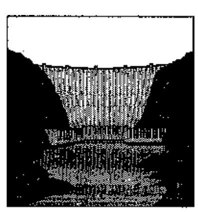
7.9 Power Production and Energy

The CALFED Bay-Delta Program would cause positive and negative effects on power and energy. Potentially significant environmental impacts associated with the Preferred Program Alternative can be avoided or reduced through mitigation measures.



7.9 Power Production and Energy

7.9.1 SUMMARY

CVP and SWP hydroelectric facilities are an important source of power in California. SWP power is used primarily to run the pumps that move state water to the farmlands and cities where it can be applied to economically beneficial uses, and to provide peak power to utility companies through exchange agreements. In addition to furnishing power to the pumping facilities located throughout the Central Valley and Delta Region, CVP power is an important source of electricity in many of California's communities, supplying the power needs of municipal utilities, irrigation districts, and institutions and facilities such as wildlife refuges, schools, prisons, and military bases. Western Area Power Administration (Western) customers have not only relied on such power for many years, but also have enjoyed the economic benefits associated with Western's relatively low power rates. SWP long-term power contracts act as exchange agreements with utility companies supplying them with peak power. Except for surplus conditions in extremely wet years, all SWP power is used for peak power exchange arrangements and to operate pumping facilities. In most years, additional power is purchased by the SWP to meet pumping load power requirements. Both CVP and SWP sell power at rates designed to recover costs, which for CVP historically have been slightly below market rates. Revenue from Western power sales is an important funding source for the CVP Restoration Fund and for repaying project debt incurred building the CVP.

CVP and SWP hydroelectric facilities are a very important source of power in many of California's communities.

Preferred Program Alternative. Although effects of the Preferred Program Alternative are expected to be both positive and negative, the negative effects predominate. Anticipated effects are summarized below:

Although effects of the Preferred Program Alternative are expected to be both positive and negative, the negative effects predominate.

- Energy use would increase as each component of the CALFED Bay-Delta Program (Program) is constructed or implemented, and as Program elements are maintained. Many Program elements have an associated electric power load, such as a pumping load. To the extent such pumping load increases exceed the increases in project generation from Program actions which alter river or reservoir operations, the increased load will initiate a chain of events leading to additional generation from other sources. For the CVP, such net increases in pumping load will decrease the amount of energy available to sell to CVP preference power customers, requiring replacement from other, generally more expensive sources. Under present conditions

these sources will typically be thermal in nature and will result in emissions and other impacts associated with the development and operation of thermal power plants.

- In general, energy use and related energy costs would decrease in areas where water conservation measures are implemented under the Water Use Efficiency Program. Exceptions include cases where agricultural water users switch from gravity-fed irrigation to sprinkler systems, and where water made available through conservation is then transferred by pumping to more remote locations.

- If storage facilities are enlarged under the Storage element, temporary and adverse reductions in available capacity and energy generation at existing hydroelectric facilities could result if such facilities are unable to generate during implementation of the Program. The Storage element also could cause a localized increase in energy use as new storage facilities are filled and perhaps a localized net increase in use if new pumped storage facilities are constructed.

- If storage facilities are developed, and water management Criterion B is assumed, CVP and SWP available capacity and generation would likely increase. However, the increase in CVP and SWP project energy use associated with the Program would be greater than the increase in power production. Therefore, the amount of power available for sale from the projects would be reduced, the amount of power the projects would need to purchase from the market would increase, and Western and DWR would likely increase their power rates.

The increase in CVP and SWP project energy use associated with the Program would be greater than the increase in power production.

- Pumping- and treatment-related energy use would increase in areas where water transfers occur.

- Long-term energy use in levee maintenance areas would decrease if the Levee System Integrity Program reduces the need for recurring maintenance of levees.

- Pumping- and treatment-related energy use would decline in areas where the Water Quality Program is implemented because of improvements in water quality. Energy use also could be reduced as land use practices that degrade water quality are changed.

- Changes in stream flows and operations caused by the Program could in turn cause beneficial or adverse effects at downstream or other hydrologically connected hydroelectric facilities that are not part of the CVP or SWP.

- The beneficial effects of the Program on recreation and other environmental resources could cause an indirect increase in energy use in the form of vehicle fuel consumption as recreation traffic increases.

Alternatives 1, 2, and 3. Alternatives 1, 2, and 3 would cause the same types of effects as those summarized above for the Preferred Program Alternative.

7.9.2 AREAS OF CONTROVERSY

Areas of controversy as defined by CEQA involve differences of opinion among technical experts or information that is not available and cannot be readily obtained. According to this definition, no areas of controversy are related to power production and energy.

Some controversial topics are listed below (these topics are addressed in Section 7.9.4):

- Issues regarding the level of detail used in the impact assessment and differentiating between CVP and SWP effects.
- Assessing peak-power effects versus average monthly effects.

The Program has no specific objectives for hydropower generation. However, the Program does seek to minimize negative effects on resources, such as hydropower generation, during and after implementation. The Program also seeks to minimize redirected impacts and to maintain linkage between the beneficiaries of actions and the costs of those actions. The Program may result in temporary or long-term changes in river and reservoir operations, which may affect the quantity, timing, and value of hydropower produced by the SWP and CVP. Additional pumping also may increase the amount of project energy use (power consumed by the CVP and SWP to move water through their systems). An increase in project energy use can reduce the amount of surplus hydropower that might otherwise be available for sale from the CVP (necessary to repay the CVP debt) and may increase the amount of power that must be purchased from outside sources to meet SWP project energy use. Under present economic conditions, fossil fuel or other thermal generation likely would be used to meet the increase in project energy use. Power from renewable resources (for example, wind or solar) would only be used if sufficient economic incentives are provided.

The Program has no specific objectives for hydropower generation. However, the Program does seek to minimize negative effects on resources, such as hydropower generation, during and after implementation.

The Program is coordinating with Western to ensure that issues are identified and properly framed, so that consequences and options are clear to stakeholders, the public, and Program decision makers. In addition, reservoirs with hydroelectric power facilities present an opportunity for reoperation for multiple benefits. The Program is continuing to assess these opportunities in conjunction with the project owners to achieve Program objectives while endeavoring to maintain equitable cost and benefit linkages.

The Program is coordinating with Western to ensure that issues are identified and properly framed, so that consequences and options are clear to stakeholders, the public, and Program decision makers.

7.9.3 AFFECTED ENVIRONMENT/ EXISTING CONDITIONS

Changes in power supplies and deliveries associated with the Program alternatives would be caused by Program-related actions and other system-wide factors occurring in many different regions throughout the study area. A system-wide analysis is necessary to accurately portray overall effects on power and energy.

A system-wide analysis is necessary to accurately portray overall effects on power and energy.

7.9.3.1 ALL REGIONS

The Program alternatives primarily will affect the state's two largest water systems, the CVP and SWP and their associated hydroelectric facilities. This section provides a brief overview of the existing conditions for each of the major power production and energy assessment variables.

The Program alternatives primarily will affect the state's two largest water systems, the CVP and SWP and their associated hydroelectric facilities.

SWP. Water deliveries from the SWP initially were provided in 1962 to Alameda and Santa Clara Counties through the SBA. SBA power generation from SWP facilities first was realized 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 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 on-peak periods. Although the SWP uses more energy than it generates from its hydroelectric facilities, DWR has exchange agreements with other utility companies and has developed other power resources. When available, surplus power is sold by DWR to minimize the net cost of pumping energy. Excess power was first sold commercially in 1968.

CVP. CVP power generation facilities initially were developed based on the premise that power could be generated to meet project use loads. The Reclamation Act of 1939 provided for surplus power to be sold first to preference customers, including irrigation and reclamation districts, cooperatives, public utility districts, municipalities, and large educational or government facilities. Surplus commercial power may be sold to non-preference utility companies. The first commercial power generated by the CVP was sold in 1945.

In addition to comprising one of the state's largest water systems, the CVP and SWP are part of an integrated electrical power system within California. All major electrical loads and generators within the state boundaries are synchronized to operate as a single cohesive system by the California ISO. In addition to the California ISO, there is a much broader system of electric generation and transmission that the CVP and SWP interact with called the Western Systems Coordinating Council (WSCC). These interactions with the WSCC could extend over the entire West Coast and inland to the desert regions of the Southwest.

All major electrical loads and generators within the state boundaries are synchronized to operate as a single cohesive system by the California ISO.

Other Hydroelectric Facilities. In addition to CVP and SWP hydroelectric facilities, other hydroelectric facilities are present in the study area. Hydroelectric generation facilities in the study area 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 water and irrigation districts. Some of the larger facilities outside the CVP and SWP systems include SCE's Big Creek System (approximately 790 megawatts [MW] of nameplate capacity) and Mammoth Pool Project (approximately 180 MW of nameplate capacity) in Fresno County; PG&E's Pit System (approximately 317 MW of nameplate capacity) and McCloud-Pit System (approximately 340 MW of nameplate capacity) in Shasta County; PG&E's Upper North Fork Feather River System (approximately 340 MW of nameplate capacity) in Plumas County; SMUD's Upper American River Project System (approximately 640 MW of nameplate capacity) in El Dorado County; Yuba County Water Agency's Yuba River Project (approximately 300 MW of nameplate capacity) in Yuba County; and the New Don Pedro Project (approximately 170 MW of nameplate capacity) jointly owned by Turlock Irrigation District and Modesto Irrigation District in Tuolumne County.

System-Wide SWP and CVP Capacity and Energy Generation. CVP and SWP hydroelectric generation facilities have a total nameplate capacity rating of approximately 3,678 MW (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 estimated to be available on average (over the 73-year hydrologic record used in this analysis), and 1,427 MW is estimated to be available during dry conditions. These levels of CVP capacity represent the instantaneous production capability of the facilities; however, the actual capability of the CVP generation to serve load on a sustained basis is considerably less due to the limited amounts of energy it is capable of producing. Approximately 1,490 MW of SWP capacity is available on average during summer, and 1,357 MW of SWP capacity is available during dry conditions. It should be noted that facilities often are not generating at full capacity.

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

Historical system-wide energy generation attributable to the SWP has ranged from about 600,000 MW hours (MWh) in 1968 to 5.4 million MWh in 1983. Total CVP energy generation and supplemental energy purchases (which are made to support sales to preference power customers) have ranged from 2.1 million MWh in 1992 to 8.8 million MWh in 1983. Nameplate CVP capacity was approximately 630 MW in 1960, increasing to approximately 2,220 MW in 1995. SWP nameplate capacity was approximately 1,340 MW in 1968 and 1,670 MW in 1995.

System-Wide SWP and CVP Project Energy Use. Current annual CVP project energy use averages 1,563 GWh, while annual SWP project energy use averages 8,412 GWh. Most of this energy is used to power the surface water pumping facilities of these projects. The SWP's historical system-wide project energy use has ranged from approximately 600,000 MWh in 1968 to 8.4 million MWh in 1990. The CVP's historical project energy use has ranged from approximately 320,000 MWh in 1963 to 1.7 million MWh in 1976.

Most of the energy used by the SWP and CVP powers the surface water pumping facilities of these projects.

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

Historical energy sales from the CVP have ranged from approximately 2 million MWh in 1960 to 7.9 million MWh in 1992. Historical revenue from CVP energy sales has ranged from approximately $10 million in 1960 to $269 million in 1987.

DWR's power program is designed to meet the pumping energy requirements of the SWP. Unlike Western, DWR does not serve preference power customers.

Net SWP Energy Requirement. 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 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 SWP net energy requirements by purchasing energy from a variety of sources.

The SWP is a net consumer of power because its project energy use exceeds the amount of energy generated at its hydroelectric facilities.

DWR and Western Power Rates. Western's current "composite energy rate" is $20.60/MWh and is equal to the total revenue requirement to be recovered from capacity and energy sales, divided by the amount of energy sales. This rate differs from the actual capacity and energy rates set by Western and was used as a proxy to estimate effects of the Program alternatives. DWR's existing "system energy rate" is $23.80/MWh and is calculated as the net SWP cost of power divided by the SWP energy requirements.

Historically, Western's capacity rates have ranged from $750/MW per month in 1960 to $7,440/MW per month in late 1991 through early 1993. The rate in 1996 was $4,320/MW per month. Western's energy rates have ranged from $3.00/MWh in 1960 through early 1978, to $31.44/MWh in late 1986 through early 1988. In 1994, the energy rate went to a base-and-tier system. The base rate in 1996 was $15.83/MWh, and the tier rate was $26.27/MWh.

The SWP is a water delivery project; DWR does not sell power capacity from the project to its water customers. Since DWR does not charge for capacity in the traditional sense, no capacity rate was calculated. The SWP system energy rate has ranged from a low of $18.40/MWh in 1993 to a high of $32.00/MWh in 1986.

The SWP is a water delivery project; DWR does not sell power capacity from the project to its water customers.

7.9.4 ASSESSMENT METHODS

In general, power and energy effects were defined by comparing conditions associated with the different Program alternatives to related conditions under the No Action Alternative. The significance criteria defined in Section 7.9.5 were applied to determine whether mitigation would be required.

Ranges of effects were defined to represent the types of effects that could result from implementing Program actions. Examples of potential alternative components were used to develop the representative ranges of effects because the specific components of the

Program have not been defined for the purpose of this programmatic review. This range of components covers all potential effects.

It is not known at this time how changes in capacity, energy generation, power costs, and project energy use caused by the Program alternatives would be allocated between the CVP and SWP. Therefore, the full range of potential effects on the CVP and SWP have been defined to reflect this uncertainty. Additional information regarding how the Program alternatives would affect the CVP versus the SWP and specific power and water users (that is, the agencies and utilities that purchase power and water from Western and DWR, and their retail customers) cannot be provided at this time. These types of allocation decisions have not been made by the agencies that would implement the Program alternatives and will not be made until after this programmatic analysis. This is why the range of effects are described in this document as *potential* effects on the CVP or the SWP. At one extreme, all of the power supply and power cost effects described herein would be experienced by the CVP and its power and water users, and none would be experienced by the SWP and its power and water users. At the other extreme, the SWP and its power and water users would experience all of the impacts. Neither of these extremes is likely because the effects are expected to be allocated to both the CVP and SWP; effects therefore would be experienced by customers of both systems. However, no basis is available to further delineate CVP versus SWP effects, and such an analysis would be speculative.

It is not known at this time how changes in capacity, energy generation, power costs, and project energy use caused by the Program alternatives would be allocated between the CVP and SWP.

Power plants that may be modified were identified, and the existing and proposed nameplate capacities were defined in MW. Changes in capacity and energy generation were defined that would be caused by changes in system operations. These changes in operation would be caused by potential (1) physical modifications to hydropower plants, (2) new storage projects, and (3) changes in reservoir releases and other measures needed to implement the various Program elements.

The effects assessed include changes in average- and dry-year energy generation. The potential for the CVP and SWP to provide ancillary services in a deregulated market was considered. Changes in annual and monthly project energy use (increases or decreases in pumping load) also were assessed. It is assumed that lost energy generation from the CVP would come as peaking power, that is electricity generated at times when it is most in demand and therefore marketable at the highest price.

The effects assessed include changes in energy generation and project energy use. Changes in annual and monthly project energy use (increases or decreases in pumping load) also were assessed.

Decisions made by Western on how and when to supply electric power or constraints placed on CVP electric generation may influence the operation of other power suppliers within the state and WSCC. If the amount of power available to Western's customers changes at a certain time of day, the customers would need to change their own power generation or make purchases from other power suppliers or the California market. While the overall demand for power may not change, an incremental change in the quantity or timing of power from the CVP or SWP would trigger an offsetting change in other power-generating resources operated in the state or WSCC.

While the overall demand for power may not change, an incremental change in the quantity or timing of power from the CVP or SWP would trigger an offsetting change in other power-generating resources operated in the state or WSCC.

Incremental resources that may be used to make up for reduced CVP and SWP generation are projected to be primarily comprised of combustion turbines (CTs) and combined cycle combustion turbines (CCCTs). According to the WSCC, these two types of power-generating facilities account for nearly one-half of all WSCC resources projected over the next 10 years. Natural gas is the predominant fuel for these technologies. The most economically efficient way of operating hydroelectric generation is to produce power for sale during peak times of demand for electricity. CTs and CCCTs are well suited to this type of operation. For purposes of assessing environmental effects, CTs and CCCTs are assumed to be the incremental resources that make up for lost or less-than-optimally timed hydroelectric generation from the CVP or SWP. It is further assumed that CTs and CCCTs will be used equally in replacing CVP and SWP power.

Land use and air quality emission impact factors are used in conjunction with estimates of lost CVP and SWP generation and load-following capacity to calculate annual quantities of air pollution and land requirements for power plants to replace the lost power. Other impacts, such as solid waste production and water consumption, tend to be of less importance for these technologies. Impact factors are multiplied by estimated changes in generation and capacity to calculate air quality and land consumption impacts. According to Western, the impact factors are as follows:

Land use and air quality emission impact factors are used in conjunction with estimates of lost CVP and SWP generation and load-following capacity to calculate annual quantities of air pollution and land requirements for power plants to replace the lost power.

Nitrogen oxide (NO_x)	750 lb/GWh of generation
Sulfur dioxide (SO_x)	10 lb/GWh of generation
Carbon monoxide (CO)	300 lb/GWh of generation
Particulate matter (PM_{10})	50 lb/GWh of generation
Carbon dioxide (CO_2)	475 tons/GWh of generation
Land requirements	0.16 acre/MW of capacity

The DWRSIM was used to define changes in available capacity and energy generation at affected state and federal hydroelectric facilities. Pumping energy at certain CVP facilities, and monthly capacity at all generating facilities were estimated using a spreadsheet postprocessor to manipulate DWRSIM-estimated reservoir levels and flows. (DWRSIM has been enhanced to directly incorporate Reclamation's PROSIM power module.) A range of operational scenarios have been defined and modeled to help characterize the range of potential effects that would be caused by the Program alternatives. The incremental effects of the Program alternatives were determined by comparing the average- and dry-year model results under each alternative to related conditions under the No Action Alternative.

For purposes of environmental impact assessment, it is assumed that lost generation is a peaking resource. A quantitative analysis of hourly peak effects cannot be conducted with DWRSIM for the quantitative power impact analysis because DWRSIM uses a monthly time-step as opposed to an hourly time-step.

Direct effects of the Program on SWP and CVP power production and replacement costs were estimated based on available information regarding variable costs of operation and maintenance, long-term open-market power rates, and the costs of new facilities and modifications to existing facilities as included in the Program.

It was assumed that Western's preference power customers and DWR would obtain replacement power from other sources as the amount of power available for sale by Western decreases and the net energy requirements of the SWP increase. Because of the long-term planning horizon, the value of DWR's replacement power was estimated based on open-market prices that are expected to be present in a deregulated market.

It was assumed that Western's preference power customers and DWR would obtain replacement power from other sources as the amount of power available for sale by Western decreases and the net energy requirements of the SWP increase.

The future price of power in California's deregulated power markets was estimated. Publicly available analyses of future power prices in the restructured industry were evaluated, together with market power analyses prepared by California's investor-owned utility companies and the California Energy Commission. These analyses were used to develop an estimated range of future prices that accounted for differences in the value of power during on- and off-peak periods. The range of long-term average power prices established for this analysis varied by approximately 15% and was based on the historical relationship between PG&E's on- and off-peak incremental rates. The ranges used for the low and high forecast are $22.50/MWh (off peak) to $26.00/MWh (on peak), and $30.00/MWh (off peak) to $34.00/MWh (on peak), respectively, in 1998 dollars. The midpoint in the range of off-peak prices was used to estimate the value of incremental pumping energy, and the midpoint in the range of on-peak prices was used to estimate the value of changes in generation. This approach assumes that system operators will continue attempting to generate electricity as much as possible when it is most valuable (during peak periods) and attempting to pump water during off-peak periods.

One of the key indicators for evaluating economic effects and associated environmental impacts of the various Program alternatives on power customers is the change in the CVP and SWP capacity to meet electrical load in a manner that minimizes the need for other power resources. This capacity is generally referred to as load-carrying capacity or load-carrying capability. Measurement of load-carrying capacity is based on the usefulness of the energy available, under adverse hydrologic conditions, in meeting the peaking requirements of customer electrical loads. This capacity is primarily a function of available energy and the characteristics of the electrical load being served. In dry hydrologic periods, it may be difficult to meet peak hourly electrical loads because available capacity is diminished (due to low reservoir levels) at the same time that it is most needed (high use hourly periods). California does not have excess peaking capacity, so a reduction in peaking capacity is generally indicative of a need for new generating capacity to be constructed on the system, with attendant effects. To the extent that all, or a large portion, of the effects associated with re-operation are placed on the CVP system, one can expect significant degradation of the capacity available for marketing by Western and hence the value of the CVP system to Western and its customers.

One of the key indicators for evaluating economic effects and associated environmental impacts of the various Program alternatives on power customers is the change in the CVP and SWP capacity to meet electrical load in a manner that minimizes the need for other power resources.

The analysis carried out for this programmatic report does not provide for the quantification of the effects associated with changes in project load-carrying capacity. As discussed earlier, the modeled time-step for this analysis has been limited to a monthly analysis, rather than an hourly analysis. As has also been discussed, actual effects to the CVP or SWP have not yet been individually identified. This allocation between the two projects will not occur at the programmatic level of this study. Allocations will need to be identified in subsequent project-level studies and environmental documents.

Energy-use effects (other than project energy use) during and after construction (for example, vehicle fuels and space heating) were assessed qualitatively. These types of effects are described but will be assessed in more detail during subsequent project-level studies, when more detailed information about specific construction procedures and conservation measures is available.

Energy use impacts (other than project energy use) during and after construction were assessed qualitatively.

7.9.5 CRITERIA FOR DETERMINING EFFECTS

Under NEPA, when economic or social effects are interrelated with natural or physical environmental effects, an EIS should discuss the economic or social impacts of the proposed action, even if they are indirect effects. The following economic effects and potential indirect physical environmental effects may result from Program actions:

- *Effects on Capacity, Energy Generation, Project Use and Other Pumping Loads, and Related Rates* - Adverse effects on the net (net refers to positive changes less negative changes) capacity of CVP hydroelectric facilities and net energy generated at such facilities were considered potentially significant if such economic effects would (a) increase Western's rates to levels that are higher than rates available in open-market conditions, (b) reduce the annual energy available for sale to preference customers during an average year by 5.0% or more, (c) reduce the energy available for sale to preference customers during any single month of an average year by 5.0% or more, or (d) cause a decrease in the value of CVP power resulting in an increase in a preference customer's average power cost by $0.50/MWh. The significance of SWP power-related effects is measured by how the effects would affect DWR's system energy rate and the net energy requirement of the SWP. Effects on DWR's system energy rate and the SWP net energy requirement were considered potentially significant if they would cause DWR's water rates to increase significantly. The significance of DWR water rate effects is addressed in Section 7.2, "Agricultural Economics," and in Section 7.5, "Urban Water Supply Economics."

- *Effects on DWR and Western Power Customers* - Western and its preference power customers would experience potentially significant adverse economic effects if Western's rates increase to the point that they exceed rates available on the open market. Such a situation would cause negative economic effects for Western's preference power customers as their power costs increase and their retail customers leave to find cheaper sources of power. Some of Western's preference power customers could experience potentially significant economic effects even if Western's

Western and its preference power customers would experience potentially significant adverse economic effects if Western's rates increase to the point that they exceed rates available on the open market.

rates increase to a level below open-market rates, although some customers could withstand rate increases better than others could. Methods to avoid these types of effects are discussed in Section 7.9.7.

To estimate the effects of the program alternatives on Western power customers, analyses were conducted to examine the effect on an "average" Western customer (for whom CVP power makes up 14% of their total current resource mix), and on a "high allocation" Western customer (for whom CVP power makes up 85% of their total current resource mix).

Significance criteria have not been developed for DWR power customers because these customers rely on a range of alternative sources of power supply and purchases from DWR do not represent a major long-term resource to them.

- *Effects on CVP Restoration Fund Power Revenues* - If water payments to the CVP Restoration Fund drop, power payments to the fund may need to increase and Western could be forced to raise power rates. This effect is considered potentially significant from the standpoint of Western and the CVP if Western's rates increase to levels that are higher than rates available on the open market. Such a situation could increase the power costs of Western's preference power customers to a point where they may want to switch power providers. Loss of these customers would impede financing the fund and threaten repayment of the CVP. Some of the measures that could help to avoid these types of effects are discussed in Section 7.9.7.

If water payments to the Restoration Fund drop, power payments to the fund may need to increase and Western could be forced to raise power rates.

- *Energy-Use Effects for Other than Pumping Load During and after Construction* - Energy-use effects for project construction and other uses such as space heating will be assessed in subsequent project-level studies. Project-specific studies will include more detailed information about the specific construction projects, required changes in operations, and proposed energy conservation measures to be followed during and after construction.

- *Land Use Impacts* - Power-related impacts on land use occur when new power plants are built as a result of either reduced generation or additional net energy consumption resulting from Program actions. While the acreage needed for replacement power plants can be calculated at a programmatic level, it is extremely speculative and may not be directly related to Program actions. In addition, the number and location of such power plants cannot be determined until they are proposed. Consequently, land use conflicts can be assessed only at the time of project-level environmental review. The location of new power facilities should be selected to avoid conflicts with adjacent incompatible land uses. Land use conflicts would be considered potentially significant impacts if power plant construction and operation would cause noise thresholds established for adjoining uses to be exceeded, or if sensitive adjoining uses such as residential or public buildings or gathering places would be exposed to potential risk of upset from explosion or the release of toxic or hazardous materials. These impacts can be mitigated to less-than-significant levels .

- *Air Quality Impacts* – Indirect impacts on air quality may occur if power lost due to reductions in hydrogeneration is replaced with generation from CTs and CCCTs. Air quality impacts can result from power plant construction (temporary impacts) or operations (ongoing impacts). Since the number and location of new power plants to be built is unknown and speculative, construction impacts cannot be assessed until site-specific project level environmental assessment is undertaken prior to construction.

  The level of air quality impacts resulting from the need for replacement power, either from new or existing power plants, will depend on the location of additional generation. Such air quality impacts would be indirect. Attendant air quality effects would be similarly dispersed. Emissions from new generation, although potentially significant, would be required to meet the air quality standards and mitigation requirements of the district in which the generation occurs. Compliance with such standards and mitigation measures are expected to prevent emission impacts from causing significant impacts, and therefore, will not have a significant effect on the environment.

The level of air quality impacts resulting from the need for replacement power, either from new or existing power plants, will depend on the location of additional generation.

  The most pronounced effects on hydrogeneration requiring replacement occur in cases with substantial storage. If surface water storage reservoirs are contructed as pump-storage facilities, a portion of the hydropower consumed bringing water to such facilities would be recouped when the water is released through generators, reducing the need for other replacement generation and attendant air emissions.

The most pronounced effects on hydrogeneration requiring replacement occur in cases with substantial storage.

7.9.6 NO ACTION ALTERNATIVE

Tables 7.9-1 and 7.9-2 summarize and compare existing conditions and conditions under the No Action Alternative for the power production and energy resources of the CVP and SWP, respectively. Conditions under the No Action Alternative reflect system water demands, pumping and other operations, power production, and energy economics using both water management Criterion A and water management Criterion B.

Power production and energy conditions under the No Action Alternative are generally expected to be similar to those described for existing conditions.

7.9.7 CONSEQUENCES: PROGRAM ELEMENTS COMMON TO ALL ALTERNATIVES

7.9.7.1 PREFERRED PROGRAM ALTERNATIVE

All Regions/All Programs

This section first summarizes potential economic effects and environmental impacts that would occur from the combined and integrated effects of different programs under the Preferred Program Alternative. For example, effects on available capacity, generation, and project use would be caused by a combination of changes in flow releases under the Ecosystem Restoration Program, possible new storage under the Storage elements, and reductions in water use and new water transfers under the Water Use Efficiency Program. Beginning with the subsection, "Ecosystem Restoration Program," the remainder of this section presents potential effects on power and energy that are associated with individual programs included in the Preferred Program Alternative.

Economic effects and environmental impacts would occur from the combined and integrated effects of different programs under the Preferred Program Alternative.

The Preferred Program Alternative, as well as all other identified alternatives, contains a range of new storage capacity and a range of possible water management criteria. The quantified effects summarized below consider the full range of these possible outcomes by examining within each alternative scenarios for no storage versus full storage and implementation of either water management Criterion A or water management Criterion B. In addtion, the full range of effects to either the CVP or SWP are considered by allocating all potential effects to either the CVP or the SWP, with no allocation between the two projects. Effects may be positive or negative. The minimum effect to either the CVP or SWP will always be zero, reflecting the allocation of all effects to the other project. The maximum positive and negative effects are provided here to present the full range of potential effects. Both positive and negative effects are likely to fall somewhere between zero and the maximum potential effect noted in this section. More detailed information is available in Tables 7.9-1, 7.9-2, and 7.9-3.

The magnitude of storage-related impacts would be less than reported below if smaller amounts of storage are added.

Western Energy Available for Sale. If the maximum quantity of storage contemplated in the Preferred Program Alternative is implemented, and water management Criterion B is assumed, the amount of energy available for sale by Western would decrease under the Preferred Program Alternative. Energy available for sale by Western could decline up to approximately 1,235 GWh per year on average, or up to 34%. This is considered a potentially significant adverse effect.

If no storage is implemented and water management Criterion B is assumed, the amount of energy available for sale by Western would increase under the Preferred Program Alternative. Energy available for sale by Western could increase up to approximately 78 GWh per year on average, or up to 2%.

The amount of energy available for sale by Western would decrease under the Preferred Program Alternative because the projected increase in CVP generation is smaller than the increase in CVP project energy use.

Table 7.9-1. Comparison of Potential Change in CVP Power Production and Energy Conditions to the No Action Alternative

ASSESSMENT VARIABLES	EXISTING CONDITIONS	NO ACTION ALTERNATIVE		POTENTIAL CHANGE FROM NO ACTION ALTERNATIVE																	
				PREFERRED PROGRAM ALTERNATIVE				ALTERNATIVE 1				ALTERNATIVE 2				ALTERNATIVE 3					
				WITHOUT STORAGE		WITH STORAGE		WITHOUT STORAGE		WITH STORAGE		WITHOUT STORAGE		WITH STORAGE		WITHOUT STORAGE		WITH STORAGE			
		A	B	A	B	A	B	A	B	A	B	A	B	A	B	A	B	A	B		
Average Energy Available for Sale (GWh)																					
Annual	3,695	3,613	3,642	71	78	-552	-1235	81	79	-638	-1133	-45	-63	-522	-1,152	-75	-279	-581	-1,671		
January	195	206	193	10	-59	-11	-115	18	-62	-34	-97	-37	-117	-7	-97	-100	-74	-82	-136		
February	231	265	230	1	4	-37	-84	7	6	-57	-55	-34	-38	-37	-57	-42	-7	-60	-64		
March	278	287	271	15	57	-71	-84	18	54	-85	-62	-12	26	-65	-63	-12	-11	-37	-121		
April	368	391	362	24	44	-41	-87	27	42	-41	-82	22	41	-40	-83	14	-29	-40	-181		
May	471	477	465	24	38	-8	-67	27	40	-8	-61	26	41	-8	-63	17	-33	-15	-150		
June	491	468	486	20	15	14	-82	7	16	4	-94	53	44	19	-95	48	33	4	-147		
July	544	491	539	44	51	-28	-97	36	49	-33	-103	89	97	-16	-104	114	81	7	-117		
August	410	360	407	-6	21	-90	-104	4	27	-79	-95	40	71	-94	-100	99	81	-42	-69		
September	228	214	219	-14	14	-58	-126	-6	14	-62	-123	9	34	-63	-125	16	12	-65	-165		
October	169	157	167	-10	-1	-94	-157	-9	1	-93	-148	-60	-51	-90	-150	-51	-80	-75	-207		
November	128	120	124	-17	-29	-73	-121	-22	-31	-78	-116	-73	-83	-70	-117	-60	-102	-68	-160		
December	183	178	179	-20	-77	-56	-110	-24	-75	-73	-97	-68	-127	-51	-99	-119	-150	-108	-155		
Western Composite Energy Rate ($/MWh)		$20.08	$20.08	-$0.40	-$0.55	$8.57	$13.18	-$0.45	-$0.56	$8.79	$12.65	$0.66	$0.55	$8.38	$12.77	$0.32	$1.12	$8.55	$16.02		
Change in "Average" Western Customer's Average Cost of Power ($/MWh)				-$0.09	-$0.09	$0.67	$1.50	-$0.10	-$0.10	$0.77	$1.37	$0.05	$0.08	$0.63	$1.40	$0.09	$0.34	$0.70	$2.03		
Change in "High Allocation" Western Customer's Average Cost of Power ($/MWh)				-$0.52	-$0.57	$4.06	$9.09	-$0.60	-$0.58	$4.70	$8.34	$0.33	$0.46	$3.84	$8.48	$0.55	$2.06	$4.28	$12.30		

Notes:

A = Criterion A.
B = Criterion B.

Table 7.9-2. Comparison of Potential Change in SWP Power Production and Energy Conditions to the No Action Alternative

ASSESSMENT VARIABLES	EXISTING CONDITIONS	NO ACTION ALTERNATIVE		POTENTIAL CHANGE FROM NO ACTION ALTERNATIVE: PREFERRED PROGRAM ALTERNATIVE				ALTERNATIVE 1				ALTERNATIVE 2				ALTERNATIVE 3			
				WITHOUT STORAGE		WITH STORAGE		WITHOUT STORAGE		WITH STORAGE		WITHOUT STORAGE		WITH STORAGE		WITHOUT STORAGE		WITH STORAGE	
		A	B	A	B	A	B	A	B	A	B	A	B	A	B	A	B	A	B
Total Available July Capacity (MW)																			
Average conditions	1,519	1,708	1,725	-11	9	97	112	-2	8	90	129	-14	5	94	129	-44	52	82	160
Dry conditions	1,327	1,413	1,432	-3	5	-80	67	-4	-5	-33	73	-6	-6	-30	60	-247	8	-80	96
Total Net Energy Requirement (GWh)																			
Average conditions	3,491	3,263	5,034	-71	-78	552	1,235	-81	-79	638	1,133	45	63	522	1,152	75	279	581	1,671
Dry conditions	3,182	2,886	3,224	-180	-103	542	892	-200	-141	423	869	-162	-49	352	974	117	197	542	1,679
System Energy Rate ($/MWh)		$26.69	$26.69	-$0.41	-$0.57	$4.94	$7.13	-$0.47	-$0.58	$5.08	$6.91	$0.61	$0.52	$4.83	$6.96	$0.33	$1.09	$4.93	$8.16

Notes:

A = Criterion A.
B = Criterion B.

Table 7.9-3. Comparison of Potential Change in Air Quality Conditions to the No Action Alternative

ASSESSMENT VARIABLES	PREFERRED PROGRAM ALTERNATIVE				ALTERNATIVE 1				ALTERNATIVE 2				ALTERNATIVE 3			
	WITHOUT STORAGE		WITH STORAGE		WITHOUT STORAGE		WITH STORAGE		WITHOUT STORAGE		WITH STORAGE		WITHOUT STORAGE		WITH STORAGE	
	A	B	A	B	A	B	A	B	A	B	A	B	A	B	A	B
Nitrogen oxide (lbs/day)																
Average conditions	-145	-159	1,134	2,537	-167	-163	1,311	2,328	92	130	1,072	2,328	153	574	1,194	3,433
Dry conditions	-371	-212	1,114	1,834	-412	-289	869	1,785	-332	-101	723	2,001	241	404	1,113	3,450
Sulfur dioxide (lbs/day)																
Average conditions	-2	-2	15	34	-2	-2	17	31	1	2	14	31	2	8	16	46
Dry conditions	-5	-3	15	24	-5	-4	12	24	-4	-1	10	27	3	5	15	46
Carbon monoxide (lbs/day)																
Average conditions	-58	-64	454	1,015	-67	-65	524	931	37	52	429	931	61	230	478	1,373
Dry conditions	-148	-85	446	734	-165	-116	347	714	-133	-40	289	800	96	162	445	1,380
Particulate matter (lbs/day)																
Average conditions	-10	-11	76	169	-11	-11	87	155	6	9	71	155	10	38	80	229
Dry conditions	-25	-14	74	122	-27	-19	58	119	-22	-7	48	133	16	27	74	230

Notes:

A = Criterion A.
B = Criterion B.

SWP Net Energy Requirements. If the maximum quantity of storage contemplated in the Preferred Program Alternative is implemented, and water management Criterion B is assumed, the SWP's net energy requirement would increase due to the large increase in SWP project energy use. The SWP's net energy requirement could increase up to approximately 1,235 GWh per year on average, or up to 25%. The percentage increase in dry years would be up to approximately 28%.

If no storage is implemented, and water management Criterion B is assumed, the SWP's net energy requirement would decrease under the Preferred Program Alternative. The SWP's net energy requirement could decrease up to approximately 78 GWh per year on average, or up to 1.5%. The percentage decrease in dry years (and assuming water management Criterion A) would be up to approximately 3.5%.

Western and DWR Rates. Western and DWR would experience an increase in power production and replacement costs from the effects summarized above, and possibly from new costs associated with adding new hydroelectric capacity. Western also would experience decreases in revenue as energy sales decline. All of these factors would require Western and DWR to raise their power rates.

Under a full-storage implementation scenario, Western and DWR would need to raise their rates.

Under a worst-case scenario—where all of the Program-related power cost increases are allocated to the CVP, the maximum quantity of storage contemplated in the Preferred Program Alternative is implemented, and water management Criterion B is assumed—Western's composite rate could increase by up to $13.18/MWh, or approximately 68%. If no storage is implemented, and water management Criterion B is assumed, Western's composite rate could decrease by up to $0.55/MWh, or approximately 2.7%.

If the maximum quantity of storage contemplated in the Preferred Program Alternative is implemented and water management Criterion B is assumed, DWR's system energy rate could increase by up to $7.13/MWh, or 27%. If no storage is implemented and water management Criterion B is assumed, DWR's system energy rate could decrease by up to $0.57/MWh, or approximately 2.2%.

The relatively wide range of these estimates reflects the notable uncertainty surrounding these projections. Actual rate increases likely would be lower than the upper end of these ranges and much uncertainty will diminish once the power effect and cost allocation decisions discussed under Section 7.9.4 are reached.

Under the worst-case scenario for Western, rate increases could significantly affect Western because its rates could be higher than those available to its customers on the open market. Open-market rates are expected to be about $34.00/MWh in 1998 dollars. Western's rates under their worst-case scenario would also approximate $34.00.

Effects on Western and DWR Power Customers. The potential Western rate increases summarized above could result in potentially adverse effects on Western's preference power customers. Western rate increases would increase the power costs of Western's

Historically, Western's rates have been some of the lowest available in California.

customers. Many of the preference power customers that are utility companies could experience a competitive disadvantage since they likely would need to increase their own rates to retail customers. Historically, Western's rates have been some of the lowest available in California. Major increases in their rates could cause adverse economic effects on not only preference power customers but also the retail power customers that buy power from the preference power customers.

If the maximum quantity of storage contemplated in the Preferred Program Alternative is implemented and water management Criterion B is assumed, Western customers could see an increase in their average cost of power under the Preferred Program Alternative. An "average" Western customer's cost of power could increase by up to approximately $1.50/MWh. A "high allocation" Western customer's cost of power could increase by up to approximately $9.09/MWh. This is considered a potentially significant adverse effect.

If no storage is implemented and water management Criterion B is assumed, Western customers could see a decrease in their cost of power under the Preferred Program Alternative. An "average" Western customer's cost of power could decrease by up to approximately $0.09/MWh. A "high allocation" Western customer's cost of power could decrease by up to approximately $0.57/MWh.

The estimated increases in DWR's system rates are not expected to cause significant effects on DWR's power customers. These customers purchase power from a variety of sources, and they do not have firm contracts with DWR. However, water customers of the SWP could incur increases in their water charges to cover the increases in power costs required to deliver SWP water. This issue is addressed in Section 7.5, "Urban Water Supply Economics."

Costs allocated to CVP project energy use are recovered by revenue received from CVP water users, natural resource agencies, and other environmental beneficiaries.

Costs allocated to CVP project energy use are recovered by revenue received from CVP water users, natural resource agencies, and other environmental beneficiaries. The rate effects in this analysis were estimated by assuming that the beneficiaries of the increase in project use caused by the Program would continue to pay approximately 30% of the estimated cost of replacement energy and that Western's preference power customers make up the difference through increased rates. This is consistent with current practice for projects authorized under Reclamation law. If the beneficiaries of increases in project use (natural resource agencies, other environmental beneficiaries, and water users) paid the full amount of related cost increases, Western power rate effects could be reduced to less-than-significant levels.

The potential adverse effects of the Program alternatives on DWR customers or on Western and its preference power customers would be caused by DWR's or Western's rates increasing to a level higher than open market rates as a result of having less peaking power to sell.

The power cost increases associated with additional SWP pumping requirements also could be assigned to beneficiaries of the increased pumping (natural resource agencies, other environmental beneficiaries, and water users). This would be a strategy for reducing the magnitude of DWR system energy rate effects on DWR power customers. The potential adverse effects of the Program alternatives on DWR customers or on Western and its preference power customers would be caused by DWR's or Western's rates increasing to a level higher than open market rates as a result of having less peaking power to sell. Instead, new generation facilities could be built from funds provided by beneficiaries of increased project use (pumping) or changes in river or reservoir operations. The new generation may be operated by Western, Reclamation, the Corps, DWR, or other entities to meet additional pumping requirements or to make up for reduced project generation. Beneficiaries could also purchase additional energy from the California energy market to meet additional pumping requirements. This would decrease lost energy available for sale from the CVP, but would generally shift generation from hydro sources to thermal sources, causing air quality impacts. Another potential mitigation strategy for avoiding significant Western power rate increases would be passing new federal legislation to shift an equitable portion of Western's share of CVP repayment obligations to the beneficiaries of the Program actions that cause the rate effects. This would reduce Western's revenue requirements and avoid pressure to increase the rates that Western must charge its preference power customers.

CVP Restoration Fund Power Payments. In a worst-case scenario, where all of the Program power and cost effects are allocated to the CVP, and Western needed to raise its composite rate to a level that is higher than rates available in a deregulated market, Western may be unable to sell energy and recover costs, including payments to the CVP Restoration Fund. The fund would be affected if other revenue sources were not obtained. If Western was forced to attempt retaining its customers by selling power below cost, some other entity could be affected, possibly federal taxpayers. CVP water rates could be raised to obtain additional revenue under such a scenario; however, the water payment "cap" would limit the amount water users could contribute, and other revenue sources eventually could need to be obtained.

If Western was unable to sell energy and recover costs, payment to the CVP Restoration Fund would be affected.

To avoid this economic effect, a cap on power payments to the fund could be adopted, similar to the cap in effect for water payments to the fund. This would help to ensure that power users do not have to increase their contributions to the fund if water payments to the fund reach their limit.

CVP power users are not expected to be affected by shortfalls in water payments to the fund. The Preferred Program Alternative is expected to cause an increase in CVP water deliveries to agricultural and M&I water users, which would enable meeting the overall target contribution to the fund from water users. If CVP water deliveries decreased, given the water payment cap in effect, payments by CVP power users to the fund may need to increase in order to make up for the shortfall in water payments to the fund.

Utility System Impacts. To meet overall increases in state electrical demand, reductions in generation from the CVP or SWP, or increases in project energy use loads would require replacement energy and capacity. Replacement energy would most likely come from a combination of CTs and CCCTs, resulting in the following estimated air emissions. These impacts may be dispersed over a wide geographic area. Emissions caused by generation of power must comply with existing air quality standards where they occur. Therefore, power generation emissions will not exceed air quality standards and are considered less than significant adverse environmental effect.

To meet overall increases in state electrical demand, reductions in generation from the CVP or SWP, or increases in project energy use loads would require replacement energy and capacity.

If the maximum quantity of storage contemplated in the Preferred Program Alternative is implemented and water management Criterion B is assumed, increased replacement energy would be required under the Preferred Program Alternative. NO_x emissions could be increased by up to 2,537 lbs/day under average water-year conditions and up to 1,834 lbs/day under dry water-year conditions. SO_x emissions could be increased by up to 34 lbs/day under average water-year conditions and up to 24 lbs/day under dry water-year conditions. CO emissions could be increased by up to 1,015 lbs/day under average water- year conditions and up to 734 lbs/day under dry water-year conditions. PM_{10} could be increased by up to 169 lbs/day under average water-year conditions and up to 122 lbs/day under dry water-year conditions.

If no storage is implemented and water management Criterion A is assumed, decreased replacement energy would be required under the Preferred Program Alternative. NO_x emissions could be decreased by up to 145 lbs/day under average water-year conditions and up to 371 lbs/day under dry water-year conditions. SO_x emissions could be decreased by up to 2 lbs/day under average water-year conditions and up to 5 lbs/day under dry water-year conditions. CO emissions could be decreased by up to 58 lbs/day under average water-year conditions and up to 148 lbs/day under dry water-year conditions. PM_{10} could be decreased by up to 10 lbs/day under average water-year conditions and up to 25 lbs/day under dry water-year conditions.

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. In general, net energy use likely would decrease on lands retired from agricultural uses under this program. Many types of energy-consuming agricultural practices would no longer occur on these lands, including tilling, harvesting, pumping water, and applying fertilizer and pesticides. Even though active management of restored areas could require energy use during grading, pumping water, and vegetation management, agricultural practices typically use more energy than restoration activities. These net energy savings would occur on approximately 130,000-190,000 acres in the Delta Region and on about 35,000-100,000 acres in the Central Valley.

Energy use likely would increase during implementation of the Ecosystem Restoration Program due to construction activities related to wetlands creation and other restoration activities.

Water Quality Program. A primary focus of the Water Quality Program is source control which addresses mine drainage, urban and industrial runoff, and agricultural drainage. These elements may indirectly affect energy, depending on the specific measures that eventually are implemented. Implementing source control measures would include temporary increases in energy use. Examples of implementation procedures that would use energy include earthwork with heavy vehicles and operation of the equipment necessary to install structural water quality controls. Long-term beneficial effects on energy use would occur as water quality improvements reduce treatment requirements.

Long-term beneficial impacts on energy use would occur as water quality improvements reduce treatment requirements.

Water Use Efficiency Program. Water conservation actions are expected to reduce M&I water and energy use but may lead to increases in agricultural energy use. The specific water efficiency measures would be determined by local water districts and users. While specific M&I measures and their effects cannot be defined at this time, it is likely that the amount of energy used by water users would be reduced as their water use declines. Examples of energy-related effects that likely would occur once the measures are successfully implemented are listed below:

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

- Reductions in urban water demands 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, water recycling projects would increase the use of energy if they require increased treatment and new pressurized distribution systems. The needs 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.

- 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 is implemented.

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 is implemented.

Levee System Integrity Program. The Levee System Integrity Program would cause direct energy effects 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. The levee modifications could help avoid long-term and recurring levee maintenance procedures that would need to be conducted without major improvements to the system. This long-term beneficial effect could help offset the short-term additional use of energy.

Water Transfer Program. 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.

Watershed Program. For the short term, the Watershed Program would require relatively minor amounts of energy compared to the amount required to construct the storage, conveyance, and levee improvement components of the Preferred Program Alternative. Some energy would be required to implement activities in both the upper and lower watersheds as fish migration barriers are removed, unstable levees are repaired, stream banks are stabilized, and riparian habitat is improved. These minor and temporary effects would be outweighed by the positive and long-term reductions in energy use caused by this program. The related improvements in water quality could reduce water treatment requirements and associated energy requirements at treatment plants. By reducing stressors and land use practices that degrade water quality, watershed management would indirectly reduce the amount of energy used by related land use practices. Examples of land use practices that degrade water quality include harmful aspects of logging, agricultural pesticide and fertilizer applications, and livestock grazing.

By reducing stressors and land use practices that degrade water quality, watershed management would indirectly reduce the amount of energy used by related land use practices.

Storage. Under the Preferred Program Alternative, new hydroelectric capacity could be added to enlarged existing or new off-stream storage sites in the Sacramento River and San Joaquin River Regions. Specific reservoir sites have not been selected for this programmatic evaluation. So long as a reasonable amount of discretion exists for scheduling pumping and generation at new storage facilities on a daily basis, a positive effect on capacity resources could result. Energy could be required to fill new pumped off-stream storage facilities. Although some energy may be generated when water is released, operation of such facilities may cause a net increase in energy use at the facility. Energy (primarily in the form of vehicle fuels) also would be needed to power construction vehicles and equipment.

New hydroelectric capacity could be added to enlarged existing or new off-stream storage sites in the Sacramento River and San Joaquin River Regions.

Temporary adverse effects on energy could occur during construction if a storage site with existing hydroelectric facilities is selected. Temporary disruptions of hydrogeneration could be necessary during construction as new hydroelectric capacity is added or as the dams at existing storage sites are enlarged.

Temporary adverse effects on energy could occur during construction if a storage site with existing hydroelectric facilities is selected.

Conveyance. The construction of new conveyance facilities would require energy to power a wide variety of construction procedures, including trenching, grading, and reclamation of disturbed areas. Operation of the conveyance facilities would increase energy use at related pumping facilities and during routine maintenance.

Based on the DWRSIM modeling conducted for the different Program alternatives, the different conveyance strategies under consideration by the Program caused only a minor effect on the system-wide assessment variables discussed at the beginning of this section.

Effects at Other Hydroelectric Facilities. The Preferred Program Alternative would change flows in streams below CVP and SWP facilities. This in turn could affect available capacity and energy generation at hydroelectric facilities that are not part of the CVP or SWP but are hydrologically connected. These other hydroelectric facilities may include a City of Redding plant on Clear Creek, Oakdale and South San Joaquin Irrigation District's plants in the Stanislaus River basin, Friant Power Authority plants on the San

The Preferred Program Alternative would change flows in streams below CVP and SWP facilities.

Joaquin River, and the Monticello Power Plant at Lake Berryessa. Specific effects at these other hydroelectric facilities could be beneficial or adverse and cannot be defined at this time. A wide range of CVP and SWP operational changes currently are being assessed during the Program study. Until more specific information about the potentially affected facilities and the timing and magnitude of CVP- and SWP-related operational changes on specific stream reaches is available, defining the related effects on other hydroelectric facilities is speculative. The effects on other facilities would be influenced not only by the hydrology changes caused by the Preferred Program Alternative but also by (1) the amount of water in storage at affected facilities when the hydrology changes occur; (2) utility-specific water, power, and environmental demands that are in place at the time of the hydrology changes; and (3) the daily, weekly, and monthly operational characteristics of the affected facilities.

Other Types of Effects. The Preferred Program Alternative could indirectly affect energy use at surface water and groundwater pumping facilities owned by local irrigation districts and municipal utility districts. The major environmental improvements resulting from the Preferred Program Alternative likely would improve or create recreation opportunities in the study area, which would indirectly cause an increase in recreation-related traffic and an associated increase in energy use.

The Preferred Program Alternative could indirectly affect energy use at surface water and groundwater pumping facilities owned by local irrigation districts and municipal utility districts.

Actions involving construction of new facilities would require the use of energy (primarily in the form of vehicle fuels) to power construction equipment. This is a temporary effect and not considered significant. Energy efficiency upgrades and energy conservation measures can be applied at the project-specific level.

7.9.7.2 ALTERNATIVE 1

This section summarizes the potential effects associated with Alternative 1 that would differ from the effects described for the Preferred Program Alternative. Like the Preferred Program Alternative, this alternative contains a range of new storage capacity and a range of possible water management criteria.

Economic effects and environmental impacts, similar to those identified under the Preferred Program Alternative, would occur from the combined and integrated effects of different programs under Alternative 1.

All Regions

Western Energy Available for Sale. If the maximum quantity of storage contemplated in Alternative 1 is implemented, and water management Criterion B is assumed, the amount of energy available for sale by Western would decrease under Alternative 1. Energy available for sale by Western could decline by up to approximately 1,133 GWh per year on average, or up to 31%. This is considered a potentially significant adverse effect.

If no storage is implemented and water management Criterion A is assumed, the amount of energy available for sale by Western would increase under Alternative 1. Energy available for sale by Western could increase by up to approximately 81 GWh per year on average, or up to 2%.

SWP Net Energy Requirements. If the maximum quantity of storage contemplated in Alternative 1 is implemented, and water management Criterion B is assumed, the SWP's net energy requirement would increase due to the large increase in SWP project energy use. The SWP's net energy requirement could increase by up to approximately 1,133 GWh per year on average, or up to 23%. The percentage increase in dry years would be up to approximately 27%.

If no storage is implemented and water management Criterion A is assumed, the SWP's net energy requirement would decrease under Alternative 1. The SWP's net energy requirement could decrease by up to approximately 81 GWh per year on average, or up to 2.5%. The percentage decrease in dry years would be up to approximately 7%.

Western and DWR Rates. Western and DWR would experience an increase in power production and replacement costs from the effects summarized above, and possibly from new costs associated with adding new hydroelectric capacity. Western also would experience decreases in revenue as energy sales decline. All of these factors would require Western and DWR to raise their power rates.

Under a worst-case scenario—where all of the Program-related power cost increases are allocated to the CVP, the maximum quantity of storage contemplated in Alternative 1 is implemented, and water management Criterion B is assumed—Western's composite rate could increase by up to $12.65/MWh, or approximately 63%. If no storage is implemented, and water management Criterion B is assumed, Western's composite rate could decrease by up to $0.58/MWh, or approximately 2.8%.

If the maximum quantity of storage contemplated in Alternative 1 is implemented and water management Criterion B is assumed, DWR's system energy rate could increase by up to $6.91/MWh, or 26%. If no storage is implemented, and water management Criterion B is assumed, DWR's system energy rate could decrease by up to $0.58/MWh, or approximately 2.2%.

Effects on Western Power Customers. If the maximum quantity of storage contemplated in Alternative 1 is implemented, and water management Criterion B is assumed, Western customers could see an increase in their average cost of power under Alternative 1. An "average" Western customer's cost of power could increase by up to approximately $1.37/MWh. A "high allocation" Western customer's cost of power could increase by up to approximately $8.34/MWh. This is considered a potentially significant adverse effect.

If no storage is implemented and water management Criterion A is assumed, Western customers could see a decrease in their average cost of power under Alternative 1. An "average" Western customer's cost of power could decrease by up to approximately

$0.10/MWh. A "high allocation" Western customer's cost of power could decrease by up to approximately $0.60/MWh.

Utility System Impacts. If the maximum quantity of storage contemplated in Alternative 1 is implemented and water management Criterion B is assumed, increased replacement energy would be required under Alternative 1. NO_x emissions could be increased by up to 2,328 lbs/day under average water-year conditions and up to 1,785 lbs/day under dry water-year conditions. SO_x emissions could be increased by up to 31 lbs/day under average water-year conditions and up to 24 lbs/day under dry water-year conditions. CO emissions could be increased by up to 931 lbs/day under average water-year conditions and up to 714 lbs/day under dry water-year conditions. PM_{10} could be increased by up to 155 lbs/day under average water-year conditions and up to 119 lbs/day under dry water-year conditions. Since emissions must comply with existing air quality standards, these impacts are considered less than significant.

If no storage is implemented and water management Criterion A is assumed, decreased replacement energy would be required under Alternative 1. NO_x emissions could be decreased by up to 167 lbs/day under average water-year conditions and up to 472 lbs/day under dry water-year conditions. SO_x emissions could be decreased by up to 2 lbs/day under average water-year conditions and up to 5 lbs/day under dry water-year conditions. CO emissions could be decreased by up to 67 lbs/day under average water-year conditions and up to 165 lbs/day under dry water-year conditions. PM_{10} emissions could be decreased by up to 11 lbs/day under average water-year conditions and up to 27 lbs/day under dry water-year conditions.

7.9.7.3 ALTERNATIVE 2

This section summarizes the potential effects associated with Alternative 2 that would differ from the effects described for the Preferred Program Alternative. Like the Preferred Program Alternative, this alternative contains a range of new storage capacity and a range of possible water management criteria.

Economic effects and environmental impacts, similar to those identified under the Preferred Program Alternative, would occur from the combined and integrated effects of different programs under Alternative 2.

All Regions

Western Energy Available for Sale. If the maximum quantity of storage contemplated in Alternative 2 is implemented and water management Criterion B is assumed, the amount of energy available for sale by Western would decrease under Alternative 2. Energy available for sale by Western could decline by up to approximately 1,152 GWh per year on average, or up to 32%. This is considered a potentially significant adverse effect.

No scenarios under Alternative 2 produce positive effects.

SWP Net Energy Requirements. If the maximum quantity of storage contemplated in Alternative 2 is implemented and water management Criterion B is assumed, the SWP's net energy requirement would increase due to the large increase in SWP project energy use. The SWP's net energy requirement could increase by up to approximately 1,152 GWh per year on average, or up to 23%. The percentage increase in dry years would be up to approximately 30%.

If no storage is implemented and water management Criterion A is assumed, the SWP's net energy requirement would decrease under Alternative 2. The SWP's net energy requirement could decrease by up to approximately 162 GWh per year during dry years, or up to 5.6%.

Western and DWR Rates. Western and DWR would experience an increase in power production and replacement costs from the effects summarized above, and possibly from new costs associated with adding new hydroelectric capacity. Western also would experience decreases in revenue as energy sales decline. All of these factors would require Western and DWR to raise their power rates.

Under a worst-case scenario—where all of the Program-related power cost increases are allocated to the CVP, the maximum quantity of storage contemplated in Alternative 2 is implemented, and water management Criterion B is assumed—Western's composite rate could increase by up to $12.77/MWh, or approximately 64%.

If the maximum quantity of storage contemplated in Alternative 2 is implemented and water management Criterion B is assumed, DWR's system energy rate could increase by up to $6.96/MWh, or 26%.

Effects on Western Power Customers. If the maximum quantity of storage contemplated in Alternative 2 is implemented and water management Criterion B is assumed, Western customers could see an increase in their average cost of power under Alternative 2. An "average" Western customer's cost of power could increase up to approximately $1.40/MWh. A "high allocation" Western customer's cost of power could increase by up to approximately $8.48/MWh. This is considered a potentially significant adverse effect.

Utility System Impacts. If the maximum quantity of storage contemplated in Alternative 2 is implemented and water management Criterion B is assumed, increased replacement energy would be required under Alternative 2. NO_x emissions could be increased by up to 2,328 lbs/day under average water-year conditions and up to 2,001 lbs/day under dry water-year conditions. SO_x emissions could be increased by up to 31 lbs/day under average water-year conditions and up to 27 lbs/day under dry water-year conditions. CO emissions could be increased by up to 931 lbs/day under average water-year conditions and up to 800 lbs/day under dry water-year conditions. PM_{10} emissions could be increased by up to 155 lbs/day under average water-year conditions and up to 133 lbs/day under dry water-year conditions. Since emissions must comply with existing air quality standards, these impacts are considered less than significant.

7.9.7.4 ALTERNATIVE 3

This section summarizes the potential effects associated with Alternative 3 that would differ from the effects described for the Preferred Program Alternative. Like the Preferred Program Alternative, this alternative contains a range of new storage capacity and a range of possible water management criteria.

Economic effects and environmental impacts, similar to those identified under the Preferred Program Alternative, would occur from the combined and integrated effects of different programs under Alternative 3.

All Regions

Western Energy Available for Sale. If the maximum quantity of storage contemplated in Alternative 3 is implemented and water management Criterion B is assumed, the amount of energy available for sale by Western would decrease under Alternative 3. Energy available for sale by Western could decline by up to approximately 1,671 GWh per year on average, or up to 46%. This is considered a potentially significant adverse effect.

No scenarios within Alternative 3 would produce positive effects.

SWP Net Energy Requirements. If the maximum quantity of storage contemplated in Alternative 3 is implemented and water management Criterion B is assumed, the SWP's net energy requirement would increase due to the large increase in SWP project energy use. The SWP's net energy requirement could increase by up to approximately 1,671 GWh per year on average, or up to 33%. The percentage increase in dry years would be up to approximately 52%.

Western and DWR Rates. Western and DWR would experience an increase in power production and replacement costs from the effects summarized above, and possibly from new costs associated with adding new hydroelectric capacity. Western also would experience decreases in revenue as energy sales decline. All of these factors would require Western and DWR to raise their power rates.

Under a worst-case scenario—where all of the Program-related power cost increases are allocated to the CVP, the maximum quantity of storage contemplated in Alternative 3 is implemented, and water management Criterion B is assumed—Western's composite rate could increase by up to $16.02/MWh, or approximately 80%.

If the maximum quantity of storage contemplated in Alternative 3 is implemented and water management Criterion B is assumed, DWR's system energy rate could increase by up to $8.16/MWh, or 31%.

Effects on Western Power Customers. If the maximum quantity of storage contemplated in Alternative 3 is implemented and water management Criterion B is assumed, Western customers could see an increase in their average cost of power under Alternative 3. An "average" Western customer's cost of power could increase by up to approximately

$2.03/MWh. A "high allocation" Western customer's cost of power could increase by up to approximately $12.30/MWh. This is considered a potentially significant adverse effect.

Utility System Impacts. If the maximum quantity of storage contemplated in Alternative 3 is implemented and water management Criterion B is assumed, increased replacement energy would be required under Alternative 3. NO_x emissions could be increased by up to 3,433 lbs/day under average water-year conditions and up to 3,450 lbs/day under dry water-year conditions. SO_x emissions could be increased by up to 46 lbs/day under average or dry water-year conditions. CO emissions could be increased by up to 1,373 lbs/day under average water-year conditions and up to 1,380 lbs/day under dry water-year conditions. PM_{10} emissions could be increased by up to 229 lbs/day under average water-year conditions and up to 230 lbs/day under dry water-year conditions. Since emissions must comply with existing air quality standards, these impacts are considered less than significant.

7.9.8 CONSEQUENCES: PROGRAM ELEMENTS THAT DIFFER AMONG ALTERNATIVES

This section presents the comparison of the Preferred Program Alternative and Alternatives 1, 2, and 3 to existing conditions. This programmatic analysis found that the potentially beneficial and adverse effects from implementing any of the Program alternatives when compared to existing conditions were the same potential effects as those identified in Section 7.9.7, which compares the Program alternatives to the No Action Alternative.

The analysis indicates different types of positive and negative power and energy effects when the Program alternatives are compared to existing conditions. Under the existing conditions scenario, population levels and power and energy demand would not increase.

At the programmatic level, the comparison of the Program alternatives to existing conditions did not identify any additional environmental consequences than were identified in the comparison of Program alternatives to the No Action Alternative. The following is a list of the potentially adverse environmental consequences:

At the programmatic level, the comparison of the Program alternatives to existing conditions did not identify any additional environmental consequences than were identified in the comparison of Program alternatives to the No Action Alternative.

- Effects on Western's preference power customers and perhaps the CVP Restoration Fund from potential increases in Western's rates.
- Effects on hydroelectric capacity, energy generation, project use and other pumping loads, and related rates.
- Air quality impacts.

7.9.9 ADDITIONAL IMPACT ANALYSIS

Cumulative Impacts. The Program alternatives and other related actions would cause cumulative impacts on power production and energy resources. For a summary comparison of cumulative impacts for all resource categories, please refer to Chapter 3. For a description of the programs and projects that contributed to this cumulative impact analysis, please see Attachment A.

Table 7.9-4 summarizes the types of power and energy effects that could be caused by related actions. These effects along with those caused by the Program alternatives all would contribute to cumulative power and energy effects in the study area. Related actions not included in Table 7.9-4 would cause additional power and energy effects, but these would mostly be limited to increases in energy use during construction, implementation, and maintenance of programs, or to increases in surface water or groundwater pumping. The Trinity River Restoration Project and the ISDP would cause power and energy effects that were considered in the environmental impact analysis presented in Sections 7.9.7 and 7.9.8. These projects, therefore, would not cause cumulative effects. Impacts caused by the shift from hydropower generation to other sources to replace reduced CVP and SWP generation or to cover increases in project energy use are included in the cumulative analysis.

Impacts caused by the shift from hydropower generation to other sources to replace reduced CVP and SWP generation or to cover increases in project energy use are included in the cumulative analysis.

Table 7.9-4. Summary of Power Production and Energy Impacts of Related Actions

RELATED ACTIONS	POTENTIAL POWER PRODUCTION AND ENERGY IMPACTS
Central Valley Project Improvement Act (CVPIA)	The changes in flow regimes caused by this project are expected to decrease CVP generation, decrease project energy use, and decrease CVP and energy available for sale. Energy use also would increase during the implementation and maintenance of some project features.
American River Water Resource Investigation	If this project results in the construction of new storage facilities, available capacity and generation at the Nimbus and Folsom power plants on the American River could be affected directly or indirectly. Such impacts could be positive or negative.
Contra Costa Water District (CCWD) Multi-Purpose Pipeline Project	An expansion of CCWD's Delta pumping capabilities would increase pumping-related energy use.
Pardee Reservoir Enlargement Project	This EBMUD project is expected to increase available capacity and generation at the Pardee Power Plant and should positively affect available capacity and generation at the downstream Camanche Power Plant.
Sacramento Water Forum Solutions	The solutions that are eventually implemented could affect available capacity and generation at the Folsom and Nimbus Power Plants.
Joint EBMUD and Sacramento Water Project	A joint water supply project by EBMUD, the City of Sacramento, and the Sacramento County Water Agency could increase pumping-related energy use at a new pumping facility as water demands increase over time.

In general, more positive hydropower capacity and energy generation cumulative impacts in the study area and less negative impacts would be experienced if the new storage projects included in the Program alternatives and some of the related actions are constructed. This is because new storage usually provides water and power system operators with more operating flexibility and often more water for hydropower generation. Some of the new storage facilities also could include new or expanded hydropower facilities. The other types of power and energy cumulative impacts associated with the related actions and the Program alternatives would include increases in CVP and SWP project energy use and increases in Western and DWR system energy rates. Western's energy rates would likely be adversely affected by both the Program alternatives and the CVPIA, since both projects are expected to decrease Western's power sales while increasing its power costs. Recent efforts by PG&E to sell its hydroelectric resources would result in a negligible effect on cumulative hydrogeneration in California because the new owners are expected to continue generation at these facilities. There could be a minor reduction in state-wide generation if additional efforts are made to retire some diversion structures that cause adverse impacts on aquatic resources, or if additional efforts are made to purchase water for in-stream aquatic resources.

New storage usually provides water and power system operators with more operating flexibility and often more water for hydropower generation.

In addition, changes in the distribution of CVP and SWP water deliveries could affect the amount of CVP energy available for sale and the net energy requirement of the SWP. An example of this would be if a larger percentage of project water exported from the Delta was supplied to urban water users in southern California. Deliveries to southern California require significantly more energy due to pumping requirements to lift the water over the Tehachapi Mountains at the Edmonston Pumping Plant.

Cumulative impacts on power capacity, generation, and energy use are expected to be potentially significant when the sum total effect of all anticipated changes in river operations resulting in net energy reduction and new facilities with associated pumping load are viewed cumulatively together with other major decision venues such as the CVPIA. The cumulative effects on power and energy would exceed some of the thresholds of significance defined for Program actions.

Growth-Inducing Impacts. The power production and energy resource effects of the Program alternatives would not induce growth. The Program alternatives are expected to decrease energy and load-following capacity available for sale in the study area. By obtaining replacement power sources, Western customers or DWR could cause indirect environmental impacts where the replacement power sources are located. New construction-related impacts are also possible given the current shortage of peaking power supplies in the western United States, and speculative investments in new generation as a result of utility industry deregulation. The present surplus of baseload facilities is expected to last for a number of years.

The power production and energy resource impacts of the Program alternatives would not induce growth.

If improvements in water supply are caused by the Preferred Program Alternative, the Program could induce growth, depending on how the additional water supply was used. If the additional water was used to expand agricultural production or urban housing development, the Program would foster economic and population growth. Expansion of agricultural production and population could affect power and energy resources, but the magnitude of the power and energy effect is not anticipated to be large enough to significantly affect power and energy resources.

Short- and Long-Term Relationships. The short-term power and energy effects caused by the Program alternatives are not expected to affect the long-term productivity of the environment.

The Preferred Program Alternative generally would maintain and enhance the long-term productivity of the environment but may adversely affect power and energy resources. Ways to reduce or avoid these effects are discussed in Sections 7.9.7 and 7.9.13.

Irreversible and Irretrievable Commitments. The Program alternatives would cause irreversible and irretrievable commitments of the nonrenewable energy resources needed to construct, implement, and maintain project structures and programs. These resources include gasoline, diesel fuel, and the fossil fuels used to generate electricity for construction and maintenance. The anticipated increase in project energy use at pumping plants also would cause irreversible commitments of resources if nonrenewable resources are used to generate electricity for the pumping plants. Providing for the construction of new replacement generation from renewable sources would reduce this potential effect.

The Program alternatives would cause irreversible and irretrievable commitments of the nonrenewable energy resources needed to construct, implement, and maintain project structures and programs.

7.9.10 MITIGATION STRATEGIES

These mitigation strategies will be considered during project planning and development. Specific mitigation measures will be adopted, consistent with the Program goals and objectives and the purposes of site-specific projects. Not all mitigation strategies will be applicable to all projects because site-specific projects will vary in purpose, location, and timing.

To the extent that Program actions cause reduction in hydrogeneration or increases in project energy consumption without offsetting reduction in other electrical loads, replacement capacity and energy must be obtained to meet the deficit. Because California presently has a shortage of peaking power capacity, the replacement power likely would lead to the construction of new power plants with comparable load-following capability.

- Increasing the efficiency of existing generators should be examined in connection with major generator maintenance as one option to meet this need.

To the extent that Program actions cause reduction in hydrogeneration or increases in project energy consumption without offsetting reduction in other electrical loads, replacement capacity and energy must be obtained to meet the deficit.

Construction of new power plants generally causes physical environmental impacts. Regardless of location, there will be air quality impacts and land use impacts. Other environmental impacts also may occur (for example, impacts on wildlife, vegetation, visual, and noise resources) depending on location. The site-specific impacts will be analyzed at the project level. At the programmatic level, the following mitigation strategies can help reduce adverse energy-related impacts from Program actions:

- Carefully selecting the location of new power plants. Whenever possible, plant locations should be selected in unpopulated areas to avoid land use conflicts. In populated areas, compatible types of generation should be selected.
- Obtaining replacement power from non-emitting sources such as other hydro, solar, and wind sources. This can occur through construction of, or the use of incentives to construct, non-emitting power plants. This approach is consistent with State and Federal policies related to promoting use of renewable resource type generation as expressed in AB 1890 and Executive Order 12902.

7.9.11 POTENTIALLY SIGNIFICANT UNAVOIDABLE IMPACTS

No potentially significant unavoidable impacts on power production and energy are associated with the Preferred Program Alternative. Project-specific subsequent analysis is necessary to fully determine the impacts of individual projects on power and energy resources, and the site-specific impacts of actions taken to offset reductions in power and energy resources.

Project-specific subsequent analysis is necessary to fully determine impacts related to power production and energy.