would occur largely during on-peak periods, and pumping during off-peak periods.

Table 2 provides the forecast range in power values used to estimate the impacts of changes in generation and pumping energy. These projections are intended to provide a reasonable range for planning purposes of the long-term average power prices in 1998 dollars.

	Low	High
Project use energy	22.5	30.0
Energy generation	26.0	34.0

Table 2. Estimated Range in Average Power Values (mills/kWh)

CVP Restoration Fund, Power Revenues, and Related Impacts

The impacts related to payments by Western's power customers to the CVP Restoration Fund were assessed by focusing on changes in total power revenue requirements and potential impacts of such obligations on Western's composite energy rate and power customers. Payment caps on the contributions by water users were established by the Central Valley Project Improvement Act (CVPIA) (see the Power Production & Energy Affected Environment Technical Report). Decreases in water deliveries to CVP water users could decrease the water user payments to the CVP Restoration Fund. This could, in turn, increase the total funding obligation of power users. The estimated change in Restoration Fund obligations of power users was addressed by considering how such obligations could be affected by changes in CVP water deliveries, the related water revenues received by the fund, and water rate caps. This information was used to assess the impacts of these changes on Western's rates.

Impacts on Western and DWR Rates and Power Customers

The value of the change in generation is equal to the difference between the market value of generation under the No Action Alternative and the market value of generation under a CALFED alternative. Similarly, the value of a change in pumping energy is equal to the difference in the market value of pumping energy between the alternatives. The difference between the value of changes in generation, and the value of changes in pumping energy requirements, represents the value of the net power impact of a CALFED alternative.

The rate impacts on Western's customers were estimated by developing a "composite energy rate," which is the total revenue requirement to be recovered from capacity and energy sales, divided by the amount of energy sales. This is in contrast to the capacity and energy rates set by Western and is used as a proxy to estimate impacts of the alternatives.

Rate impacts on the SWP were estimated by calculating a "system energy rate," which is the net cost of power divided by the SWP energy requirements.

The No Action Alternative CVP composite energy rate and the No Action Alternative SWP system energy rate were then calculated to determine the significance of the impact on Western's power customers and on the SWP.

For Western, the amount and cost of supplemental power purchases required to meet obligations to preference power customers was estimated, and the impact of that change in supplemental power cost on Western's composite energy rate was projected. Increases in CVP project energy use were not assumed to be funded by power customers. If additional subsidies by power customers were imposed, rate impacts would be larger than estimated in this report.

For the SWP, the revenue requirement was adjusted by the value of the net power impact. The total energy used to calculate the system energy rate also was adjusted to reflect the change in SWP net energy requirement.

The revised CVP composite energy rate and SWP system energy rate then were compared to the rates calculated for the No Action Alternative.

Other Types of Energy Use Impacts

The construction of new reservoirs, conveyance facilities, and levee systems would increase the use of energy during construction periods, as would the implementation of other elements in CALFED alternatives: Ecosystem Restoration Program; Water Quality Program, Including Watershed Management Coordination; and Water Efficiency Program, Including Water Transfers. After their implementation, CALFED alternatives would increase energy use as new facilities were maintained and recreationists drove to areas that benefited from environmental improvements. Additional, more-detailed analysis of the types of impacts and potential energy conservation measures will take place in subsequent project-level studies when more specific information regarding the components of CALFED alternatives is available. For example, with respect to the Water Use Efficiency Program, specific energy use impacts cannot be determined at this time because local water districts eventually will be responsible for deciding how broad water efficiency program policies included in the CALFED alternatives will be implemented with specific measures.

SIGNIFICANCE CRITERIA

The following significance criteria were used to gauge the significance of potential impacts caused by the CALFED action alternatives.

An impact on the capacity of hydroelectric facilities and the amount of energy generated at such facilities was considered potentially significant and adverse if a CALFED action would increase the cost of power and associated rates to levels higher than rates available in open-market conditions. This impact would increase customer power costs to a point where customers likely would switch power providers, and could threaten repayment of CVP capital and operating costs in a competitive market.

The significance of SWP power-related impacts is measured by how they affect DWR's system energy rate and the net energy requirement of the SWP. Impacts on DWR's system energy rate and the SWP net energy requirement would be significant if they cause DWR's water rates to increase significantly. The significance of DWR water rate impacts is addressed by the agricultural economics and M&I economics resource areas.

The significance of energy use impacts will be assessed in subsequent project-level studies. Subsequent studies will have more detailed information about the specific construction projects, changes in operations that would be required, and proposed energy conservation measures to be followed during and after construction.

The contribution of power customers to the CVP Restoration Fund has a floor, but no specific ceiling. Therefore, the key issue is whether Western's power customers would experience a rate increase caused by an overall increase in the total funding obligation of power customers to the CVP Restoration Fund. This could happen if the total revenue from CVP water users (the other major funding source for the fund) is reduced. Increases in the obligation of CVP power customers to fund the CVP Restoration Fund would be significant and adverse if such increases caused Western's power rates to exceed competitive market prices.

If Western is forced to raise power rates due to an increase in the overall power funding obligation to the Restoration Fund, Western's customers could switch power providers. This type of impact would be significant if rates increase to levels that are higher than rates available in open-market conditions. This

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would increase the power costs of Western's customers to a point where they would likely switch power providers; this, in turn, could threaten repayment of CVP capital and operating costs.

Western and its preference power customers would experience significant and adverse impacts if Western's rates increased to the point that they exceed the rates available on the open market. Such a situation would cause Western's customers to experience negative economic impact as their power costs increase and their customers leave to find cheaper sources of power. DWR power customers rely on a range of alternative sources of power supply, and purchases from DWR do not represent a major long-term resource to such customers.

ENVIRONMENTAL CONSEQUENCES

Comparison of No Action Alternative to Existing Conditions

Conditions under the No Action Alternative are those future conditions (approximately in the year 2020) that would be present in the study area without implementing CALFED. No Action Alternative conditions are the baseline against which the CALFED alternatives were compared to define their potential impacts. No Action Alternative conditions would differ from the existing capacity and energy conditions defined in this Technical Report. Tables 3 and 4 summarize existing and No Action Alternative capacity and energy resource conditions.

Differences in the estimated values for the key assessment variables between existing conditions and the No Action Alternative are in part attributable to enhancements to DWRSIM and changes in assumptions that are reflected in the No Action Alternative results. Enhancements to DWRSIM include modifications to (1) more accurately estimate south-of-Delta deliveries, (2) better represent the San Joaquin River Basin, and (3) recognize other details regarding the Bay-Delta system. Assumptions were revised from existing conditions assumptions to recognize increased SWP & CVP demands consistent with 2020-level develoment.

Western's composite energy rate and the SWP system energy rate under existing conditions are consistent with recent estimates published by Western (1997a) and DWR (series 1968-1996). The value of supplemental sales reflected in this estimate was revised to be consistent with the value used to assess the impact of changes in CVP net energy available for sale. In developing the No Action Alternative case, supplemental purchases were deleted from the analysis. This occurs because Western's marketing plans for year 2004 and beyond do not call for Western to purchase any power for re-sale to preference customers, except at the specific request of individual customers in which case the cost of such purchases is paid by the requesting customer. The subsequent estimate of Western's composite energy rate under the No Action Alternative is 21.59 mills/kWh.

The DWR system energy rate estimate for the No Action Alternative also was adjusted to reflect a consistent assumption regarding the unit price of power purchases. In contrast to the increase in the estimate of Western's composite energy rate, this adjustment yielded a reduction in the estimated SWP system energy rate. The estimates of Western's composite energy rate and the SWP system energy for the No Action Alternative case provide a consistent benchmark for evaluating the rate impacts of CALFED alternatives.

Comparison of CALFED Alternatives to No Action Alternative

The impacts to power production and energy resulting from the storage and conveyance program element will vary by alternative, as

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Assessment Variables	Affected Environment (Existing Conditions)	No Action Alternative (2020 Conditions)	CALFED Action Alternatives (2020 Conditions)							
			Alternative 1		Alternative 2			Alternative 3		
			1A, 1B	1C	2A	2B, 2E	2D	3A	3B, 3H	3E, 3I
			Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Scenario 7	Scenario 8
Total Available Summer Capacity (MW)										
- Average Conditions	1,679	1,682	1,682	1,682 to 1,829	1,687 to 1,686	1,682 to 1,829	1,682 to 1,809	1,682 to 1,706	1,682 to 1,853	1,682 to 1,853
- Dry Conditions	1,427	1,464	1,464	1,464 to 1,536	1,464 to 1,489	1,464 to 1,536	1,464 to 1,536	1,464 to 1,484	1,464 to 1,520	1,464 to 1,520
Total Annual Energy Generation (GWh)										
- Average Conditions	5,265	5,248	5,248	5,248 to 5,751	5,248 to 5,751	5,248 to 5,751	5,248 to 5,751	5,248 to 5,751	5,248 to 5,751	5,248 to 5,751
- Dry Conditions	2,875	2,893	2,893	2,393 to 3,590	2,393 to 3,590	2,393 to 3,590	2,393 to 3,590	2,393 to 3,590	2,393 to 3,590	2,393 to 3,590
Total Annual Project Energy Use (GWh)										
- Average Conditions	1,563	1,572	1,577	1,577 to 3,699	1,577 to 3,699	1,577 to 3,699	1,577 to 3,699	1,577 to 3,699	1,577 to 3,699	1,577 to 3,699
- Dry Conditions	1,252	1,159	1,159	1,159 to 3,097	1,159 to 3,097	1,159 to 3,097	1,159 to 3,097	1,159 to 3,097	1,159 to 3,097	1,159 to 3,097
Total Annual Energy Available for Sale[1] (GWh)										
- Average Conditions	3,702	3,671	3,671	3,671 to 2,053	3,671 to 2,053	3,671 to 2,053	3,671 to 2,053	3,671 to 2,053	3,671 to 2,053	3,671 to 2,053
- Dry Conditions	1,723	1,734	1,734	1,734 to 493	1,734 to 493	1,734 to 493	1,734 to 493	1,734 to 493	1,734 to 493	1,734 to 493
Western Composite Energy Rate (mills/kWh)		21.59	21.59	21.59 to 56.61	21.59 to 23.43	21.59 to 56.11	21.59 to 35.67	21.59 to 24.97	21.59 to 73.55	21.59 to 73.55

[1] Energy available for sale is equal to CVP maximum project generation minus CVP maximum project energy use. Negative values represent a net energy requirement.

Table 3. Comparison of Range in Potential CVP Power Production and Energy Conditions

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Assessment Variables	Affected Environment (Existing Conditions)	No Action Alternative (2020 Conditions)	CALFED Action Alternatives (2020 Conditions)							
			Alternative 1		Alternative 2			Alternative 3		
			1A, 1B	1C	2A	2B, 2E	2D	3A	3B, 3H	3E, 3I
			Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Scenario 7	Scenario 8
Total Available Summer Capacity (MW)										
- Average Conditions	1,490	1,475	1,475	1,475 to 1,622	1,475 to 1,622	1,475 to 1,622	1,475 to 1,622	1,475 to 1,622	1,475 to 1,622	1,475 to 1,622
- Dry Conditions	1,357	1,362	1,362	1,362 to 1,434	1,362 to 1,434	1,362 to 1,434	1,362 to 1,434	1,362 to 1,434	1,362 to 1,434	1,362 to 1,434
Total Annual Energy Generation (GWh)										
- Average Conditions	4,362	4,898	4,898	4,898 to 5,401	4,898 to 5,401	4,898 to 5,401	4,898 to 5,401	4,898 to 5,401	4,898 to 5,401	4,898 to 5,401
- Dry Conditions	2,853	2,987	2,987	2,987 to 3,684	2,987 to 3,684	2,987 to 3,684	2,987 to 3,684	2,987 to 3,684	2,987 to 3,684	2,987 to 3,684
Total Annual Project Energy Use (GWh)										
- Average Conditions	8,412	10,682	10,682	10,682 to 12,804	10,682 to 12,804	10,682 to 12,804	10,682 to 12,804	10,682 to 12,804	10,682 to 12,804	10,682 to 12,804
- Dry Conditions	6,212	6,777	6,777	6,777 to 8,715	6,777 to 8,715	6,777 to 8,715	6,777 to 8,715	6,777 to 8,715	6,777 to 8,715	6,777 to 8,715
Total Net Energy Requirement[1] (GWh)										
- Average Conditions	4,050	5,784	5,784	5,784 to 7,402	5,784 to 7,402	5,784 to 7,402	5,784 to 7,402	5,784 to 7,402	5,784 to 7,402	5,784 to 7,402
- Dry Conditions	3,359	3,791	3,791	3,791 to 5,031	3,791 to 5,031	3,791 to 5,031	3,791 to 5,031	3,791 to 5,031	3,791 to 5,031	3,791 to 5,031
System Energy Rate (mills/kWh)		26.69	26.69	26.69 to 33.60	26.69 to 27.57	26.69 to 33.00	26.69 to 30.30	26.69 to 28.11	26.69 to 33.87	26.69 to 33.87

[1] The SWP's net energy requirement is equal to SWP maximum project energy use minus SWP maximum generation.

Table 4. Comparison of Range in Potential SWP Power Production and Energy Conditions

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Alternatives		Change in Dry Summer Capacity (MW)		Change in Total Annual Energy Generation (GWh)		Change in Total Annual Project Energy Use[3] (GWh)		Change in Total Annual Energy Available For Sale[4] (GWh)		Change in Western Composite Energy Rate (%)
Scenario	Configuration	Average Conditions	Dry Conditions	Average Conditions	Dry Conditions	Average Conditions	Dry Conditions	Average Conditions	Dry Conditions	
Alternative 1										
Scenario 1	1A, 1B	0	0	0	0	0	0	0	0	0.00%
Scenario 2	1C	147	72	503	698	2122	1938	(1618)	(1241)	0.83%
Alternative 2										
Scenario 3	2A	4	25	98	101	540	205	(442)	(104)	0.35%
Scenario 4	2B, 2E	147	72	503	698	2122	1938	(1618)	(1241)	0.83%
Scenario 5	2D	127	69	375	399	1449	986	(1074)	(587)	0.51%
Alternative 3										
Scenario 6	3A	24	20	122	189	833	490	(712)	(301)	0.61%
Scenario 7	3B, 3H	171	57	571	1027	2627	3481	(2056)	(2454)	1.12%
Scenario 8	3E, 3I	171	57	571	1027	2627	3481	(2056)	(2454)	1.12%

[1] Impacts are defined as the difference between conditions under each CALFED alternative (and under 2020 level of development) and the No Action alternative. Impacts attributable to CVP facilities will range from zero (all impacts attributable to CVP facilities) to the maximum impact exhibited in this table (all impacts attributable to SWP facilities).

[2] The nameplate capacity ratings of facilities do not vary under different hydrologic conditions.

[3] Project energy use is the amount of energy used by CVP facilities.

[4] Energy available for sale is equal to CVP maximum project generation minus CVP maximum project energy use. Negative values represent a net energy requirement.

Table 5. Summary of Maximum CVP Power Production and Energy Impacts

Alternatives		Change in Dry Summer Capacity (MW)		Change in Total Annual Energy Generation (GWh)		Change in Total Annual SWP Pumping Energy Requirement[3] (GWh)		Change in Total Annual Net Energy Requirement[4] (GWh)		Change in SWP System Energy Rate (%)
Scenario	Configuration	Average Conditions	Dry Conditions	Average Conditions	Dry Conditions	Average Conditions	Dry Conditions	Average Conditions	Dry Conditions	
Alternative 1										
Scenario 1	1A, 1B	0	0	0	0	0	0	0	0	0.00%
Scenario 2	1C	147	72	503	698	2,122	1,938	1,618	1,241	-0.68%
Alternative 2										
Scenario 3	2A	4	25	98	101	540	205	442	104	-0.16%
Scenario 4	2B, 2E	147	72	503	698	2,122	1,938	1,618	1,241	-0.68%
Scenario 5	2D	127	69	375	399	1,449	986	1,074	587	-0.51%
Alternative 3										
Scenario 6	3A	24	20	122	189	833	490	712	301	-0.21%
Scenario 7	3B, 3H	171	57	571	1,027	2,627	3,481	2,056	2,454	-0.77%
Scenario 8	3E, 3I	171	57	571	1,027	2,627	3,481	2,056	2,454	-0.77%

[1] Impacts are defined as the difference between conditions under each CALFED alternative (and under 2020 level of development) and the No Action alternative. Impacts attributable to SWP facilities will range from zero (all impacts attributable to SWP facilities) to the maximum impact exhibited in this table (all impacts attributable to CVP facilities).

[2] The nameplate capacity ratings of facilities do not vary under different hydrologic conditions.

[3] SWP pumping energy requirement is the amount of energy used by SWP pumping facilities.

[4] The SWP's net energy requirement is equal to SWP maximum pumping energy requirement minus SWP maximum generation.

Table 6. Summary of Maximum SWP Power Production and Energy Impacts

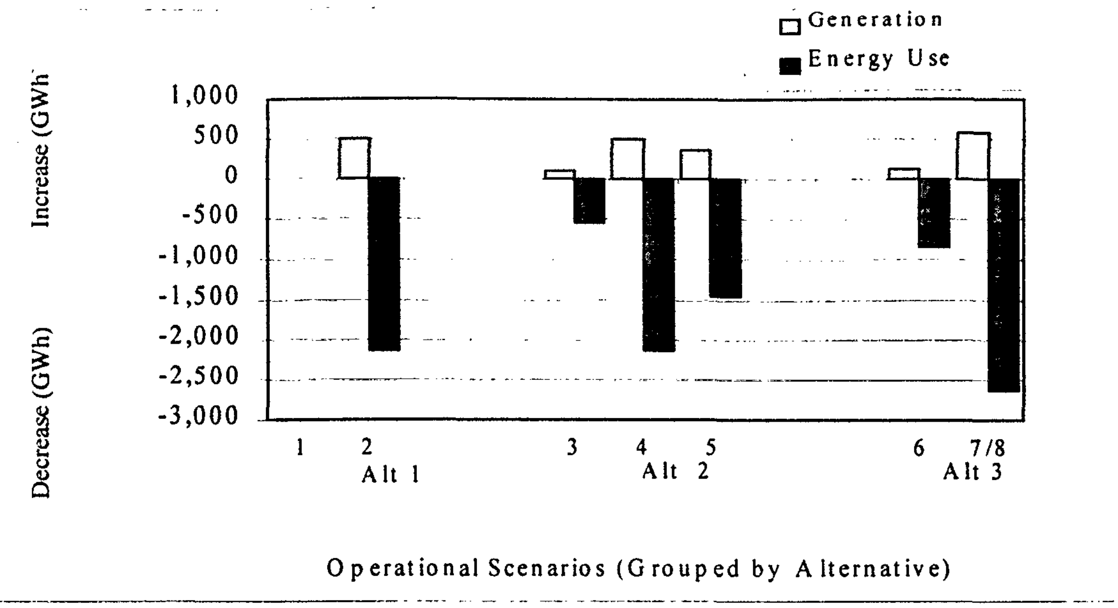

Figure 2. Average Annual Generation and Energy Use for Pumping—Maximum Potential Change from No Action Alternative Conditions

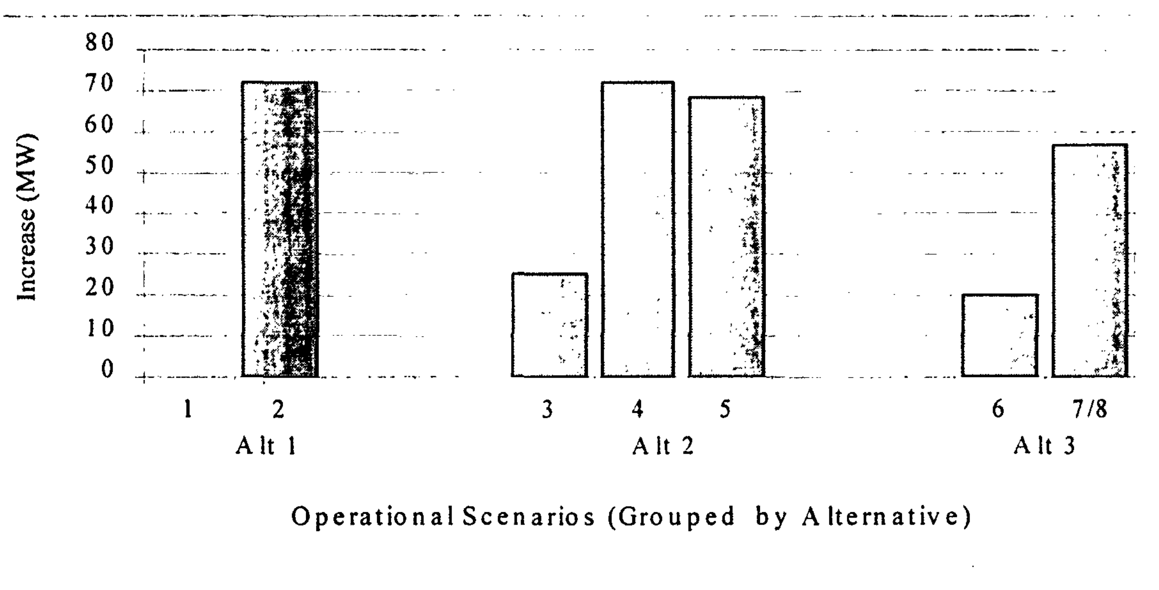

Figure 3. Maximum Change from No Action Alternative Conditions in July Capacity of CVP or SWP Facilities in a Dry Water Year

discussed below. Impacts to power production and energy resulting from other program elements, such as ecosystem restoration, do not vary substantially from one alternative to another at the programmatic level. Therefore, the discussion of environmental consequences associated with other program elements are not grouped by alternative. In those cases where no environmental impacts have been associated with a program element with a region, the program elements is not discussed. Tables 3 and 4 describe the SWP and CVP power production and energy condition under each alternative configuration.

Tables 5 and 6 summarize the remainder of the key results of the CALFED power production and energy resource impacts analysis. Table 5 summarizes the key CVP-related results while Table 6 summarizes the key SWP-related results. The impacts shown in Tables 5 and 6 are described below.

Figure 2 depicts the maximum annual energy generation and pumping energy impacts of each alternative.

Although the CALFED alternatives would increase net energy use, reservoir levels generally are projected to be higher under dry summer conditions. This provides a beneficial impact of increasing the maximum capacity available to produce energy during peak summer periods when demand for electricity, and power values, are highest. The dry year capacity impacts are shown in Figure 3.

Figure 3 shows that the addition of storage yields additional dry year capacity, as shown in Scenario 2 (Alternative Configuration 1C), Scenario 4 (Alternative configurations 2B and 2E), and Scenarios 7 and 8 (Alternative configurations 3B, 3E, 3H, and 3I). Each of these scenarios include the assumption that the corresponding CALFED alternative would add new reservoir storage north and south of the Delta. Scenario 5 (Alternative Configuration 2D), in which storage south of the Delta is assumed, also shows an increase in dry year summer capacity. Although the impacts are small, both Scenario 3 (Alternative Configuration 2A) and Scenario 6 (Alternative Configuration 3A) show increases in dry year summer capacity.

Figure 4 shows the average potential change in net CVP energy available for sale, or net SWP energy requirements. All scenarios except Scenario 1 would cause a net increase in energy requirements. Scenarios 7 and 8 of Alternative 3 would cause the largest net increase (approximately 2,454 gigawatt hours [GWh] per year).

Figure 5 shows the average net value of annual CVP or SWP energy generation and project energy use impacts. Scenario 1 of Alterative 1 would not cause a change in power values, while Scenarios 7 and 8 of Alternative 3 would cause the largest change in power values (a decrease of approximately $50 million per year).

Figure 6 shows the maximum potential impacts of CALFED alternatives on DWR's system energy rate. All scenarios except Scenario 1 would cause a decrease in DWR's system energy rate. Scenarios 2, 4, 7, and 8 would cause the largest decrease (less than 0.8%).

Power production and energy conditions under Alternative 1 would be different than those under the No Action Alternative and existing conditions. The potential impacts described below were defined by comparing the conditions summarized in Tables 3 and 4, and presented in additional tables and figures in the remainder of this section. The more detailed information is unique to some of the capacity and energy resource assessment variables and is needed to assess related impacts.

ALTERNATIVE 1

Tables 3 and 4 describe major SWP and CVP power production and energy conditions under each configuration of Alternative 1 and the 2020 level of development. Conditions described in these tables include total nameplate capacity, total available capacity, total annual energy generation, total annual project energy use, net energy available for Western sales, and net SWP energy requirements.

HYDROELECTRIC GENERATION AND PROJECT ENERGY USE IMPACTS

Impacts during Construction

Alternative 1 may include new water storage facilities if Alternative Configuration 1C is selected. Alternative configurations 1A and 1B do not include new storage facilities. Under Alternative Configuration 1C, new hydroelectric capacity would be added to existing or new storage sites in the Sacramento River and San Joaquin River regions. It is not known what reservoir sites would be selected under this alternative; however, the hydroelectric capacity would increase under this alternative. So long as a reasonable amount of discretion exists for

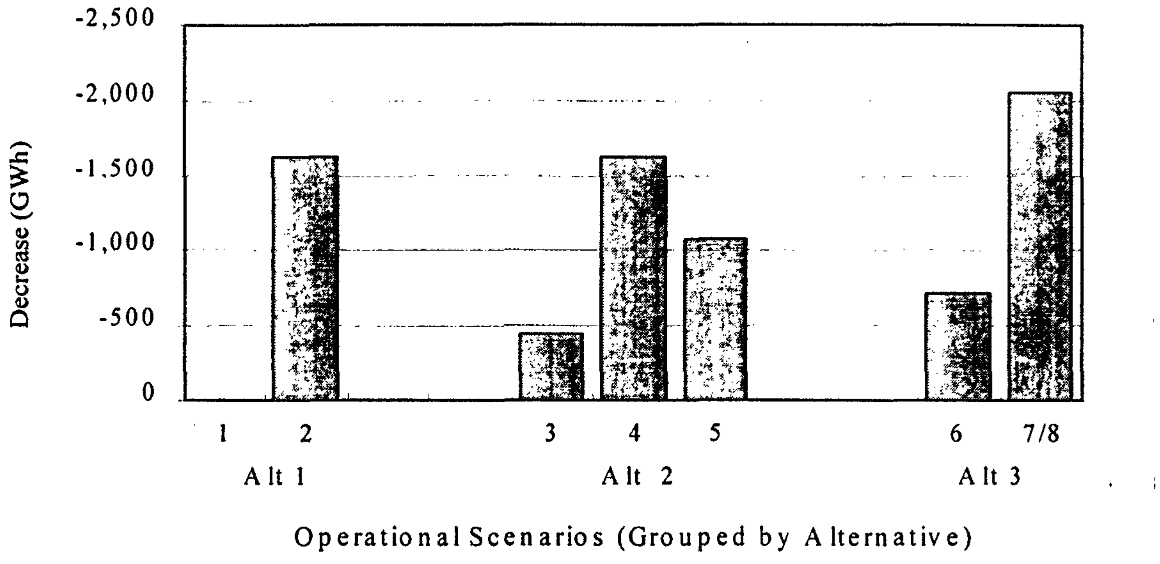

Figure 4. **Average Annual Net CVP Energy Available for Sale or Net SWP Energy Requirements—Maximum Potential Change from No Action Alternative Conditions**

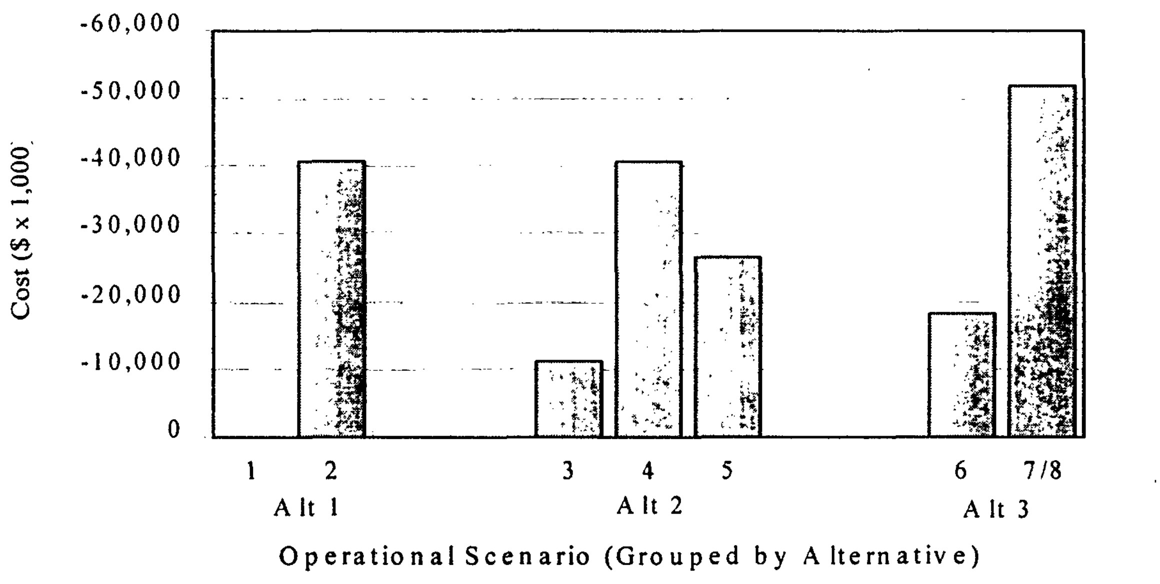

Figure 5. **Average Net Value of Annual CVP or SWP Energy Generation and Project Energy Use—Maximum Potential Change from No Action Alternative Conditions**

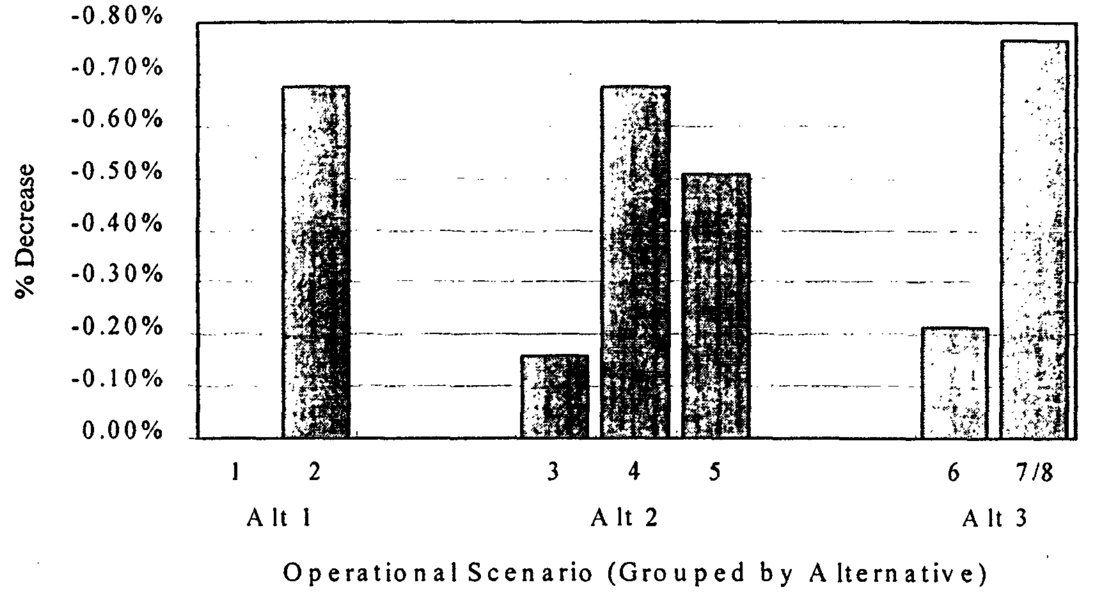

Figure 6. DWR's System Energy Rate—Maximum Potential Change from No Action Alternative Conditions

scheduling pumping and generation at these new facilities on a daily basis, a positive impact on capacity resources would result. Energy would be required to fill these additional storage facilities, and although energy would be recovered when water is released, operation of such facilities may increase energy use.

A minor temporary adverse impact would occur during construction if a storage site with existing hydroelectric facilities, such as Lake Berryessa or Shasta Lake, was selected. Temporary disruptions of hydrogeneration would likely be necessary during construction as new hydroelectric capacity was added or as the dams at existing storage sites were enlarged.

Impacts during construction would be the same for all alternatives.

Impacts during Operation

Changes in stream flows for habitat restoration and water quality improvement may alter capacity and generation at SWP and CVP hydroelectric power plants. Annual increases of 300,000 to 500,000 acre-feet of critical-period flows are expected as a result of stream flow alterations included in Alternative 1. These flows are part of the Ecosystem Restoration Program, Water Quality Program, and Coordinated Watershed Management, and are included in each of the CALFED alternatives. The timing of diversions also would be altered to avoid entrainment effects. These programs also require additional water deliveries to restore and maintain various habitat types in the Bay and Delta regions. The impacts of all these operational changes are reflected in the DWRSIM results defined in Tables 3 and 4 and subsequent tables in this section. (Note: Analysis to be updated when enhancements to DWRSIM are complete.)

Alternative configurations 1A and 1B are represented as Scenario 1 (see Table 1). Operational impacts from Scenario 1 result from the changes in operation described above. Alternative Configuration 1C is represented by Scenario 2. Scenario 2 includes the same operational changes included in Scenario 1 plus new conveyance facilities, enlarged Delta channels, and new surface water and groundwater storage facilities.

Tables 7 and 8 summarize the monthly and annual energy generation and project energy use impacts of Alternative 1 on the SWP and CVP power systems, respectively. Table 7 also defines the potential impacts of Alternative 1 on CVP energy available for sale. The impacts of lternative 1 on the net energy requirements of the SWP are defined in Table 8.

Tables 7 and 8 illustrate that both energy generation and project use loads are estimated to increase under Scenario 2 as compared to the No Action Alternative. However, the increase in energy generation is much smaller (estimated at approximately 500 GWh annually), while the increase in project use loads is approximately 2,100 GWh on an average annual basis. This would result in a potential reduction in net energy available for sale for Western, or an increase in net energy requirements to the CVP, of about 1,600 GWh. The net reduction in dry years is estimated at about 1,200 GWh.

Figure 7 depicts the estimated average monthly profile of potential energy generation and project energy use impacts on CVP. Minimum potential impacts of Alternative 1 are reflected by the No Action Alternative results, and maximum potential impacts are shown in the Scenario 2 results. Figure 8 provides a similar representation for the SWP. Project use loads are projected to increase throughout the year. Generation also would increase, but more modestly, in all but summer months, when on-peak generation likely would be most highly valued.

Figure 9 shows the estimated impact on monthly available capacity to the CVP, and Figure 10 shows the impact on the SWP, based on average monthly reservoir levels during the critical dry period of 1929 to 1934. The addition of storage north and south of the Delta is assumed in Scenario 2 and Alternative Configuration 1A. The net effect is an increase in estimated dry year capacity in each month, with relatively larger increases in fall and winter, smaller increases in summer, and the smallest increases in early spring.

Tables 9 and 10 show the potential increase in estimated dry year summer energy resulting under Scenario 2. As expected, additional storage yields both increased capacity and increased energy generation.

SWP AND CVP POWER PRODUCTION AND REPLACEMENT COST IMPACTS

Operational changes identified for Alternative 1 under "Hydroelectric Generation and Project Energy Use Impacts," provide the basis for determining related impacts to SWP and CVP power production and replacement costs. Western or DWR could experience changes in such costs as they incur capacity and generation impacts, or need to replace lost capacity or energy. Changes in production costs would be passed on to power customers via rate changes.

In the short term, power providers are expected to replace lost capacity and energy with power from the open or "spot" market. This will help minimize adverse and short-term production cost impacts caused by CALFED alternatives because power rates on the open market may remain relatively flat for some time as the transition to a competitive electric market continues. By minimizing their production and replacement costs, power providers such as Western and DWR can delay rate increases for as long as possible. In the long term, after current surplus power conditions end, power rates are expected to reflect the costs of constructing and operating the most economic generation projects.

Based on an estimated price range of 26 to 34 mills/kWh for energy generated by the SWP and CVP (shown in Table 2), the annual value of the system generation impact was calculated for Scenarios 1 and 2. Figure 12 illustrates that, based on the definition of the DWRSIM cases on which this analysis is based, Scenario 1, which describes Alternative configurations 1A and 1B, would not affect power production and energy values. Scenario 2, which describes Alternative Configuration 1C, would yield increased generation benefits and increased pumping energy expenses, with the net effect being an increase in estimated annual expense of approximately $40 million.

Month	Energy Generation				Project Energy Use				Energy Available For Sale[1]			
	Scenario 1		Scenario 2		Scenario 1		Scenario 2		Scenario 1		Scenario 2	
	Avg	Dry	Avg	Dry	Avg	Dry	Avg	Dry	Avg	Dry	Avg	Dry
October	317	175	368	221	139	100	358	283	178	74	10	(62)
November	301	148	366	196	145	100	335	251	156	47	31	(55)
December	348	133	412	176	169	153	327	308	179	(21)	85	(132)
January	367	124	447	170	182	179	384	356	185	(55)	63	(187)
February	402	128	458	166	157	140	351	255	245	(12)	107	(89)
March	442	175	514	226	174	99	386	229	269	76	127	(3)
April	482	284	514	341	110	48	290	219	372	236	225	122
May	569	329	606	392	85	39	228	181	484	290	377	211
June	600	429	619	481	75	54	211	190	525	375	408	291
July	617	443	594	530	102	79	241	277	515	364	353	253
August	475	325	465	420	107	65	227	253	368	260	238	166
September	328	202	387	272	133	101	360	294	194	101	27	(23)
Annual Total	5,248	2,893	5,751	3,590	1,577	1,159	3,699	3,097	3,671	1,734	2,053	493
Annual Change From No Action	0	0	503	698	0	0	2,122	1,938	0	0	(1,618)	(1,241)

[1] Negative values represent a net energy requirement.

Table 7. Maximum Average CVP Energy Generation, Project Energy Use, and Energy Sales Under Alternative 1 (Mwh x 1,000)

Month	Energy Generation				Project Energy Use				Net Energy Requirement			
	Scenario 1		Scenario 2		Scenario 1		Scenario 2		Scenario 1		Scenario 2	
	Avg	Dry	Avg	Dry	Avg	Dry	Avg	Dry	Avg	Dry	Avg	Dry
October	291	219	342	265	871	527	1,090	710	580	308	748	445
November	268	185	333	234	836	539	1,027	690	568	354	693	456
December	339	213	403	256	896	602	1,055	757	557	389	652	501
January	338	130	419	176	819	540	1,021	718	480	410	602	542
February	386	174	442	212	796	564	991	679	411	390	549	467
March	434	220	505	270	934	648	1,147	778	501	429	642	508
April	449	327	482	384	939	602	1,119	773	490	275	637	389
May	490	291	526	355	865	513	1,008	655	375	222	482	301
June	500	352	519	404	821	493	957	629	321	141	438	225
July	606	376	583	464	989	619	1,129	818	383	243	545	354
August	493	298	484	393	972	604	1,092	793	479	306	609	400
September	304	203	363	272	941	524	1,168	717	638	322	805	445
Annual Total	4,898	2,987	5,401	3,684	10,682	6,777	12,804	8,715	5,784	3,791	7,402	5,031
Annual Change From No Action	0	0	503	698	0	0	2,122	1,938	0	0	(1,618)	(1,241)

Table 8. Maximum Average SWP Energy Generation, Project Energy Use, and Energy Sales Under Alternative 1 (Mwh x 1,000)

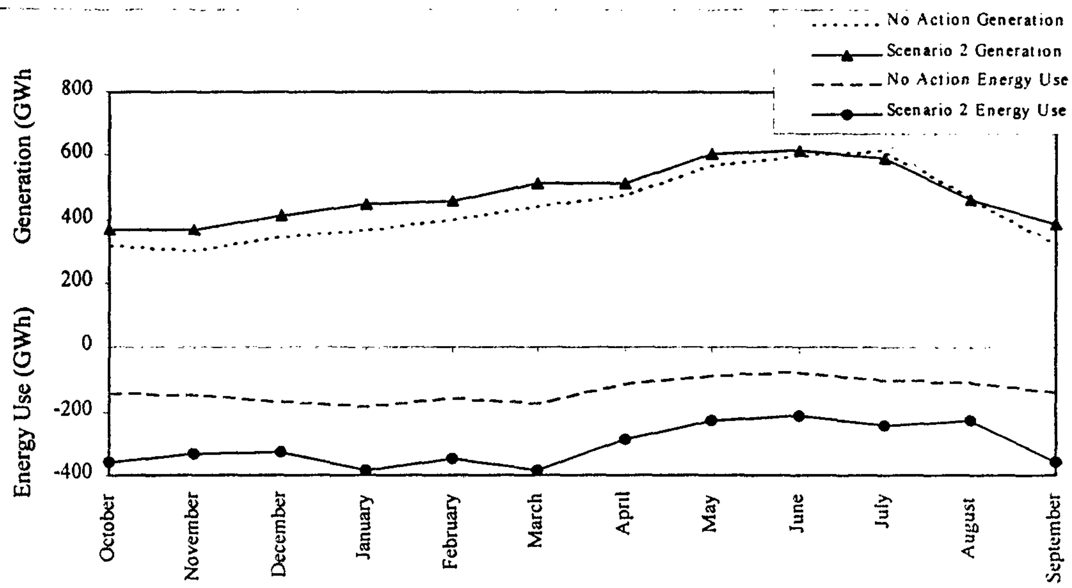

Figure 7. Range of CVP Energy Generation and Project Energy Use Impacts in an Average Water Year under Operational Scenario 2

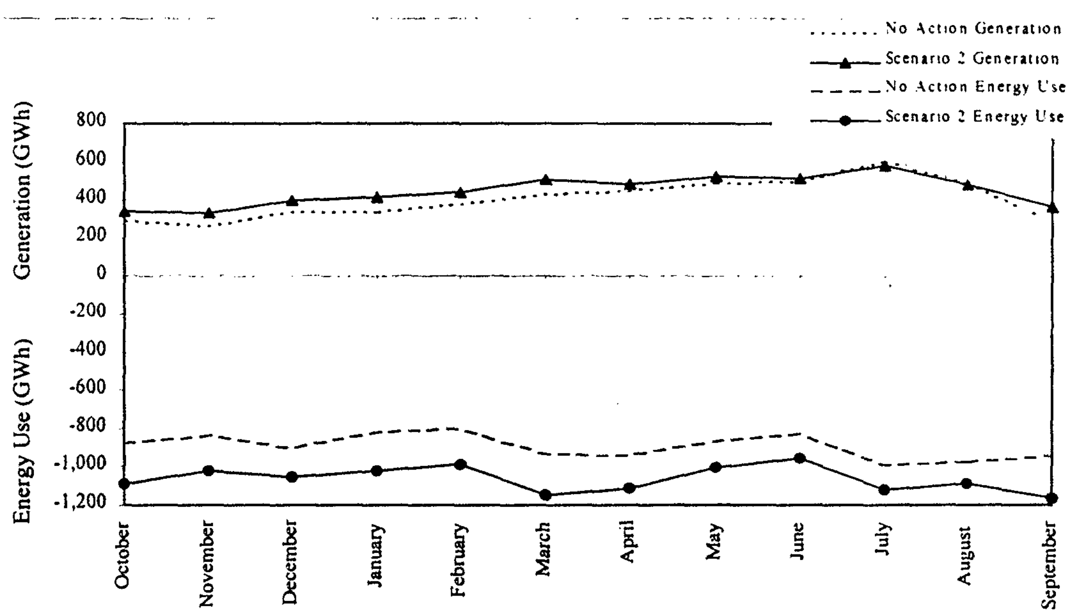

Figure 8. Range of SWP Energy Generation and Project Energy Use Impacts in an Average Water Year under Operational Scenario 2

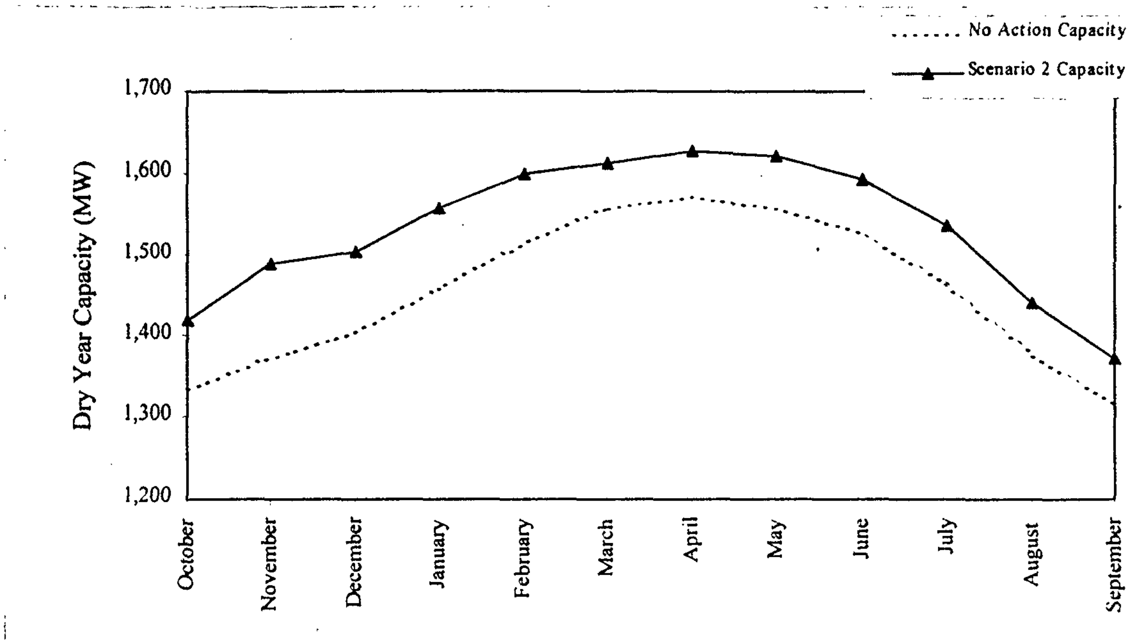

Figure 9. Range of CVP Capacity Impacts in a Dry Water Year under Operational Scenario 2

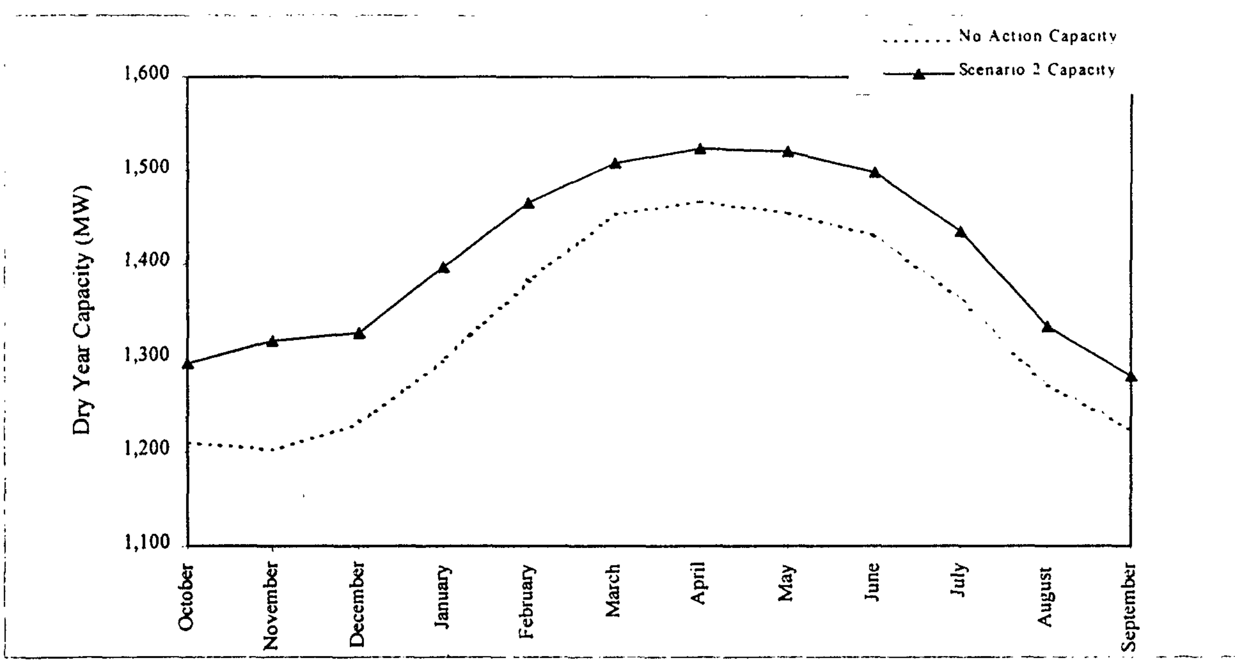

Figure 10. Range of SWP Capacity Impacts in a Dry Water Year under Operational Scenario 2

Western and DWR Power Rate Impacts

The estimated impact of Configuration 1C on the CVP composite energy rate, as compared to the No Action Alternative, could increase as much as 108%. The change in the SWP system energy rate is projected to be an increase of 18%. Configurations 1A and 1B would not cause power rate impacts.

The allocation of joint use costs and power costs between the SWP and CVP systems, and the contribution of CVP project use power to additional pumping energy requirements, may affect these results.

Impacts on Power Payments to the CVP Restoration Fund

Each Alternative 1 configuration was estimated to result in the same or greater water deliveries to agricultural and M&I water users, as compared to the No Action Alternative. This would allow water users to meet their contribution to the Restoration Fund at a lower average cost per acre-foot, depending on how costs associated with the Alternative 1 facilities were allocated among water, power, environmental, and other users. A decrease in the ability of water users to pay may result. It would be speculative to estimate whether the reduction in average cost of the Restoration Fund obligation to water users would be sufficient to offset any reduction in Fund obligation of power users is not expected to increase under Alternative 1. Therefore, Alternative 1 has no potential for significant adverse impacts on Western or its customers due to increased Restoration Fund obligations

Impacts would be the same under Alternatives 2 and 3.

Impacts on Western and DWR Power Customers

The estimated impacts on Western's composite energy rate described under "Western and DWR Power Rate Impacts" do not represent potentially significant adverse impacts on Western's preferred power customers. These rates remain below the assumed MCP of energy and ancillary services. These customers would be free to secure energy and ancillary services from other suppliers if Western's costs were too high in the deregulated bulk power market. Similarly, a potential decrease in the SWP system average energy rate may result. This does not necessarily yield a net benefit and must be considered together with the impacts on SWP pumping energy requirements.

Impacts would be the same under Alternative 2.

Other Types of Energy Use Impacts

Ecosystem Restoration Program

Energy use likely would increase during implementation of the Ecosystem Restoration Program due to construction activities related to wetlands creation and other restoration activities. Some increase in energy use to maintain restored areas is likely, including pumping to deliver water to restored wetlands.

Energy use would decrease on lands retired from agricultural uses under the program. Many types of energy-consuming agricultural practices would no longer occur on these lands, including tilling, harvesting, and applying fertilizer and pesticides. These energy savings would occur on approximately 130,000 to 190,000 acres in the Delta Region and on about 35,000 to 100,000 acres in the Central Valley.

Impacts would be the same under Alternative 2.

Water Quality Program and Coordinated Watershed Management

The Water Quality Program focuses on source control of mine drainage, urban and industrial runoff, and agricultural drainage. The program may result in indirect energy impacts, depending on the specific measures that eventually are

Alternatives	Scenario	June	July	August	September	Total	Increase (Decrease) from No Action
No Action		429	443	325	202	1,399	---
1A, 1B	1	429	443	325	202	1,399	---
1C	2	481	530	420	272	1,703	304
2A	3	434	458	318	210	1,420	21
2B, 2E	4	481	530	420	272	1,703	304
2D	5	442	494	376	253	1,565	166
3A	6	425	435	325	200	1,385	(14)
3B, 3E, 3H, 3I	7, 8	494	512	413	271	1,690	291

Table 9. Maximum Change in CVP Dry Year Summer Energy Generation (GWh)

Alternatives	Scenario	June	July	August	September	Total	Increase (Decrease) from No Action
No Action		352	376	298	203	1,229	---
1A, 1B	1	352	376	298	203	1,229	---
1C	2	404	464	393	272	1,533	304
2A	3	357	392	291	211	1,251	21
2B, 2E	4	404	464	393	272	1,533	304
2D	5	365	428	349	254	1,396	166
3A	6	348	369	298	201	1,216	(14)
3B, 3E, 3H, 3I	7, 8	417	446	387	272	1,522	291

Table 10. Maximum Change in SWP Dry Year Summer Energy Generation (GWh)

implemented. Impacts would primarily include temporary increases in energy use to implement source control measures. Examples of implementation procedures that would use energy include earthwork with heavy vehicles and installing structural water quality controls. Long-term beneficial impacts would occur as water quality improvements reduce treatment requirements.

In the short term, implementation of the Watershed Management Coordination actions would require relatively minor amounts of energy compared to the energy required to construct the major storage, conveyance, and levee improvement elements of the other programs. Some energy would be required to implement program elements in upper and lower watersheds where fish migration barriers are removed, unstable levees were repaired, stream banks were stabilized, and riparian habitat was improved.

The minor temporary negative energy impacts of implementing Coordinated Watershed Management would be outweighed by the positive long-term reductions in energy use caused by the program. The related improvements in water quality could reduce water treatment requirements and associated energy requirements at treatment plants. By reducing "stressors" and damaging land use practices, watershed management measures would indirectly reduce the amount of energy used by related land use practices. The program would address aspects of logging, agricultural pesticide and fertilizer applications, and livestock grazing.

Impacts would be the same under Alternative 2.

Levee System Integrity Program

The Levee System Integrity Program would cause direct energy impacts during construction. Levee system modifications are relatively energy-intensive activities during their construction phases as energy is needed to power construction equipment, worker vehicles, pumps, and other equipment. Although levee modifications use energy in the short term, they could prevent long-term levee maintenance procedures that would be needed without major improvements to the system. This would be a long-term beneficial impact that could help offset the additional use of energy in the short term.

Impacts would be the same under Alternative 2.

Water Use Efficiency Program, Including Water Transfers

The Water Use Efficiency Program would reduce M&I water use but may lead to increases in agricultural power use. Specific water efficiency measures would be determined by local water districts and users. It is likely that such measures would lead to beneficial and long-term energy savings. The amount of energy used directly and indirectly by water users would be reduced as their water use declines. Examples of the types of energy-related impacts that likely would occur when measures were successfully implemented are listed below.

- Urban water users would experience reductions in water heating requirements as their water use declines. Most energy savings would be in the form of reductions in the amount of natural gas used to power water heaters.

- Reductions in urban water demands also would reduce pumping and treatment requirements for M&I water districts, thus saving additional energy.

- More efficient use of environmental diversions would reduce pumping requirements in certain areas and would lead to more energy savings.

- The water recycling element of the program potentially would delay the construction of new supply projects and related energy use during construction, operation, and maintenance of the projects. On the other hand, some water recycling projects would

- increase the use of energy if they increased local pumping requirements. This would occur in areas where recycling plants are at the "tail-end" of water systems or downhill from end-users that use the recycled water. Some recycling projects also could increase energy use if they increased water treatment requirements.

- Agricultural water users may increase energy use as they switch from gravity-fed irrigation systems to sprinkler systems.

In the short term, energy use would increase during the implementation phase of the specific conservation measures. Over the long term, the installation of conservation devices and other efficiency measures may decrease overall energy use in the study area, depending on the extent to which increased agricultural pumping in support of sprinkler irrigation was implemented.

Energy use would increase in areas receiving new water supplies under the Water Transfer Program if the water deliveries result in new urban or agricultural uses that could not occur without the deliveries. Water transfers also may increase energy use at pumping and treatment facilities if the transfers require an increase in pumping or treatment requirements. Impacts would be the same under Alternative 2.

Storage and Conveyance

If Alternative Configuration 1C was implemented, energy would be needed to construct new storage projects in the Sacramento River and San Joaquin River regions. Energy would be needed to power construction equipment and vehicles, and would be used by construction workers as they commute to and from construction sites. Smaller amounts of energy also would be required to operate and maintain the storage projects included in this alternative.

Two alternative configurations of Alternative 1 (1B and 1C) include two conveyance projects in the Delta Region (the south Delta modifications and the SWP and CVP improvement projects). Alternative Configuration 1C would require constructing a water conveyance facility from the Sacramento River to a reservoir storage site in the Sacramento River Region. Each of these representative and example projects would require energy to power a wide variety of construction-related activities, including trenching, grading, and workers commuting to and from construction sites.

A minor amount of energy would be needed to maintain the conveyance facilities after construction. A substantially greater amount of energy would be required at local irrigation and municipal utility district pumping facilities, as discussed below.

Other Types of Operational-Related Energy Use Impacts

This section addresses potential energy use impacts at groundwater pumping and water treatment facilities. These facilities belong to local irrigation districts and municipal utilities and would be affected indirectly by CALFED alternatives.

Alternative configurations 1A and 1B would not affect energy use at groundwater pumping plants. Alternative Configuration 1C would increase energy use at such plants, but the increase would be minor and much less than the changes associated with Alternatives 2 and 3. Alternative Configuration 1C is the only Alternative 1 configuration that includes a new groundwater storage program, and it also is the only Alternative 1 configuration that would cause an average increase in SWP and CVP surface water exports and deliveries. The groundwater program would be located in both the Sacramento and San Joaquin valleys, and would increase the amount of energy needed to pump groundwater. An increase in surface water exports and deliveries could reduce to some extent reliance on groundwater pumping and associated energy use.

Unlike Alternative configurations 1A and 1B, Alternative Configuration 1C could change energy use at water treatment plants. Energy use could increase as M&I water utilities treat the water associated with this Alternative Configuration's higher levels of average CVP and SWP exports and deliveries. These impacts would be less than the related impacts associated with Alternatives 2 and 3.

Energy Use Impacts Caused by Traffic and Navigation Impacts after Construction

The CALFED alternatives are expected to result in major environmental improvements in the study area. Recreation opportunities would be increased for many types of recreationists (boating enthusiasts at reservoirs, fishers, hunters, bird watchers, and others). As recreation use increased in areas with environmental improvements, recreation-related traffic also would increase. This would cause an indirect increase in the amount of fuel used in the study area and in the areas from which recreationists travel.

IMPACTS AT OTHER POTENTIALLY AFFECTED HYDROELECTRIC POWER PLANTS

Alternative 1 and other CALFED alternatives likely would change the hydrology in streams affected by SWP and CVP operations. This in turn likely would affect available capacity and energy generation at hydroelectric facilities that are not part of the CVP or SWP but are located in the same watershed. These other hydroelectric facilities may include a city of Redding plant on Clear Creek; Oakdale and South San Joaquin Irrigation District plants in the Stanislaus River Basin; Friant Power Authority plants on the San Joaquin River; and the Monticello Power Plant at Lake Berryessa.

Specific impacts on these other hydroelectric facilities could be positive or negative and cannot be defined at this time. A wide range of SWP and CVP operational changes currently are being assessed during the CALFED study. Until more specific information about the timing and magnitude of SWP- and CVP-related operational changes on specific stream reaches are available, it is speculative to define related impacts on other hydroelectric facilities. The magnitude of capacity and energy impacts on other hydroelectric facilities would vary on a case-by-case basis, depending on the nature of any reoperation, including how such reoperation changes with water-year type and the projected seasonal, weekly, and daily configurations. Impacts on other facilities would be influenced not only by the hydrologic changes caused by CALFED alternatives, but also by the amount of water in storage at affected facilities when the hydrology changes occur; by utility-specific water, power, and environmental demands that are in place at the time of the hydrology changes; and by the daily, weekly, and monthly operational characteristics of the affected facilities.

Impacts would be the same under Alternatives 2 and 3.

ALTERNATIVE 2

Tables 3 and 4 describe major SWP and CVP power production and energy conditions for each configuration of Alternative 2 and the 2020 level of development. Power production and energy conditions under Alternative 2 would be different than those under No Action Alternative conditions and existing conditions. The related impacts are described below.

HYDROELECTRIC GENERATION AND PROJECT ENERGY USE IMPACTS

Impacts during Operation

Scenario 4 includes a substantial increase in additional storage (up to 6.5 million acre-feet [MAF]) through new surface and groundwater storage facilities. Scenario 5 includes a smaller increase in additional storage (up to 2.0 MAF).

Tables 11 and 12 summarize the monthly and annual energy generation and project energy use impacts of Alternative 2 on the SWP and CVP power systems, respectively. Table 11 also defines the potential impacts of Alternative 2 on CVP energy sales, and Table 12 defines potential impacts on the SWP's net energy requirement.

Tables 11 and 12 illustrate that both energy generation and project use loads were estimated to increase under Scenario 3 as compared to the No Action Alternative. However, the increase in energy generation is much smaller, estimated to be approximately 100 GWh annually, while the increase in project use loads is approximately 540 GWh on an average annual basis. Scenario 3 would result in a potential reduction in net energy available for sale for Western, or an increase in net energy requirements to the CVP, of about 440 GWh. The net reduction in dry years is estimated at about 100 GWh.

Figure 11 depicts the estimated average monthly profile of potential energy generation and project energy use impacts of Alternative Configuration 2A on CVP. Minimum potential impacts are reflected by the No Action Alternative results, and maximum potential impacts are shown in the Scenario 3 results. Figure 12 provides a similar representation for the SWP. Project use loads are projected to increase slightly throughout the year with slightly larger increases in late fall and smaller increases in winter. Generation also increases during most months, but more modestly. In summer, when on-peak generation is likely to be most highly valued, a slight increase in generation is estimated for July, and a slight decrease for August.

Figure 13 shows the estimated average monthly profile of potential energy generation and project energy use impacts of Alternative configurations 2B and 2E on the CVP. Minimum potential impacts are reflected by the No Action Alternative results, and maximum potential impacts are shown in Scenario 4 results. Figure 14 provides a similar representation for the SWP. A substantial increase in project use loads during most months of the year would result.

Generation also would increase during most months, but would be nearly the same during summer, when on-peak generation likely would be most highly valued.

Figure 15 shows the estimated average monthly profile of potential energy generation and project energy use impacts of Alternative Configuration 2D on the CVP. Minimum potential impacts are reflected by the No Action Alternative results, and maximum potential impacts are shown in the Scenario 5 results. Figure 16 provides a similar representation for the SWP. Project use loads are projected to increase substantially throughout the year. Generation also would increase during most months but only slightly.

Figure 17 shows the estimated impact of Alternative Configuration 2A on monthly capacity available to the CVP, and Figure 18 shows the impact on the SWP, based on average monthly reservoir levels during the critically dry period of 1929 to 1934. Although Alternative Configuration 2A, represented by Scenario 3, does not include significant new storage, average reservoir levels generally are projected to be higher in a dry year, resulting in potential increased available capacity.

Figure 19 shows the range of estimated impact of Alternative configurations 2B and 2E on monthly capacity available to the CVP, and Figure 20 shows the potential impacts on the SWP, based on the average monthly reservoir levels during the same critically dry period. Minimum potential impacts are reflected by the No Action Alternative results, and maximum potential impacts are shown in Scenario 4 results.

Significant additional storage is planned in these alternative configurations, and increased

Month	Energy Generation						Project Energy Use						Energy Available For Sale[1]					
	Scenario 3		Scenario 4		Scenario 5		Scenario 3		Scenario 4		Scenario 5		Scenario 3		Scenario 4		Scenario 5	
	Avg	Dry	Avg	Dry	Avg	Dry	Avg	Dry	Avg	Dry	Avg	Dry	Avg	Dry	Avg	Dry	Avg	Dry
October	330	181	368	221	355	209	208	109	358	283	291	204	123	73	10	(62)	64	5
November	321	156	366	196	339	175	229	109	335	251	284	193	93	47	31	(55)	55	(18)
December	365	167	412	176	379	161	239	186	327	308	286	252	126	(19)	85	(132)	93	(92)
January	378	124	447	170	404	145	204	208	384	356	288	269	174	(85)	63	(187)	117	(125)
February	408	131	458	166	421	149	187	169	351	255	283	194	221	(38)	107	(89)	138	(45)
March	447	180	514	226	484	213	194	100	386	229	332	165	253	79	127	(3)	152	48
April	487	297	514	341	511	317	152	73	290	219	247	137	335	224	225	122	265	180
May	576	338	606	392	600	360	124	49	228	181	184	109	452	289	377	211	416	251
June	609	434	619	481	635	442	117	60	211	190	166	112	492	374	408	291	468	330
July	657	458	594	530	642	494	157	121	241	277	193	179	500	337	353	253	449	315
August	438	318	465	420	485	376	124	65	227	253	176	147	313	253	238	166	308	229
September	329	210	387	272	367	253	182	113	360	294	296	184	147	97	27	(23)	71	69
Annual Total	5,346	2,994	5,751	3,590	5,622	3,292	2,117	1,364	3,699	3,097	3,026	2,145	3,228	1,630	2,053	493	2,597	1,147
Annual Change From No Action	98	101	503	698	375	399	540	205	2,122	1,938	1,449	986	(442)	(104)	(1,618)	(1,241)	(1,074)	(587)

[1] Negative values represent a net energy requirement.

Table 11. Maximum Average CVP Energy Generation, Project Energy Use, and Energy Sales Under Alternative 2 (Mwh x 1,000)

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Month	Energy Generation						Project Energy Use						Net Energy Requirement					
	Scenario 3		Scenario 4		Scenario 5		Scenario 3		Scenario 4		Scenario 5		Scenario 3		Scenario 4		Scenario 5	
	Avg	Dry	Avg	Dry	Avg	Dry	Avg	Dry	Avg	Dry	Avg	Dry	Avg	Dry	Avg	Dry	Avg	Dry
October	304	226	342	265	329	254	940	535	1,090	710	1,023	631	635	310	748	445	694	377
November	288	193	333	234	306	212	920	548	1,027	690	976	631	632	355	693	456	670	419
December	356	247	403	256	370	240	967	635	1,055	757	1,014	701	611	388	652	501	644	460
January	349	130	419	176	376	151	841	570	1,021	718	925	631	491	440	602	542	549	480
February	392	177	442	212	405	195	827	593	991	679	923	618	435	416	549	467	518	423
March	438	224	505	270	475	257	954	650	1,147	778	1,092	714	516	426	642	508	617	457
April	454	340	482	384	478	360	981	627	1,119	773	1,076	691	528	287	637	389	598	331
May	497	300	526	355	520	322	904	523	1,008	655	964	583	407	223	482	301	443	261
June	509	357	519	404	535	365	863	499	957	629	913	551	354	142	438	225	378	187
July	647	392	583	464	631	428	1,045	662	1,129	818	1,081	720	398	270	545	354	449	292
August	456	291	484	393	503	349	990	604	1,092	793	1,042	686	534	313	609	400	539	337
September	305	211	363	272	343	254	990	536	1,168	717	1,104	607	685	325	805	445	761	354
Annual Total	4,996	3,088	5,401	3,684	5,273	3,386	11,222	6,982	12,804	8,715	12,130	7,763	6,226	3,894	7,402	5,031	6,858	4,377
Annual Change From No Action	98	101	503	698	375	399	540	205	2,122	1,938	1,449	986	(442)	(104)	(1,618)	(1,241)	(1,074)	(587)

Table 12. Maximum Average SWP Energy Generation, Project Energy Use, and Energy Sales Under Alternative 2 (Mwh x 1,000)

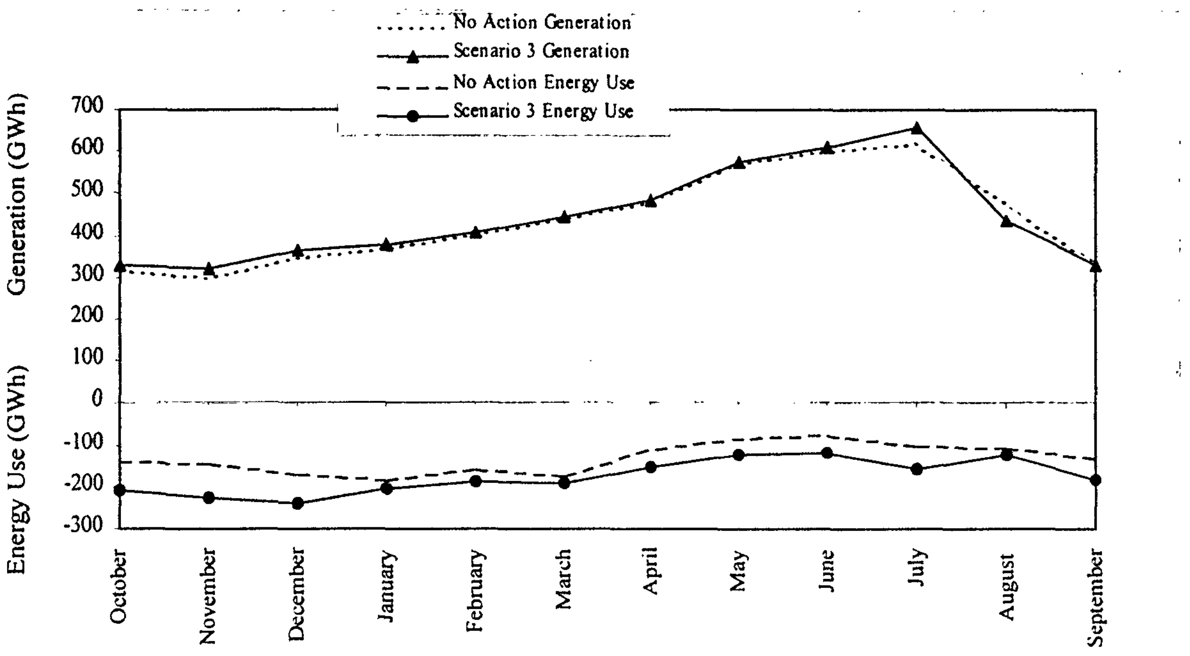

Figure 11. Range of CVP Energy Generation and Project Energy Use Impacts in an Average Water Year under Operational Scenario 3

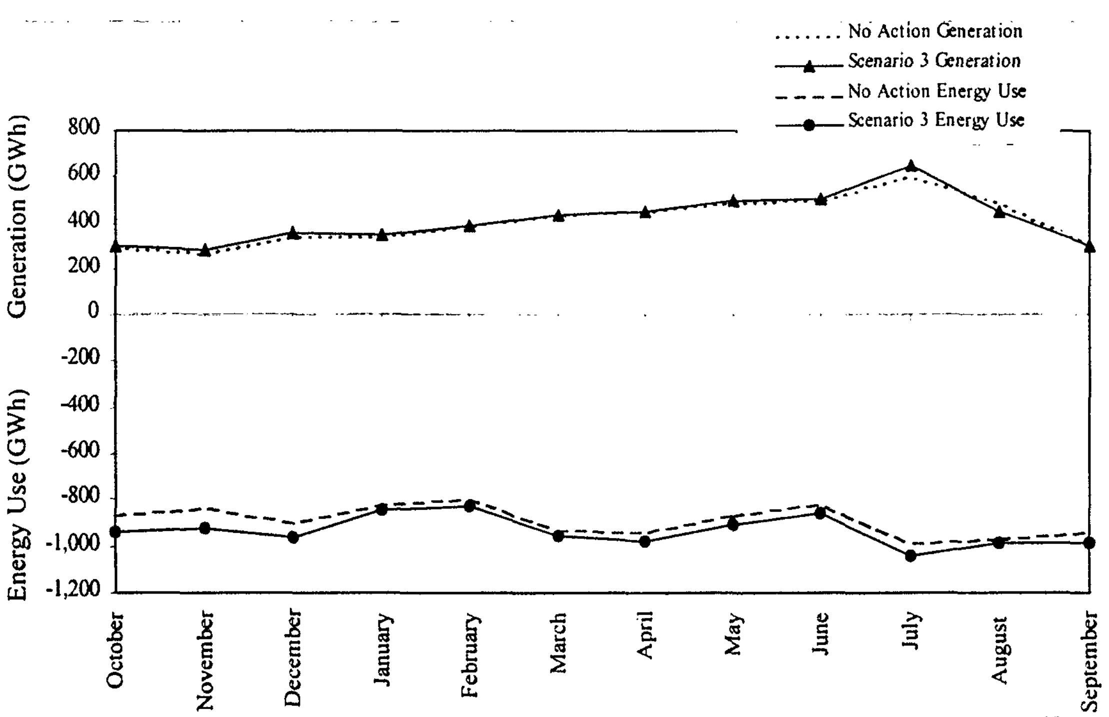

Figure 12. Range of SWP Energy Generation and Project Energy Use Impacts in an Average Water Year under Operational Scenario 3

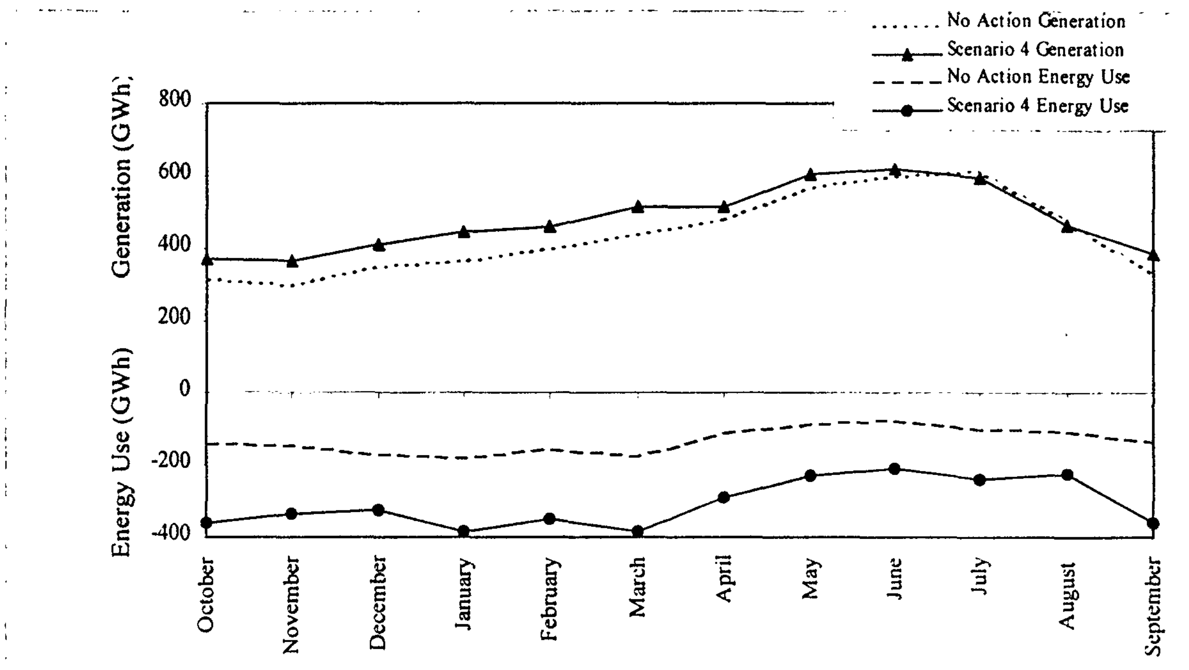

Figure 13. Range of CVP Energy Generation and Project Energy Use Impacts in an Average Water Year under Operational Scenario 4

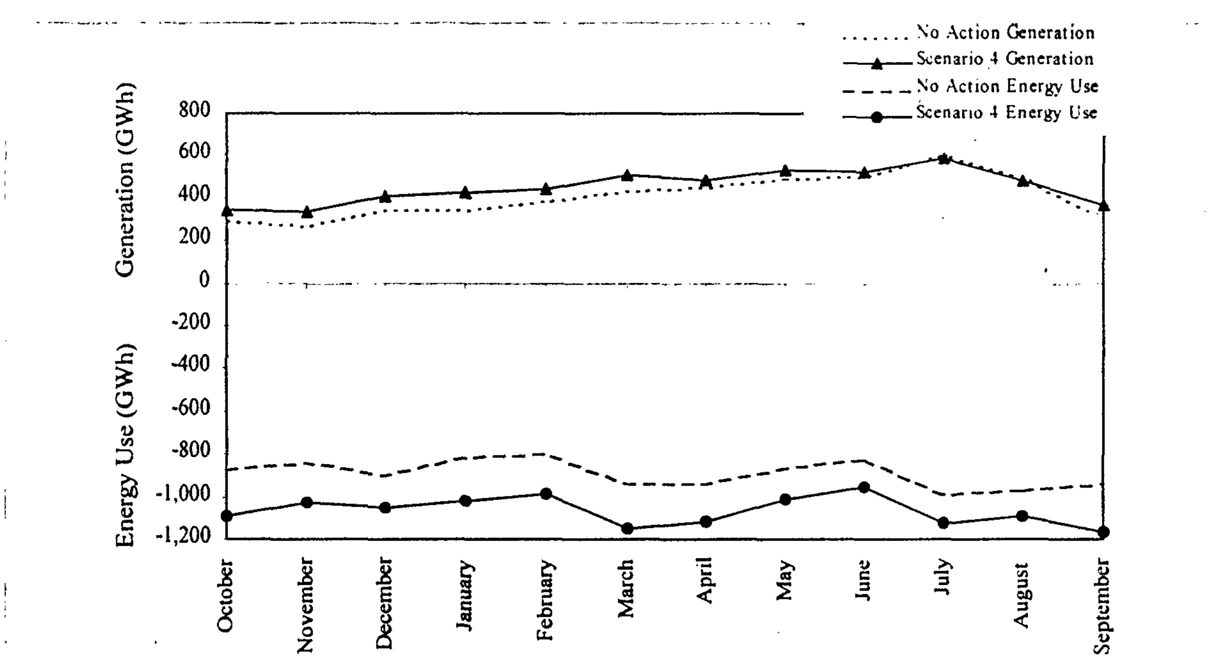

Figure 14. Range of SWP Energy Generation and Project Energy Use Impacts in an Average Water Year under Operational Scenario 4

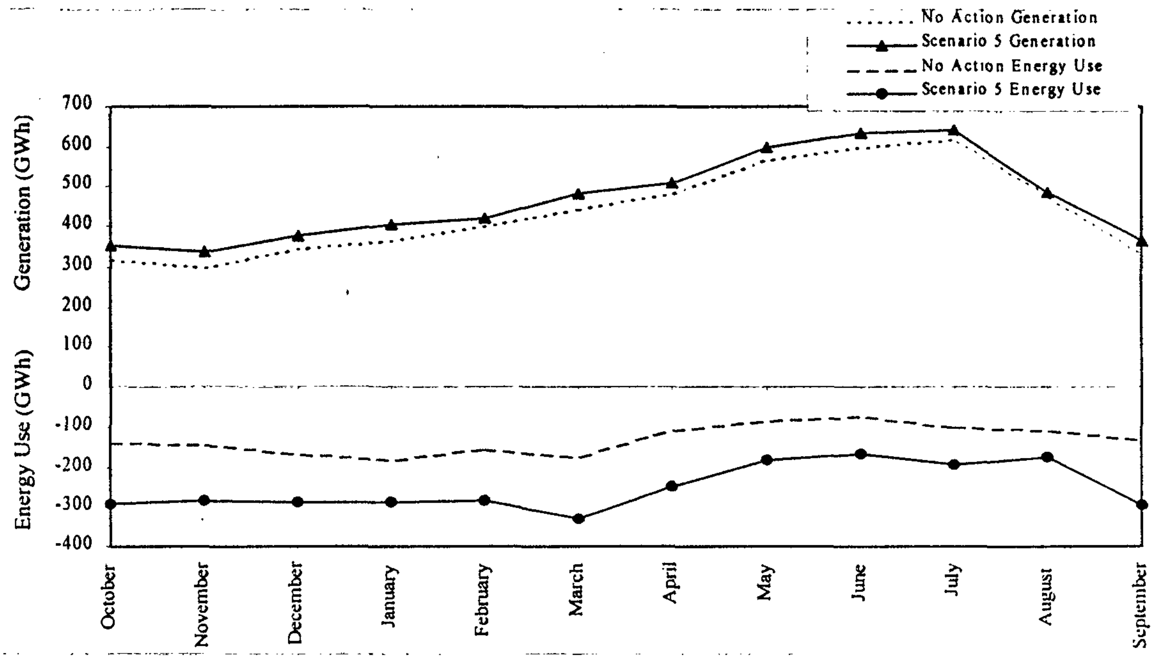

Figure 15. Range of CVP Energy Generation and Project Energy Use Impacts in an Average Water Year under Operational Scenario 5

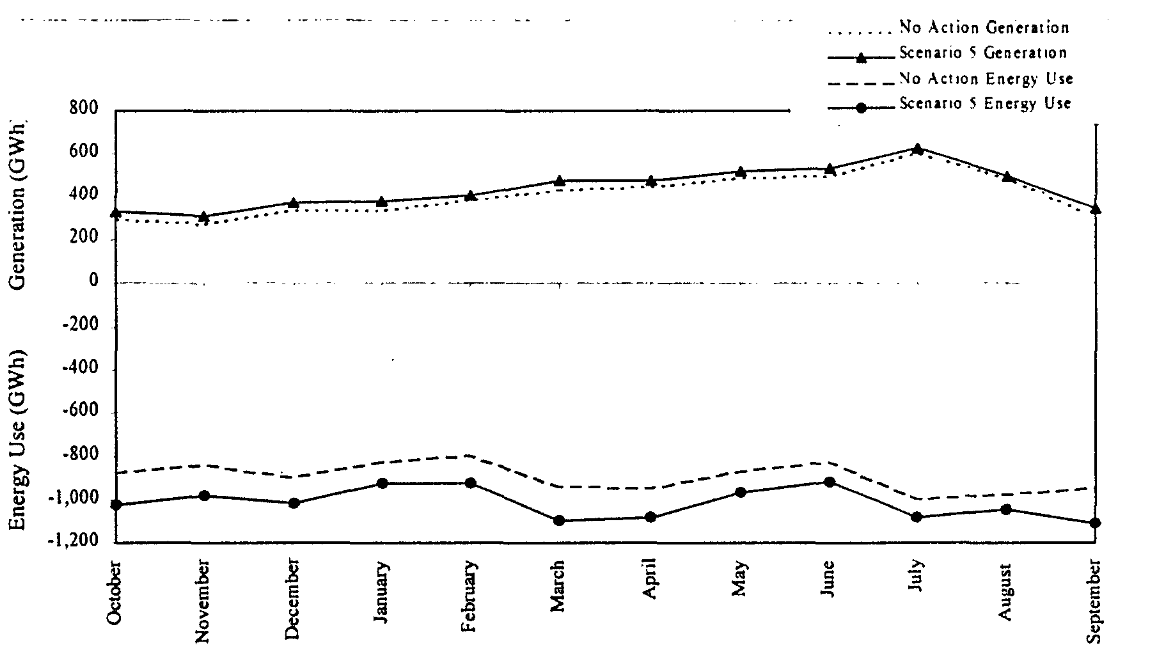

Figure 16. Range of SWP Energy Generation and Project Energy Use Impacts in an Average Water Year under Operational Scenario 5

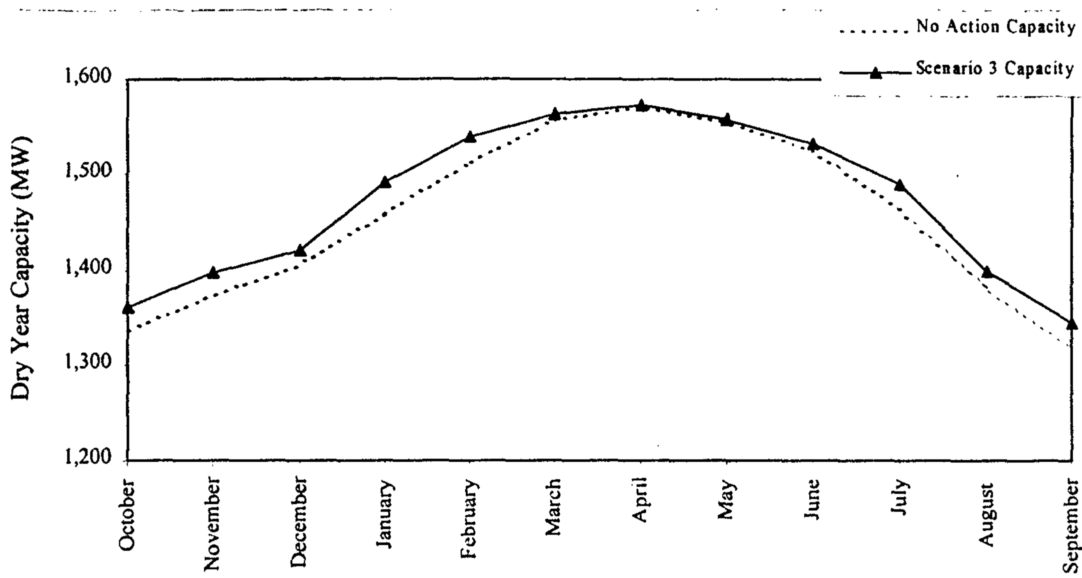

Figure 17. Range of CVP Capacity Impacts in a Dry Water Year under Operational Scenario 3

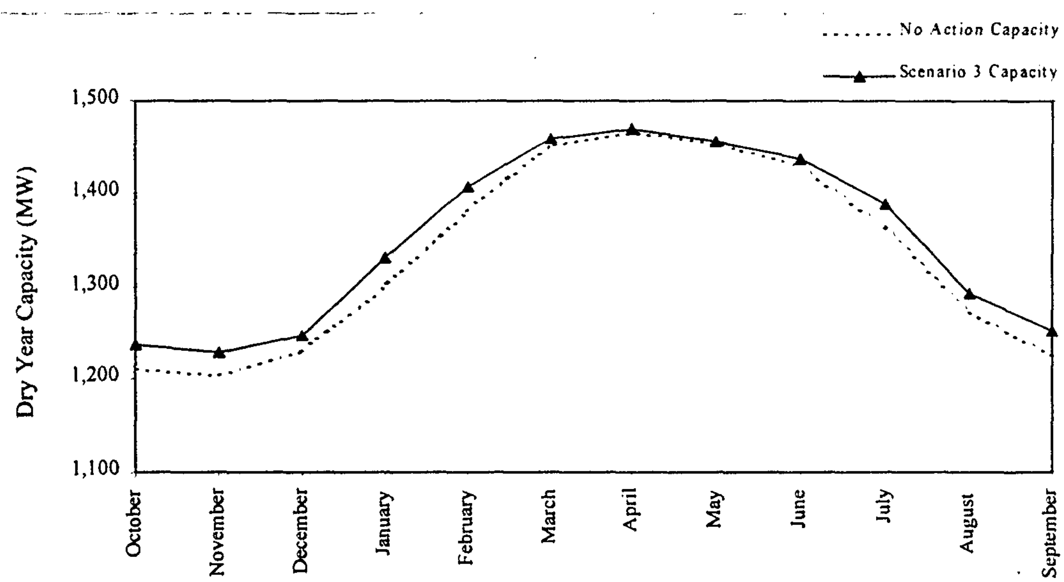

Figure 18. Range of SWP Capacity Impacts in a Dry Water Year under Operational Scenario 3

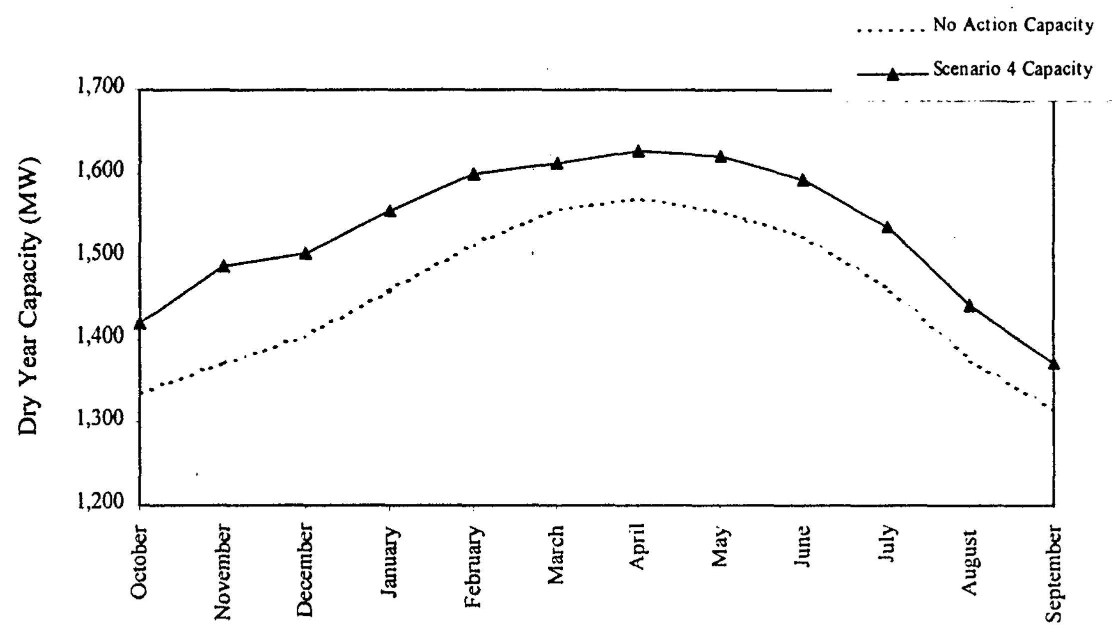

Figure 19. Range of CVP Capacity Impacts in a Dry Water Year under Operational Scenario 4

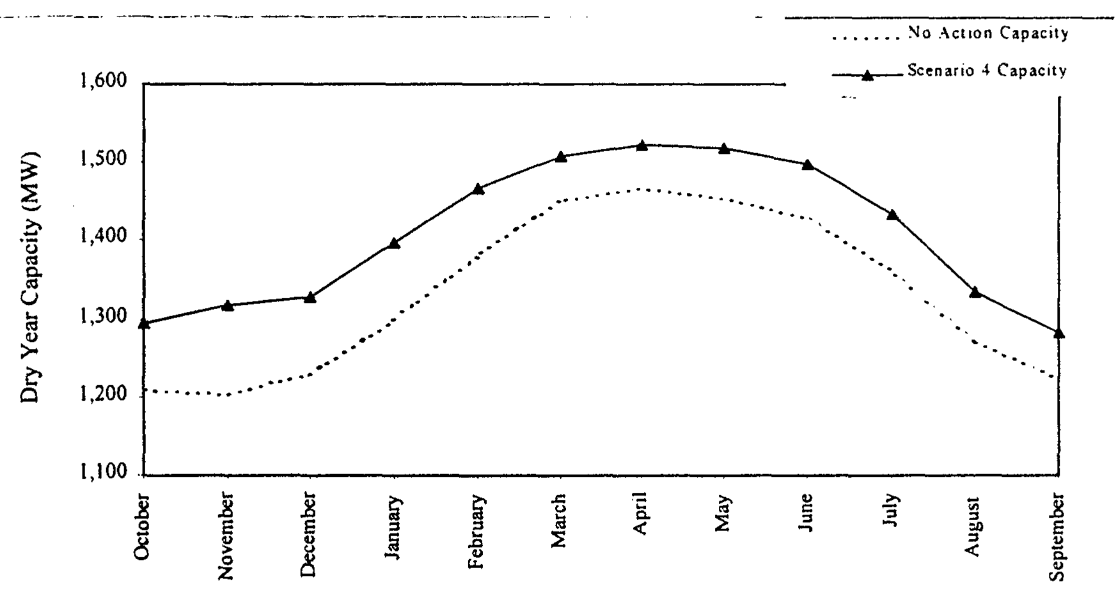

Figure 20. Range of SWP Capacity Impacts in a Dry Water Year under Operational Scenario 4

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available capacity is projected during all months.

Figure 22 shows the estimated impact of Alternative Configuration 2D on monthly capacity available to the CVP, and Figure 24 shows the impact on the SWP, based on the average monthly reservoir levels during the same critically dry period. Minimum potential impacts are reflected by the No Action Alternative results, and maximum potential impacts are shown in Scenario 4 results. Additional storage is planned only south of the Delta in this Alternative Configuration. Increased available capacity is projected during all months.

SWP AND CVP POWER PRODUCTION AND REPLACEMENT COST IMPACTS

Operational changes identified for Alternative 2 under "Hydroelectric Generation and Project Energy Use Impacts," provide the basis for determining related impacts to SWP and CVP power production and replacement costs. Based on the estimated price range of prices for energy generation shown in Table 2, the annual value of the system generation impact was calculated for Scenarios 3, 4, and 5. Figure 23 illustrates that, based on the DWRSIM cases on which this analysis is based, Scenarios 3, 4, and 5 all would yield slight increases in the value of generation that are overshadowed by increases in the cost of additional pumping energy requirements, resulting in increased net expenses. Scenario 3, which has no significant new storage, would result in an increased net cost of about $11.2 million annually, while Scenarios 4 and 5 would involve net increased expenses of approximately $40.6 and $26.8 million, respectively.

WESTERN AND DWR POWER RATE IMPACTS

The estimated impact of Scenario 2 on the Western composite energy rate as compared to the No Action Alternative would be an increase of 9%. Scenario 4 could result in an increase of 162%, and Scenario 5 could result in an increase of 65%. The estimated impact on the SWP energy rates under the scenarios are 3%, 24%, and 14%, respectively.

Water Storage and Conveyance

Some of the Alternative 2 configurations include new storage projects, and these projects would use energy during their construction phases, and to a lesser extent during their operation and maintenance phases. These impacts would occur in the Sacramento River Region under Alternative configurations 2B and 2E, and in the San Joaquin River Region under Alternative configurations 2B, 2D, and 2E.

Alternative 2 includes new conveyance facilities that would be constructed in the Sacramento River Region (Alternative configurations 2B and 2E include a new conveyance facility from the Sacramento River to a new storage site), the Delta Region (all four of this alternative's configurations include new conveyance facilities in this region) and the San Joaquin River Region (each Alternative Configuration would include a new conveyance project such as the Mid-Valley Canal Project). Energy use impacts would occur in each of these regions during the construction of these conveyance facilities, and to a lesser extent, during their operation and maintenance.

Other Types of Operational-Related Energy Use Impacts

Alternative configurations 2B and 2E include the new Sacramento and San Joaquin Valley groundwater program, while Alternative configurations 2A and 2D do not. Therefore, Alternative configurations 2B and 2E likely would increase energy use at groundwater pumping plants. The water transfer program included in all configurations of this alternative also could increase groundwater pumping and energy use since many potential water transfers directly or indirectly involve groundwater. The

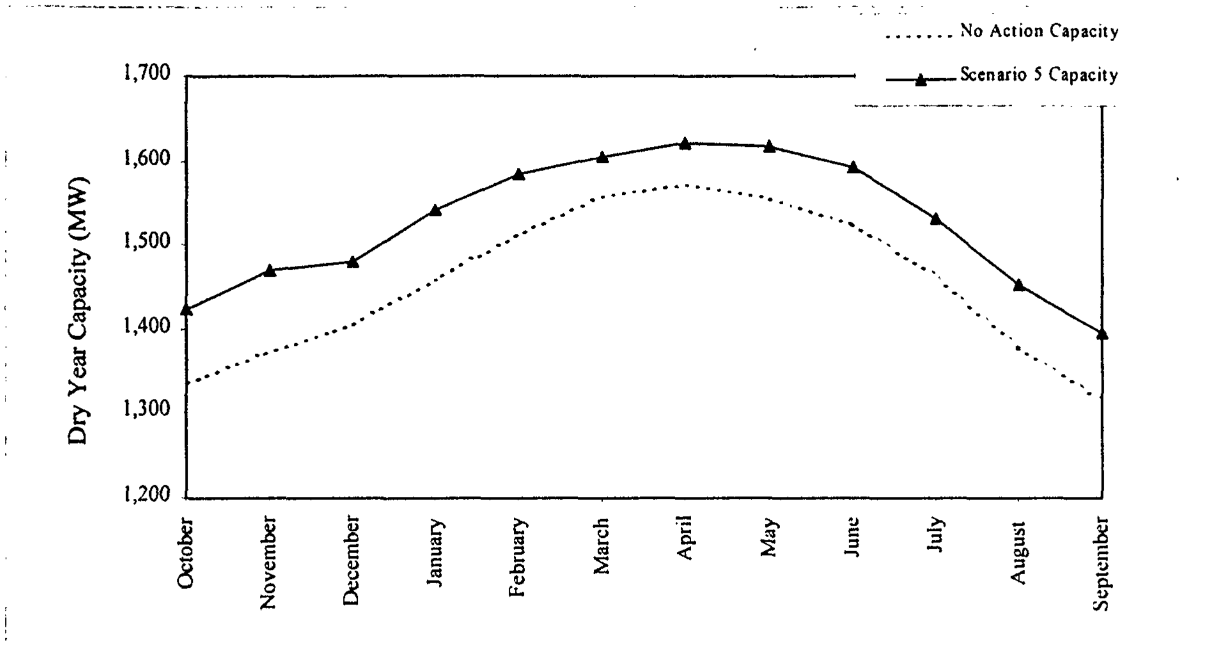

Figure 21. Range of CVP Capacity Impacts in a Dry Water Year under Operational Scenario 5

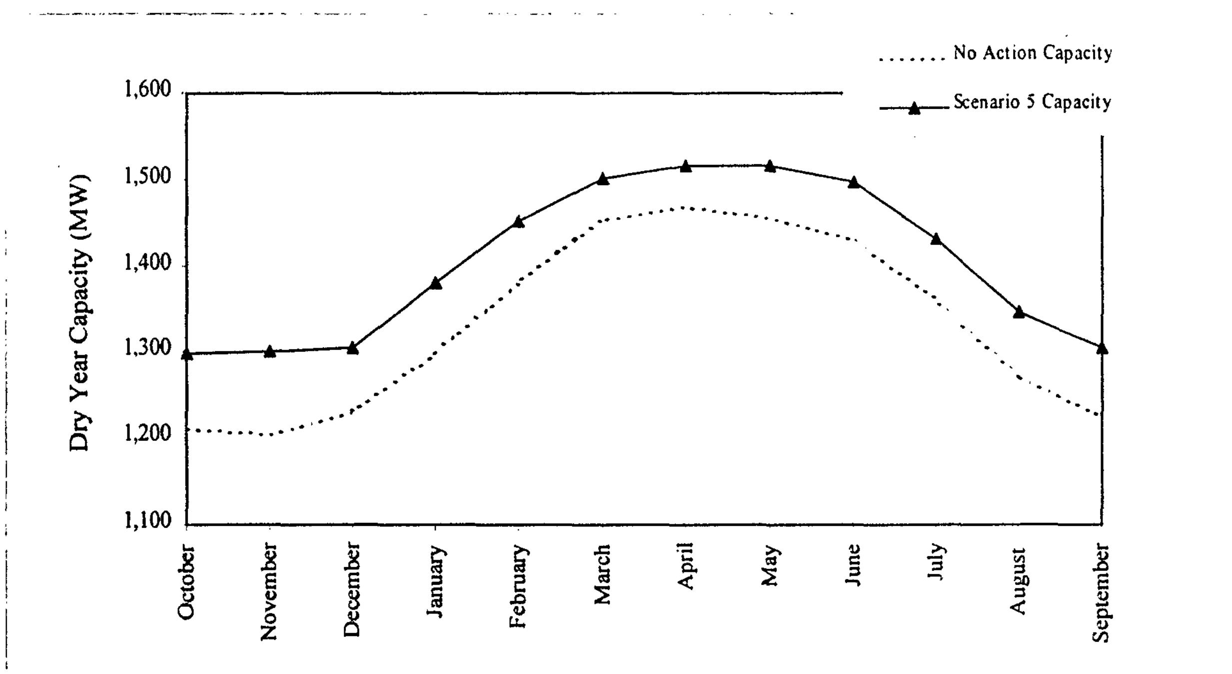

Figure 22. Range of SWP Capacity Impacts in a Dry Water Year under Operational Scenario 5

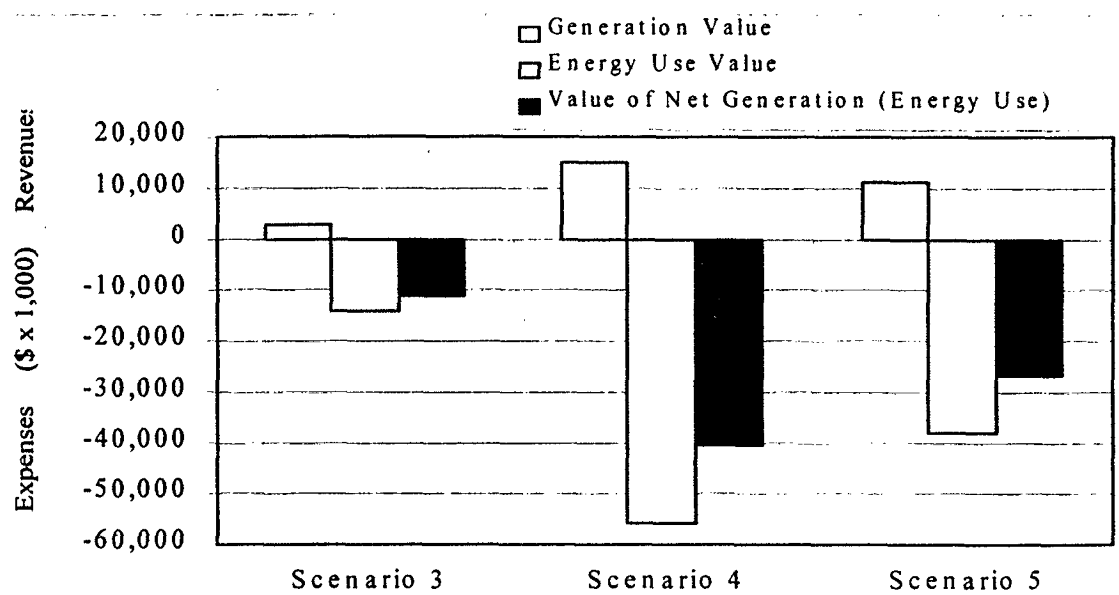

Figure 23. Value of Alternative 2 Generation and Project Energy Use—Maximum Potential Change from No Action Alternative Conditions

water transfer-related energy use impacts associated with Alternative 2 would be less than those associated with Alternative 3 (Alternative 1 does not include a water transfer program). The average increase in CVP and SWP exports and deliveries caused by all configurations of Alternative 2 could decrease energy use at groundwater pumping plants if these exports and deliveries decreased the use of groundwater.

Energy use at water treatment plants would likely increase under Alternative 2 as average SWP and CVP exports and deliveries increase, and as additional water transfers also increase the amount of water that requires treatment. These types of impacts would be higher under Alternative configurations 2B, 2D, and 2E than they would be under Alternative Configuration 2A. Overall, Alternative 2 would increase energy use at water treatment plants more than Alternative 1 but less than Alternative 3.

ALTERNATIVE 3

Tables 3 and 4 describe major SWP and CVP production and energy conditions for each configuration of Alternative 3 and the 2020 level of development. Power production and energy conditions under Alternative 3 would be different than those under No Action Alternative conditions and existing conditions. The related impacts are described below.

HYDROELECTRIC GENERATION AND PROJECT ENERGY USE IMPACTS

Impacts during Operation

Three different DWRSIM scenarios were defined for the five different configurations of Alternative 3. Alternative Configuration 3A is represented as DWRSIM Scenario 6. Operational impacts from DWRSIM Scenario 6 result from changes in operation due to implementation of the program components included in each alternative, through-Delta conveyance modifications, and a 5,000-cubic foot per second (cfs) capacity isolated conveyance facility. Alternative configurations 3B and 3H are represented as DWRSIM Scenario 7. Scenario 7 includes a substantial increase in additional storage (up to 6.7 MAF) through new surface water and groundwater storage facilities. Alternative configurations 3E and 3I are represented as DWRSIM Scenario 8. Scenario 8 includes an increase in additional storage through new surface storage facilities and a 15,000-cfs capacity isolated conveyance facility.

Tables 13 and 14 summarize the monthly and annual energy generation and project energy use impacts of Alternative 3 on the SWP and CVP power systems, respectively. Table 13 also defines the potential impacts of Alternative 3 on CVP energy sales, and Table 14 defines potential impacts on the SWP's net energy requirement.

Tables 13 and 14 illustrate that both energy generation and project use loads were estimated to increase under Scenario 6 as compared to the No Action Alternative. However, the increase in energy generation is much smaller, estimated to be approximately 120 GWh annually, while the increase in project use loads is approximately 830 GWh on an average annual basis. This would result in a potential reduction in net energy available for sale for Western, or an increase in net energy requirements to the CVP, of about 710 GWh. The net reduction in dry years is estimated to be about 300 GWh.

Figure 24 depicts the estimated average monthly profile of potential energy generation and project energy use impacts on CVP. Minimum potential impacts of Alternative Configuration 3A are reflected by the No Action Alternative results, and maximum potential impacts are shown in Scenario 6 results. Figure 25 provides a similar representation for the SWP. Pumping energy requirements are projected to increase in spring and fall, with smaller increases in winter, and very little change in July and August. Generation also would increase notably in summer, when on-peak generation likely would be most highly valued, with more modest impacts the remainder of the year.

Figure 26 provides a profile of potential energy generation and project energy use impacts of Scenarios 7 and 8 on the CVP. Figure 27 provides a similar illustration of potential impacts on the SWP. Substantial increases in pumping energy requirements are projected through the year, with slightly smaller increases in July and August. Energy generation also would increase in most months, but some decrease in July energy is projected, with little change in other summer months.

Figure 28 shows the estimated impact on monthly capacity available to the CVP, and Figure 29 shows the impact on the SWP, based on average monthly reservoir levels during the critically dry period of 1929 to 1934. Alternative Configuration 3A, represented by Scenario 6, involves no significant new storage; however, slightly higher reservoir levels result in a small increase in estimated dry year summer capacity.

Figure 30 shows the range of potential estimated impacts of Alternative configurations 3B, 3E, 3H, and 3I on monthly dry year capacity available to the CVP, and Figure 31 provides a similar illustration for SWP. New storage north and south of the Delta would provide substantial increases in capacity during fall and winter, with somewhat smaller increases during summer, when capacity would be most valuable .

SWP AND CVP POWER PRODUCTION AND REPLACEMENT COST IMPACTS

Operational changes identified for Alternative 3 provide the basis for determining related impacts on SWP and CVP power production and replacement costs. Based on the estimated range of prices for energy generation shown in Table 2, the annual value of the system generation impact was calculated for Scenarios

Month	Energy Generation						Project Energy Use						Energy Available For Sale[1]					
	Scenario 6		Scenario 7		Scenario 8		Scenario 6		Scenario 7		Scenario 8		Scenario 6		Scenario 7		Scenario 8	
	Avg	Dry	Avg	Dry	Avg	Dry	Avg	Dry	Avg	Dry	Avg	Dry	Avg	Dry	Avg	Dry	Avg	Dry
October	343	175	393	251	393	251	232	87	416	427	416	427	111	88	(23)	(177)	(23)	(177)
November	327	152	379	210	379	210	255	101	373	353	373	353	72	50	6	(143)	6	(143)
December	377	155	446	201	446	201	254	196	390	434	390	434	123	(42)	56	(233)	56	(233)
January	384	137	469	195	469	195	217	279	442	502	442	502	167	(143)	27	(308)	27	(308)
February	405	149	466	235	466	235	187	187	395	444	395	444	218	(38)	72	(210)	72	(210)
March	452	215	521	252	521	252	215	127	436	395	436	395	237	87	85	(143)	85	(143)
April	519	350	527	432	527	432	254	159	398	410	398	410	265	191	129	22	129	22
May	606	366	605	455	605	455	212	119	306	328	306	328	395	247	298	127	298	127
June	650	425	625	494	625	494	160	80	244	294	244	294	490	345	381	201	381	201
July	550	435	534	512	534	512	103	116	197	347	197	347	446	319	337	164	337	164
August	418	325	458	413	458	413	118	89	216	318	216	318	300	236	243	96	243	96
September	337	200	396	271	396	271	203	108	391	387	391	387	134	92	5	(116)	5	(116)
Annual Total	5,369	3,082	5,819	3,920	5,819	3,920	2,410	1,648	4,204	4,640	4,204	4,640	2,959	1,433	1,615	(720)	1,615	(720)
Annual Change From No Action	122	189	571	1,027	571	1,027	833	490	2,627	3,481	2,627	3,481	(712)	(301)	(2,056)	(2,454)	(2,056)	(2,454)

[1] Negative values represent a net energy requirement.

Table 13. Maximum Average CVP Energy Generation, Project Energy Use, and Energy Sales Under Alternative 3 (Mwh x 1,000)

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Month	Energy Generation						Project Energy Use						Net Energy Requirement					
	Scenario 6		Scenario 7		Scenario 8		Scenario 6		Scenario 7		Scenario 8		Scenario 6		Scenario 7		Scenario 8	
	Avg	Dry	Avg	Dry	Avg	Dry	Avg	Dry	Avg	Dry	Avg	Dry	Avg	Dry	Avg	Dry	Avg	Dry
October	317	219	367	295	367	295	963	514	1,148	854	1,148	854	646	295	780	559	780	559
November	294	189	346	247	346	247	947	540	1,065	792	1,065	792	653	351	718	545	718	545
December	368	234	437	281	437	281	982	645	1,118	883	1,118	883	613	411	681	602	681	602
January	356	143	440	201	440	201	854	641	1,078	864	1,078	864	498	498	638	663	638	663
February	389	195	450	281	450	281	827	611	1,035	868	1,035	868	438	415	584	587	584	587
March	444	259	512	296	512	296	976	676	1,197	944	1,197	944	532	418	684	648	684	648
April	487	393	494	475	494	475	1,083	713	1,227	964	1,227	964	597	320	733	489	733	489
May	527	329	525	417	525	417	991	593	1,086	802	1,086	802	465	264	561	385	561	385
June	550	348	525	417	525	417	906	519	990	733	990	733	356	171	465	316	465	316
July	539	369	524	446	524	446	991	656	1,085	888	1,085	888	452	287	562	442	562	442
August	436	298	477	387	477	387	984	628	1,081	857	1,081	857	547	330	604	470	604	470
September	313	201	371	272	371	272	1,011	531	1,199	810	1,199	810	698	330	827	538	827	538
Annual Total	5,020	3,176	5,469	4,014	5,469	4,014	11,515	7,267	13,309	10,259	13,309	10,259	6,496	4,091	7,840	6,245	7,840	6,245
Annual Change From No Action	122	189	571	1,027	571	1,027	833	490	2,627	3,481	2,627	3,481	(712)	(301)	(2,056)	(2,454)	(2,056)	(2,454)

Table 14. Maximum Average SWP Energy Generation, Project Energy Use, and Energy Sales Under Alternative 3 (Mwh x 1,000)

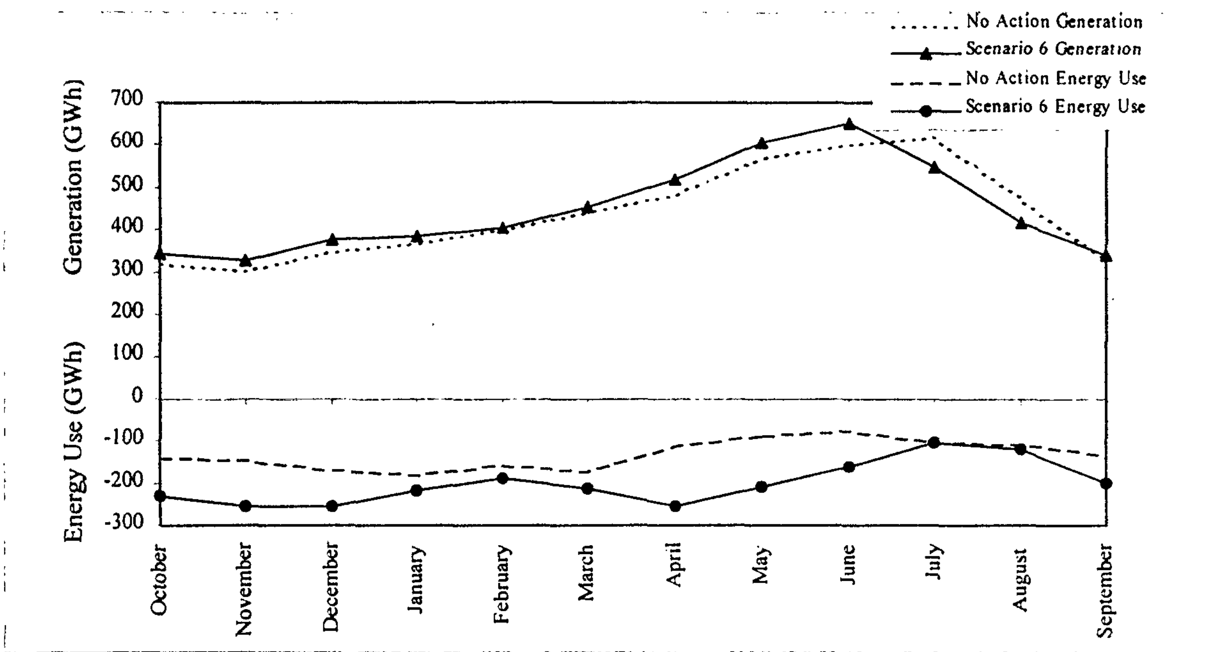

Figure 24. Range of CVP Energy Generation and Project Energy Use Impacts in an Average Water Year under Operational Scenario 6

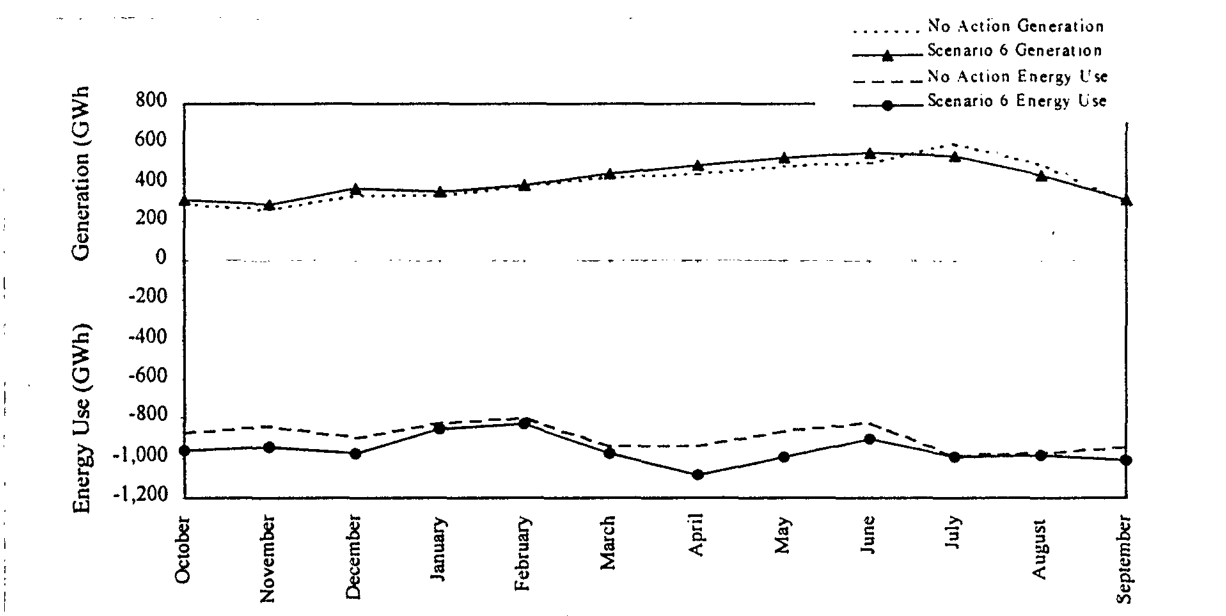

Figure 25 Range of SWP Energy Generation and Project Energy Use Impacts in an Average Water Year under Operational Scenario 6

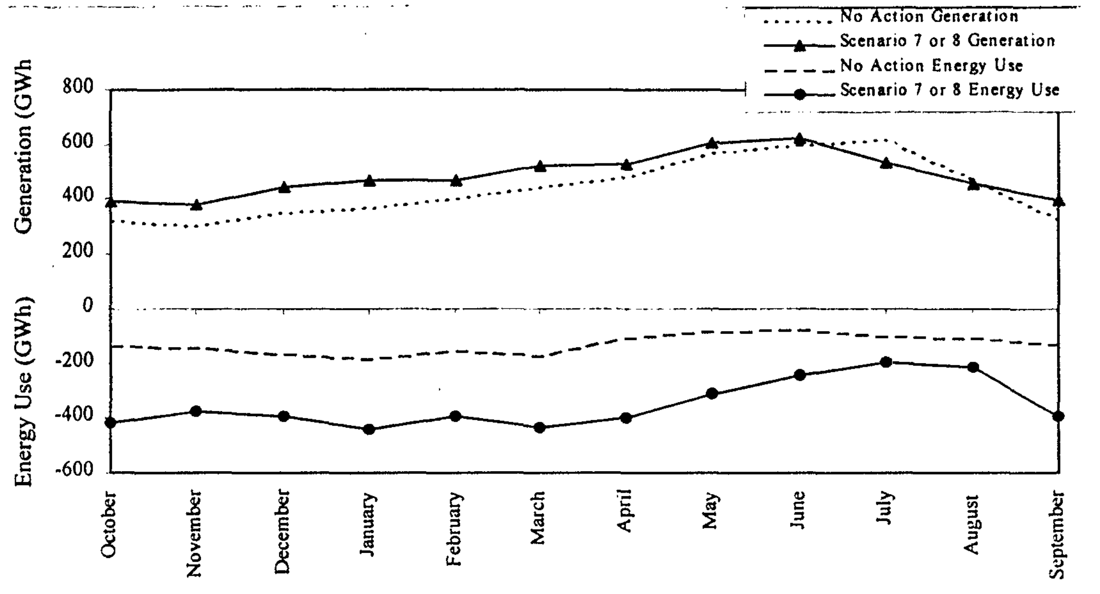

Figure 26. Range of CVP Energy Generation and Project Energy Use Impacts in an Average Water Year under Operational Scenario 7 or 8

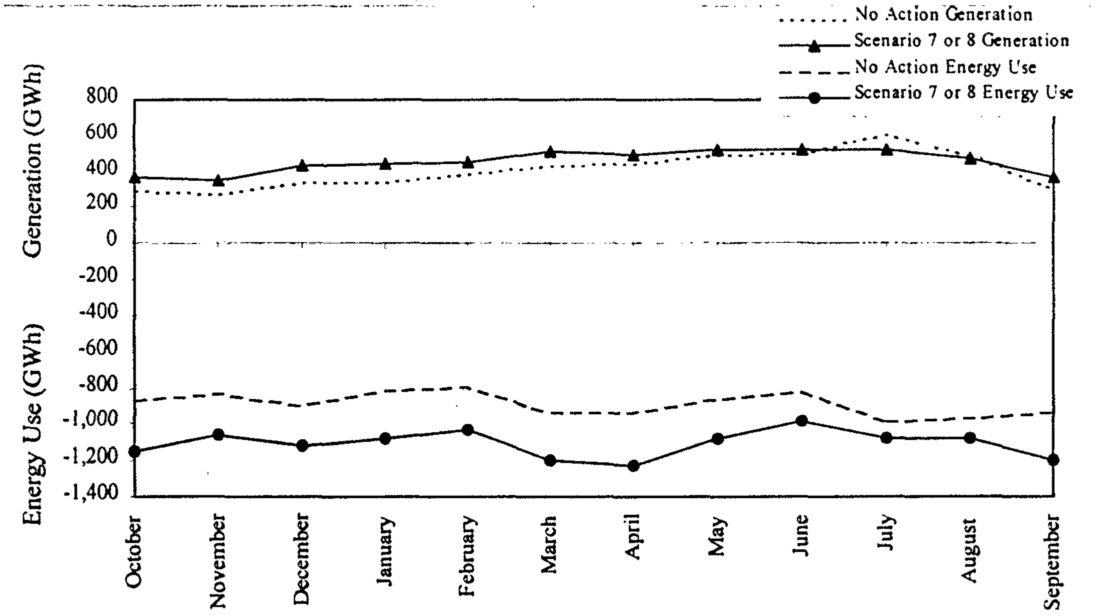

Figure 27. Range of SWP Energy Generation and Project Energy Use Impacts in an Average Water Year under Operational Scenario 7 or 8

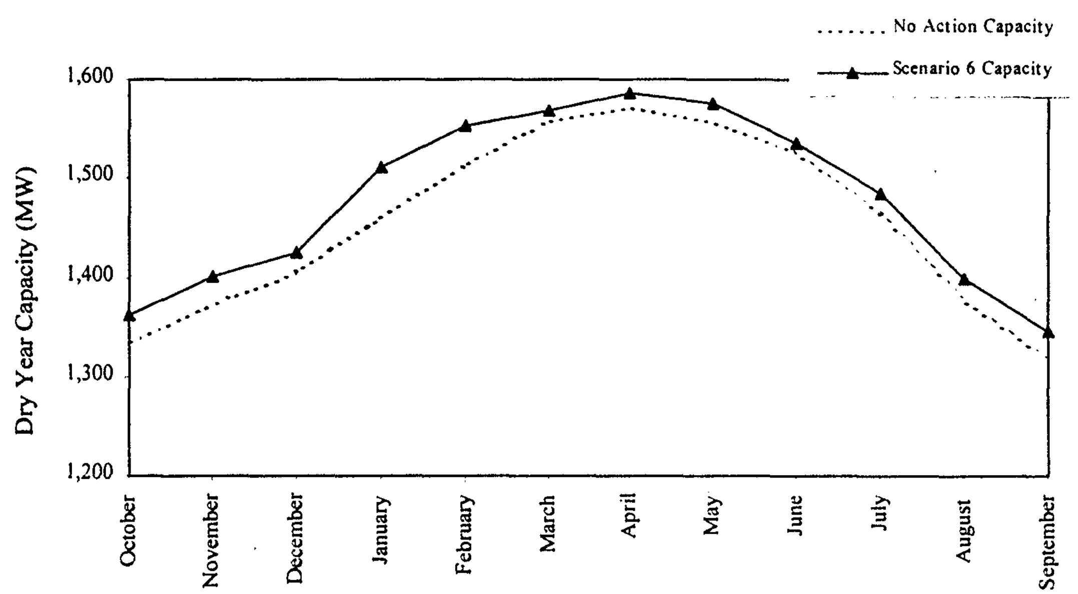

Figure 28. Range of CVP Capacity Impacts in a Dry Water Year under Operational Scenario 6

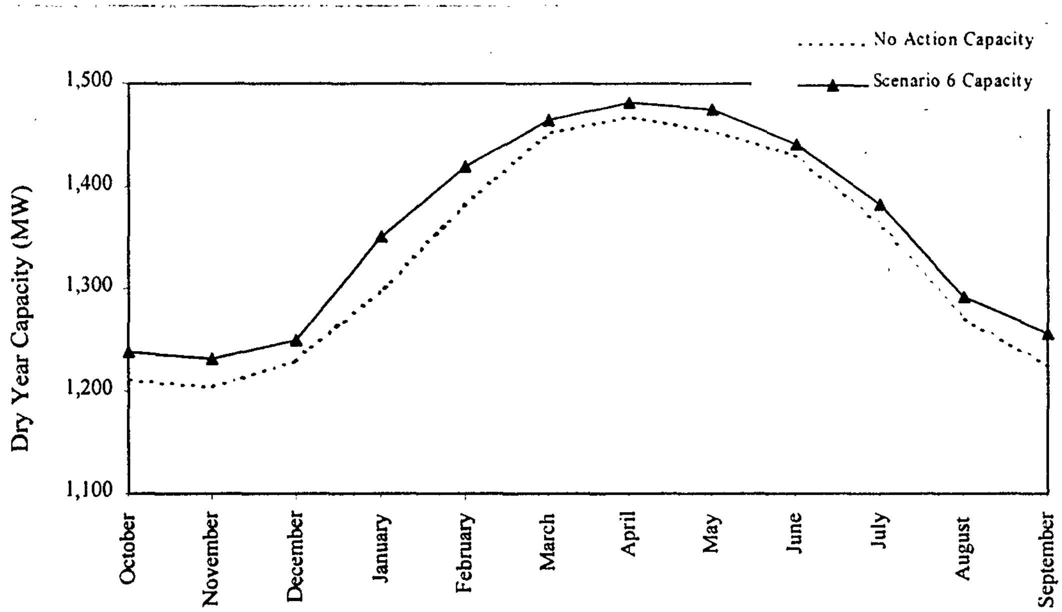

Figure 29. Range of SWP Capacity Impacts in a Dry Water Year under Operational Scenario 6

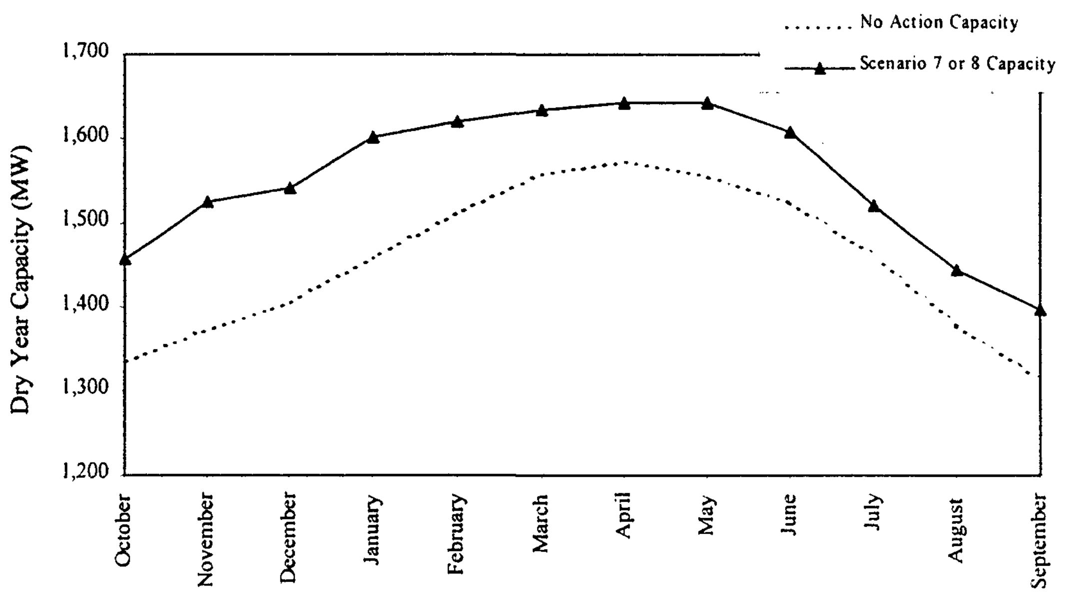

Figure 30. Range of CVP Capacity Impacts in a Dry Water Year Under Operational Scenario 7 or 8

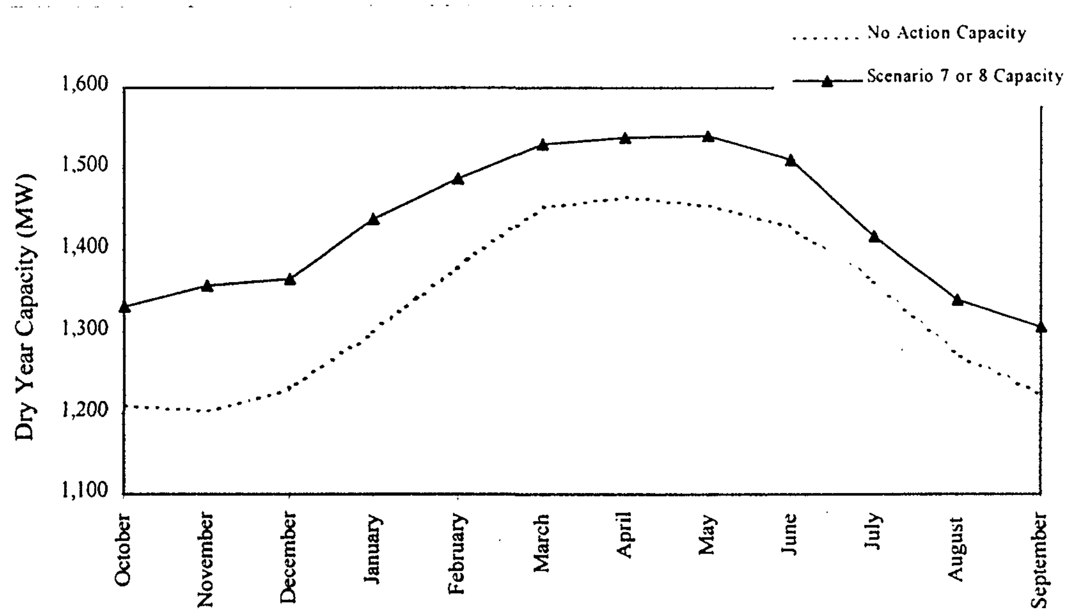

Figure 31. Range of SWP Capacity Impacts in a Dry Water Year Under Operational Scenario 7 or 8

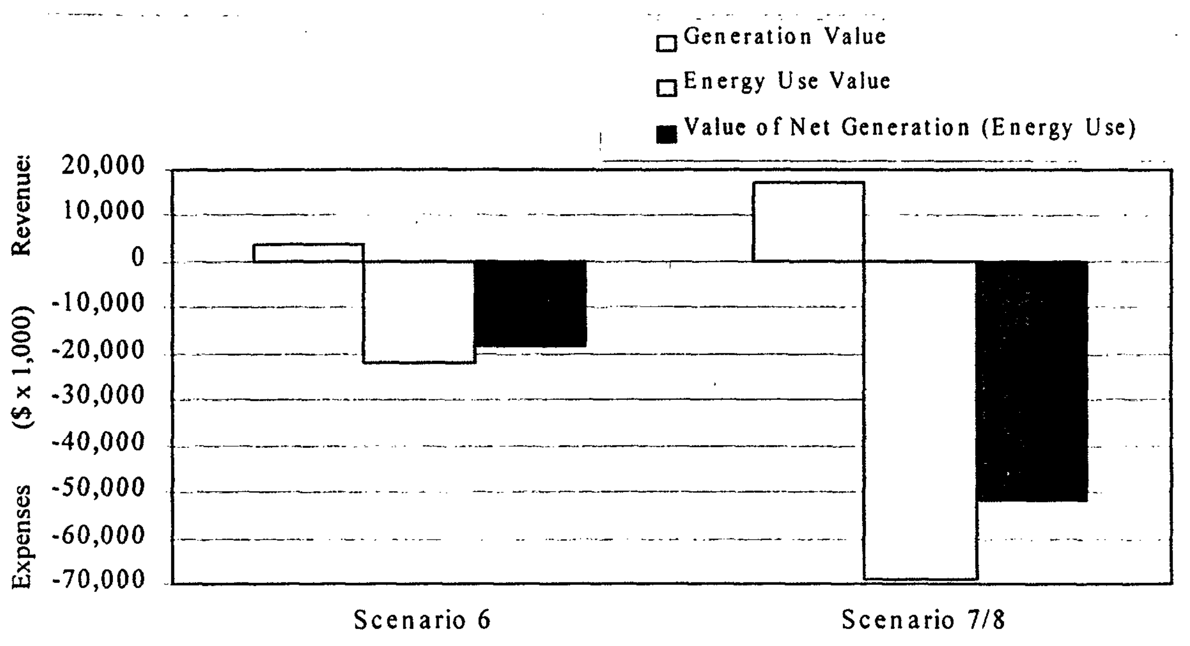

Figure 32. Value of Alternative 3 Generation and Project Energy Use—Maximum Potential Change from No Action Alternative Conditions

6, 7, and 8. Figure 34 illustrates that, based on the DWRSIM cases on which this analysis is based, Scenarios 6, 7, and 8 would yield slight increases in the value of generation that are overshadowed by increases in the cost of additional pumping energy requirements, resulting in increased net expenses. Scenario 6, which includes no significant new storage, would result in an increased net cost of about $18.2 million annually, while Scenarios 7 and 8 would involve net increased expenses of approximately $51.8 million.

WESTERN AND DWR POWER RATE IMPACTS

The estimated impact of Scenario 6 on Western composite energy rates, as compared to the No Action Alternative, would be an increase of 16%. Scenarios 7 and 8 could result in an increase of 241% in the Western composite energy rate. The estimated impact on the SWP energy rate under the scenarios are 55 and 27%, respectively.

POWER PAYMENTS TO THE CVP RESTORATION FUND

Each Alternative 3 configuration is estimated to result in the same or greater water deliveries to agricultural and M&I water users, as compared to the No Action Alternative. By the same reasoning used for Alternative 1, Alternative 3 has no potential for significant adverse impacts on Western or Western's customers due to increased Restoration Fund obligations.

Storage and Conveyance

Most of the Alternative 3 configurations include new storage projects, and these projects would use energy during their construction phases and, to a lesser extent, during their operation and maintenance phases. These impacts would occur in the Sacramento River Region and in the San Joaquin River Region under Alternative configurations 3B, 3E, 3H and 3I. They would occur in the Delta Region under Alternative configurations 3B, 3E, and 3I.

Energy use would increase during the construction of the conveyance facilities included in this alternative, and to a lesser extent, during their maintenance. Because each configuration of Alternative 3 includes new conveyance facilities, Alternative 3 likely would require the most energy during its construction (especially in the Delta Region).

Other Types of Operational-Related Energy Use Impacts

The groundwater program included in Alternative configurations 3B, 3H, and 3I would increase energy use at groundwater pumping plants. The water transfer program included in all configurations of Alternative 3 would directly or indirectly increase energy use at such plants. The water transfer-related energy use impacts would be higher under Alternative 3 than they would be under Alternatives 1 or 2.

The average increase in SWP and CVP exports and deliveries caused by all configurations of Alternative 3 could decrease energy use at groundwater pumping plants if these exports and deliveries decreased the use of groundwater.

All configurations of Alternative 3 would cause the same types of energy use impacts at water treatment plants as described for Alternative 1. These impacts would be higher under Alternative 3 than they would be under Alternatives 1 or 2 because Alternative 3 would cause the highest level of water transfers and the largest increase in SWP and CVP exports and deliveries.

Comparison of CALFED Alternatives to Existing Conditions

Comparison of CALFED Alternatives to existing conditions indicates that:

- All potentially significant adverse impacts that were identified when compared to the No Action Alternative would still be considered significant when compared to existing conditions.
- No additional significant environmental consequences have been identified when Program effects are compared to existing conditions as opposed to No Action.
- The beneficial effects of the Program would still be beneficial when compared to existing conditions.

MITIGATION STRATEGIES

The significant and adverse impacts of the CALFED alternatives on Western and its power customers would be caused by Western's rates increasing to the point that they would be higher than open market rates. Therefore, Western's rates would no longer be competitive and Western's customers would no longer enjoy rates that have historically been less expensive than other sources.

The following mitigation strategies are designed to help reduce the magnitude of Western's rate increases under the CALFED alternatives and to keep Western's rates below open market rates.

- Cost allocated to CVP Project Energy Use are covered by revenue received from CVP water users, natural resource agencies, and other environmental beneficiaries. Consistent with current practice for projects authorized under Reclamation law, rate impacts have been estimated assuming that these beneficiaries of increased Project Energy Use pumping requirements pay approximately 30% of the estimated cost of replacement energy and that preference power customers make up the difference through increased rates. If the rates paid on behalf of these beneficiaries of increases in project use energy were based on the market cost of that energy, then Western rate impacts could be reduced to insignificant levels. This mitigation strategy may require that beneficiaries of the CALFED alternatives (natural resource agencies, other environmental beneficiaries, and water users) would pay a greater share of the cost increases associated with implementing the alternatives.

- Assigning costs associated with additional pumping requirements to the beneficiaries of such increased pumping is also a potential mitigation strategy for reducing the impact on the DWR system energy rate and on customers of the State Water Project.

- Other mitigation strategies include other options for avoiding significant Western rate increases. For example, federal legislation could be passed to reduce Western's share of CVP repayment obligations, thereby reducing Western's revenue requirements and the rates that Western must charge its preference customers.

It should be noted the results of this analysis and conclusions regarding impact significance could change once joint use costs are defined and allocated to power, and the power-related costs of the CALFED action alternatives are allocated among the CVP and SWP.

POTENTIALLY SIGNIFICANT UNAVOIDABLE IMPACTS

No potentially significant unavoidable impacts on power production and energy were identified.

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