Chapter 16
Power

Hydroelectric facilities are a part of the State Water Project (SWP) and Central Valley Project (CVP) facilities at dams and reservoirs. As water is released from Project reservoirs, the generation facilities produce power that is both used by the Projects and marketed to electric utilities, government and public installations, and commercial customers. Both Projects rely on their hydropower resources to reduce the cost of operations and maintenance and to repay the cost of Project facilities. Hydropower from the Projects is an important renewable energy and comprises approximately 36 percent of the online capacity of California hydroelectric facilities. Overall, CVP/SWP hydroelectric facilities are nearly seven percent of the total online capacity of California power plants.

The SWP uses its power primarily to run the pumps that move SWP water to farmlands and cities, where it can be applied to economically beneficial uses, and to provide peak power to California utilities. SWP long-term power contracts act as exchange agreements with utility companies. These exchange agreements allow the SWP and a utility to integrate the use of their individual power resources in a mutually beneficial manner. In these agreements the SWP provides on-peak energy to the utility in exchange for the return of a greater amount of mid-peak and off-peak energy. The SWP may also receive other compensation in the form of annual monetary payments and/or reduced transmission service rates for SWP facilities served by the utility. Except during surplus conditions in extremely wet years, all SWP power is used for peak power exchange agreements and to operate pumping facilities. In all years, the SWP must purchase additional power to meet pumping requirements.

CVP power is a source of electricity for CVP pumping facilities throughout the Central Valley and Sacramento-San Joaquin Delta, and for many of California's communities. The Western Area Power Administration (Western) sells excess CVP capacity and energy (supplementary to CVP internal needs) to municipal utilities, irrigation districts, and institutions and facilities such as wildlife refuges, schools, prisons, and military bases. Both CVP and SWP sell power at rates designed to recover costs. For the CVP these rates have been slightly below market rates historically. Revenue from Western power sales is an important funding source for the CVP Restoration Fund and for repaying Project debt incurred building the CVP.

EWA actions could change the pattern of power operations at SWP and CVP facilities compared to historical temporal patterns, alter the monthly and hourly (on/off-peak) load at SWP and CVP pumping facilities, affect demand for regional energy resources through increased local groundwater pumping, and affect the economic relationships associated with the temporal changes in SWP/CVP generation and pumping. Generation and groundwater pumping cost effects for non-CVP/SWP facilities (sellers) would be accounted for in the negotiated water price. In addition to these potential electric system effects, capacity and energy demands for increased pumping could necessitate greater utilization of other power generation methods that may have more environmental effects than SWP/CVP hydroelectric power plants, resulting in indirect environmental effects.

16.1 Area of Analysis

The area of analysis for the evaluation of potential effects upon hydropower generation due to implementation of the Environmental Water Account (EWA) actions includes the power plants, pumping plants and associated facilities located along the SWP and CVP Projects of the Sacramento, Feather, Yuba, American and Merced river systems, as well as those of the Delta Region and Export Service Area. There are no hydroelectric facilities on the mainstem of the San Joaquin River. Also in the area of analysis are reservoirs, powerplants, and pumping plants not owned or operated as part of the SWP or CVP. The specific hydroelectric facilities evaluated are listed below and shown on Figure 16-1. These facilities include power and pumping plants potentially affected by EWA actions, as well as "pass-through facilities," through which EWA water would pass without affecting operations. These details are provided in the individual facility descriptions under Section 16.2, Affected Environment/Existing Conditions.

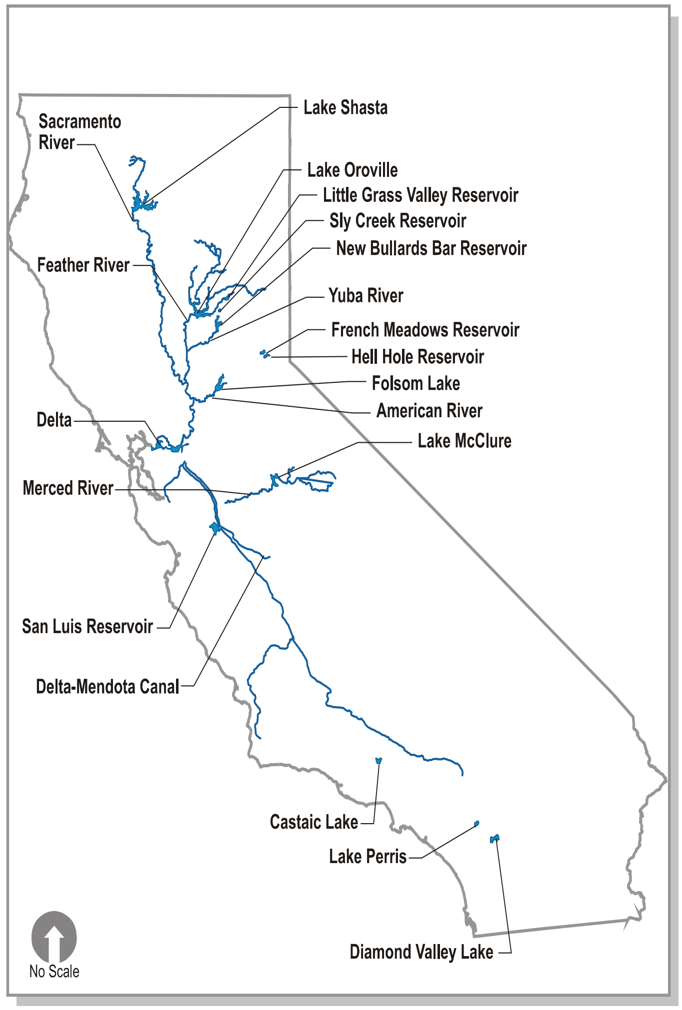

Figure 16-1
Power Area of Analysis

Hydroelectric Facilities by Region:

UPSTREAM FROM THE DELTA REGION

- Sacramento River
    - Central Valley Project
        - Shasta Power Plant
        - Keswick Power Plant
- Feather River

- South Fork Project
  - Sly Creek Power Plant
  - Woodleaf Power Plant
  - Forbestown Power Plant
  - Kelly Ridge
- State Water Project
  - Lake Oroville/Hyatt-Thermalito Power Plant Complex

- Yuba River
  - Yuba River Development Project
    - Colgate Power House
    - Englebright Reservoir/Narrows Power House I and Narrows Power House II
- American River
  - Middle Fork Project
    - French Meadows Power Plant
    - Hell Hole Power Plant
    - Lowell J. Stephensen Power Plant
    - Ralston Power Plant
    - Oxbow Power Plant
  - Central Valley Project – Lower American River
    - Folsom Reservoir/Power Plant
    - Lake Natoma/Nimbus Power Plant
- Merced River
  - Exchequer Power Plant
  - McSwain Power Plant

DELTA REGION

- Central Valley Project
  - Tracy Pumping Plant
- State Water Project
  - Harvey O. Banks Pumping Plant

EXPORT SERVICE AREA

- Central Valley Project
  - O'Neill Pumping-Generating Plant
- State Water Project
  - Edmonston Pumping Plant
  - Pyramid Lake/William E. Warne Power Plant
  - Castaic Power Plant
  - Silverwood Lake/Pearblossom Pumping Plant/Mojave Siphon Power Plant
  - San Luis Reservoir (joint Federal/State facility)/William R. Gianelli Pumping Plant
  - Dos Amigos Pumping Plant (joint Federal/State facility)
- Non-Project Facilities
  - Diamond Valley Reservoir/Hiram W. Wadsworth Pumping Plant.

16.2 Affected Environment/Existing Conditions

16.2.1 CVP Hydropower System

Hydropower generation at CVP facilities substantively contributes to the reliability of California's electrical power system. The CVP hydropower system consists of eight power plants and two pump-generating plants (Table 16-1). This system is fully integrated with the northern California power system and provides a significant portion of the hydropower available for use in northern and central California. The installed capacity of the system is 2,044,350 kilowatts (kW) (USBR 2001). In comparison, the combined capacity of the 368 operational hydroelectric power plants in California is 12,866,000 kW. The area's major power supplier, the Pacific Gas and Electric Company (PG&E), has a generating capacity from all sources of over 20,000,000 kW.

Table 16-1
Power Resources of the Central Valley Project

Unit	*Maximum Generating Capacity (kW)*
Sacramento River Service Area	
Carr[(4)]	184,000
Lewiston [(1)(4)]	350
Keswick	105,000
Shasta	584,000
Spring Creek[(4)]	200,000
Trinity[(4)])	140,000
Subtotal	1,213,350
American River Service Area	
Folsom	215,000
Nimbus	17,000
Subtotal	232,000
Delta Export and San Joaquin Valley	
New Melones	383,000
O'Neill [(2)]	14,000
San Luis [(2),(3)]	202,000
Subtotal	599,000
TOTAL	2,044,350

Source: Reclamation 2001.
(1) Not marketed to CVP.
(2) Pump-generating plant.
(3) Jointly owned, pumping and generating facility, Federal share only.
(4) CVP power plants unaffected by EWA actions.

Power produced by the CVP hydropower system first meets Project water pumping loads, or "Project use power," at CVP pumping facilities (Table 16-2). Western markets power that is surplus to Project use as "commercial power" under long-term, firm contracts to municipal and governmental entities (preference customers[1]) at cost-based rates (based on generating/pumping costs). In an average year, preference customers buy 4,600 gigawatt hours (GWh) of energy and 1,700,000 kW of capacity at

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1 Preference customers are those who have contracts subject to the requirements of Reclamation law which provide that preference in the sale of Federal power shall be given to municipalities and other public corporations or agencies and also to cooperatives and other nonprofit organizations financed in whole or in part by loans made pursuant to the Rural Electrification Act of 1936 (Reclamation Project Act of 1939, Section 9(c), 43 U.S.C. 485h(c))

rates that recover the full cost of production and repayment obligations of Project investment with interest (Reclamation 2001). Western has completed and is in the process of implementing its post-2004 Marketing Plan for CVP hydropower resources that are surplus to Project use power needs after the long-term preference customer contracts expire in 2004.

Table 16-2
Major Pumping Plants of the Central Valley Project

Unit	*Capacity (cfs)*	*Average Annual Energy Use (kWh)*
American River Service Area		
Folsom Pumping Plant	350	1,041,000
Delta Export and San Joaquin Valley		
Contra Costa Canal	410	18,908,000
Dos Amigos[(1)]	13,200	180,146,000[(2)]
O'Neill	4,200	87,185,000
San Luis[(1)]	11,000	306,225,000[(2)]
Tracy	4,600	620,712,000

Source: Reclamation 2001.
[(1)] Joint State-Federal facility.
[(2)] Federal energy use.
kWh = kilowatthour

16.2.2 SWP Hydropower System

The primary purpose of the SWP power generation facilities is to meet energy requirements of the SWP pumping plants. To the extent possible, SWP pumping is scheduled during off-peak periods, and energy generation is scheduled during peak periods. Although the SWP uses more energy than it generates from its hydroelectric facilities, the Department of Water Resources (DWR) has exchange agreements with other utility companies and has developed other power resources. DWR sells surplus power, when it is available, to minimize the net cost of pumping energy. DWR first sold excess power commercially in 1968.

The SWP conveys an annual average of about 2.5 million acre-feet (AF) of water through its 17 pumping plants, 8 hydroelectric power plants, 32 storage facilities, and 660-plus miles of aqueduct and pipelines. Affordable hydroelectric generation provides the greatest share of SWP power resources. The combined 900-megawatt (MW) Hyatt Pumping-Generating Plant and Thermalito Pumping-Generating Plant (Hyatt-Thermalito) at Lake Oroville generate about 2,200 GWh of energy in a median water year, while the Thermalito Diversion Dam Power Plant (3,000 kW capacity)[2] adds another 24 GWh of energy per year. Generation at SWP plants, (Gianelli, Alamo, Devil Canyon, Warne, and Mojave Siphon), varies with the amount of water conveyed. These five plants generate about one-sixth of the total energy used by the SWP. The SWP Hydropower and Pumping Plants and their generating capacities are listed in Tables 16-3 and 16-4.

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2 Generating capacities listed in this chapter are installed capacities (the sums of rated capacities of plant generating units).

Table 16-3 Major Power Plants of the State Water Project	
Hydroelectric Power plant	***Generation Capability (kW)***
Thermalito	3,000
Hyatt-Thermalito	759,000
Gianelli	222,000
Alamo	17,000
Warne	74,000
Mojave Siphon	33,000
Devil Canyon	276,000

Source: California Department of Water Resources Bulletin 132-00 2001.

Table 16-4 Major Pumping Plants of the State Water Project	
Hydroelectric Power plant	***1999 Annual Energy Use (kWh)***
North Bay Interim	14,000
Cordelia	8,694,000
Barker Slough	7,925,000
South Bay	94,982,000
Del Valle	342,000
Banks	762,516,000
Buena Vista	285,669,000
Teerink	287,012,000
Chrisman	647,035,000
Edmonston	2,269,898,000
Pearblossom	339,027,000
Oso	107,796,000
Las Perillas	9,956,000
Badger Hill	26,232,000
Devil's Den	17,203,000
Bluestone	17,241,000
Polonio Pass	17,461,000

Source: DWR Bulletin 132-00 2001.

16.2.3 Other Hydroelectric Facilities

Other hydroelectric generation facilities in the area of analysis are owned by investor-owned utility companies, such as PG&E and Southern California Edison (SCE); by municipal agencies, such as the Sacramento Municipal Utility District (SMUD); and by several agencies. Larger facilities outside the CVP and SWP systems include PG&E's Upper North Fork Feather River System (approximately 340,000 kW capacity) in Plumas County; SMUD's Upper American River Project System (approximately 640,000 kW capacity) in El Dorado County; and the Yuba County Water Agency (YCWA) Yuba River Development Project (approximately 300,000 kW capacity) in Yuba County (CALFED 1999).

16.2.4 Seasonal Variation of Pumping and Generation

During the winter (December through February), Delta export and San Luis Reservoir pumping demands are high until San Luis Reservoir fills. San Luis Reservoir does not fill every year. Power generation may increase beyond fall levels if flood control operations require additional releases from reservoirs. In a typical year, CVP generation is usually sufficient to satisfy Project use but insufficient to satisfy both Project pumping requirements and preference customer load requirements for the winter months, and Western must purchase additional energy from other sources in the winter. Generation from SWP hydropower facilities and the Reid Gardner coal-fired plant are sufficient to satisfy SWP pumping loads.

During the spring (March through May), exports from the Delta may be limited because San Luis Reservoir is full or because of Delta export limitations; thus, Project-pumping loads may be lower in spring than in winter. The need for late season rainfall and snowmelt flood releases also governs the timing of power generation. Spring is a transitional period for power, as the purchase of additional energy is sometimes, but not always, required for CVP pumping and preference load requirements. Generation from SWP hydropower facilities and the Reid Gardner coal-fired plant are sufficient to satisfy SWP pumping loads.

The system's water demands are highest during the summer (June through August). Releases to meet these demands produce energy at the upstream reservoirs and at the San Luis Reservoir. Although generation at CVP power plants is high because of releases for CVP water demands, pumping loads combined with high preference customer loads frequently require the import of additional energy from the Pacific Northwest. SWP generation at its hydropower facilities is also higher in response to increased releases; however, this generation coupled with Reid Gardner generation is typically insufficient to meet SWP loads. In the summer the SWP relies on its power exchange agreements and energy purchases (primarily from the Pacific Northwest) to meet its remaining energy requirements.

16.2.5 Upstream from the Delta Region

The power facility descriptions included below cover the major power and pumping plants potentially affected by the EWA Program, as well as any "pass-through facilities" through which EWA water would pass without affecting operations (e.g., Edmonston pumping plant, Lake Silverwood, Pyramid Lake). The pass-through facility descriptions are included here to provide representative information on system operations. Sections 16.2.5.1 through 16.2.5.5 present data for the Sacramento, Feather, Yuba, American, and Merced/San Joaquin river systems, respectively.

16.2.5.1 Sacramento River

16.2.5.1.1 Central Valley Project

<u>Shasta</u>

The Shasta Power Plant, constructed in 1944, is a CVP facility at the foot of Shasta Dam on the Sacramento River. Water from the dam is released through the 15-foot-diameter penstocks (power plant intake pipeline) leading to the five main generating units and two station service units. The Shasta Power Plant is a peaking plant - it produces power on a schedule corresponding to peak electrical system usage rather than at a constant rate 24 hours per day. Its power is dedicated first to meeting the requirements of the Project facilities. The plant's installed capacity is 629,000 kW, and it has an annual average net generation of 2,466 GWh (Reclamation/Placer County Water Agency 2002). The energy remaining after meeting CVP Project use needs is marketed to various preference customers throughout California.

Keswick

The Keswick Power Plant, constructed in 1949, is a CVP facility just below Keswick Dam on the Sacramento River. Unlike Shasta, the Keswick Power Plant runs throughout the day at a constant rate, providing a uniform release to the Sacramento River. The Keswick Power Plant has three generating units with a combined capacity of 117,000 kW and an average annual net generation of 399.3 GWh (Reclamation 2002).

16.2.5.2 Feather River

16.2.5.2.1 South Fork Project

The South Fork Project, covering 82 square miles in three counties, consists of 8 dams, 17 tunnels, 21 miles of canals and conduits, 4 hydroelectric power plants and 21 miles of road. Oroville-Wyandotte Irrigation District (OWID) operates all four hydroelectric power plants (Sly Creek, Woodleaf, Forbestown, and Kelly Ridge), which have a combined generating capacity of more than 100,000 kW (Oroville-Wyandotte Irrigation District 2002b). OWID sells its electricity to PG&E wholesale; in exchange, PG&E pays for the operation and maintenance of the power facilities. OWID has partnered with PG&E since the late 1950s under an agreement that ends in 2009. The South Fork Project provides over 150,000 AF of water storage along with electricity. Although most of the hydropower produced goes to PG&E under contract, OWID also receives cash payments for power produced at its Sly Creek Power Plant.

16.2.5.2.2 Sly Creek

OWID owns the Sly Creek Power Plant located on the central portion of the South Fork Feather River at Sly Creek Reservoir. OWID moves water out of Sly Creek reservoir through the turbine-generator, which has a capacity of 15,000 kW. The generator at Sly Creek Reservoir nets an average 0.5 GWh of monthly generation (Oroville-Wyandotte Irrigation District 2002b).

16.2.5.2.3 Woodleaf

The Woodleaf Power Plant is on the South Fork Feather River just below Sly Creek Reservoir. At Lost Creek, OWID diverts water into the Woodleaf penstock. The Woodleaf Power Plant has a 62,000 kW generating capacity and produces an average of 6.9 GWh of electricity monthly (Oroville-Wyandotte Irrigation District 2002b). OWID moves water from the Woodleaf Power Plant through the Forbestown Diversion Dam.

16.2.5.2.4 Forbestown

The Forbestown Power Plant is on the South Fork Feather River below Ponderosa Dam. OWID transports water to the Forbestown Diversion Dam, then through the Forbestown Tunnel to the Forbestown Power Plant. The power plant has a generating capacity of 39,000 kW and generates an average of 3.7 GWh monthly (Oroville-Wyandotte Irrigation District 2002b). From the Forbestown powerhouse, the water flows through a series of canals and tunnels into Miners Ranch Reservoir.

16.2.5.2.5 Kelly Ridge

The Kelly Ridge Power Plant, operated by OWID, is near the mouth of the South Fork Feather River. OWID sends water from the Miners Ranch Reservoir into the Kelly Ridge Tunnel, which leads to the power plant penstock. The power plant has a generating capacity of 10,000 kW and produces an average of 3.8 GWh of electricity monthly (Oroville-Wyandotte Irrigation District 2002b).

16.2.5.2.6 State Water Project

<u>Oroville</u>

DWR stores winter and spring runoff in Lake Oroville for release to the Feather River as necessary for Project purposes (water supply, power generation, flood protection, fish and wildlife enhancement, and recreation). These releases generate power at the Hyatt-Thermalito Power Plant Complex.

On a weekly basis, DWR schedules releases to accommodate water supply requirements, water quality and quantity requirements in the Delta, instream flow requirements in the Feather River, power requirements, and flood control. DWR updates this weekly plan as needed to respond to changing conditions.

DWR schedules hourly releases through the Edward Hyatt and Thermalito Pumping Generating plants to maximize the amount of energy produced when power values are highest. Because the downstream water supply is not dependent on hourly releases, and pumping of SWP water can occur at off-peak times; energy prices primarily dictate hourly operations for the power generation facilities.

Storage in Thermalito Forebay and Afterbay helps to maximize the value of Project energy and maintain uniform flows in the Feather River downstream from the Oroville facilities. The Thermalito Afterbay also provides storage for pump-back operations, which are designed to maximize profit from the power generation facilities. DWR releases water from Lake Oroville when power prices are high, then pumps water not needed to meet downstream requirements back into Lake Oroville from Thermalito Forebay and Afterbay when power prices are low. Because DWR operates the power plants to maximize weekday generation when power prices are highest, storage is usually higher in the Afterbay at the end of each week than at the beginning. Downstream releases during the weekend, or pumpback to Lake Oroville (to prepare for the following week's operation) lowers the water in the Afterbay.

16.2.5.3 Yuba River

16.2.5.3.1 Yuba River Development Project

The Yuba River Development Project, constructed by the YCWA, was completed in 1970 and provides flood control protection for Yuba and Sutter Counties, irrigation water for Yuba County agriculture, recreation, and hydropower generation. The

Yuba River Development Project comprises a system of three dams, three tunnels, and four power plants.

Colgate
Colgate Power House is at the convergence of the Middle and North Yuba rivers, at the upstream end of Englebright Reservoir. The Colgate Tunnel follows a path from New Bullards Bar Reservoir about 3 miles to the Colgate Power House. YCWA will operate this facility, which is under contract with PG&E, until 2016. This power plant has a capacity of 315,000 kW (Harper 2001). Average annual generation is 1,314 GWh (Yuba County Water Agency, http://www.ycwa.com/drdat.htm).

Englebright
Narrows Power House I and Narrows Power House II are at the outlet of Englebright Reservoir on the main Yuba River about 2 miles northeast of Smartville (Aikens 2001). PG&E operates the Narrows Power House I, and YCWA operates the Narrows Power House II. Narrows Power House I, with a capacity of 12,000 kW, produces an average 3.8 GWh of electricity monthly and Narrows Power House II, with a capacity of 49,000 kW, produces an average 6.3 GWh of electricity monthly (California Hydropower 1998).

16.2.5.4 American River

16.2.5.4.1 Middle Fork Project

The Middle Fork Project is a multipurpose project that uses the waters of the Middle Fork of the American River, the Rubicon River, and certain tributaries for irrigation, domestic, and commercial purposes and for the generation of electric energy. Principal features of the Middle Fork Project are two storage and five diversion dams, five power plants, diversion and water transmission facilities, five tunnels, and related facilities. The power plants have a combined generating capacity of 247,000 kW and include Hell Hole, French Meadows, Lowell J. Stephenson, Ralston, and Oxbow. The power division of Placer County Water Agency (PCWA) operates the Middle Fork Project.

French Meadows
The French Meadows Power Plant is at Hell Hole Reservoir south of the South Fork of the American River. PCWA diverts water from French Meadows Reservoir through the French Meadows Tunnel. The water passes through the Francis turbine at the power plant, which has a capacity of 15,300 kW (Placer County Water Agency 1967). French Meadows Power Plant generates an average of 5.2 GWh monthly. The water is then held in Hell Hole Reservoir.

Hell Hole
The Hell Hole Power Plant is on the Rubicon River at Hell Hole Reservoir. Water flows from the reservoir through the Hell Hole Dam to the Hell Hole Power Plant. The Hell Hole Power Plant has a capacity of 725 kW (Placer County Water Agency 1967) and generates an average of 0.19 GWh monthly. From the plant, the water flows through a tunnel to the Ralston Afterbay.

<u>Lowell J. Stephenson</u>
The Lowell J. Stephenson Power Plant is on the Middle Fork of the American River at the Middle Fork-Ralston Interbay. Water for the power plant comes from French Meadows Reservoir, through the French Meadows Tunnel, through Hell Hole Reservoir, and finally through the Middle Fork Tunnel. The water passes over the Impulse turbine at the power plant, which has a capacity of 116,100 kW (Placer County Water Agency 1967). The Lowell J. Stephenson Power Plant generates an average of 43.1 GWh monthly. The water flows from the power plant through the Ralston Tunnel.

<u>Ralston</u>
The Ralston Power Plant is on the Rubicon River at the Ralston Afterbay. Water for the Ralston Power Plant follows the same path as the water for the Lowell J. Stephenson Power Plant, through the Ralston Tunnel, to the Ralston Power Plant. The Ralston Power Plant has an Impulse turbine and a capacity of 79,200 kW (Placer County Water Agency 1967). The Ralston Power Plant generates an average of 31.2 GWh monthly. From the plant, the water flows back into the Ralston Tunnel, which continues to the Oxbow Power Plant (below).

<u>Oxbow</u>
The Oxbow Power Plant is on the Middle Fork of the American River at the Oxbow Bar. Water for the Oxbow Power Plant flows from the Ralston Power Plant through the Ralston Tunnel. The plant has a Francis turbine and a capacity of 6,128 kW (Placer County Water Agency 1967). From the power plant, the water continues to the Auburn Ravine and to the lower American River.

16.2.5.4.2 Central Valley Project - Lower American River
<u>Folsom Reservoir and Lake Natoma</u>
The Folsom Power Plant is at the foot of Folsom Dam on the north side of the American River. Its three generating units are tied into the CVP power system through the 20-mile-long Folsom-Elverta 230-kV transmission line. The Nimbus Power Plant is on the right abutment of Nimbus Dam (Lake Natoma) on the north side of the American River. The principal purpose of the Folsom and Nimbus power plants is to generate power using the water releases mandated for downstream appropriators, flood control, fish, and other uses.

The Folsom Power Plant has three generating units, with a combined capacity of 215,000 kW and a combined release capacity of approximately 8,600 cfs (Reclamation 2001). By design, the facility is operated as a peaking facility. Peaking plants schedule the daily water release volume during the peak energy demand hours to maximize generation at the time of greatest need. During other hours of the day, the plant may release little or no water, generating little or no power. The Folsom Power Plant generates an average annual 620 GWh.

To avoid fluctuations in flow in the lower American River, Nimbus Dam and Lake Natoma serve as a regulating facility. While the water surface elevation fluctuates, releases to the lower American River remain constant. The Nimbus Power Plant consists of two generating units with a release capacity of approximately 5,100 cfs

(Reclamation 2001). Electric generation from this facility is continuous throughout the day.

16.2.5.5 Merced/San Joaquin River

16.2.5.5.1 Merced River

Merced Irrigation District's (MID) plants at New Exchequer and McSwain Dams on the Merced River generate power that is sold to utility companies (most recently PG&E), which sell it to consumers. The power plant at the base of Exchequer Dam began operation in June 1926. Since 1967, when the McSwain and New Exchequer Dams were completed, MID has produced nearly 10,000 GWh of electricity, which is an average of nearly 325 GWh a year (Merced Irrigation District 2000). The New Exchequer Power Plant provides electric power to eastern Merced County. Under a long-term contract expiring in 2014, MID also sells electricity generated at its New Exchequer Power Plant to PG&E, for its customers in Northern California.

16.2.5.5.2 Exchequer

The Exchequer Power Plant is on the Merced River below Exchequer Dam. The plant has a capacity of 80,100 kW and an average monthly energy production of 26.3 GWh.

16.2.5.5.3 McSwain

The McSwain Power Plant is on the Merced River below McSwain Dam. The plant has a capacity of 9,000 kW and an average monthly energy production of 3.75 GWh.

16.2.5.5.4 San Joaquin River

No hydroelectric facilities are on the mainstem of the San Joaquin River.

16.2.6 Sacramento-San Joaquin Delta Region

The Delta facilities do not operate to generate power supply; instead, they consume large quantities of energy. Among the Delta facilities that need power to operate are the Tracy and Harvey O. Banks Pumping Plants, described below.

16.2.6.1 Central Valley Project

16.2.6.1.1 Tracy Pumping Plant

The U.S. Bureau of Reclamation (Reclamation) completed the Tracy Pumping Plant in 1951. The Tracy facilities include an inlet channel, pumping plant, and discharge pipes. The pumping plant lifts water 197 feet from the Delta into the Delta-Mendota Canal. Each of the six pumps at Tracy is powered by a 22,500-horsepower motor and is capable of pumping 767 cfs (Reclamation 2001). CVP power plants supply power to run the pumps. The water is pumped through three 15-foot-diameter discharge pipes and carried about 1 mile up to the Delta-Mendota Canal. The intake canal includes the Tracy Fish Screen, which was built to intercept downstream migrant fish so they may be returned to the main channel. The Tracy Pumping Plant is a "pass-through" facility relative to this analysis.

16.2.6.2 State Water Project

16.2.6.2.1 Harvey O. Banks Pumping Plant

The Harvey O. Banks Pumping Plant is on the southern edge of the Delta and can lift 21,000 AF/day of water 224 feet into the California Aqueduct. The Clifton Court Forebay, which precedes the Banks Pumping Plant, provides storage and regulation of flows into the Banks Pumping Plant. The construction of Banks Pumping Plant was completed in 1963, with seven pump units and a total pumping capacity of 6,400 cfs. In 1986, four additional pumps were installed in the plant, increasing its capacity to 10,670 cfs (California Department of Water Resources 2002). The Harvey O. Banks Pumping Plant is a "pass-through" facility relative to this analysis.

16.2.7 Export Service Area

16.2.7.1 Central Valley Project

16.2.7.1.1 O'Neill Pumping-Generating Plant

O'Neill Pumping-Generating Plant is on the Delta Mendota Canal in Merced County, 70 miles from the Tracy Pumping Plant and 12 miles west of Los Banos. O'Neill Dam and Forebay are joint Federal/State facilities on the San Luis Creek, 2.5 miles downstream from San Luis Dam. The O'Neill Pumping-Generating Plant is a conventional plant consisting of an intake channel leading off the Delta-Mendota Canal and six pump-generating units. Normally, these units operate as pumps to lift water 45 to 53 feet into the O'Neill Forebay. The forebay also releases water to the Delta-Mendota Canal. During releases to the Delta-Mendota Canal, the O'Neill plant generates electricity. When operating as pumps and motors, each unit, with a 6,000 horsepower motor, can discharge 700 cfs. When operating as turbines and generators, each unit has a generating capacity of about 4,200 kW (Reclamation 2001). The authorizing legislation for the plant states that power generated at the facility cannot be used for commercial purposes. O'Neill Forebay is a joint State and Federal facility, but O'Neill Pumping-Generating Plant only moves CVP water between the CVP Delta-Mendota Canal and O'Neill Forebay. No State water goes through the plant because the California Aqueduct flows by gravity into O'Neill Forebay.

16.2.7.2 Joint Central Valley Project/State Water Project

16.2.7.2.1 San Luis Reservoir

The State of California operates and maintains the William R. Gianelli Pumping Plant (formerly the San Luis Pumping Plant) under an agreement with Reclamation. The plant is in Merced County, on the San Luis Creek, 12 miles west of Los Banos. This joint Federal/State facility, at San Luis Dam, lifts water with pump turbines from the O'Neill Forebay into the San Luis Reservoir. During the irrigation season, water released from San Luis Reservoir generates energy as it flows back through the pump turbines to the forebay. Each of the eight pumping-generating units has a 63,000-horsepower motor and a capacity of 53,000 kW as a generator (Reclamation 2001). As a pumping plant to fill San Luis Reservoir, each unit lifts 1,375 cfs at a design dynamic head of 290. As a generating plant, each unit passes 2,120 cfs at a design dynamic head of 197 feet. The plant pumps CVP and SWP water for offstream storage.

16.2.7.2.2 Dos Amigos Pumping Plant

This joint Federal/State facility, 17 miles south of the forebay, is a relift plant in the San Luis Canal. The plant contains six pumping units, each with a 40,000-horsepower motor, capable of delivering 2,200 cfs at 125 feet of head (Reclamation 2001). The Dos Amigos Pumping Plant is a "pass-through" facility relative to this analysis.

16.2.7.3 State Water Project

16.2.7.3.1 Buena Vista Pumping Plant

Buena Vista Pumping Plant is located on the California Aqueduct about 24 miles southwest of Bakersfield in Kern County. The plant has an installed capacity of about 5,400 cfs and lifts water from about elevation 295 feet to 500 feet.

16.2.7.3.2 Teerink Pumping Plant

The John R. Teerink Wheeler Ridge Pumping Plant is located on the California Aqueduct about 27 miles downstream from the Buena Vista Pumping Plant. This plant lifts water from about elevation 492 feet to 725 feet.

16.2.7.3.3 Chrisman Pumping Plant

The Ira J. Chrisman Wind Gap Pumping Plant is located on the California Aqueduct about 1.6 miles downstream from the Teerink Pumping Plant. The plant lifts water approximately 515 feet.

16.2.7.3.4 Edmonston Pumping Plant

Water enters into the Edmonston Pumping Plant from the California Aqueduct. The Edmonston Pumping Plant lifts water 1,926 feet (the highest single lift in the world) to enter 8.5 miles of tunnels crossing the Tehachapi Mountains. From this point the water continues south through Quail Lake, Pyramid Lake, and finally to Castaic Lake. The Edmonston Pumping Plant has 14 pump units with a total plant capacity of 4,480 cfs (Castaic Lake Water Agency 2002). The Edmonston Pumping Plant is a "pass-through" facility relative to this analysis.

16.2.7.3.5 Pyramid Lake

The DWR owns and operates the William E. Warne power plant. Located on the Gorman Creek arm of Pyramid Lake, the power plant helps meet the SWP need for electricity. This plant has an installed capacity of 78,000 kW and generates up to 358 GWh a year (California Department of Water Resources 1997). Water flowing from Pyramid Lake through the 7.5-mile-long Angeles Tunnel spins the turbines in the Castaic Power Plant.

16.2.7.3.6 Castaic Power Plant

Elderberry Forebay, a small reservoir separated from Castaic Lake by Elderberry Forebay Dam, is at the upper end of Castaic Lake and provides regulating storage for the Castaic Power Plant. The Castaic Power Plant generates electricity during on-peak periods (weekday daylight hours) when extra power is needed in the Los Angeles area. During off-peak periods (nights and Sundays) when local power is less costly, the plant pumps water back into Pyramid Lake. This operation also reduces the cost of power required to move SWP water from Northern to Southern California. Castaic Power Plant is a cooperative venture of DWR and the City of Los Angeles Department of Water and Power.

16.2.7.3.7 Silverwood Lake

Water reaches Silverwood Lake from the East Branch of the California Aqueduct. The Pearblossom Pumping Plant east of Palmdale pumps the water 542 feet from the Antelope Valley floor to an elevation of 3,479 feet. Flowing downhill through an open aqueduct, the water is then piped under the Mojave River bed through the 29.4 megawatt Mojave Siphon Power Plant and into Silverwood Lake (California Department of Water Resources 1997). Water released from the south end of Lake Silverwood flows through the 3.8-mile San Bernardino Tunnel, plunges 1,400 feet into Devil Canyon Power Plant, and then flows into Lake Perris via the Santa Ana Valley pipeline. These are "pass-through" facilities relative to this analysis.

16.2.7.4 Non-Project

16.2.7.4.1 Diamond Valley Lake

Diamond Valley Lake is located approximately four miles southwest of the City of Hemet and completed filling in December 2002. Water for the reservoir comes from the Colorado River Aqueduct, delivered through the San Diego Canal into the reservoir forebay and from the SWP via Lake Silverwood. This reservoir has a pumping plant consisting of twelve pumps, each with a 5,000-horsepower motor. The facilities also include a 1,000 cubic foot per second hydrologic control structure at the Colorado River Aqueduct (Temecula Valley 2000). Of the 12 pumps, four have been converted to pumping–generating units with a unit capacity of 3,000 kW. Additional pumps are planned for conversion at a later date. The Hiram W. Wadsworth Pumping Plant is a "pass-through" facility relative to this analysis.

16.2.8 Regulatory Setting

Western is the marketing agency for power generated at Reclamation's CVP facilities. Created in 1977 under the Department of Energy (DOE) Organization Act, Western markets and transmits electric power throughout 15 western states. Western's Sierra Nevada Customer Service Region (Sierra Nevada Region) annually markets approximately 8,000,000 kilowatthours (kWh), including 3,000,000 kWh produced by CVP generation and 5,000,000 kWh produced by other sources.

Western's mission is to sell and deliver electricity that is excess to Project use (power required for CVP Project operations). Western's power marketing responsibility includes managing the Federal transmission system and, as a Federal agency, ensuring that operations of the hydropower facilities are consistent with its regulatory responsibilities. Specifically, Western's capacity and energy sales must be in conformance with the laws that govern its sale of electrical power. The hydroelectric generation facilities of the CVP are operated by Reclamation. Reclamation manages and releases water in accordance with the various acts authorizing specific projects and in accordance with other laws and enabling legislation. Hydropower operations at each facility must comply with minimum and maximum flows and other constraints set by Reclamation, U.S. Fish and Wildlife Service (USFWS), or other regulatory agencies, acting in accordance with law or policy.

Existing contracts for the sale of Sierra Nevada Region power resources expire December 31, 2004. Western has developed a marketing plan that defines the products to be offered and the eligibility and allocation criteria that would lead to allocations of CVP electric power resources beyond the year 2004.

16.3 Environmental Consequences/Environmental Impacts

16.3.1 Assessment Methods

The monthly gross CVP and SWP electrical generation and capacity for the various conditions simulated in this study were estimated using results from a CALSIM II simulation, utilizing several data post-processing tools. Assessment methods are described in detail in Attachment 1, Modeling Description. Differences in generation and capacity between alternative conditions were then evaluated to assess effects. Also evaluated were differences in the amount of energy needed to pump water at the Project pumping plants.

16.3.2 Significance Criteria

16.3.2.1 Hydropower

EWA actions would result in a potentially significant adverse effect on hydropower production if generation at affected facilities were substantially reduced. An effect on hydropower production was considered potentially significant if implementing an EWA action would cause:

- A decrease in surface-water elevations beyond optimum efficient levels in reservoirs within the area of analysis that would decrease the efficiency of the power generation facilities. Decreased efficiency would cause the power plant to produce less energy with the same amount of water release.

- A change in timing of reservoir releases, which could shift generation to a time of year when power has lower value. The value for power varies by season, typically with lower prices in the spring and somewhat higher prices in the late summer and early fall. The current open power market, however, is less predictable and may not follow this traditional pattern. Therefore, any change in timing is considered potentially significant.

Reduction in CVP/SWP generation could be a cost effect either because the entities would be precluded from selling excess energy or might be required to purchase additional energy for their own or customer's loads. Similarly, if capacity was reduced relative to the Baseline Condition, then a cost effect could be incurred.

16.3.2.1.1 Pumping Load

EWA actions would result in a potentially significant adverse impact on power if the timing of pumping was changed, or if energy consumed by the pumps would be substantially increased. An effect on power was considered potentially significant if implementing an action would cause:

- A change in timing of pumping, which could shift the load to a time of year when power has higher costs. Because of the uncertainty of the open power market, any change in timing is considered potentially significant.

- An increase in pumping energy requirements for purveyors who withdraw water from reservoirs. The energy requirements would increase if the reservoir levels decrease as a result of the EWA.

16.3.3 Environmental Consequences/Environmental Impacts of the No Action/No Project Alternative

The No Action/No Project alternative reflects the condition for CVP/SWP power production should the EWA water acquisition strategy not be implemented. Releases and storage of EWA asset water would change the timing of generation at some facilities. Without the EWA water purchases, the Project power facilities would operate as under the affected environment/existing conditions setting. Under No Action/No Project, there would be no changes in CVP/SWP power production or usage, no new power facilities constructed/operated, and no facilities would be taken off-line because there would be no EWA. Therefore, no effects would be associated with the No Action/No Project Alternative.

As described in Section 3.4, the California Environmental Quality Act (CEQA) basis of comparison is the Affected Environment. The National Environmental Policy Act (NEPA) basis of comparison is the Future Conditions Without the Project. As described in the above paragraph, the Affected Environment and the Future Conditions Without the Project (No Action/No Project Alternative) are the same; therefore, they are collectively referred to as the Baseline Condition in the following sections.

16.3.4 Environmental Consequences/Environmental Impacts of the Flexible Purchase Alternative

For power resources, the environmental consequences of utilizing stored reservoir water, groundwater substitution, and crop idling vary by the specific water bodies affected, as discussed below. Environmental consequences of source shifting do not vary substantially by location; therefore, the effect analysis is grouped by acquisition type. In those cases where no environmental consequences to power resources have been associated with an acquisition type, the acquisition type is not discussed. All changes to surface-water elevations and flows are in comparison to the Baseline Condition. Only those power facilities that have the potential to be affected by the EWA Program are included below. The analysis of the Flexible Purchase Alternative incorporates implementation of the Variable Assets described in Attachment 1, Modeling Description.

16.3.4.1 Upstream from the Delta Region

16.3.4.1.1 Sacramento River

EWA agencies' acquisition of Sacramento River Contractor water via groundwater substitution or crop idling would cause changes in the release pattern from Lake Shasta in June through September. EWA transfer water from idling or groundwater substitution could be temporarily stored in Lake Shasta and then released during July through September. The EWA would not change the amount of water that is released from Lake Shasta, but would alter the release pattern. Lake Shasta surface water elevation likely would be slightly lower than the Baseline Condition because of “borrowing” of Shasta storage for July pumping of EWA water prior to August/September crop idling water being available; reduced head (on average less than 0.3 foot) would therefore slightly decrease the head component of generation efficiency. Changes in the release patterns to facilitate pumping of EWA water of the crop idling water also alter the monthly generation efficiency; however, average annual Shasta/Keswick generation is insignificantly decreased by only 263 kWh (Table 16-5). As stated previously, the value of power fluctuates throughout the year. Typically, prices are higher in late summer and fall and lower in the spring. Groundwater substitution would have no effect on Shasta/Keswick generation, and crop-idling would create slightly increased generation in July and slightly less generation in August and September compared to the Baseline Condition. However, in an open market, seasonal price fluctuations may not always reflect the norm. These effects could be potentially significant. Mitigation measures listed in Section 16.3.9 would reduce these potentially significant effects on power production and energy to less than significant.

Table 16-5
Shasta/Keswick Average Monthly Generation (kWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Baseline	193,762	227,992	210,737	203,075	230,313	265,015	306,337	237,885	147,652	131,929	111,254	161,237	2,427,188
FPA	193,762	227,992	210,737	203,075	230,313	265,015	308,873	236,328	146,410	131,929	111,254	161,237	2,426,924
Difference	0	0	0	0	0	0	2,535	(1,557)	(1,242)	0	0	0	(263)

FPA – Flexible Purchase Alternative

16.3.4.1.2 Feather River

Lake Oroville

EWA agencies' acquisition of Feather River Contractor water via groundwater substitution or crop idling would decrease the releases from Lake Oroville in May and June. Water acquired by the EWA agencies would be held in Lake Oroville in May and June and released during July through September. An increase in surface elevation compared to the Baseline Condition would increase the head and therefore the efficiency of power generation during May and June. Decreases in releases during May and June and pattern changes for July through September in response to pumping EWA water will temporally alter generation (Table 16-6). However, on an average annual basis, Oroville/Thermalito generation will increase by about 2,800 kWh.

Table 16-6
Oroville/Thermalito Average Monthly Generation (kWh)[(1)]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Baseline	174,284	202,551	216,738	201,680	248,429	305,033	295,319	251,909	120,963	97,946	80,266	139,954	2,335,071
FPA	176,165	202,851	216,856	199,946	238,885	292,568	323,923	254,344	114,009	97,946	80,266	140,122	2,337,881
Difference	1,881	300	118	(1,734)	(9,543)	(12,465)	28,605	2,435	(6,954)	0	0	168	2,810

FPA – Flexible Purchase Alternative
(1) Thermalito pumpback operations not included

Effects related to the value of power generated later in the summer could be potentially significant. Mitigation measures listed in Section 16.3.9 would reduce these potentially significant effects on power production and energy to less than significant.

EWA agencies' acquisition of stored reservoir water would include release of water from Sly Creek and Little Grass Valley Reservoirs in November to be held in Lake Oroville until the following summer. This water would increase the head component of generation efficiency, creating slightly higher generation at Oroville in the November through April period, assuming that the water is not spilled by flood operations. Sly Creek and Little Grass Valley Reservoirs may refill during the winter and spring, potentially holding water that belongs to the CVP/SWP. If that water were owed to the Projects, it would be repaid the following summer. Refill by Sly Creek and Little Grass Valley Reservoirs would only capture up to the amount released in November to Lake Oroville. Therefore, Lake Oroville already would contain as much or more water than it is foregoing due to refill of Sly Creek and Little Grass Valley Reservoirs. Thus, there would be no effects on power production and energy from EWA acquisition of stored reservoir water from Little Grass Valley and Sly Creek.

16.3.4.1.3 Yuba River

EWA agencies' acquisition of YCWA stored reservoir water would result in releases from New Bullards Bar Reservoir in July, August, and September. The water released in July through September would produce increased power production compared to the Baseline Condition. Increased flows through Narrows Power House I and Narrows Power House II, downstream from New Bullards Bar Reservoir, would allow PG&E to produce more power. This is a potentially beneficial effect on power production and energy.

EWA agencies acquisition of water through groundwater substitution would decrease New Bullards Bar releases in April through June. Power generation along the Yuba River would be decreased while water was held in New Bullards Bar Reservoir and increased when released between July and September. Effects would be similar to those described above for groundwater substitution on the Sacramento and Feather Rivers. Effects related to the value of power generated later in the summer could be potentially significant. Mitigation measures listed in Section 16.3.9 would reduce these potentially significant effects on power production and energy to less than significant.

16.3.4.1.4 *American River*

French Meadows and Hell Hole Reservoirs

EWA agencies' acquisition of PCWA stored reservoir water would result in releases from French Meadows and Hell Hole reservoirs in July, August, and September. The water released in July through September would generate increased power production relative to the Baseline Condition. Increased flows through the French Meadows and Hell Hole Power plants would allow PG&E to produce more power. This is a potentially beneficial effect on power production and energy.

Folsom Reservoir and Lake Natoma

EWA agencies' acquisition of Sacramento Groundwater Authority's stored groundwater and upstream stored reservoir water would change water levels in the reservoir during summer. Groundwater purchases, which are estimated to be small in magnitude, would be held in Folsom Reservoir until the time of EWA use, thereby increasing storage in Folsom. Increased generation would be available with this water, as it is presently being used upstream from Folsom Dam.

Upstream stored water purchases likely would take place over the July through September period, but some portion likely would be used for pumping EWA water in advance of upstream releases. This advanced use would require a "borrowing" of CVP storage in Folsom Reservoir during early summer, with payback completed by the end of September. Studies show that typically (72-year period of record), increased releases from Folsom Reservoir for pumping EWA water can cause a reduction in storage during July and August. Although storage is lower in these months, the increased release for pumping EWA water during July and August creates an increase in Folsom/Nimbus generation of about 2,600 kWh. During September there is decreased generation associated with the reduction in head (storage) at the beginning of the month; however, the additional release for pumping EWA water results in more generation, about 150 kWh, creating an increase in annual generation of 2,760 kWh (Table 16-7). If upstream water purchases were completed prior to July, an increase in surface elevation compared to the Baseline Condition would increase the head and thus likely increase the efficiency of power generation, thereby creating an even greater net generation benefit at Folsom.

Table 16-7
Folsom/Nimbus Average Monthly Generation (kWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Baseline	70,534	76,780	69,458	65,509	73,438	77,230	75,421	45,465	49,251	29,517	41,982	59,709	734,295
FPA	70,534	76,780	69,458	65,509	73,438	77,230	77,259	46,235	49,403	29,517	41,982	59,709	737,055
Difference	0	0	0	0	0	0	1,838	770	152	0	0	0	2,760

FPA – Flexible Purchase Alternative

Upstream reservoirs would refill during the wet season under normal refill conditions and would be full at the beginning of the following season, thus resulting in no adverse power effects. During refill, however, the upstream reservoirs may utilize Project water. The water use would be calculated after the refill is complete. The water would then be slowly released from the upstream reservoirs during the late summer into Folsom Reservoir. During this time, Folsom Reservoir would have lower elevations relative to the Baseline Condition, which would decrease the efficiency of power generation.

As described above for the Sacramento River, altering water release (power production) could produce positive or negative effects. EWA activities could temporally shift hydropower generation. This may result in a shift of generation from on-peak to off-peak periods, resulting in generation of lower economic value. In addition, the changes in water levels in Folsom Reservoir would alter the power needs for those agencies that pump directly out of the reservoir, which could potentially cause effects. Because the elevation differences are small, on average 0.4 foot or less, there would be little effect.

Effects related to the economic value of power generated or additional pumping costs experienced by agencies pumping water from Folsom Reservoir could be potentially significant. Mitigation measures listed in Section 16.3.9 would reduce these potentially significant effects on power production and energy to less than significant.

Lake Natoma
EWA agencies' acquisition of American River Contractor water via groundwater purchase and upstream stored reservoir water purchase would increase flows through Nimbus Power Plant during summer and fall months. Generation at Lake Natoma is solely dependent upon flow, thus generation would increase. Therefore, the effects on power production would be considered less than significant.

16.3.4.1.5 Merced River

New Exchequer
EWA agencies' acquisition of Merced River Contractor water via groundwater substitution or crop idling would decrease the releases from New Exchequer and McSwain Dams from April through September. Water acquired by the EWA agencies would be held in New Exchequer Reservoir during the irrigation season and released during October through December. Fewer releases from April through September would result in less generation during that period. However, the increase in surface elevation during the summer months compared to the Baseline Condition would increase the head and therefore the efficiency of power generation. As described above for the Sacramento River, delaying water release (power production) until the fall could produce beneficial effects. Effects related to the value of power generated later in the fall could be potentially significant. Mitigation measures listed in Section 16.3.9 would reduce these potentially significant effects on power production and energy to less than significant.

McSwain Dam
EWA agencies acquisition of Merced River Contractor water via groundwater substitution or crop idling would decrease the releases from McSwain Dam during the irrigation season. Power production at McSwain is regulated at the dam's gates and is minimally reliant on head. Decreased flows from McSwain would decrease energy generation. Effects related to the value of power generated later in the fall could be potentially significant. Mitigation measures listed in Section 16.3.9 would reduce these potentially significant effects on power production and energy to less than significant.

16.3.4.2 Delta Region

16.3.4.2.1 Pumping Energy Cost Effects of the Flexible Purchase Alternative

The EWA Program would shift a portion of CVP and SWP Delta exports from December through June, to July through September, based on the timing of EWA fish actions and on replacement pumping. This would shift export pumping to the summer when recent information shows that electricity costs are greater.

Modeling of pumping operations under the Baseline Condition was conducted using CALSIMII. As described in Attachment 1, pumping operations reflecting EWA actions are not readily identifiable over the 70-year period of record; however, a 15-year period of record (1979 – 93) were developed for Delta fisheries and water quality analyses (see Attachment 1) reflecting two potential EWA scenarios, water acquisition at 600 TAF and a "Typical" water purchase scenario at between 200 and 300 TAF (refer to Section 2.4.3). These two 15-year scenarios are compared to the Baseline Condition using the post-processor tools to estimate the change in electricity use and associated economic cost.

Figure 16-2 shows the average combined monthly electricity usage at Tracy, O'Neill, and Banks Pumping Plants under the Baseline Condition and under the 600 TAF acquisition (Maximum Water Purchase) scenario. Electricity usage was calculated as 297 kWh/af for Banks pumping and 298 kWh/acre foot for the Tracy/O'Neill pumping. Relative to the Baseline, there are no pumping changes October through November, but there are decreases in Flexible Purchase Alternative pumping December through June in response to EWA fish actions and increases in Flexible Purchase Alternative pumping July through September for makeup pumping. Figure 16-3 shows a similar pumping pattern for the Baseline Condition and the "Typical" Water Purchase Scenario.

The amount of energy required to pump an acre-foot of water from the Delta does not vary during the year; however, the cost of electrical energy does vary from month to month. An estimate of export pumping costs must be made both in energy and dollars to fully analyze the effects of the Flexible Purchase Alternative. To do so requires data on the patterns of export pumping and energy costs.

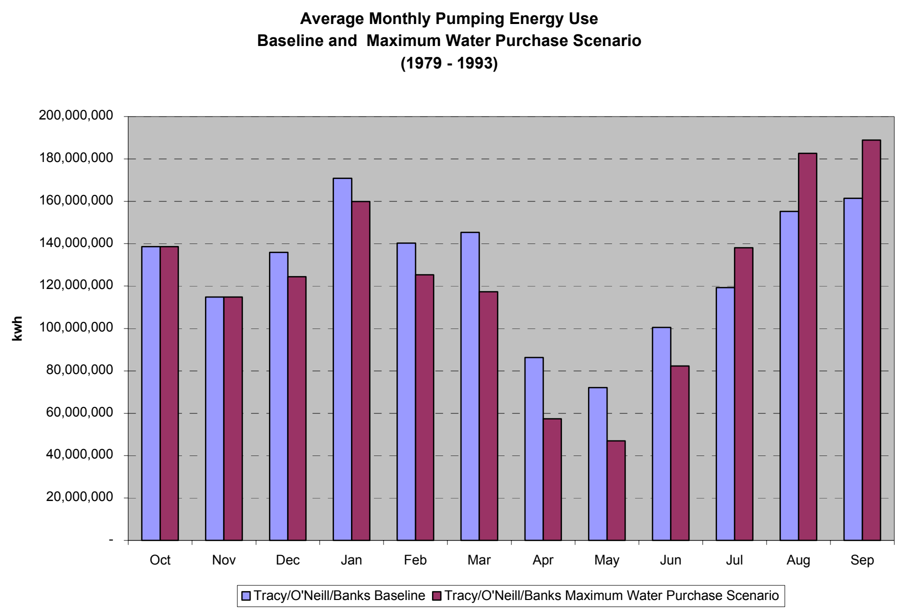

Figure 16-2
Average Monthly Pumping Load at Banks and Tracy/O'Neill Pumping Plants for Baseline and EWA at 600 TAF, 1979-93 Study Period of Record

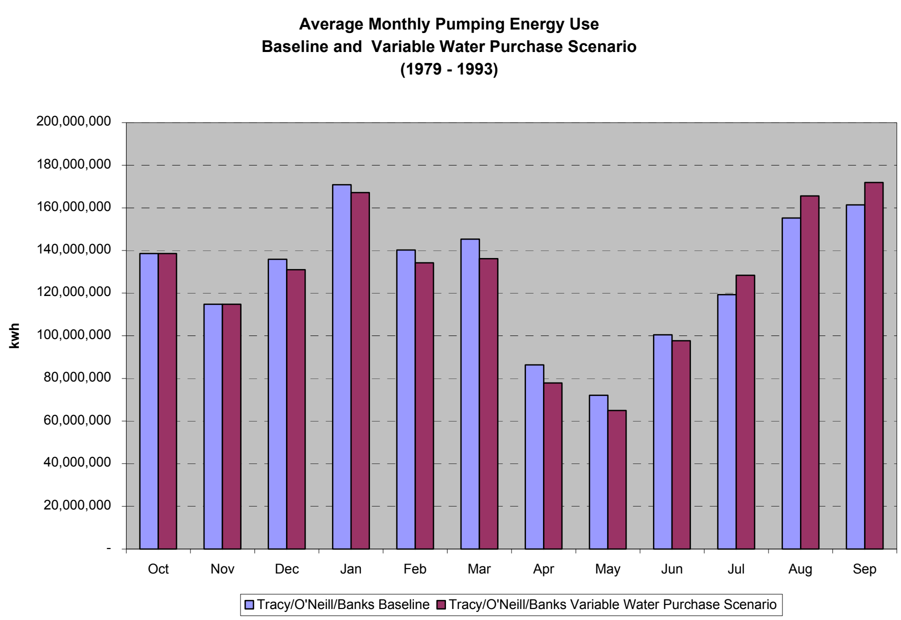

Figure 16-3
Average Monthly Pumping Load at Banks and Tracy/O'Neill Pumping Plants For Baseline and Typical EWA Scenario, 1979-93 Study Period of Record

Table 16-8 contains simulation data for monthly average Delta export pumping and estimated year 2005 on-peak electricity rates. The California Energy Commission "2002 – 2012 Electricity Outlook Report" dated February 2002 projects monthly average peak spot prices for 2005 in the $27 to $39/MWh range (Table 16-8). (See [Figure II-2-4] at http://www.energy.ca.gov/reports/2002-06-10_700-01-004F.PDF).

The monthly export data are used to calculate the energy results shown in Figures 16-2 and 16-3. It is notable that the total export pumping in the Flexible Purchase Alternative does not match the baseline total. This condition occurs when, in the 15-year studies, hydrology or operational constraints affect replacement pumping (see Attachment 1 for additional explanation for each year). For the purposes of this analysis, it is assumed that annual exports should be equal for the Baseline and Flexible Purchase Alternative; therefore, the water volume, labeled as Difference Water in Table 16-8, is assumed to be pumped sometime during the July through September period, which maximizes the energy costs of the scenarios.

Table 16-9 presents the estimated export pumping costs for the Baseline and Flexible Purchase Alternative. During the October through June months, export pumping is reduced by EWA actions and this is reflected by the lower average monthly pumping costs in the Flexible Purchase Alternative, compared to the Baseline Condition. Conversely, when replacement pumping occurs during the July through September months, pumping costs are higher with the Flexible Purchase Alternative.

Summing the entire year, and adding the additional cost of pumping the Difference Water, the water acquisitions at 600 TAF creates an additional average annual export pumping cost of $263,671. Analysis of the individual 15 years shows that the annual cost ranges between $525,000 and a savings of $6,000.

Summing the entire year, and adding the additional cost of for pumping the Difference Water, the Typical Water Purchase Scenario creates an additional average annual export pumping cost of $360,690. Analysis of the individual 15 years shows that the annual cost ranges between $1,665,000 and a savings of $950,000.

Table 16-8
Simulated Average Monthly Combined Export Pumping at Banks and Tracy (1979-93)
Estimated 2005 Monthly On-Peak Energy Rate

	Baseline TAF	600 TAF Purchase Scenario TAF	Typical EWA Purchase Scenario TAF	2005 On-Peak Spot Market Price ($/MWh)
October	466	466	466	$35
November	386	386	386	$39
December	457	418	424	$35
January	574	538	550	$31
February	472	422	431	$29
March	489	395	428	$29
April	290	193	226	$28
May	243	158	176	$27
June	338	277	281	$27
July	401	464	465	$27
August	522	614	609	$34
September	543	635	630	$31
Total	5,180	4,965	5,072	N/A
Difference Water	0	215	108	N/A

Table 16-9 Simulated Average Combined Export Pumping Costs at Banks and Tracy (1979-93)			
	Baseline $	**600 TAF Purchase Scenario $**	**Typical EWA Purchase Scenario $**
October	$ 4,851,084	$ 4,851,084	$ 4,851,084
November	$ 4,478,112	$ 4,478,112	$ 4,478,112
December	$ 4,756,842	$ 4,355,217	$ 4,585,492
January	$ 5,295,443	$ 4,957,285	$ 5,181,508
February	$ 4,067,828	$ 3,636,417	$ 3,891,662
March	$ 4,213,104	$ 3,402,164	$ 3,950,963
April	$ 2,416,067	$ 1,606,010	$ 2,180,282
May	$ 1,947,651	$ 1,267,680	$ 1,752,288
June	$ 2,711,502	$ 2,222,250	$ 2,637,936
July	$ 3,222,621	$ 3,728,936	$ 3,465,157
August	$ 5,277,254	$ 6,211,591	$ 5,631,478
September	$ 5,005,159	$ 5,857,054	$ 5,328,128
Total	$ 48,242,667	$ 46,573,799	$47,934,090
Total Comparison to Baseline	0	$ (1,668,868)	$ (308,577)
Cost to Pump Difference Water	0	$ 1,932,539	$ 669,267
Average Annual Cost	0	$ 263,671	$ 360,690

16.3.4.2.2 Pumping Energy Cost Effects of the Fixed Purchase Alternative

The Fixed Purchase Alternative described in Chapter 2 was not quantitatively analyzed in the EIS/EIR for each year of the modeled period of record. As is discussed in the resource areas, the Flexible Purchase Alternative scenarios with as much as 600 TAF of exports, impose a much larger burden on upstream release and Delta export facilities, and are more demanding of operational adjustments by the SWP and CVP than a 185 TAF project with only 35 TAF originating in the Upstream from the Delta Region.

In the worst case, assuming that all of the 35 TAF upstream from the Delta purchased is pumped in the least favorable time with respect to power prices, and, that the offsetting pumping curtailments occur at the time of lowest power prices, the cost differential of the 35 TAF would be about $73,000. Subtract from this $73,000 the savings associated with the other 150 TAF (185 – 35 = 150) of pumping foregone by EWA water purchases south of the Delta which do not need to be exported, there is a net power benefit. Assuming that the foregone pumping is 150 TAF, at a pumping energy rate of 298 kWh/AF, and a cost of $27.00/MWh, the annual savings are $1,205,000; creating an annual net benefit of $1,132,000 ($1,205,000 - $73,000 = $1,132,000).

16.3.5 Regional Water Purchase Areas

16.3.5.1 Effect of the Flexible Purchase Alternative on the Regional Electricity Market

The Flexible Purchase Alternative could affect the regional electricity market; although it is not anticipated to have a significant effect on generation from CVP or SWP hydroelectric power plants (see previous discussion in this chapter). However, the shift in timing of Delta exports would increase electric power demand during July, August, and September, the three months of the year with the smallest projected surplus in the California electricity market. The California Energy Commission "2002 Monthly Electricity Forecast: California Supply Demand Capacity Balances for May – December" projects a surplus of 3,400,000 to 3,900,000 kW per month for the July through September period ([Table 16-5] in http://www.energy.ca.gov/reports/700-02-003F/2002-05-10_700-02-003F.PDF). This projection applies to statewide electricity supplies and demands. The amount of supply in excess of demand would probably be less in the northern California region.

Shifting the timing of pumping also may shift the energy use from off-peak hours in the spring to on-peak hours during the summer at the export facilities. This shift from off- to on-peak is a potential problem from an economic standpoint because of the price differential between on- and off-peak power. Also, to the extent that additional on-peak load will be present, California's electrical capacity available during the most critical time of the year will be diminished. On some days it may be necessary to curtail EWA water purchase pumping in response to electrical system emergencies. In addition, discontinuation of the Western-PG&E contract could result in Independent System Operator scheduling costs for the CVP. During the term of the Western-PG&E contract, PG&E has carried the costs of scheduling CVP loads and likely could readily absorb fluctuations in CVP power operations within its much larger system. However, Reclamation/Western will become responsible for the timely declaration of loads and resources after 2004. To the extent that conveyance of EWA water purchases and EWA actions affect day-to-day CVP power scheduling, there may be additional costs borne by the CVP. These effects could be potentially significant. Mitigation measures listed in Section 16.3.9 would reduce these potentially significant effects on power production and energy to less than significant.

16.3.5.1.1 EWA at 600 TAF Acquisitions (Maximum Water Purchase) Scenario

The EWA at 600 TAF would result in an average electricity increase of about 45,900,000 kWh per month at the Project pumps during July, August, and September. In addition, groundwater wells in the Sacramento Valley would increase their use of electricity for water supply replacement. The increased use of electricity by groundwater wells can be estimated in comparison to the incremental power consumed by the Project pumps. At most, the incremental amount of groundwater pumped by the wells would be 200 thousand acre-feet (TAF), which is the maximum volume thought to be available for purchase north of the Delta. The lift would be about one-eighth of the Delta lift; thus, an estimate of 36 kWh/af is assumed as the energy cost. This is based on an average groundwater lift of 30 feet compared to the

Project pumps lift of about 250 feet. Therefore, the groundwater wells, in aggregate, could increase electricity use by at most 7,200,000 kWh (200,000 af * 36 kWh/af = 7,200,000 kWh) or 2,400,000 kWh per month during these three months.

In total, EWA at 600 TAF is estimated additional July through September export pumping could increase electricity use by 45,900,000 kWh and groundwater wells could increase regional electricity use by 2,400,000 kWh for a combined average of 48,300,000 kWh per month. Assuming 24-hour operation throughout the month, the increased power demand would be 66,350 kW. This represents less than 2 percent of the projected statewide electrical surplus during these months.

16.3.5.1.2 Typical Water Purchase Scenario

The Typical Water Purchase Scenario would result in an average electricity increase of about 34,300,000 kWh per month at the Project pumps during July, August, and September. In addition, groundwater wells in the Sacramento Valley would increase their use of electricity for water supply replacement. The increased use of electricity by groundwater wells can be estimated in comparison to the incremental power consumed by the Project pumps. At most, the incremental amount of groundwater pumped by the wells would be 200 TAF, which is the maximum volume thought to be available for purchase north of the Delta. The lift would be about one-eighth of the Delta lift; thus, an estimate of 36 kWh/af is assumed as the energy cost. This is based on an average groundwater lift of 30 feet compared to the Project pumps lift of about 250 feet. Therefore, the groundwater wells, in aggregate, could increase electricity use by at most 7,200,000 kWh (200,000 af * 36 kWh/af = 7,200,000 kWh) or 2,400,000 kWh per month during these three months.

In total, the Typical Water Purchase Scenario is estimated additional July through September export pumping could increase electricity use by 34,300,000 kWh, and groundwater wells could increase regional electricity use by 2,400,000 kWh for a combined average of 36,700,000 kWh per month. Assuming 24-hour operation throughout the month, the increased power demand would be 49,850 kW. This represents about one and one-half percent of the projected statewide electrical surplus during these months.

16.3.6 Export Service Area

16.3.6.1 San Luis Reservoir

EWA export pumping restrictions in the spring would place an additional burden on San Luis Reservoir for meeting south of Delta water demands prior to EWA water purchases in the summer. As a consequence, San Luis Reservoir storage and water-surface elevations from April until September would be lower. From April through June, San Luis Reservoir releases would be slightly higher and generation would be slightly greater than under the Baseline Condition. From July through September, San Luis releases would be reduced, relative to the Baseline Condition, when EWA water purchases are made available from the Delta. As a result of reduced reservoir releases, generation at San Luis for this period would be less than that in the Baseline Condition.

Although the annual San Luis generation would be little changed, the change in generation from summer to spring could have an economic effect on power operations because of temporal price differences. These effects could be potentially significant. Mitigation measures listed in Section 16.3.9 would reduce these potentially significant effects on power production and energy to less than significant.

EWA agencies' acquisition of water via source shifting would delay deliveries from San Luis Reservoir to the Export Service Area until after San Luis reaches its lowpoint. EWA actions would cause pumping facilities in the Export Service Area, including Edmonston and Dos Amigos, to pump later in the year compared to the Baseline Condition. Electricity prices may be more expensive at the modified pumping times. This would cause potentially significant economic impacts. Mitigation measures listed in Section 16.3.9 would reduce these potentially significant effects on power production and energy to less than significant.

16.3.7 Environmental Consequences/Environmental Impacts of the Fixed Purchase Alternative

The Fixed Purchase Alternative would involve the same actions as the Flexible Purchase Alternative, although to a lesser degree. The Fixed Purchase Alternative limits Upstream from the Delta Region transfers to 35 TAF and Export Service Area transfers to 150 TAF. The Flexible Purchase Alternative scenarios allow transfers up to 600 TAF and do not specify transfer limits in the Upstream from the Delta Region or Export Service Area. The effects described for the Flexible Purchase Alternative represent the effects on water supply and management for a maximum transfer amount; therefore, impacts considered less than significant under this alternative also would be considered less than significant for a lesser transfer amount (the Fixed Purchase Alternative). Analysis of the Fixed Purchase Alternative incorporates implementation of the Variable Assets described in Attachment 1, Modeling Description. Pumping energy cost effects of the Fixed Purchase Alternative are discussed in Section 16.3.4.2.2.

16.3.8 Comparative Analysis of Alternatives

16.3.8.1 Upstream from the Delta Region

As described above, the Fixed Purchase Alternative would limit Upstream from the Delta Region transfers to a maximum acquisition of 35 TAF from all water sources. In most years, this amount could be obtained from stored reservoir water purchases. In subsequent dry years, this amount could be less than 35 TAF and the same for the Flexible Purchase Alternative due to the limited availability of water from the Upstream from the Delta reservoirs. The Flexible Purchase Alternative would permit Upstream from the Delta Region transfers of up to 600 TAF. The changes in timing of releases from reservoirs that generate power and on the costs for pumping of water from the Delta under the Flexible Purchase Alternative would be substantially different from that of the Fixed Purchase Alternative. Although the Fixed Purchase Alternative is not expected to significantly effect power, the Flexible Purchase Alternative may due to the volume of water involved in the transfers.

16.3.8.2 Export Service Area

The effects of the two alternatives in the Export Service Area relate to the effects to power generation and pumping for San Luis Reservoir. Management of EWA assets may release water earlier from San Luis at a time when power is less expensive and cause pumping of refill water at a time when power is more expensive. The Flexible Purchase Alternative will involve the release and pumping of more EWA assets than the Fixed Alternative and therefore would have greater effects on power. As described under the Export Service Area analysis for the Flexible Purchase Alternative, any potentially significant impacts can be mitigated by implementation of the Mitigation Measures presented in Section 16.3.9. These measures would also be applied to the Fixed Purchase Alternative.

Table 16-10 summarizes the potential effects upon power for both alternatives.

16.3.9 Mitigation Measures

During times when acquisition of water for EWA would result in the value of power generated later in the summer being less than under the Baseline Condition, the EWA Program is responsible for covering those additional costs, as outlined in the CALFED Record of Decision, under the EWA Operating Principles Agreement. The agreement states:

> "EWA shall impose no net, increased incremental costs upon the Projects. The Management Agencies and Project Agencies shall develop a financing plan to cover all costs of the EWA from non-contractor funding sources. The plan shall address increased Project operating costs, both power and ancillary costs, of both the SWP and CVP resulting from implementation of the EWA; crediting the EWA as appropriate for reduced operating costs; crediting the EWA for certain power benefits; and revenues realized from the sale of EWA assets . . . . Considering the importance of acquiring water to the success of the EWA, the Project Agencies and Management Agencies shall meet and confer to develop alternatives for funding power and other incidental costs, if such costs interfere with the successful operation of the EWA."

According to this agreement, EWA shall mitigate any adverse economic, reliability, capacity or operational effects to CVP/SWP power operations or Project power users as a result of implementing the EWA Program.

16.3.10 Potentially Significant Unavoidable Impacts

The Flexible Purchase Alternative does not have any potentially unavoidable impacts. The adverse effects on Project power reduction and increased pumping costs caused by the shifting in the timing of releases of water from Project reservoirs can be mitigated through implementation of the mitigation measures provided in Section 16.3.9.

Table 16-10
Potential Transfer Amounts and Comparison of the Flexible and Fixed Purchase Alternatives for Power Resources

Region	Asset Acquisition or Management	Result	Effects	Flexible Purchase Alternative Change from Baseline	Fixed Purchase Alternative Change from Baseline	Significance of Flexible Purchase Alternative	Significance of Fixed Purchase Alternative	Comments
Sacramento River Region	Groundwater substitution/crop idling. Flexible: 166,000 AF Fixed: 35,000 AF	Altered temporal distribution of Keswick Releases.	Altered Lake Shasta monthly storage, compared to non-EWA conditions, caused by inability to match timing of asset acquisition with release for Delta export.	No decrease in the surface water elevation beyond optimum efficient levels in reservoirs that would decrease the efficiency of the power generation at CVP facilities. A change in timing of reservoir release, which could shift generation to a time of year when power has lower value.	No decrease in the surface water elevation beyond optimum efficient levels in reservoirs that would decrease the efficiency of the power generation at CVP facilities. A change in timing of reservoir release, which could shift generation to a time of year when power has lower value.	Potentially significant impact; Less-than-significant impact with mitigation measures.	Potentially significant impact; Less-than-significant impact with mitigation measures.	
Feather River Region	Stored Reservoir Water Flexible & Fixed: Sly Creek – 5,000 AF Little Grass Valley – 12,000 AF	Water released from Sly Creek and Little Grass Valley Reservoirs	Altered Sly Creek and Little Grass Valley Reservoir storage	No decrease in the surface water elevation beyond optimum efficient levels in reservoirs that would decrease the efficiency of power generation facilities. Potential change in timing of reservoir release, which could shift generation to a time of year when power has lower value.	No decrease in the surface water elevation beyond optimum efficient levels in reservoirs that would decrease the efficiency of power generation facilities. Potential change in timing of reservoir release, which could shift generation to a time of year when power has lower value.	Less-than-significant impact.	Less-than-significant impact.	

Table 16-10
Potential Transfer Amounts and Comparison of the Flexible and Fixed Purchase Alternatives for Power Resources

Region	***Asset Acquisition or Management***	***Result***	***Effects***	***Flexible Purchase Alternative Change from Baseline***	***Fixed Purchase Alternative Change from Baseline***	***Significance of Flexible Purchase Alternative***	***Significance of Fixed Purchase Alternative***	***Comments***
			Altered Lake Oroville monthly storage, compared to non-EWA conditions, caused by inability to match timing of asset acquisition with release for Delta export.	No decrease in the surface water elevation beyond optimum efficient levels in reservoirs that would decrease the efficiency of the SWP power generation facilities. A change in reservoir release, which could shift generation to a time of year when power has lower value.	No decrease in the surface water elevation beyond optimum efficient levels in reservoirs that would decrease the efficiency of the SWP power generation facilities. A change in reservoir release, which could shift generation to a time of year when power has lower value.	Potentially significant impact; Less-than-significant impact with mitigation measures.	Potentially significant impact; Less-than-significant impact with mitigation measures.	Mitigation measures would only be implemented if the value of power generated later in the summer was less than under the Baseline Condition.
	Groundwater Substitution/ Crop Idling Flexible: 230,000 AF Fixed: 35,000 AF	Altered temporal distribution of Oroville Releases	Altered Lake Oroville monthly storage, compared to non-EWA conditions, caused by inability to match timing of asset acquisition with release for Delta export.	No decrease in the surface water elevation beyond optimum efficient levels in reservoirs that would decrease the efficiency of the SWP power generation facilities. A change in reservoir release, which could shift generation to a time of year when power has lower value.	No decrease in the surface water elevation beyond optimum efficient levels in reservoirs that would decrease the efficiency of the SWP power generation facilities. A change in reservoir release, which could shift generation to a time of year when power has lower value.	Potentially significant impact; Less-than-significant impact with mitigation measures.	Potentially significant impact; Less-than-significant impact with mitigation measures.	

Table 16-10
Potential Transfer Amounts and Comparison of the Flexible and Fixed Purchase Alternatives for Power Resources

Region	***Asset Acquisition or Management***	***Result***	***Effects***	***Flexible Purchase Alternative Change from Baseline***	***Fixed Purchase Alternative Change from Baseline***	***Significance of Flexible Purchase Alternative***	***Significance of Fixed Purchase Alternative***	***Comments***
Yuba River Region	Flexible: 100,000 AF Fixed: 35,000 AF		Altered Bullards Bar monthly storage	No decrease in the surface water elevation beyond optimum efficient levels in reservoirs that would decrease the efficiency of the power generation facilities. Potential change in timing of reservoir release	No decrease in the surface water elevation beyond optimum efficient levels in reservoirs that would decrease the efficiency of the power generation facilities. Potential change in timing of reservoir release	Less-than-significant impact.	Less-than-significant impact.	No potential impacts to any entity other than seller.
	Groundwater Substitution Flexible: 85,000 AF Fixed: 35,000 AF	Water regulated at New Bullards Bar	Altered New Bullards Bar Reservoir monthly storage compared to non-EWA conditions	No decrease in the surface water elevation beyond optimum efficient levels in reservoirs that would decrease the efficiency of the power generation facilities. Potential change in reservoir release, which could shift generation to a time of year when power has lower value.	No decrease in the surface water elevation beyond optimum efficient levels in reservoirs that would decrease the efficiency of the power generation facilities. Potential change in reservoir release, which could shift generation to a time of year when power has lower value.	Potentially significant impact; Less-than-significant impact with mitigation measures.	Potentially significant impact; Less-than-significant impact with mitigation measures.	No potential impacts to any entity other than seller.

Table 16-10
Potential Transfer Amounts and Comparison of the Flexible and Fixed Purchase Alternatives for Power Resources

Region	Asset Acquisition or Management	Result	Effects	Flexible Purchase Alternative Change from Baseline	Fixed Purchase Alternative Change from Baseline	Significance of Flexible Purchase Alternative	Significance of Fixed Purchase Alternative	Comments
American River Region	Stored Reservoir Water Flexible & Fixed: 20,000 AF	Water is released from French Meadows and Hell Hole Reservoirs	Altered French Meadows and Hell Hole Reservoir storage	No decrease in the surface water elevation beyond optimum efficient levels in reservoirs that would decrease the efficiency of the power generation facilities. Change in timing of reservoir release	No decrease in the surface water elevation beyond optimum efficient levels in reservoirs that would decrease the efficiency of the power generation facilities. Change in timing of reservoir release	Less-than-significant impact.	Less-than-significant impact.	No potential impacts to any entity other than seller.
	Stored Reservoir Water, Groundwater Purchase, and Crop Idling 41,000 AF	Water regulated at Folsom Lake	Altered Folsom Reservoir monthly storage compared to non-EWA conditions caused by inability to match timing of asset acquisition with release for Delta export.	No decrease in the surface water elevation beyond optimum efficient levels in reservoirs that would decrease the efficiency of the power generation facilities. A change in reservoir release, which could shift generation to a time of year when power has lower value. An increase in pumping energy requirements for purveyors who withdraw water from reservoirs.	No decrease in the surface water elevation beyond optimum efficient levels in reservoirs that would decrease the efficiency of the power generation facilities. A change in reservoir release, which could shift generation to a time of year when power has lower value. An increase in pumping energy requirements for purveyors who withdraw water from reservoirs.	Potentially significant impact; Less-than-significant impact with mitigation measures.	Potentially significant impact; Less-than-significant impact with mitigation measures.	Mitigation measures would be implemented if the economic value of power generated was less than under the Baseline Condition, or if additional pumping costs were experienced by agencies pumping water from Folsom Reservoir.

Table 16-10
Potential Transfer Amounts and Comparison of the Flexible and Fixed Purchase Alternatives for Power Resources

Region	***Asset Acquisition or Management***	***Result***	***Effects***	***Flexible Purchase Alternative Change from Baseline***	***Fixed Purchase Alternative Change from Baseline***	***Significance of Flexible Purchase Alternative***	***Significance of Fixed Purchase Alternative***	***Comments***
Merced/San Joaquin River Regions	Stored groundwater Purchase Flexible & Fixed: 25,000 AF	Water regulated at Lake McClure	Alteration of monthly storage in New Exchequer and McSwain compared to non-EWA conditions	No decrease in the surface water elevation beyond optimum efficient levels in reservoirs that would decrease the efficiency of the power generation facilities. A change in reservoir release, which could shift generation to a time of year when power has lower value.	No decrease in the surface water elevation beyond optimum efficient levels in reservoirs that would decrease the efficiency of the power generation facilities. A change in reservoir release, which could shift generation to a time of year when power has lower value.	Potentially significant impact; Less-than-significant impact with mitigation measures.	Potentially significant impact; Less-than-significant impact with mitigation measures.	No potential impacts to any entity other than seller.
Delta Region	Crop Idling, Groundwater Substitution, Stored Groundwater Purchase, Stored Reservoir Water Purchase	Upstream from Delta reservoirs release water	Alteration of Delta exports	A change in timing of pumping, which could shift the load to a time of year when power has higher costs.	A change in timing of pumping, which could shift the load to a time of year when power has higher costs.	Potentially significant impact; Less-than-significant impact with mitigation measures.	Potentially significant impact; Less-than-significant impact with mitigation measures.	Mitigation measures would be implemented if the economic cost of Delta export pumping was greater than under the Baseline Condition.

Table 16-10
Potential Transfer Amounts and Comparison of the Flexible and Fixed Purchase Alternatives for Power Resources

Region	Asset Acquisition or Management	Result	Effects	Flexible Purchase Alternative Change from Baseline	Fixed Purchase Alternative Change from Baseline	Significance of Flexible Purchase Alternative	Significance of Fixed Purchase Alternative	Comments
Export Service Area	Source Shifting	Water is released from Metropolitan Water District reservoirs	Alteration of water levels in San Luis Reservoir	A change in timing of pumping, which could shift the load to a time of year when power has higher costs. An increase in pumping energy requirements for purveyors who withdraw water from reservoirs.	A change in timing of pumping, which could shift the load to a time of year when power has higher costs. An increase in pumping energy requirements for purveyors who withdraw water from reservoirs.	Potentially significant impact; Less-than-significant impact with mitigation measures.	Potentially significant impact; Less-than-significant impact with mitigation measures.	
	Borrowed Project Water	Water is released from San Luis Reservoir	Alteration of water levels in San Luis Reservoir	A decrease in the surface water elevation beyond optimum efficient levels in reservoirs that would decrease the efficiency of the power generation facilities. A change in reservoir release, which could shift generation to a time of year when power has lower value.	A decrease in the surface water elevation beyond optimum efficient levels in reservoirs that would decrease the efficiency of the power generation facilities. A change in reservoir release, which could shift generation to a time of year when power has lower value.	Potentially significant impact; Less-than-significant impact with mitigation measures.	Potentially significant impact; Less-than-significant impact with mitigation measures.	

16.3.11 Cumulative Effects

There is a potential for cumulative effects to CVP/SWP power production for other water acquisition programs that alter the timing of water releases from Project reservoirs. In the past, these programs have included specific terms for use of Project power in contractual documents. Recent year EWA water purchases have been facilitated by terms of Interim Protocol documents. Because the other programs remain in the planning stages, or are subject to CVP/SWP policies that are evolving, operational details of the programs cannot be described. Any power effects of these programs would not constitute environmental effects, but rather economic losses. The Flexible Purchase Alternative could purchase up to 600 TAF upstream from the Delta; these transfers would use all the export capacity of the CVP/SWP pumps. Therefore, the analysis of 600 TAF also covers the effects of other water purchases or transfers that convey water through the Delta. Power effects in the cumulative condition would be essentially the same as those shown for the Flexible Purchase Alternative.

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