7.8 Energy

This section describes the environmental setting, potential impacts, and mitigation measures for energy impacts that may result from changes in hydrology or changes in water supply. CEQA requires a discussion of potential energy impacts to ensure that energy implications are considered, with emphasis on avoiding or reducing inefficient, wasteful, and unnecessary consumption of energy. Appendix F of the State CEQA Guidelines (Cal. Code Regs., tit. 14, § 15000 et seq.) presents energy impact questions that an agency may include in its analysis, and these issues are discussed in the analysis.

Changes in hydrology would result in an increase in hydropower generation in spring and a decrease in summer. Decreases in summer would likely be offset by gas-fired power.

Changes in water supply could cause a reduction in the energy used to export water from the Delta and could cause an increase in the energy used to replace reduced Sacramento/Delta supplies from actions such as increased groundwater pumping and other water management actions, such as groundwater storage and recovery, water transfers, and water recycling. The energy requirements of desalination also are relevant and included in a comparative energy analysis.

This analysis focuses on how changes in hydrology and changes in water supply interact with localized hydropower, power flow grid reliability, and overall statewide energy supplies and goals. The analysis includes the use of alternate energy sources, such as natural gas or other renewable sources, as a response to changes in the pattern of hydropower generation.

Section 7.1, *Introduction, Project Description, and Approach to Environmental Analysis*, describes reasonably foreseeable methods of compliance and response actions, including actions that would require construction. These actions are analyzed for potential environmental effects in Section 7.21, *Habitat Restoration and Other Ecosystem Projects*, and Section 7.22, *New or Modified Facilities*.

7.8.1 Environmental Checklist

VII. Energy	Potentially Significant Impact	Less than Significant with Mitigation Incorporated	Less-than-Significant Impact	No Impact
Impact Topics:				
a. The effects of the project on energy resources	☒	☐	☐	☐
b. The effect of the project on peak and base period demands for electricity and other forms of energy	☒	☐	☐	☐
c. The effects of the project on local and regional energy supplies and requirements for additional capacity	☒	☐	☐	☐
d. The degree to which the project complies with existing energy standards	☒	☐	☐	☐

VII. Energy		Potentially Significant Impact	Less than Significant with Mitigation Incorporated	Less-than-Significant Impact	No Impact
e.	Energy requirements and energy use efficiencies by amount and fuel type for each stage of the project	☒	☐	☐	☐
f.	The project's projected transportation energy use requirements and its overall use of efficient transportation alternatives	☐	☐	☒	☐

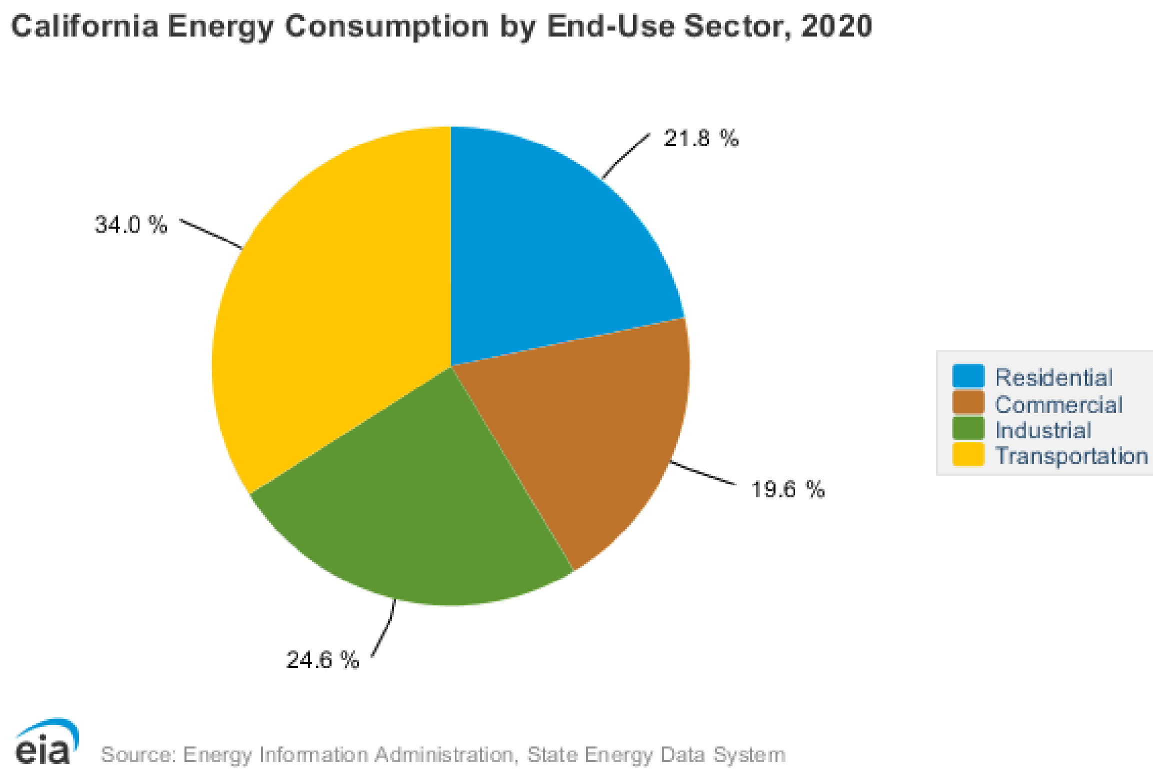
Note: Checklist items are from Appendix F of the State CEQA Guidelines (Cal. Code Regs., tit. 14, § 15000 et seq.).

7.8.2 Environmental Setting

This section describes the energy conditions and relevant regulatory setting, including background information on state energy production, to inform the impact discussion in this section and in Section 7.21, *Habitat Restoration and Other Ecosystem Projects*; Section 7.22, *New or Modified Facilities*; and Chapter 9, *Proposed Voluntary Agreements*.

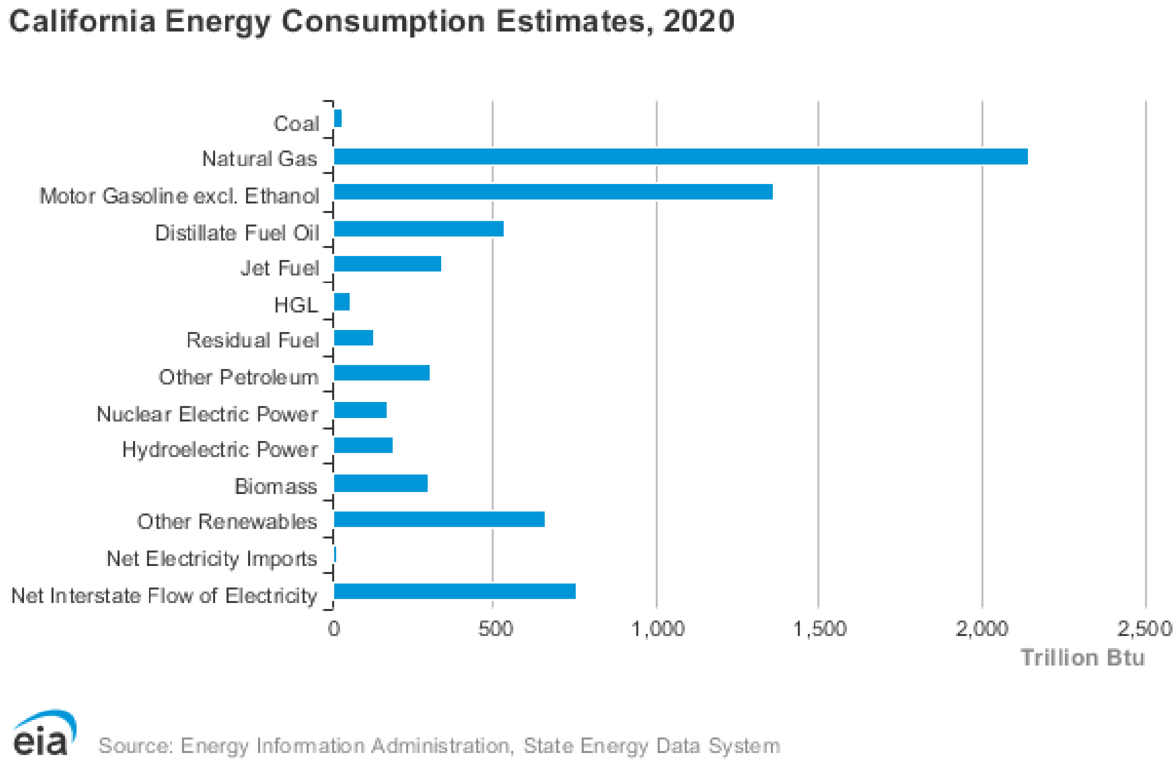
7.8.2.1 Overall Energy Use in California

California's total energy consumption in 2020 was 6,923 trillion British thermal units (EIA 2022a). Figure 7.8-1 illustrates California's energy consumption by sector in 2020. The transportation sector accounted for 34 percent of California's energy use, the industrial sector 24.6 percent, the commercial sector 19.6 percent, and the residential sector 21.8 percent (EIA 2022b). Figure 7.8-2 illustrates California's energy consumption estimates by type of energy source in 2020. In 2020, natural gas and motor gasoline (excluding ethanol) accounted for approximately half of all energy consumption. All other energy sources included in the figure (other renewables, net interstate flow of electricity, distillate fuel oil, biomass, other petroleum, jet fuel, residual fuel, nuclear electric power, hydroelectric power, hydrocarbon gas liquids, coal, and net electricity imports) accounted for less than 15 percent of consumption each.



Source: EIA 2022b

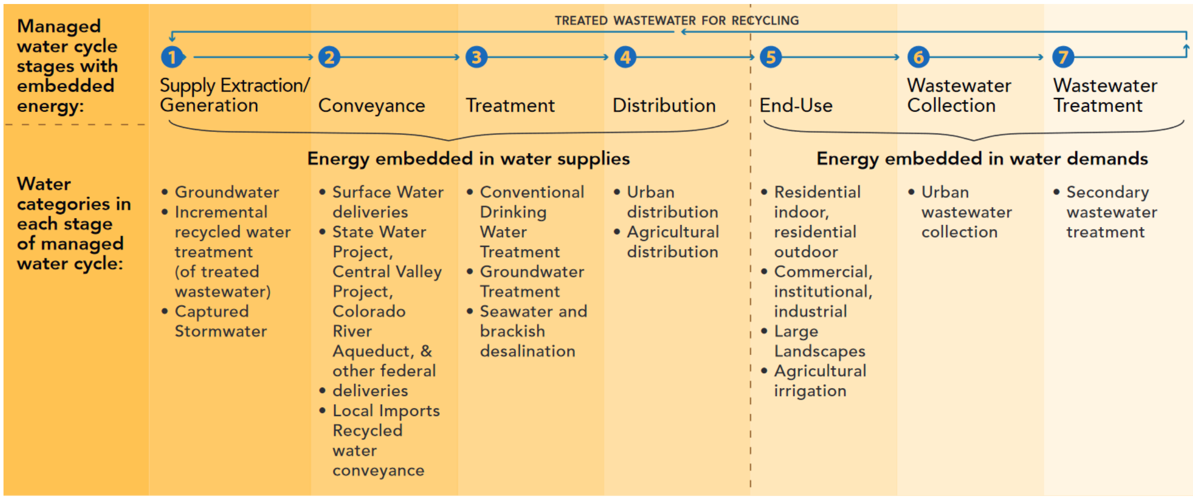
Figure 7.8-1. California Energy Consumption by End Use Sector, 2020



Source: EIA 2022b
Btu = British thermal unit
excl. = excluding
LPG = liquified petroleum gas

Figure 7.8-2. California Energy Consumption Estimates by Type of Energy Source, 2020

California's water system is energy intensive. The Pacific Institute reported that studies have estimated that about 20 percent of California's total statewide electricity use, one-third of non-power plant natural gas consumption, and 88 billion gallons of diesel fuel consumption are related to California's water system, including water collection and treatment, water use, and wastewater management, with a large share of the total associated with heating water (Pacific Institute 2021). Water end uses consume the most energy. Residential water use accounts for the largest share of energy consumed in the water sector, largely because of the energy expended in heating water within homes. Figure 7.8-3 illustrates the elements of water sector with embedded energy (Pacific Institute 2021).



Source: Pacific Institute 2021

Figure 7.8-3. Stages of the Water Cycle with Embedded Energy—California Water Sector

7.8.2.2 Electricity in California

California consumed 277,764 gigawatt-hours (GWh) of electricity in 2021 (CEC 2022), which represents about 14 percent of the state's total energy consumption. Total in-state electricity generation for California was 194,127 GWh in 2021; electricity imports were 83,636 GWh, for a total of 277,764 GWh. Imports represented approximately 30 percent of the total GWh (CEC 2022).

Table 7.8-1 summarizes fuel sources for electric power in California for 2021. Of the total electricity consumption, 38 percent was derived from natural gas, 9.2 percent was derived from large hydropower sources, 34 percent was derived from renewables (biomass, geothermal, small hydropower, solar, and wind), and 7 percent was from unspecified sources. About 9 percent of the total was derived from nuclear power plants, and 3 percent of the total was derived from coal-fired power plants. (CEC 2022.)

Table 7.8-1. Fuel Sources for Electric Power in California in 2021

Fuel Type	California In-State Generation (GWh)	Percent of California In-State Generation	Northwest Imports (GWh)	Southwest Imports (GWh)	California Power Mix (GWh)	Percent California Power Mix
Coal	303	0.2	181	7,788	8,272	3.0
Large hydropower	12,036	6.2	12,042	1,578	25,656	9.2
Natural gas	97,431	50.2	45	7,880	105,356	37.9
Nuclear	16,477	8.5	524	8,756	25,758	9.3
Oil	37	0.0	-	-	37	0.0
Other	382	0.2	68	15	465	0.2
Biomass	5,381	2.8	864	26	6,271	2.3
Geothermal	11,116	5.7	192	1,906	13,214	4.8
Small hydro [a]	2,531	1.3	304	1	2,835	1.0
Solar	33,260	17.1	220	5,979	39,458	14.2

Fuel Type	California In-State Generation (GWh)	Percent of California In-State Generation	Northwest Imports (GWh)	Southwest Imports (GWh)	California Power Mix (GWh)	Percent California Power Mix
Wind	15,173	7.8	9,976	6,405	31,555	11.4
Unspecified sources of power	0	0.0	8,156	10,731	18,887	6.8
Total	194,127	100.0	32,572	51,064	277,764	100.0

Source: CEC 2022.

In-state generation is reported generation from units 1 megawatt and larger.

GWh = gigawatt hour

hydro = hydropower

[a] Hydropower facilities smaller than 30 megawatts of generation capacity are considered "small" hydro and are part of the Renewables Portfolio Standard.

California Renewables Portfolio Standard

In an effort to increase reliance on renewable energy sources, the California Renewables Portfolio Standard (RPS) was established in 2000. As specified through Senate Bill (SB) 100 (De León), Statutes of 2018, amended Public Utilities Code sections 399.11, 399.15, and 399.30, the RPS, which is administered by the California Public Utilities Commission (CPUC), sets requirements that 44 percent of electricity retail sales be served by renewable resources by 2024, 50 percent by 2026, 52 percent by 2027, and 60 percent by 2030. Facilities that contribute to the RPS include geothermal, biomass, biogas, wind, solar, and small hydropower facilities (CPUC 2017). As further specified through SB 100, providers of electricity will eventually be obligated to supply 100 percent carbon-free electricity by 2045. To attain this goal, energy sources that are not part of the RPS can be included as long as they do not emit carbon dioxide. These additional zero-carbon energy sources could include sources such as large hydropower facilities, nuclear power plants, or natural gas facilities with carbon capture and storage. SB 1020 (Laird), Clean Energy, Jobs, and Affordability Act of 2022, Statutes of 2022, Public Utilities Code sections 454.59 and 739.13 set additional interim targets of 90 percent renewable resources by 2035 and 95 percent by 2040. SB 1020 also requires state agencies to rely on 100 percent renewable energy and zero-carbon resources to serve their own facilities by 2035.

7.8.2.3 Overview of the Transmission System in California

California's electrical transmission system links regions within the state as well as to sources outside California. Linkage is critical to the success of meeting peak needs. The California Independent System Operator (CAISO) is an independent and regional transmission organization responsible for operating and balancing the transmission grid for about 80 percent of California and parts of Nevada (CAISO 2017). A handful of other agencies operate and balance the electric grid in the rest of California. Coordination among energy generators and among regions results in reliable and efficient use of electricity.

Approximately two-thirds of California's electric demand is met with in-state resources. To meet California's remaining electric demand, electricity is imported from either the Southwest or the Northwest. Most of California's imports for coal- and natural gas–fired generation come from the Southwest (mostly Arizona and southern Nevada). The Southwest has a variety of natural gas–fired plants that help meet its and California's peak demand. Much of the energy imported from the Northwest comes from unspecified sources, but a substantial amount is from renewables, especially wind and hydropower. In 2021, California imported 83,636 GWh of electricity—16 percent from large hydropower, 11 percent from nuclear power, 7.4 percent from solar, and 19.6 percent from wind (CEC 2022).

Electric generation resources have technological and operational characteristics that allow them to be categorized. These characteristics guide the role they play in the generation portfolio and how they operate as a system to meet demand. For example, dispatchable resources are capable of being cycled up and down to meet load demands, whereas generation at non-dispatchable facilities cannot easily be controlled quickly. To balance supply and demand almost instantaneously and to accommodate non-dispatchable resources, such as nuclear generation and variable renewable generation, the electricity system needs dispatchable resources. In California, natural gas–fired generation is the predominant resource used to maintain the supply–demand balance (CEC 2016).

Some types of non-dispatchable energy facilities, such as geothermal, nuclear, and coal, are used to meet baseload. These facilities typically run continuously except for unscheduled outages or maintenance. Even if prices drop below marginal costs at these facilities, they may be unable to reduce output. Coal plants can adjust production over a 24-hour period but compensate little to short-term fluctuations in the supply–demand balance because they cannot change output rapidly and represent only a small portion of the electricity used by the state, 3 percent in 2021 (CEC 2016).

Electricity from renewable resources, such as wind and solar, is considered non-dispatchable because renewables depend on the weather as their fuel source. Their output cannot be dispatched, but it can be curtailed or limited. For example, when solar generation decreases as the sun sets and increases as the sun rises, dispatchable resources must be available to balance the system. This dynamic may change in the future; construction of large amounts of cost-effective energy storage could allow more flexibility in the timing of the use of renewable energy (CEC 2016).

Capacity Requirements for Local Zones in California

In general, electricity can flow readily throughout the western part of the United States and Canada. However, the electric grid is more reliable and efficient when local regions are able to generate their own electricity. In 2004, CPUC adopted the Resources Adequacy program, which requires each load-serving entity (i.e., each utility) to procure enough resources to meet 100 percent of its total forecast load plus a 15 percent reserve. Each year, CAISO conducts local capacity technical studies, which include computer modeling to examine the ability of local area generation to meet local electricity demands during periods of heavy loads and contingency events. The *contingency operating condition* refers to an unplanned outage of a major generating station or key transmission facilities (i.e., line or transformer). The contingency condition represents a stressed grid trying to accommodate peak demands while one or more facilities are not available to meet those demands. The annual studies examining the load capacity requirement have indicated that there are a few subarea deficiencies during contingency events but overall capacity in the CAISO region is expected to generally be sufficient.

CAISO also conducts summer assessment reports on projected summer conditions. The 2022 summer assessment was carried out during a period of statewide drought in California, which severely reduced the amount of hydropower available to meet peak needs. CAISO reported that 2022 was the third consecutive year of lower-than-normal hydropower capacity. The assessment found that other sources of electricity could compensate for the loss of locally generated hydropower in northern California, but the CAISO electrical grid was vulnerable during the summer of 2022. (CAISO 2022)

Grid Reliability

Prior to 2020, the California electric grid had been reliable since 2001, with outages generally due to wildfires and infrastructure problems, not inadequate electric supply. However, increased reliance on variable renewable sources, reduction in natural gas facilities, and inadequate planning for combinations of contingencies and heat waves set the stage for supply shortages that resulted in the need for rolling outages in the CAISO service area during August 14 and 15, 2020; these are described in more detail in Appendix A5, *Hydropower, Energy Grid, and Export Energy Analyses*.

Specific triggers for these outages included the following.

- A heat wave that increased demand for electricity in the western United States (CAISO 2021).
- Inadequacies in the market practices in the day-ahead energy market and in the planning process for determining sufficiency of electricity generating facilities (CAISO 2021).
- Decreases in generation at some natural gas and renewable facilities (CAISO 2021).

During some of the subsequent days in August and September 2020, Flex Alerts were called to seek voluntary reductions in customer energy use during hours when electric power is most likely to be in short supply (typically from 4:00 to 9:00 p.m.). This action, combined with additional measures to reduce specific large demands on the electric grid and increase electricity supply, helped prevent additional rolling outages (CAISO 2021).

7.8.2.4 Hydropower Generation and Related Energy Use

For this discussion, *hydropower facility*, *powerhouse,* and *power plant* are used interchangeably. Numerous hydropower generation facilities are in the Sacramento River watershed and Delta eastside tributaries regions, although none are in the Delta. Figure 7.8-4 shows the locations of the largest hydropower facilities in the Sacramento/Delta and differentiates those that are eligible for the RPS from those that are not. The total power generation potential from all the facilities in these regions is approximately 6 gigawatts (GW) of electricity.

Four large reservoirs in the Sacramento Valley generate a considerable percentage of the hydropower in the Sacramento/Delta. These reservoirs are Shasta, Oroville, New Bullards Bar, and Folsom. Facilities at these reservoirs are evaluated in more detail than other hydropower facilities because they would be likely to experience the largest changes in hydropower generation associated with changes in hydrology due to their size and the estimated changes in operations at these reservoirs. Water stored in these large reservoirs is intended for supply upon release; therefore, electricity generated upon release is incidental to the release. Water is not stored solely for the purpose of energy generation.

Shasta Dam forms the largest storage reservoir in the state, Shasta Reservoir, which can hold about 4.55 million acre-feet (MAF) (1 acre-foot [AF] equals 325,900 gallons). The Shasta Power Plant, located just below the dam, is the largest energy producer of all the hydropower facilities in California. It generated 989,277 net megawatt-hours (MWh) in 2021 (EIA 2023). Average annual power generation for the Shasta Power Plant from 2007 through 2016 was 1,649,228 MWh (^EIA 2017).

Lake Oroville is a keystone facility of the SWP and is its largest reservoir, with a capacity of about 3.36 MAF (DWR 2017). Lake Oroville and Oroville Dam are part of a complex that includes the Edward C. Hyatt Power Plant, Thermalito Diversion Dam and Power Plant, the Feather River Fish

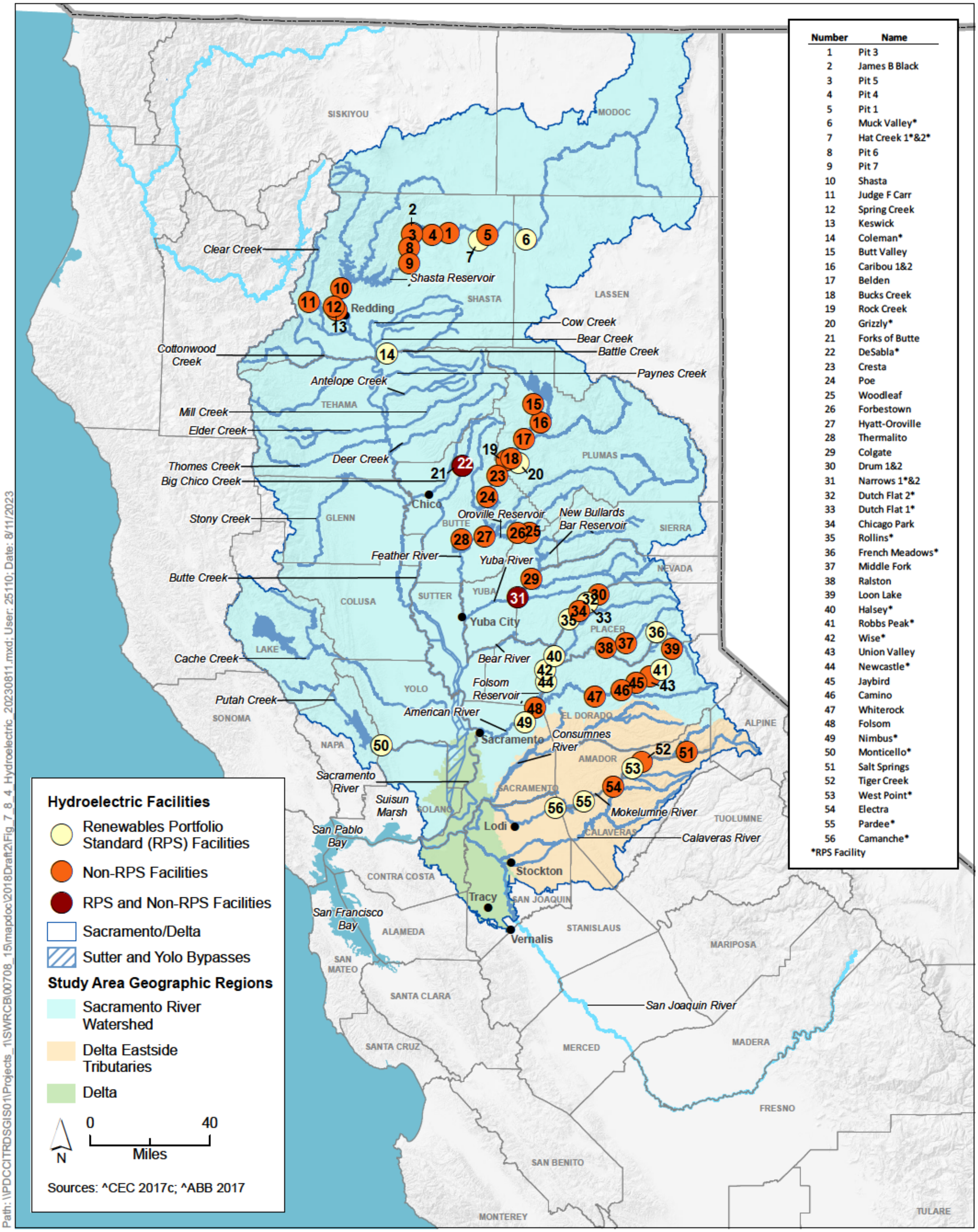


Figure 7.8-4
The Largest Hydroelectric Facilities in the Sacramento/Delta

Hatchery, Thermalito Power Canal, Thermalito Forebay, Thermalito Pumping-Generating Plant, Thermalito Afterbay, and the Lake Oroville Visitor Center (DWR 2017). The Edward C. Hyatt Power Plant is the second-largest energy producer of all the hydropower facilities in California. It generated 288,724 MWh in 2021 (EIA 2023). Average annual power generation for the Hyatt Power Plant from 2007 through 2016 was 1,307,885 MWh (^EIA 2017).

Hydropower facilities on the Yuba River include New Colgate Powerhouse and a small Fish Release Powerhouse, both of which are associated with New Bullards Bar Reservoir, which has a storage capacity of 970 thousand acre-feet (TAF). The New Colgate Powerhouse generated 518,171 MWh in 2021 (EIA 2023). Average annual power generation for the New Colgate Powerhouse from 2007 through 2016 was 937,096 MWh (^EIA 2017). Englebright Reservoir is located downstream of New Bullards Bar Reservoir; it supplies water to Narrows 1 and Narrows 2 Powerhouses.

Folsom Lake, with a storage capacity of 977 TAF, is located on the American River about 23 miles northeast of Sacramento. The Folsom Power Plant at Folsom Dam generated 155,570 net MWh in 2021 (EIA 2023). Average annual power generation for the Folsom Power Plant from 2007 through 2016 was 422,556 MWh (^EIA 2017).

In addition, numerous reservoirs in the upper watersheds are primarily operated for hydropower production, although some have a water supply component for agriculture and urban use. The hydropower projects store as much water in spring as possible while sending any excess runoff through the powerhouses. Water is then released from storage in summer months during times of peak energy demand. Many of the upstream powerhouses are run-of-the-river facilities that depend on river flow and an elevation drop with little or no storage. Most of the facilities are regulated by the Federal Energy Regulatory Commission (FERC) and under Clean Water Act section 401. Several facilities depend on interbasin diversions that move water from one watershed to another. For example, diversions from the South Yuba River watershed to the Bear River via the Drum Canal provide flow to Drum 1 and 2 hydropower facilities.

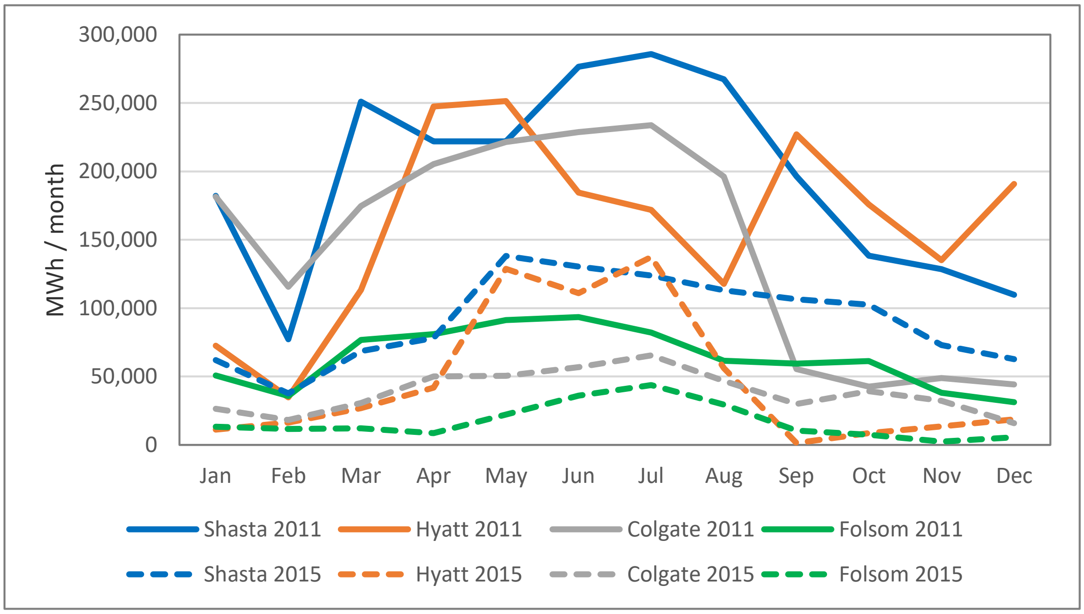
Hydropower generation associated with export water from the CVP and SWP is described under the *Energy for CVP and SWP Exports* subsection. Some export reservoirs—reservoirs receiving Sacramento/Delta supply—generate hydropower to recoup some of the energy costs of pumping the water to the reservoir.

Hydropower facilities are described in more detail in Appendix A5, *Hydropower, Energy Grid, and Export Energy Analyses*.

Hydropower Generation Data

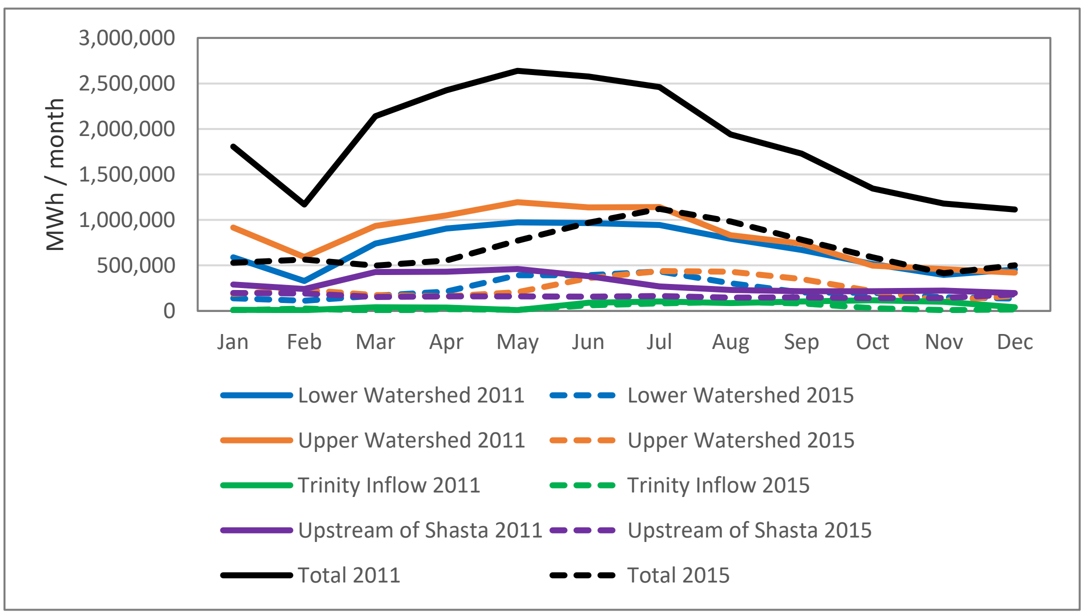
Hydropower generation depends on the quantity of water discharged through the powerhouse and the height of the water above the powerhouse. The height of water increases the pressure of the water, creating more energy. The discharge and height of the water vary between wet years and dry years. For example, 2011 was a wet year, during which much of northern California received about 137 percent of average precipitation (DWR 2022aa); 2015 was a dry year after 3 preceding dry years, and northern California received about 70 percent of average precipitation. Monthly net electricity generation totals for the Shasta, Edward C. Hyatt, Folsom, and Colgate hydropower plants were obtained from the U.S. Energy Information Administration (EIA) Monthly Generation Time Series File (EIA Form 923) (^EIA 2017). Figure 7.8-5 shows monthly net generation for the four hydropower plants during calendar years 2011 and 2015. Monthly net generation for hydropower plants in the Sacramento River watershed and Delta eastside tributaries regions during calendar years 2011 and

2015 is shown on Figure 7.8-6. Figure 7.8-7 shows annual generation for hydropower plants in these regions from 2007 through 2016. See Appendix A5, *Hydropower, Energy Grid, and Export Energy Analyses,* for more information about the facilities included in the subregions presented in Figure 7.8-6 and Figure 7.8-7.



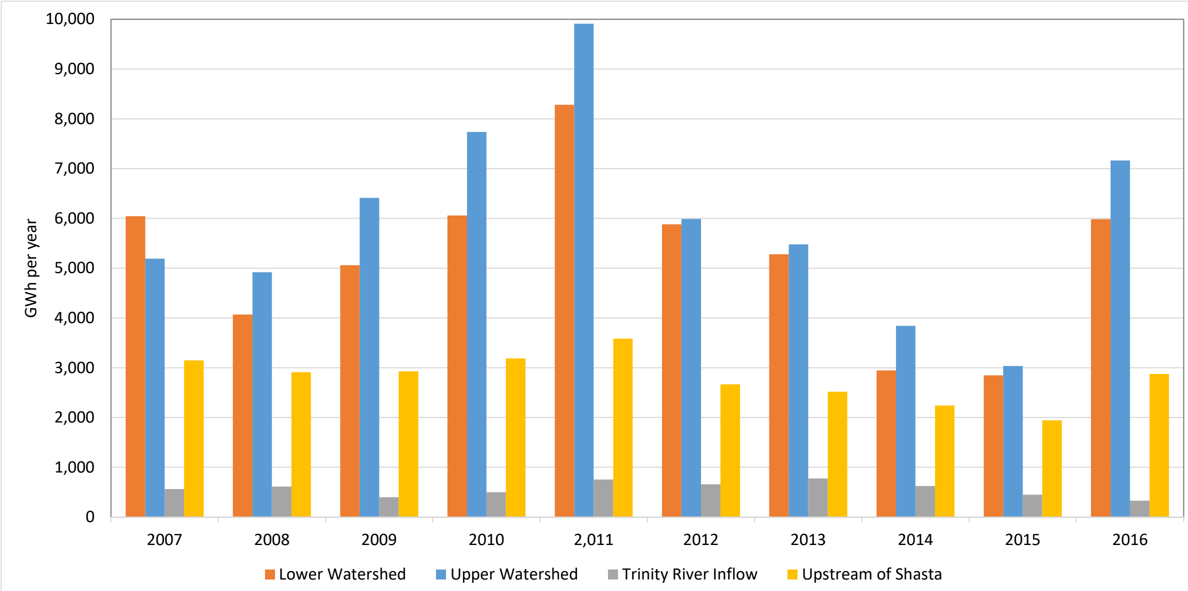
Source: ^EIA 2017.
MWh = megawatt-hour

Figure 7.8-5. 2011 and 2015 Monthly Generation—Shasta, Hyatt, Colgate, and Folsom Hydropower Plants



Source: ^EIA 2017.
MWh = megawatt-hour

Figure 7.8-6. 2011 and 2015 Monthly Generation for Hydropower Plants in the Sacramento River Watershed and Delta Eastside Tributaries Regions



Source: ^EIA 2017.
GWh = gigawatt-hour

Figure 7.8-7. Annual Hydropower Generation for Facilities in the Sacramento River Watershed and Delta Eastside Tributaries Regions

At many reservoirs, particularly rim reservoirs, power is generated incidentally by the release of water from the reservoir for delivery or for flood-control purposes and not for the sole intent of generating power. Therefore, power generation generally increases during summer months when reservoirs release water for delivery. In wet years, power generation also may be elevated in spring when reservoirs need to release water for flood-control purposes. In contrast, during dry water years, when reservoirs have plenty of storage space for spring runoff, power generation is often greatest in summer coincident with delivery releases.

In wet years like 2011, when rainfall and snow are plentiful, runoff from the mountains in northern California is used to create the most electricity in spring when runoff is the highest and in summer when reservoirs release water for other uses. During dry years like 2015, which was preceded by other dry years, a higher percent of runoff from the few storms is stored in reservoirs for release in summer, resulting in increases in generation occurring later, in late spring or early summer. Generally, less electricity is generated in dry years. Data for water years 2011 and 2015 are presented side by side to show an example of the differences in hydropower generation caused by differences in precipitation (Figure 7.8-5 and Figure 7.8-6).

Energy for CVP and SWP Exports

In addition to the hydropower facilities described in the preceding section for the Sacramento River watershed and Delta eastside tributaries regions, multiple facilities are in the southern part of the study area. However, these facilities depend on Delta exports and can recapture only a fraction of the energy needed to convey water up to these facilities.

Exporting water from the Delta to the San Francisco Bay Area (Bay Area), Central Coast, San Joaquin Valley, and Southern California regions requires a large amount of energy. The two largest export facilities are Banks Pumping Plant and Jones Pumping Plant, owned and operated by the California

Department of Water Resources (DWR) for the SWP and the U.S. Bureau of Reclamation (Reclamation) for the CVP, respectively. These two water projects are some of the largest consumers of electrical energy in the state, with the SWP being the largest single user of electricity in the state (DWR 2022b). Reclamation and DWR also own the largest hydropower facilities in the state—Shasta and Hyatt.

The CVP's monthly energy generation during 2016 was estimated to be from 100,000 to 1,100,000 MWh. On a monthly basis, the CVP itself uses between 10,000 and 180,000 MWh (81 Fed. Reg. 27433–27439). The majority of energy used by the CVP is to deliver water to customers along the Delta-Mendota Canal and San Luis Canal (shared with CVP). Deliveries to these customers require significant energy use by pump stations. Flows in other CVP canals are mostly gravity-fed or use little energy for diversion pumps. Of the energy needed to support CVP deliveries during a normal water year type, all is met through sources of self-generation at hydropower facilities. None of the power generation by CVP is considered to be in-conduit hydropower. CVP is a net producer of power. The balance of power not needed for delivering water is sold to CVP customers for further conveyance and pumping of water and to other long-term contractors via the Western Area Power Administration (WAPA). As of 2016, WAPA marketed about 1,580 megawatts (MW) of power from the CVP under long-term contracts to customers in northern and central California and Nevada (81 Fed. Reg. 27433–27439). WAPA distributes power through WAPA-owned transmission lines and operates its own balancing authority in California under the umbrella of the Balancing Authority of Northern California, although almost half of the power distributed by WAPA in California (as of 2016) goes to customers within the CAISO area (^EE Online 2016).

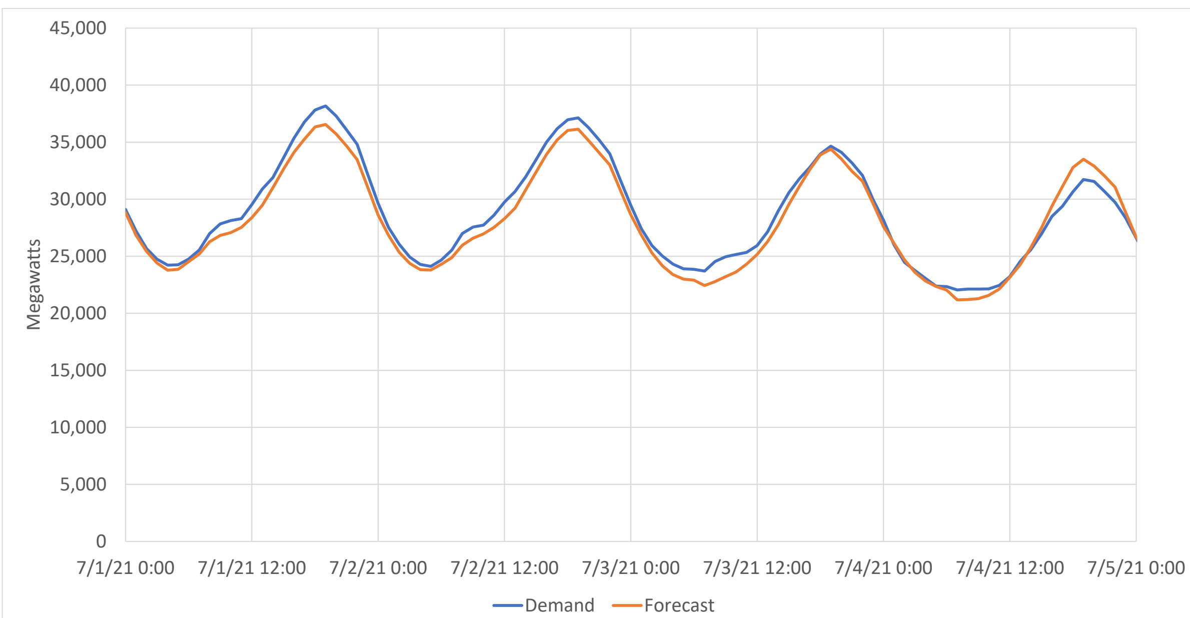
SWP's energy use for pumping water ranges from about 6,000,000 to 9,500,000 MWh per year (DWR 2022b). Every year, DWR must purchase additional power to meet some of its pumping requirements for the SWP. During normal water years, the energy needed to support SWP deliveries is met through multiple sources: 38 percent through in-conduit hydropower generated during the process of delivering the water, 35 percent through other sources of self-generation, and the balance (27 percent) purchased under long-term wholesale power contracts or through short-term power purchases (CPUC 2010). The energy required to pump and deliver water from the Delta to the CVP and SWP water contractors depends on the volume of water delivered each month and the pumping plants (elevation lifts) that are needed to deliver the water to the contractors. Because the water is delivered to contractors in the same percentages regardless of the total amount of water delivered, the amount of energy used to deliver each TAF of water to the system remains relatively consistent. The CVP delivers most of its water to the San Joaquin Valley region, whereas the SWP delivery area includes the Central Coast and Southern California regions. Consequently, it takes more energy to deliver 1 TAF to the SWP than it does to deliver it to the CVP because the water is pumped over mountain ranges.

As described in Appendix A5, *Hydropower, Energy Grid, and Export Energy Analyses,* based on analysis performed for the California WaterFix project (^DWR and Reclamation 2016), the average net energy factor for SWP exports was determined to be about 2,420 MWh/TAF. Similarly, the average net energy factor for CVP exports was determined to be about 363 MWh/TAF. These net energy factors include the recapture of some energy along the downhill portions of the conveyance system.

Electricity Demand Cycle

California's demand for electricity does not remain constant throughout the day. During summer, for instance, little electricity is used in the early morning hours because there is little activity in most homes, most offices are quiet, and air conditioners are not needed for the cooler morning temperatures. As people return home from work and turn on air conditioning and other home devices, energy demand spikes. The cycle of highs and lows requires a base level of energy on the electric grid, and it requires energy generation to meet peak needs. Peak demands do not always coincide with renewable sources, such as solar and wind energy generation. It is not possible to respond to peak demands with generation from coal or nuclear power because these facilities need more time to ramp up production. Typically, increased generation from natural gas facilities and hydropower meets the energy demand during these daily peaks.

Hydropower provided approximately 10 percent of the state's total electricity use in 2021 (in-state electricity production and imports), including 9 percent from large hydropower and an additional 1 percent from small hydropower (CEC 2022). Because of its peaking capacity, however, hydropower has importance beyond the total annual generation. Figure 7.8-8 illustrates California's forecasted demand and actual demand for July 1–4, 2021. On cooler days, the actual energy use can be less than what is forecasted, but agencies balancing the transmission grid schedule powerhouses to meet the forecasted levels. Base power serves the lower part of the curve, and the higher part of the curve (peak demand) is met with peak energy production.



Source: EIA 2021a.

Figure 7.8-8. Example of California Electrical Forecasted Demand and Actual Demand July 1–4, 2021

Hydropower can be used to a limited extent to follow loads and provide power during peak times, but the total energy available fluctuates annually based on weather. Increasing environmental constraints also affect the timing of hydropower availability. Electric generation is low on the list of priorities, which include flood control, public supply, maintenance of water temperature and flows for fish spawning, and irrigation.

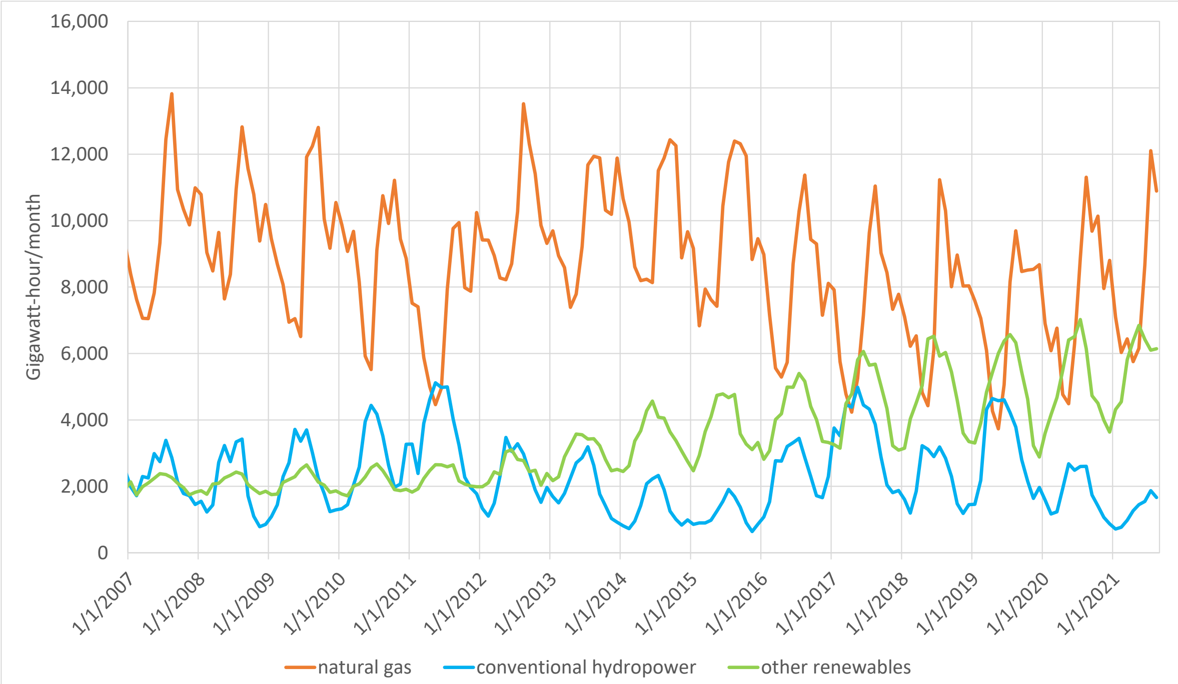
Hydropower helps meet peak demands in two ways—single-use releases and pumped storage. The vast majority of hydropower facilities are single-use facilities where water passes only once through the facility. Typically, a single-use hydropower facility needs to release a certain amount of base flow to the river but has some ability to ramp releases up or down to meet peak energy demands. The ability to ramp releases up or down varies by facility and depends on factors such as whether the flow is controlled by a reservoir, instream flow requirements, and presence and size of reregulating reservoirs downstream of the facility that allow dampening of the fluctuations in flow. The ability to ramp releases up or down allows hydropower facility operators to increase profits by supplying energy when demand and prices are high.

Pumped storage facilities pump water from a lower-elevation reservoir to a higher-elevation reservoir during periods of off-peak demand for electricity in order to generate hydropower during periods of peak demand. Pumped storage facilities consume electricity when pumping water up to a reservoir and then generate electricity during peak periods of demand as the water flows out of the reservoir and downhill through powerhouse turbines. Although pumped storage projects use more energy than they produce (net negative), they provide a benefit by helping balance the grid. These projects pump water uphill at times of abundant energy and generate energy during times of shortage (^CEC 2017b). There are five pumped storage facilities: Lake Hodges, Castaic Lake, San Luis Reservoir, O'Neill Forebay, and Lake Oroville (Mathias et al. 2016).

See Appendix A5, *Hydropower, Energy Grid, and Export Energy Analyses,* for more information about daily fluctuations in hydropower generation to meet daily periods of peak demand.

Natural Gas, Hydropower, and Other Renewable Energy Production

Hydropower plants and natural gas–fired plants are the largest and most versatile sources for meeting both peak and base electricity needs. Both of these energy sources can compensate for fluctuations in solar and wind energy production, and production of both solar and wind energy is increasing. The monthly California energy production levels for natural gas, hydropower, and other renewables (mostly wind and solar) are compared in Figure 7.8-9 for years 2007 through 2021. During most months shown in the comparison, natural gas–fired electric powerhouses generated in excess of 6,000 GWh per month (GWh/month), while hydropower never reached that rate of energy production. Natural gas facilities are able to increase or decrease generation to match the shifts in demand for electricity that cannot be matched at the same scale by other sources of energy. Renewable energy production from sources other than hydropower has increased steadily from an average of about 2,000 GWh/month in 2011 to monthly averages that exceed 6,000 GWh/month during peak summer solar months. Figure 7.8-9 shows utility-scale energy and does not include small-scale solar production, which also has been increasing and has now reached approximately 2,000 GWh/month during summer months (EIA 2021b).



Source: EIA 2021b.

Figure 7.8-9. Monthly Natural Gas, Conventional Hydropower, and Other Renewable Electrical Production in California 2007–2021

Closer evaluation of a 2013–2020 subset of the historical energy generation for months with higher generation, May through October, demonstrates the increased use of natural gas during summer and early fall months compared with other months (Table 7.8-2). November through April are not shown because natural gas generation is relatively low then. Hydropower and other renewable generation are also high in summer, but they both tend to peak earlier than natural gas generation.

Table 7.8-2. Natural Gas, Hydropower, and Other Renewable Monthly Generation (gigawatt hour)

	2013	2014	2015	2016	2017	2018	2019	2020
Natural Gas								
May	7,789	8,235	7,420	5,736	5,253	4,426	3,731	4,488
June	9,217	8,135	10,441	8,703	7,155	6,116	5,059	6,287
July	11,680	11,509	11,766	10,275	9,636	11,232	8,159	8,873
August	11,937	11,885	12,399	11,375	11,041	10,300	9,691	11,306
September	11,891	12,434	12,316	9,434	9,029	8,012	8,468	9,683
October	10,316	12,257	11,947	9,298	8,436	8,963	8,513	10,137
Hydropower [a]								
May	2,707	2,079	1,255	3,200	4,982	3,114	4,581	2,680
June	2,861	2,226	1,545	3,317	4,451	2,893	4,604	2,485
July	3,193	2,326	1,908	3,448	4,326	3,184	4,223	2,599
August	2,629	1,903	1,690	2,867	3,865	2,844	3,787	2,603
September	1,766	1,253	1,375	2,297	2,884	2,301	2,796	1,738
October	1,409	1,008	905	1,718	2,045	1,479	2,157	1,413

	2013	2014	2015	2016	2017	2018	2019	2020
Other Renewables (excluding hydropower)								
May	3,575	4,278	4,738	4,989	5,809	6,442	6,006	6,408
June	3,553	4,569	4,786	4,983	6,060	6,520	6,375	6,508
July	3,422	4,084	4,671	5,399	5,646	5,922	6,568	7,024
August	3,433	4,053	4,770	5,163	5,680	6,031	6,326	6,145
September	3,223	3,642	3,580	4,405	5,024	5,448	5,435	4,730
October	2,807	3,375	3,273	4,015	4,339	4,596	4,629	4,505

Source: EIA 2021b.

[a] Not including energy generated by pumped storage.

7.8.2.5 Energy Associated with Groundwater Pumping and Other Water Management Actions

The amount of energy needed to pump groundwater depends on the depth of the groundwater and the efficiency of the system. Groundwater typically requires more energy for pumping than surface water, and energy requirements increase with well depth. The California Energy Commission (CEC) estimated that water supplied from groundwater requires from 400 to 1,200 kilowatt-hours (kWh) of electric power per acre-foot (AF) (CEC 2015). In California, it is estimated that approximately 6 billion kWh of energy is used to pump groundwater (NGWA 2017).

Renewable energy sources, including energy obtained from wind turbines, windmills, and solar arrays, can be used to pump groundwater. Solar-powered pumping systems have been used in the United States for more than 20 years. As photovoltaic modules become more affordable and the energy efficiency of both the modules and solar-powered pumps increases, it will become a leading technology in remote areas. Generally, renewable energy sources are considered most feasible when the cost of tapping into the closest public power grid far exceeds the costs of using the renewable source (Van Pelt and Waskom 2012).

Energy required for water treatment is dictated by the water quality of the source and the specific end use. Groundwater treatment often requires only disinfection, such as chlorination, and therefore typically requires less energy than surface water treatment. The energy intensity of groundwater chlorination is low and is estimated to be about 3 kWh/AF (EPRI 2002).

Once water is treated, energy is used to pump the water through the water distribution system to its final end user. Additional energy is used at the location of end use, where water is heated, pressurized, pumped, or cooled (Sanders and Webber 2013). The distribution to end users varies with the efficiency of the system and can have a much higher energy intensity for older structures that are more prone to break down and leak. About 10 to 60 percent of treated water is estimated to be lost during delivery in the United States due to damaged and leaking pipelines. Water loss is, therefore, associated with energy loss because energy that could have otherwise been used for different purposes is now used for water distribution.

The energy required for groundwater storage and recovery operations is similar to that for groundwater pumping infrastructure, although additional energy may be required if water is actively applied using injection wells. Passive recharge requires little additional energy once the infrastructure is in place. Because higher water levels result in less energy used to pump water, groundwater storage and recovery saves energy and may be more efficient and cost effective than conveying water over long distances.

Recycled water requires energy to treat it; however, because treatment is likely already required before wastewater can be discharged into the environment, water reuse does not require much more energy. Recycled water also replaces treated surface water or groundwater that typically requires more energy to procure and treat for use. Therefore, recycling can be a low-energy replacement option if it is available. Water recycling for nonpotable reuse requires less energy because it has lower treatment requirements.

Water conservation and efficiency measures—such as low-flow appliances, efficient irrigation systems, and xeriscaping—reduce runoff of wastewater, which, in turn, reduces the energy required for treatment. Some low-flow appliances, such as showerheads and clothes washers, are also more energy-efficient because they reduce hot water usage, and thereby also save energy (Cooley and Phurisamban 2016).

Energy consumption for operation of desalination plants is discussed in Section 7.22, *New or Modified Facilities*, as well as in the discussion for Impact EN-e in the subsection titled *Evaluation of Energy Costs for Actions to Replace Reduction in Water Supply from the Sacramento/Delta*.

7.8.3 Impact Analysis

Appendix F of the State CEQA Guidelines (Cal. Code Regs., tit. 14, § 15000 et seq.) contains recommendations for assessing energy impacts and mitigation measures that may be considered in making a decision on a project. CEQA requires a discussion of potential energy impacts to ensure that energy implications are considered, with emphasis on avoiding or reducing inefficient, wasteful, and unnecessary consumption of energy. Appendix F was used as guidance for the following discussion of the energy implications of the proposed Plan amendments. Modeling was conducted to evaluate how the proposed Plan amendments would affect energy demand and generation in California, including the following.

- Changes in hydropower generation within the Sacramento River watershed and the Delta eastside tributaries regions.
- Effect of summer reduction in hydropower generation on reliability of the electric grid (power flow modeling).
- Reduction in the energy needed for CVP and SWP exports from the Delta.

A description of the methods for and results of these analyses is provided in more detail in Appendix A5, *Hydropower, Energy Grid, and Export Energy Analyses*. Increases in energy for other water management actions to replace reduced Sacramento/Delta supplies are evaluated under Impact EN-e.

Changes in hydrology affecting flows and reservoir levels would result in an increase in hydropower generation in spring and a decrease in summer. Decreases in hydropower generation may necessitate increased production from other power facilities, likely natural gas-fired power facilities. Changes in water supply include reduced Sacramento/Delta supply to some agricultural and municipal uses and could result in a reduction in the energy used to convey Sacramento/Delta supply. The reduction in Sacramento/Delta supply could cause an increase in energy use to replace supplies if water users implement actions such as increased groundwater pumping or other water management actions. The various energy requirements of these actions are compared and evaluated. This comparative analysis also includes the energy requirements that may result from operation of a desalination facility to replace reduced supplies. (Construction and maintenance of a desalination facility is comprehensively addressed in Section 7.22, *New or Modified Facilities*; however, for the purposes of the comparative energy analysis, operational energy requirements of desalination are also relevant and discussed in this section.)

Section 7.21, *Habitat Restoration and Other Ecosystem Projects*, and Section 7.22, *New or Modified Facilities*, describe and analyze potential energy-related impacts from various actions that involve construction.

Impact EN-a: The effects of the project on energy resources

Evaluation of Hydropower Generation in the Sacramento River Watershed and Delta Eastside Tributaries Regions

Hydropower Generation Methods

The analysis of hydropower effects in the Sacramento River watershed and Delta eastside tributaries regions focused on the 47 facilities that could be evaluated based on Sacramento Water Allocation Model (SacWAM) results. The power capacity of these facilities represents about 80 percent of the total hydropower capacity in these regions. Approximately 17 percent of the remaining hydropower capacity is at facilities not expected to be affected by the type of hydrologic changes likely to occur with the proposed Plan amendments. These include the Judge Francis Carr facility, which is powered by imports from the Trinity River watershed, and the facilities upstream of Shasta Reservoir. Operations upstream of Shasta Reservoir are not included in SacWAM because hydrology and hydropower generation in this area would not be expected to change much in response to the proposed Plan amendments, as explained in Chapter 2, *Hydrology and Water Supply*.

Two types of calculations were used to estimate monthly hydropower generation at the 47 facilities that were evaluated based on SacWAM results.

- **Flow- and head-based calculations.** For the four largest facilities expected to be most affected by the proposed Plan amendments, hydropower generation was calculated in a detailed manner based on flow through the turbines, powerhouse efficiency, and hydraulic head (the vertical distance between the powerhouse turbines and water surface elevation in the reservoir). This more detailed approach was used for Folsom, Shasta, Edward C. Hyatt (Oroville), and Colgate (New Bullards Bar) hydropower facilities. Total power capacity at these four facilities is 1,987 MW, or approximately 33 percent of the total hydropower capacity in the Sacramento River watershed and Delta eastside tributaries regions.
- **Flow-based calculations.** For the other 43 facilities evaluated, hydropower generation was estimated by assuming that full powerhouse generating capacity could be attained when flows through the powerhouse were at the maximum flow capacity for the facility and that, during lower flows, power generation would depend on the fraction of the full flow going through the facility. For example, if flow through the facility was at 50 percent of the maximum possible flow, then energy generation was assumed to be at 50 percent of the full powerhouse generating capacity.

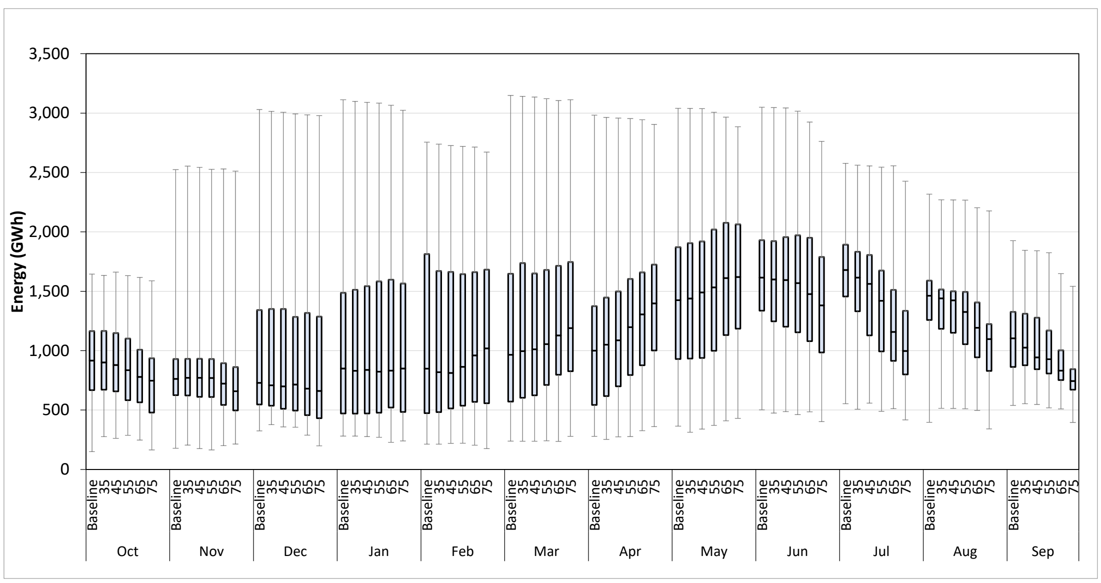
Estimated Effects on Hydropower Generation

Chapter 6, *Changes in Hydrology and Water Supply*, includes SacWAM results for instream flow changes in increments of 10 percent, from 35 percent unimpaired flow up to 75 percent (referred to as numbered flow scenarios, such as "35 scenario," "45 scenario"). The proposed program of implementation for the Plan amendments provides for a range of flow scenarios from 45 to 65, with default implementation starting at the 55 scenario. The 35 and 75 flow scenarios are also presented to inform the analyses of low and high flow alternatives in Section 7.24, *Alternatives Analysis*.

The main effect of the proposed Plan amendments on hydropower would be an increase in generation during the spring and a reduction during the summer, resulting primarily from changes in flow (Figure 7.8-10). The largest increases in hydropower generation were estimated to occur during April, with the calculated hydropower generation increasing incrementally with each 10 percent increase in the flow requirement. Median values are used to assess results because they represent the general long-term effect. Changes at the extreme high and low percentiles are expected to be smaller and represent a small number of years.

Under the proposed Plan amendments (45 to 65 scenario), April would be the month of highest increased flow and, therefore, electricity generation. Based on the modeling, April median hydropower generation would rise between 87 and 305 GWh, compared with the baseline condition hydropower production of 1,000 GWh for the facilities evaluated. The largest decrease in hydropower generation would occur during July, when median hydropower generation would decrease by 116 to 521 GWh when compared with the baseline condition July median production of 1,679 GWh.

For the 55 scenario, the reduction in July median hydropower production of about 260 GWh represents about 15 percent of the baseline median generation in July. Median July hydropower generation for the 55 scenario of 1,420 GWh would be well within the baseline condition range of production for July, which is roughly from 550 to 2,580 GWh. The reduction in summer hydropower generation would be replaced by other sources of electricity, particularly increased generation at natural gas facilities.



Energy for scenarios was estimated with flow and storage simulated by SacWAM.
GWh = gigawatt hour

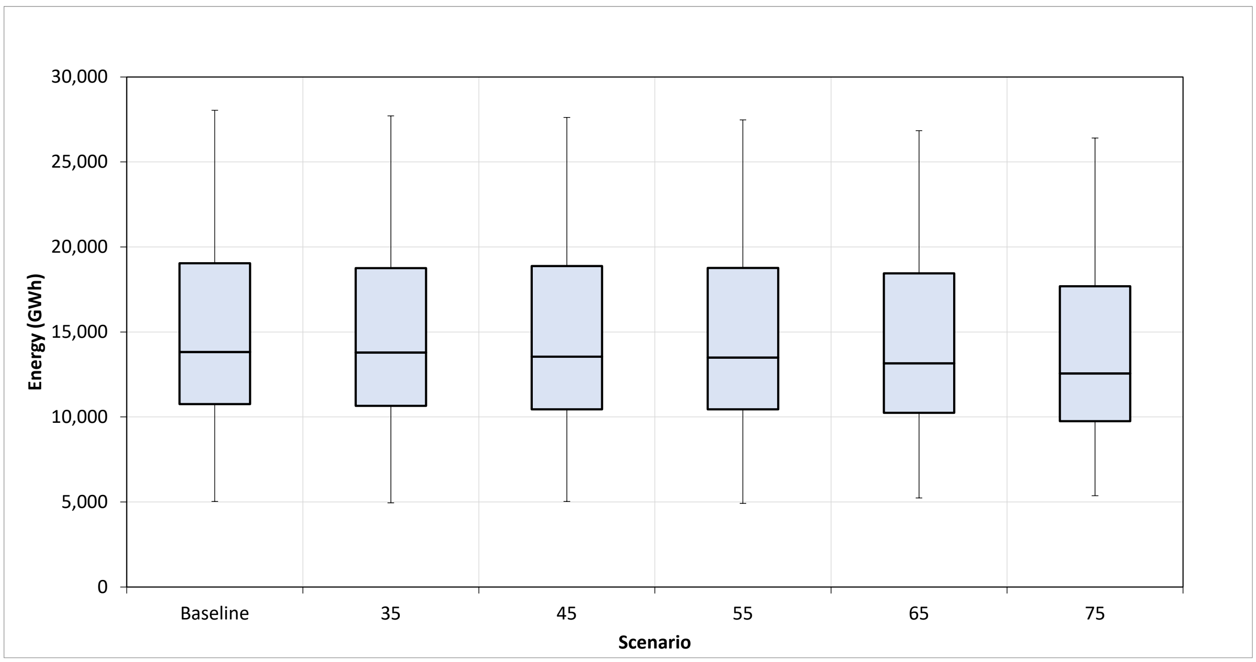
Figure 7.8-10. Monthly Hydropower Generation for Sacramento River Watershed and Delta Eastside Tributaries Regions—Facilities Potentially Subject to Changes in Flow as Simulated by SacWAM

Annually, hydropower effects would be relatively small because the total annual flow would not change, and reservoir storage would not be expected to be greatly reduced (Figure 7.8-11 and Table 7.8-3). However, small annual changes may result from the following conditions.

- Increases in flow that may exceed the capacity of some hydropower facilities; this would occur primarily during wet years.
- Changes in reservoir water surface elevations.
- Changes in interbasin diversions, which would affect the total annual volume of water moving through some facilities.

On an annual basis, the median change in hydropower energy generation would be between a 270-GWh reduction for the 45 scenario and a 669-GWh reduction for the 65 scenario, compared with the baseline condition median hydropower generation of 13,820 GWh (Table 7.8-3).

For the 55 scenario, the reduction in median annual hydropower generation is 328 GWh, which represents a decrease of about 2.4 percent in hydropower generation in the Sacramento River watershed and Delta eastside tributaries regions. When compared with all of the electricity generated in California for 2015 (196,195 GWh, Table 7.8-1), a dry year, this annual change (328 GWh) represents a 0.17-percent decrease.



Energy for scenarios was estimated with flow and storage simulated by SacWAM.
GWh = gigawatt hour

Figure 7.8-11. Annual Hydropower Generation for Sacramento River Watershed and Delta Eastside Tributaries Regions—Facilities Potentially Subject to Changes in Flow as Simulated by the Sacramento Water Allocation Model

Table 7.8-3. Cumulative Distribution of Annual Hydropower Generation: Baseline Condition and Change from Baseline Condition (gigawatt hour)

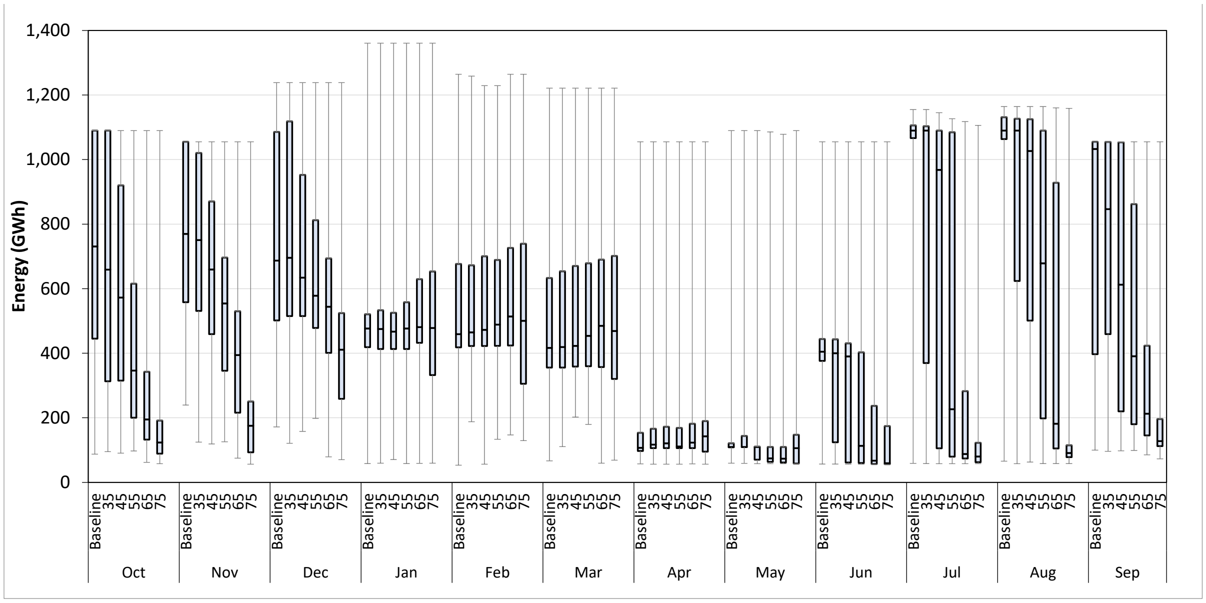
Percentile	Baseline	35	45	55	65	75
0	5,028	-81	6	-106	212	339
10	8,729	-205	-232	-290	-583	-1,203
25	10,756	-97	-307	-309	-513	-1,002
50	13,820	-24	-270	-328	-669	-1,255
75	19,045	-287	-170	-283	-601	-1,354
90	22,044	-488	-617	-822	-1,053	-1,978
100	28,036	-323	-414	-559	-1,192	-1,626
Average	14,701	-141	-257	-413	-649	-1,149

While reduced hydropower is not significant statewide, hydropower production can be an important local resource, and reduced hydropower generation could be significant for an individual project or community. Potential localized impacts on hydropower are further evaluated under Impact EN-c.

Evaluation of Change in Energy to Export Sacramento/Delta Water Supply

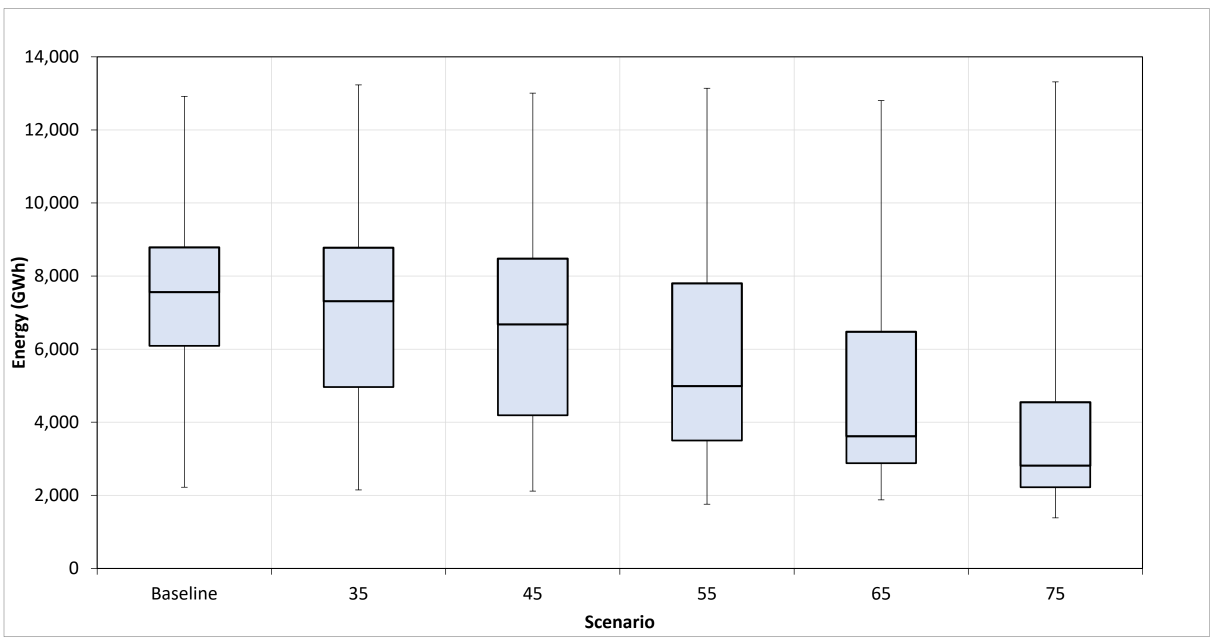
A large amount of energy is required to pump CVP and SWP exports uphill toward their destinations, and only a portion of this energy can be recaptured when some of the water drops in elevation on its way to its final destination. Potential energy effects associated with changes in CVP and SWP exports were estimated using energy factors that are estimates of the average energy needed to export a volume of water. Based on the analysis performed for the California WaterFix project (^DWR and Reclamation 2016), the average net energy factor for SWP exports was determined to be about 2,420 MWh/TAF, and the average net energy factor for CVP exports was determined to be about 363 MWh/TAF. The energy factors incorporate the effect of partial energy recapture at hydropower generation facilities along the downhill portions of the conveyance system. These energy factors were used to estimate monthly energy required for SWP and CVP Delta exports under the baseline condition and for the flow scenarios.

Changes in hydrology would result in decreased water exports for the SWP and CVP. The average reduction in exports could range from about 420 to 1,660 TAF for the 45 to 65 scenarios. The reduction in CVP and SWP water exports would likely cause a substantial reduction in the amount of energy needed to move water to consumers. The energy evaluation shows these reductions to be largest during the June to December period, corresponding to the period when SacWAM estimated that exports would be most affected (Figure 7.8-12). Large reductions in SWP and CVP exports would result in a reduction in energy use that could be large, with the average of annual calculated export energy being approximately 840 to 2,590 GWh less than the baseline condition (Figure 7.8-13 and Table 7.8-4).



Energy for scenarios was estimated with CVP and SWP Delta exports simulated by SacWAM.
GWh = gigawatt hour

Figure 7.8-12. Estimated Monthly Changes in Energy Required for CVP and SWP Exports



Energy for scenarios was estimated with CVP and SWP Delta exports simulated by SacWAM.
GWh = gigawatt hour

Figure 7.8-13. Estimated Annual Changes in Energy Required for CVP and SWP Exports

Table 7.8-4. Cumulative Distribution: Energy for Exports—Baseline Condition and Change from Baseline Condition (gigawatt hour)

Percentile	Baseline	35	45	55	65	75
0	2,219	-72	-102	-463	-344	-836
10	3,676	-59	-385	-806	-1,281	-1,766
25	6,090	-1,126	-1,899	-2,588	-3,213	-3,871
50	7,562	-248	-883	-2,572	-3,947	-4,748
75	8,785	-11	-309	-982	-2,308	-4,240
90	10,364	-207	-582	-1,130	-1,573	-3,558
100	12,919	312	86	221	-117	397
Average	7,393	-313	-839	-1,667	-2,589	-3,714

The annual average energy savings associated with simulated reductions in Delta exports is much larger than the estimated annual average reduction in hydropower generation in the Sacramento River watershed and Delta eastside tributaries regions (e.g., 2,590 GWh versus 650 GWh for the 65 scenario). However, the reduction in energy use would likely be less if north-to-south water transfers are used to replace reduced exports.

As discussed and evaluated in more detail under Impact EN-e, the primary way changes in hydrology and changes in water supply would affect energy requirements is by reducing the energy needed to transport Sacramento/Delta water supply and by increasing energy used to replace reduced Sacramento/Delta water supply. The energy used to replace reduced Sacramento/Delta water supply depends on how water users respond to the decreased Sacramento/Delta water deliveries. Depending on the location, water users may adopt any of a series of options, such as switching to or increasing use of groundwater supplies, and other water management actions, such as groundwater storage and recovery, water transfers, water recycling, and water conservation measures. Another response action is desalination. Because energy to replace Sacramento/Delta water supply could be more energy intensive, the overall impact would be potentially significant. Potential impacts on energy sources from other water management actions and desalination, as well as mitigation to avoid or reduce those impacts, are addressed under Impact EN-e.

Impact EN-b: The effect of the project on peak and base period demands for electricity and other forms of energy

Changes in hydrology and changes in water supply may affect the peak and base period demands for electricity. There are two types of peak demands for electrical energy. One is the annual peak demand, and the other is the daily peak demand. In California, the annual peak is in the summer, and the daily peak is in the early evening. During the summer months, household demands increase for cooling purposes. Peak demand generally occurs in July, August, or September but can also be high during heatwaves in June (CAISO 2023).

Changes in hydrology would result in decreased water exports for the SWP and CVP, which would result in a reduction in energy use that could be large, with calculated average annual energy for exports being approximately 840 to 2,590 GWh less for the 45 to 65 scenarios when compared with the baseline condition (Figure 7.8-13 and Table 7.8-4). Much of that energy use reduction would be in the summer months that correspond to peak energy demand.

However, changes in hydrology would also result in a reduction in hydropower generation during the summer as described for Impact EN-a, and changes in water supply would result in reduced Sacramento/Delta surface water supply. Reduced Sacramento/Delta surface water supply could cause an increase in energy demand, depending on how much of the reduced Sacramento/Delta water supply is replaced and what methods are used for the replacement. As described for Impact EN-e, increases in energy use to replace Sacramento/Delta water supply would be potentially significant. This increase in energy use would represent an increase in demand that likely would be largest in the summer, when water use is greatest, but it could affect both base and peak demand. Based on the determination for Impact EN-e, Impact EN-b would be potentially significant. Potential impacts on energy sources from increased use of groundwater or other water management actions and mitigation to avoid or reduce those impacts are addressed under Impact EN-e.

Impact EN-c: The effects of the project on local and regional energy supplies and requirements for additional capacity

Changes in hydrology would result in changes in hydropower energy production that would primarily affect 3 of the 10 regional energy areas in California: Sierra, Sacramento, and Stockton. These areas can be supplied by both hydropower and gas-fired electrical production facilities; therefore, as one facility increases energy production, the other can be reduced to meet demand. The estimated increase in median hydropower production during the month of April, the month of largest additional production, ranges from 87 and 305 GWh for the Sacramento River watershed and the Delta eastside tributaries regions for the 45 to 65 scenarios. This potential change is well within the typical fluctuation shown in the data under the baseline condition. Therefore, the additional electricity would be available on these portions of the grid, as it has been under the baseline condition.

During the summer months, there would be a drop in hydropower production in the Sacramento River watershed and Delta eastside tributaries regions. The decrease in hydropower production in this area would likely be offset by an increase in natural gas–fired power in the area. Modeling results indicate that median production during July would decrease by 116 to 521 GWh for the 45 to 65 scenarios. Because natural gas–fired power facilities are present in the area, natural gas facilities would likely increase productivity as necessary to keep the local area power supply balanced.

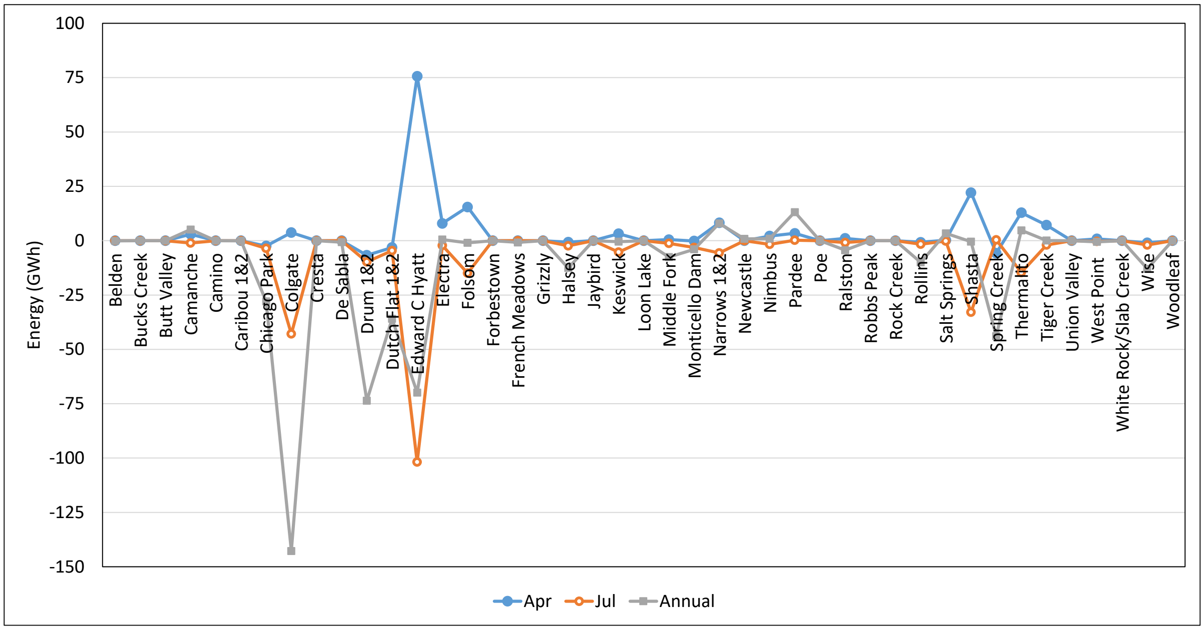
These changes in hydropower generation would be within the baseline condition range of capacity for the Sacramento River watershed and Delta eastside tributaries regions, and existing systems are usually capable of meeting the supply needs of the region. To further evaluate whether changes in hydrology could affect grid reliability in the region, a power flow analysis was performed (described under *California Power Flow Grid Reliability*). The power flow analysis relied on the estimated changes in hydropower at individual hydropower facilities.

Effects at Individual Facilities

Changes in hydrology simulated by SacWAM would result in a range of hydropower effects at the hydropower facilities in the Sacramento River watershed and Delta eastside tributaries regions. The largest changes in flow and hydropower would be expected to occur at the rim reservoirs and downstream because modification of the rim reservoir operations is the primary way the flow objectives would be met. Many facilities above the rim reservoirs would not be expected to experience large hydrologic changes because consumptive use and reservoir storage in this area are relatively small, so, in general, no large hydrologic changes would likely be needed in this area to meet the flow requirements. However, in some cases, implementation of the flow objectives could result in a reduction of water diversions between watersheds, particularly for the higher end of the flow range. A reduction in interbasin diversions could reduce generation at facilities that depend on the diversions. Conversely, a few facilities may benefit from the retention of flows within a watershed.

To show which facilities would be most affected, a summary of average changes at all the facilities evaluated is provided for the 55 scenario (Figure 7.8-14). Effects would be less or more pronounced in the 45 and 65 scenarios, respectively. The figure shows results for April (the month with the largest increases in hydropower generation) and July (the month with the largest decreases in hydropower generation), as well as the annual total. As expected, based on facility size and location, large changes occur at Shasta, Oroville (Hyatt Powerhouse), New Bullards Bar (Colgate Powerhouse), and Folsom. Other reservoir facilities or facilities downstream of rim reservoirs that show moderate changes in hydropower generation include the following.

- Keswick Power Plant (supplied primarily by releases from Shasta Reservoir)—Affected primarily by changes in release schedule from Shasta Reservoir but also some reduced inflow from Spring Creek Power Plant.
- Spring Creek Power Plant (supplied by Clear Creek and Trinity River water in Whiskeytown Reservoir)—Inflow from the Trinity River watershed does not change between scenarios, but releases from Whiskeytown Reservoir to the Spring Creek Power Plant are reduced in order to retain more water in Clear Creek.
- Pardee and Camanche Power Plants (supplied by Mokelumne River)—Reduction in diversions from Pardee Reservoir to the East Bay Municipal Utility District pipeline results in more water being released from Pardee and Camanche Reservoirs through their two power plants.
- Thermalito Power Plant (supplied by Feather River)—Affected primarily by changes in release schedule from Lake Oroville.
- Narrows 1 & 2 Power Plant (supplied by Yuba River)—Increase in generation caused by reduction in diversions from the Yuba River to other basins. Also affected by change in releases from New Bullards Bar Reservoir.



GWh = gigawatt hour

Figure 7.8-14. Estimated Average Change in Hydropower Generation for the 55 Scenario at Individual Hydropower Facilities

Multiple facilities in the upper watershed showed small to large changes in hydropower generation.

- Drum 1 & 2 Powerhouses (located along the conveyance between the Yuba and American Rivers to Bear River)—Reduction in generation caused by reduction in diversions from the Yuba River to the Bear River.
- Halsey and Wise Powerhouses (located along the conveyance between the Bear River to Auburn Ravine and the American River)—Reduction in generation caused by reduction in diversions from Bear River to Auburn Ravine and the American River.
- Chicago Park, Dutch Flat 1 & 2, and Rollins Powerhouses (supplied by the Bear River)—Reductions in hydropower generation caused by reduction in interbasin diversions to the Bear River.
- Middle Fork and Ralston Powerhouses (supplied by water in the Middle Fork American River basin, including the Rubicon River)—Small increases in hydropower in the spring and reductions in the summer caused by increases in releases from Hell Hole and French Meadows Reservoirs to meet instream flow requirements in the spring, followed by reduction in releases in the summer. Occasional exceedances of power plant capacity in the spring result in small reductions in net annual generation.
- Tiger Creek and Electra Power Plants (supplied by North Fork Mokelumne River)—Small increases in hydropower in the spring and reductions in the summer caused by small increases in releases from upstream reservoirs to meet instream flow requirements in the spring, followed by reduction in releases in the summer.

These estimated changes in hydropower generation do not by themselves indicate whether local and regional energy supplies would be affected. As long as the electric grid can move sufficient energy to where it is needed, there is no need for additional capacity. The ability of the electric grid to handle reductions in hydropower generation at facilities depends on generation capacity at other facilities and on the ability of the grid infrastructure to convey electricity from those facilities.

While changes in hydrology would not result in significant reductions in energy production from reduced hydropower statewide, there could be localized significant impacts for an individual project or community. Implementation of Mitigation Measure MM-EN-a–e can avoid or minimize impacts on hydropower generation.

As discussed in Chapter 5, *Proposed Changes to the Bay-Delta Plan for the Sacramento/Delta*, the proposed Plan amendments allow for and encourage water users on tributaries to work together to meet the proposed flow and cold water habitat requirements in a manner that minimizes impacts on hydropower production to the extent possible. The proposed Plan amendments also allow two or more tributaries to work together to meet flow requirements, which could be a method for tributaries with significant interbasin diversions for hydropower production to reduce impacts on hydropower, although there could still be issues with timing and other issues that would need to be addressed. In addition, the proposed Plan amendments promote voluntary implementation plans that could amplify the ecological benefit of new and existing flows with physical habitat restoration or other complementary ecosystem measures that may reduce the volume of water that needs to be dedicated for instream purposes, resulting in smaller effects on hydropower generation. Water users would be encouraged to work together to tailor approaches to meet the proposed Plan amendments in a manner that minimizes disruptions to other important beneficial uses, including hydropower.

The proposed Plan amendments include a cold water habitat narrative objective that requires rim reservoir operators on the Sacramento/Delta tributaries to develop and implement long-term strategies and annual operations plans to meet the cold water habitat requirements that consider a tributary’s unique structural, operational, and hydrological characteristics. Upstream water users would be required to participate in development of the strategies to the extent that their operations affect achievement of requirements below the rim reservoirs. As determined by the Executive Director of the State Water Board, upstream reservoir operators may also be required to develop their own strategies if their reservoir operations would affect achievement of the narrative objective for stream segments above the rim reservoirs. The proposed Plan amendments call for the cold water habitat objective to be implemented to the extent possible in a manner that avoids hydropower impacts. The requirements themselves may also reduce significant reservoir drawdown impacts (preventing water levels from dropping below hydropower intake facilities and preventing reductions in hydraulic head), thereby protecting hydropower production.

Other existing requirements may already limit hydropower production to some degree. Many reservoirs with hydropower operations are subject to regulation by FERC and have independent obligations to meet temperature and other instream flow requirements. Many reservoirs also are subject to other Endangered Species Act (ESA) and California Endangered Species Act requirements, including biological opinion provisions. To the extent possible, Bay-Delta Plan requirements are proposed to be integrated with ongoing efforts in the FERC relicensing process and associated water quality certification by the State Water Board, as well as ESA and CEQA requirements.

It is not certain how parties may choose to cooperate to implement the proposed Plan amendments and whether impacts from localized reductions in hydropower generation could be fully mitigated. Therefore, potential impacts from changes in hydrology due to localized reductions in hydropower generation remain potentially significant.

California Power Flow Grid Reliability

Methods

To evaluate whether changes in hydrology might produce a reduction in hydropower capacity that could stress the California electric grid, electric grid reliability was evaluated by power flow modeling with Power Gem's Transmission Adequacy and Reliability Assessment software (TARA), as described in Appendix A5, *Hydropower, Energy Grid, and Export Energy Analyses*, and summarized here. The power flow assessment was performed using the 2021 power flow case representing the electric grid under heavy summer demand condition for the entire Western Interconnection, including detailed representation of the California electric grid. The purpose of the power flow modeling was to determine whether electrical generation at other facilities could compensate for a reduction in hydropower generation and to determine if there would be any local constraints on the flow of electricity due to local reduction in hydropower. Transmission line flows and substation voltages were evaluated for reliability criteria violations (i.e., overload) under normal operating conditions and under contingency operating conditions. Under normal conditions, all generation and transmission facilities were assumed to be in service.

The power flow assessment only analyzed the 75 scenario because this scenario would result in the greatest reductions in reservoir storage (head) and the largest changes in flow for hydropower due to reduced interbasin diversions between watersheds and shifts in flow from summer to spring (see Appendix A5, *Hydropower, Energy Grid, and Export Energy Analyses*). For both the normal and contingency operating conditions, grid reliability for the 75 scenario was compared with the baseline condition. If this evaluation had indicated reliability concerns, the lower flow scenarios would have been evaluated as well.

To consider the largest reduction in power that might affect the electric grid, hydropower results for July were used as input to the power flow model. July represents a time of peak summer demand for electricity, and July hydropower modeling results show the largest reductions in hydropower associated with the flow scenarios. Hydropower results for below-normal water years were used in the power flow assessment because those results show the largest hydropower reductions associated with the 75 scenario (in terms of MW).

Because the power flow model simulates electricity during the daily period of peak demand, the hydropower values estimated from SacWAM results were scaled up to represent daily peaking activity. Under the baseline condition and the 75 scenario, hydropower peaking operations would still occur in order to maximize hydropower during the daily time of peak demand. Hydropower was estimated as the hydropower derived from the SacWAM results increased by a fraction to represent typical peaking operations that would occur in the absence of a contingency. The analysis assumed no increase in peaking percent when there was a reduction in hydropower. As described in Appendix A5, *Hydropower, Energy Grid, and Export Energy Analyses,* the peaking fraction was estimated as 0.54 based on hourly CAISO data for all CAISO hydropower facilities combined; CAISO does not provide data for individual hydropower facilities. The degree of peaking operations varies from facility to facility and from day to day, but the use of the aggregated value is sufficient for estimating the effect of peaking operations and the adequacy of electric power supply to maintain grid reliability.

Results

The power flow assessment found that the 75 scenario did not cause reliability criteria violations under normal or contingency conditions that could not be rectified with a temporary redispatch of generation. Electricity generation at other facilities is able to compensate for a reduction in hydropower in the Sacramento/Delta. Because reductions in hydropower generation for all other flow scenarios (35, 45, 55, and 65) are less than the reductions associated with the 75 scenario, these lower flow scenarios would also not be expected to cause any violations of reliability criteria. More information about the power flow results is presented in Appendix A5, *Hydropower, Energy Grid, and Export Energy Analyses,* including a discussion of loading of transmission lines that would be most affected by the reduction in hydropower under the 75 scenario.

Although the power flow modeling results show that the California electric grid would generally be reliable under both baseline conditions and the proposed Plan amendments, the rolling blackout events that occurred during August 14 and 15, 2020, indicate there are some extreme circumstances that can cause California's electric grid to become unreliable due to inadequate electric supply, leading to the need for rotating power outages. If these rotating outages occur again, changes in hydrology could cause an incremental exacerbation of the outages. During the August 14, 2020 period of rolling power outages, demand for CAISO power peaked at 46,777 MW. To prevent grid failure, rolling blackouts were instituted to reduce power use by approximately 1,000 MW. As described in Appendix A5, *Hydropower, Energy Grid, and Export Energy Analyses*, Section A5.3.4, *Power Flow Assessment Results*, the summer peak hydropower generated in the Sacramento/Delta is approximately 3,600 MW for baseline conditions, 3,200 MW for the 45 scenario, 2,900 MW for the 55 scenario, and 2,400 MW for the 65 scenario, with most of the reduction due to reduction in flow. The estimated 700 MW reduction in power generation associated with the 55 scenario represents approximately 1.5 percent of the CAISO peak energy demand during the August 14, 2020 rolling blackouts. Under the proposed Plan amendments (45 to 65 scenarios), incremental effects due to changes in hydrology on power outages would be rare and would represent a relatively small effect on the state as a whole but could represent a significant temporary impact on the affected communities, similar to what is described under *Effects at Individual Facilities*.

Actions taken by CAISO will help improve grid reliability (CAISO 2021), and implementation of Mitigation Measure MM-EN-a–e can avoid or minimize impacts on hydropower generation. However, it is not certain when CAISO actions will become fully effective, nor is it certain whether Mitigation Measure MM-EN-a–e will fully mitigate localized reductions in hydropower generation. Therefore, potential local impacts associated with rotating power outages remain potentially significant.

Impact EN-d: The degree to which the project complies with existing energy standards

Overall Per Capita Consumption

As explained under Impact EN-a*,* changes in hydrology would result in a net decrease in annual hydropower generation. Further, changes in water supply could cause a reduction in the energy used to export water from the Delta as well as an increase in energy used to replace reduced Sacramento/Delta supplies. Changes in water supply may cause water users to rely on other replacement sources of water, such as increased groundwater pumping and other water management actions, including groundwater storage and recovery, water recycling, and water conservation. Seawater desalination is another potential response action evaluated here and in Section 7.22, *New or Modified Facilities.* Use of replacement supplies and other water management actions, with the exception of conservation actions, would likely increase the use of energy when compared with the baseline condition (see Impact EN-e).

Actual increases in energy consumption are difficult to forecast, given the myriad consumer and water district responses to changes in water supply. Wastewater treatment plant modifications, new desalination plants, and conservation measures would all take time to bring online once the proposed Plan amendments are implemented. Water agencies and consumers may elect to construct alternative energy facilities to offset the additional energy required to operate the replacement water supply facilities. There could be periods after implementation of the proposed Plan amendments in which the increased energy usage for replacement water supplies due to groundwater pumping and other water management actions could significantly exceed the net reductions in energy usage resulting from reduced exports. The changes in per capita energy consumption would likely be a mere fraction of the energy used by individuals in California. However, because energy use in the state could increase, as described for Impact EN-e, there would not be a decrease in overall per capita energy consumption. Potential impacts on energy sources from groundwater pumping and other water management actions, as well as mitigation to avoid or reduce those impacts, are addressed under Impact EN-e.

Reliance on Natural Gas or Oil

Changes in hydrology would result in net decreases in annual hydropower generation. Initially, these decreases would likely be offset by natural gas–fired power plants. Natural gas is currently the largest electrical energy source in California and the most effective at meeting daily spikes in demand besides hydropower. Therefore, the proposed Plan amendments would likely cause some increased reliance on natural gas and there would not be a decrease in reliance on natural gas or oil. Implementation of Mitigation Measure MM-EN-a–e can avoid or minimize impacts on hydropower generation.

Reliance on Renewable Energy Resources

In an effort to increase reliance on renewable energy sources, the California RPS was established in 2000 and is administered by CPUC. Facilities that can contribute to the RPS include geothermal, biomass, biogas, wind, solar, and small hydropower facilities (CPUC 2017). As discussed in Section 7.8.2.2, *Electricity in California*, SB 100 and SB 1020 identify increasingly stringent renewable energy goals for the RPS, with providers of electricity eventually obligated to supply 100 percent carbon-free electricity by 2045. State agencies must rely on 100 percent renewable energy and zero-carbon resources to serve their own facilities by 2035. To attain these goals, energy sources such as large hydropower and nuclear power, that are not part of the RPS, can be included as long as they do not emit carbon dioxide.

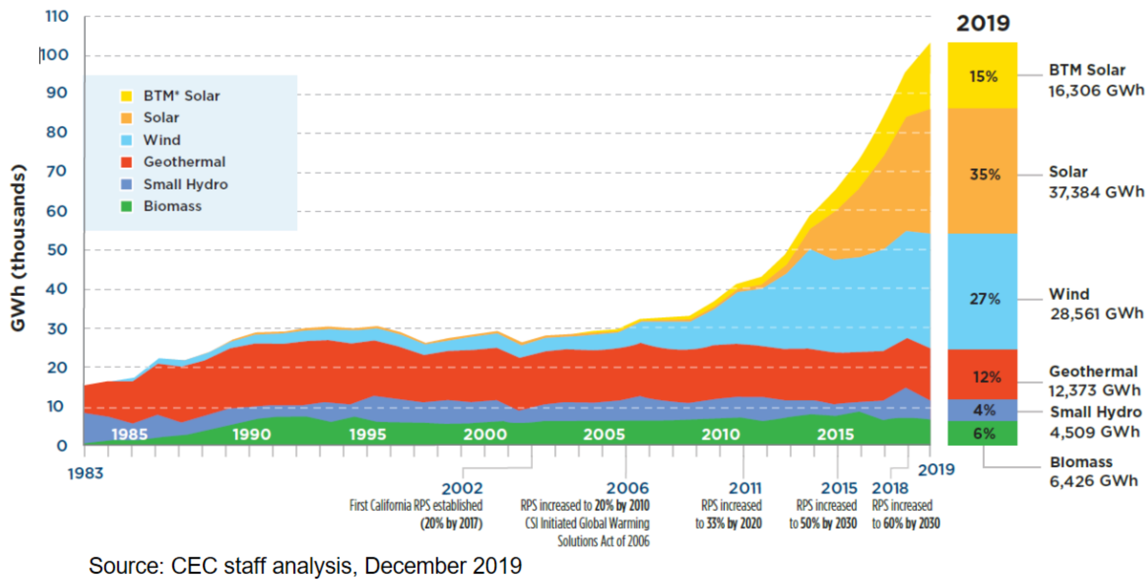
Only small hydropower facilities are eligible to contribute to the RPS. Generation at 16 of the small hydropower facilities that contribute to the California RPS was estimated with SacWAM results (Appendix A5, *Hydropower, Energy Grid, and Export Energy Analyses,* Table A5-5). These facilities have a total summer capacity of 282 MW, which represents about 57 percent of the capacity of small hydropower facilities in the portions of the Sacramento River watershed and Delta eastside tributaries regions modeled by SacWAM. Changes in hydrology are not expected to change generation at the facilities above Shasta Reservoir because these facilities do not have a large effect on the flow regime, as shown in Chapter 2, *Hydrology and Water Supply*.

Hydropower effects at the 16 RPS powerhouses that were modeled are shown in Appendix A5, *Hydropower, Energy Grid, and Export Energy Analyses*. The small hydropower facilities show an increase in generation associated with the flow requirements only during April, whereas the combined facilities show an increase for February through May. In addition, the percent reduction in average annual generation at these 16 facilities is expected to be greater than the percent reduction for all facilities combined.

In terms of grid reliability, the small hydropower facilities are much less important than the larger hydropower facilities. Hydropower generation at the 16 small hydropower facilities is much smaller than the total generation that was modeled; average annual baseline condition generation for all modeled facilities was 14,701 GWh (Table 7.8-3), whereas average annual baseline condition generation for the 16 small hydropower facilities was only 904 GWh (Appendix A5, *Hydropower, Energy Grid, and Export Energy Analyses*, Table A5-9). However, generation at the small hydropower facilities is important because it contributes to attainment of the RPS, whereas generation at the larger facilities does not. After the 60 percent RPS objective is attained, large hydropower facilities will be allowed to contribute to the attainment of 100 percent carbon-free electricity.

Average changes in annual small hydropower generation at the 16 facilities that were evaluated using SacWAM results could range from a decrease of about 30 GWh for the 45 scenario to a decrease of about 100 GWh for the 65 scenario (Table A5-9 in Appendix A5, *Hydropower, Energy Grid, and Export Energy Analyses.*) For the 55 scenario, the average estimated reduction in generation for the 16 facilities evaluated is 56 GWh per year (Table A5-9 in Appendix A5). This number was then expanded to include an estimate of reduced generation at the other small hydropower facilities in the evaluation area that contribute to the RPS but were not modeled: Coleman powerhouse and the 58 facilities with capacity less than or equal to 10 MW. The expansion assumed that these hydropower facilities would experience the same percent reduction as the ones that were modeled. The expanded average reduction in generation is about 100 GWh per year for the 55 scenario at all small hydropower facilities in the Sacramento/Delta that contribute to the RPS.

Recent annual trends in in-state energy generation show that solar and wind energy generation are growing, while there has not been much increase in small hydropower, geothermal, or biomass generation (Figure 7.8-15).



Source: CEC 2020.
CSI = California Solar Initiative; GWh = gigawatt hour; Hydro = hydropower; RPS = Renewables Portfolio Standard

Figure 7.8-15. California Energy Commission California Renewables Portfolio Standard Progress

These increases in wind and solar energy generation contribute toward the RPS objectives and will contribute to the eventual goal of 100 percent zero-carbon electricity. For the goals of SB 100 and SB 1020 to be reached, even larger increases in renewable and zero-carbon electricity generation will be needed. These increases in generation will be much larger than the estimated reduction in hydropower generation associated with changes in hydrology, with an estimated average reduction of 100 GWh per year for RPS-eligible facilities for the 55 scenario and estimated average reduction of 413 GWh per year for the 55 scenario (Table 7.8-3) for all hydropower facilities in the evaluation area. The estimated change in hydropower generation is not significant when compared with the recent increases in renewable generation and the expected future increases in zero-carbon generation. Therefore, the proposed Plan amendments are unlikely to prevent the attainment of the goals of SB 100 and SB 1020.

Although the proposed Plan amendments would be unlikely to hinder the attainment of the objectives of SB 100 and SB 1020, the amendments could increase overall per capita energy consumption and could increase reliance on natural gas; therefore, this impact would be potentially significant. Implementation of Mitigation Measure MM-EN-a–e can avoid or minimize impacts on hydropower generation, including impacts on energy sources from increased groundwater pumping and use of other water management actions, and can help increase the degree to which the proposed Plan amendments comport with statewide energy standards. The existing water supply sector is already very energy intensive. As the state moves forward with reducing reliance on the Delta for water supplies, opportunities exist to implement alternative solutions that take into account considerations for energy production and use. Changes in water supply would likely reduce the availability of surface water for diversion by some users, which provides an incentive to use water more efficiently, extending supplies and reducing energy demands.

While the State Water Board has some authority to ensure mitigation is implemented for some actions, other mitigation measures are largely within the jurisdiction and control of other agencies or depend on how water users respond to the proposed Plan amendments. Accordingly, the State

Water Board cannot guarantee that measures will always be adopted or applied to fully mitigate potential energy impacts. Therefore, unless and until the mitigation is fully implemented, the impacts remain potentially significant.

Impact EN-e: Energy requirements and energy use efficiencies by amount and fuel type for each stage of the project

Changes in hydrology and changes in water supply would affect energy requirements by reducing energy needed to transport Sacramento/Delta water supply and by increasing energy used to replace reductions in Sacramento/Delta water supply. The reductions in water supply are described in Chapter 6, *Changes in Hydrology and Water Supply*, and would be largest at the higher end of the flow range (65 scenario). In response to reduced Sacramento/Delta water supplies, water users may adopt any of a series of options, such as switching to or increasing use of groundwater supplies and other water management actions, such as groundwater storage and recovery, water transfers, water recycling, and agricultural and municipal water conservation measures. Most of the energy for water supply replacement would be electrical and would depend on the range of fuels and renewable sources used to power the electric grid.

Depending on how water users respond to the decreased water deliveries (with potential responses including a range of possible actions, including water transfers), the energy used to replace reduced Sacramento/Delta water supply could exceed the energy saved by pumping less water from the Delta. As a method of providing replacement water, conservation of water would require the least energy (and even reduce energy consumption in some instances), and desalination of ocean water would require the most energy. Energy required for desalination is included in this section because desalination is a response action that could be taken to replace reduced Sacramento/Delta supply; it is relevant to facilitate comparison between actions and allow a comprehensive assessment of the energy requirement to replace lost supplies.

Evaluation of Energy Costs for Actions to Replace Reduction in Water Supply from the Sacramento/Delta

In response to reduced Sacramento/Delta water supplies, water users may switch to or increase use of groundwater supplies and other water management actions, such as groundwater storage and recovery, water transfers, water recycling, and agricultural and municipal water conservation measures. Desalination is another potential response action relevant to energy impacts. Not all options would be economically or practically available to every area receiving Sacramento/Delta water. Energy use is only one consideration when water users elect to switch to or supplement with a different water source. Table 7.8-5 summarizes the existing energy costs of pumping CVP and SWP export water and existing energy costs associated with possible response actions that may be taken to replace reductions of Sacramento/Delta water supply. Table 7.8-5 also provides the average reduction of Sacramento/Delta water supply for the 55 scenario to illustrate how much water may need replacement for each region. Reduction in water supply would be less or more pronounced in the 45 and 65 scenarios, respectively. The discussion following the table describes these values and why they may vary between regions.

Table 7.8-5. Existing Energy Costs for Pumping Sacramento/Delta Water Supply and Possible Response Actions

Geographic Region	Current Energy Cost for Delivery of Sacramento/Delta Water Supply (kWh/AF)	Unit Energy Cost for Response Actions (kWh/AF)								Average Reduction in Sacramento/ Delta Water Supply for the 55 Scenario (TAF/year) (from Chapter 6, *Changes in Hydrology and Water Supply*)
		Groundwater Pumping	Groundwater Storage and Recovery/ Conjunctive Use	Water Recycling for Nonpotable Reuse	Water Transfers	Agricultural Water Conservation	Municipal Water Conservation	Seawater Desalination		
Sacramento River Watershed	0 to 240	350	350	0 to 510	0 to 240	-80 to 200	-290 to -8,850	N/A		606
Delta Eastside Tributaries and Delta [a]	0 to 40	350 [b]	350 [b]	0 to 510 [b]	0 to 40	-80 to 200	-290 to -8,850	N/A		48
San Francisco Bay Area	50 to 1,170	450	0	0 to 540	50 to 1,170	-80 to 200	-290 to -8,850	4,100 to 5,100		180
San Joaquin Valley	230 to 680	370 [c] to 450 [d]	370 [c] to 450 [d]	0 to 510	230 to 680	-80 to 200	-290 to -8,850	N/A		379
Central Coast	730 to 2,830	480	480	0 to 540	730 to 2,830	-80 to 200	-290 to -8,850	4,100 to 5,100		19
Southern California	2,580 to 3,240	650	650	0 to 420	2,580 to 3,240	-80 to 200	-290 to -8,850	4,100 to 5,100		450

Sources: Provided below by topic

Energy values are rounded to the nearest 10 kilowatt-hour per acre-foot (kWh/AF).

N/A = not applicable because action is not expected in response to reduction in Sacramento/Delta water supply

TAF = thousand acre-feet

[a] The Delta eastside tributaries region is combined with the Delta region because both regions would not be expected to have substantial reductions in water supply, and energy costs of replacement water would generally be similar.

[b] Assumed to be the same as the Sacramento River watershed.

[c] Estimate for San Joaquin River DWR hydrologic region.

[d] Estimate for Tulare Lake DWR hydrologic region.

Conveyance Energy Costs

The energy cost for conveying export water depends on how high water must be pumped before it can reach its ultimate destination, as well as how much of the energy expended in pumping can be recaptured as water drops in elevation. Energy needed to convey water to the Central Coast and Southern California regions is high because of the need to traverse mountain ranges. The values in Table 7.8-5 generally agree with the energy intensity values used in the export energy analysis.

Within each region, the energy cost varies depending on the ultimate destination of the water within the region. For example, for the Bay Area, the energy cost of conveying water is about 1,100 kWh/AF for delivering SWP water to the Santa Clara Valley Water District and Lake Del Valle, but only about 50 kWh/AF for delivering to the East Bay Municipal Utility District service area. For the Central Coast region, SWP and CVP conveyance energy costs are between 730 kWh/AF for CVP deliveries and 2,800 kWh/AF for SWP deliveries to the Santa Barbara County area. Values in Table 7.8-5 are based on information in CEC 2005, Pacific Institute 2021, ^Wilkinson 2000, and CPUC 2010.

These values are approximate and capture the range of conveyance energy costs that might be expected. Other studies have refined these estimates to estimate single numbers for entire regions. For example, a 2006 CEC study developed a more refined estimate of southern California energy conveyance costs by considering additional hydropower generation within the Metropolitan Water District of Southern California system and conveyance losses, resulting in an estimated weighted average energy cost of conveying water via the east and west branches of the SWP to be 3,170 kWh/AF (CEC 2006).

Groundwater Pumping

The energy intensity for groundwater pumping presented in Table 7.8-5 is based on information provided in a Pacific Institute document regarding the water-energy nexus in California (Pacific Institute 2021). Energy needed for groundwater pumping depends on depth to groundwater, and the values for each region reflect the condition of the groundwater subbasins within each region. Actual energy costs for pumping groundwater will vary within each region. For example, several sources indicated higher energy costs than those presented in Table 7.8-5, such as 650 kWh/AF for the Santa Clara Valley Water District in the Bay Area (CEC 2006) and 950 kWh/AF for the Chino Basin in Southern California (CEC 2005).

Groundwater pumping is less likely to occur in areas where groundwater supply is limited and is not expected to occur to a substantial degree in the Central Coast region. In addition, groundwater subbasins in many parts of the San Joaquin Valley are overdrafted and are subject to the Sustainable Groundwater Management Act, which could limit groundwater use in the future.

Groundwater Storage and Recovery

The energy required for groundwater storage and recovery operations is similar to that for groundwater pumping, although additional energy may be required if water is actively applied using injection wells. Because higher groundwater levels result in less energy needed to pump water, groundwater storage and recovery may save energy compared with regular groundwater pumping and may be more efficient and cost effective than conveying water over long distances. The numbers presented in Table 7.8-5 are based on estimates of energy for groundwater pumping and do not incorporate an energy benefit associated with rising groundwater levels. They also do not incorporate energy that may be needed to convey water to a recharge site, which could be substantial if the water bank causes substantially more uphill conveyance than would otherwise occur.

In the Central Coast and San Joaquin Valley regions, groundwater storage and recovery may be a more feasible method to replace reduction in surface water supply than traditional groundwater pumping. For this reason, estimated energy costs associated with groundwater pumping in these regions (Pacific Institute 2021) are provided in the groundwater storage and recovery column in Table 7.8-5.

Actual energy costs associated with groundwater storage and recovery will depend on the depth to groundwater and conveyance costs. For example, groundwater pumping by Westlands Water District has been estimated to be 740 kWh/AF (CEC 2006), substantially higher than the 450 kWh/AF estimated for the Tulare Lake Region (Table 7.8-5 [Tulare Lake Region values are included in the San Joaquin Valley geographic region]). As part of an evaluation for the CEC, the Irrigation Training and Research Center evaluated energy costs at three water banking facilities in the southern San Joaquin Valley: Arvin Edison Water Storage District, Kern County Water Agency, and Semitropic Water Storage District (CEC 2003). Estimated energy costs for the Arvin Edison groundwater bank are the highest at 1,100 kWh/AF due to relatively large conveyance costs and depth to groundwater. In contrast, contributions to the Kern County Water Agency's water bank are moved by gravity, and the estimated energy cost of 400 kWh/AF is primarily associated with pumping water out of the bank. At the Semitropic Water Storage District, the energy cost to put water in the groundwater bank is close to zero, but energy for extraction depends on who uses the water. Groundwater pumping by farmers in the district is estimated to require 485 kWh/AF, whereas groundwater that is pumped from the bank and into the California Aqueduct is estimated to require 650 kWh/AF.

Water Recycling

Water recycling requires energy for water treatment; however, because treatment is likely already required before wastewater can be discharged into the environment, the energy cost of recycled water is limited to the incremental increase in energy needed to meet end use water quality requirements. The actual incremental energy cost of water recycling will depend on end use. For example, recycled water for landscape irrigation requires less intensive treatment than recycled water that may contact edible portions of food crops (Pacific Institute 2021).

The estimated range of incremental increases in energy needed to generate nonpotable recycled water are presented in Table 7.8-5. At the low end, no incremental increase in energy would be needed for recycling (CEC 2006, p. 24). The high-end values are from 420 to 540 kWh/AF (Pacific Institute 2021). These values represent the difference in energy required for standard secondary treatment and tertiary treatment plus disinfection. These values do not include any increase in energy that might be associated with conveyance of recycled water above existing energy costs for conveyance.

Recycled water for potable reuse is currently uncommon in California, and direct reuse—in which wastewater is treated to a high enough standard that it is reinjected back into a city's drinking water system—is not yet allowed (Pacific Institute 2021). A limited amount of indirect potable reuse occurs, in which treated wastewater is first discharged into an environmental buffer, such as a reservoir or groundwater, and later treated at a conventional drinking water treatment facility (Pacific Institute 2021).

Water Transfers

If water transfers originate from the Sacramento/Delta, the energy cost of water transfers would be similar to the energy needed to deliver Sacramento/Delta water supply to an area. For this reason, the energy intensities for water transfers presented in Table 7.8-5 are the same as those presented for the energy for delivery of Sacramento/Delta water supply. Water transfers could originate from an area other than the Sacramento/Delta, which could result in different, most likely lower, energy costs for conveyance. For example, water transfers that originate in the same basin as the destination could occur at minimal energy cost (e.g., similar to the 0–40 kWh/AF for the Delta eastside tributaries and Delta regions, see Table 7.8-5). The estimated energy cost of 2,115 kWh/AF (Pacific Institute 2021) for transfers from the Colorado River to southern California via the Colorado River Aqueduct, while high, is less than the energy needed to send SWP water to southern California.

Agricultural Water Conservation Measures

Agricultural conservation measures often include converting to drip or microspray irrigation methods. The change in energy intensity associated with conversion to drip/micro-irrigation may range from an energy savings of about 80 kWh/AF associated with conversion from standard sprinklers to drip/micro-irrigation to an energy cost of about 190 kWh/AF associated with conversion from flood irrigation to drip/micro-irrigation (Pacific Institute 2021; CEC 2003). Other types of agricultural water conservation measures, such as deficit irrigation and canal lining (once constructed), may have minimal energy effect on agricultural operations.

These changes in energy intensity values are different from the other values presented in Table 7.8-5 because the energy is not used to replace lost water supply but is instead used to stretch the remaining supply. Water conservation measures for agriculture may be applied to a greater volume of water than the reduction in supply.

Municipal Water Conservation

As described in Section 7.8.2, *Environmental Setting*, municipal water use is energy intensive. The energy savings associated with municipal water conservation as evaluated here is the sum of savings associated with reduced water treatment, municipal distribution, heating, and wastewater collection and treatment. Of these components, only municipal distribution is expected to vary substantially by region (Pacific Institute 2021). Implementation of municipal conservation measures to reduce urban water use can lead to an energy savings of from about 290 to 8,850 kWh/AF.

The higher number is the energy savings associated with reduced indoor residential water use in areas with high energy costs for water distribution, and the lower number is the energy savings associated with reduced urban landscape irrigation in areas with low energy costs for water distribution. The larger number (8,850 kWh/AF) includes energy costs of treatment (230 kWh/AF), municipal distribution (980 kWh/AF), residential water heating (6,830 kWh/AF), wastewater collection (110 kWh/AF), and secondary wastewater treatment (700 kWh/AF). The value of 980 kWh/AF for municipal distribution is the high end of the range for municipal distribution. It is the estimated distribution cost for the San Francisco Bay Area, but it could be applicable to certain portions of any region. Residential water heating uses more energy than other processes associated with municipal water use. The estimated energy cost associated with residential water heating of 6,830 kWh/AF is based on the amount of warming typically associated with different types of appliances (24.2 degrees Fahrenheit on average, derived from Pacific Institute 2021, Appendix Table 29), and the estimated percent of homes that use electric water heaters (32 percent, from

Pacific Institute 2021). It is important to note that this energy cost is only for electricity. The estimated additional energy use for water heating in the 64 percent of homes that use natural gas is 67 million British thermal units per acre-foot (MMBtu/AF) (Pacific Institute 2021).

The smaller number for energy savings associated with municipal water conservation (290 kWh/AF) represents energy savings associated with reductions in landscape irrigation in regions with low energy costs for distribution. Landscape irrigation is less energy intensive because it does not incur the energy cost associated with heating and wastewater treatment. This low-end energy cost of landscape irrigation is the sum of an estimated 240 kWh/AF for drinking water treatment and 50 kWh/AF for urban water distribution. (Pacific Institute 2021).

These potential energy savings do not include the savings associated with reduction in energy for conveyance of Sacramento/Delta supply, groundwater pumping, or desalination. As mentioned above, they also do not include the energy savings with reduced use of natural gas water heaters. Municipal water conservation can provide a substantial reduction in energy use per AF, although—in some regions (particularly the San Joaquin Valley, the Delta, and the Delta eastside tributaries), municipal water use is small compared with agricultural water use (see Chapter 2, *Hydrology and Water Supply*).

Desalination

Operation of desalination facilities also requires substantial energy consumption. CEC estimated that water generated from seawater desalination plants requires from 4,100 to 5,100 kWh of electric power per AF of water produced (CEC 2015). Energy use for desalination varies depending on the salinity; the higher the salinity, the more energy that is needed to remove the salt to meet water quality standards. Measures to improve efficiency and increase use of low-cost power include installing improved reverse osmosis membranes and using off-peak power, which is less expensive and typically created using renewable power sources. In addition, energy recovery devices are now also available and in use. These devices work by capturing the hydraulic energy of the highly pressurized saltwater brine (the byproduct of desalination) and transferring it to the incoming seawater.

Desalination of ocean seawater is not feasible in the regions that are not adjacent to the ocean: the Sacramento River watershed, Delta eastside tributaries, Delta, and San Joaquin Valley regions. However, it is possible that desalination of brackish water could be used in these regions to augment water supply by treating brackish surface water or groundwater at a smaller energy cost, although discharge of brine wastewater would be problematic. Average energy cost for desalination of brackish water has been estimated to range between 1,600 kWh/AF and 1,700 kWh/AF, not including energy that may be needed to pump brackish groundwater from aquifers to supply the desalination facility (Pacific Institute 2021). Desalination of brackish water is already occurring at multiple facilities in California, particularly in southern California. Because the financial cost of desalination is high, and agricultural fields tend to be inland, desalination may not be feasible for agricultural water users.

Consideration of Net Energy Effects Associated with Reduction in Sacramento/Delta Water Supply

The net change in energy use associated with reduction in Sacramento/Delta water supply would depend on the response actions that are chosen. There is much uncertainty in the degree to which each approach would be used. Desalination of ocean water would be the most energy-intensive replacement mechanism, at a cost of approximately 4,500 kWh/AF. Conservation would be the least energy-intensive way to replace reduction in water supply. Municipal water conservation can lead to large energy savings (up to 8,850 kWh/AF of electricity for indoor residential water use, not including energy savings associated with reduced use of natural gas).

In reality, the full suite of replacement options would be used, and energy effects would be somewhere between those associated with seawater desalination and indoor water conservation. To the extent that they occur, water transfers would likely counteract the energy savings associated with conveyance of exports, producing a net energy effect that is close to zero. Based on cost and need for proximity to the ocean, desalination of ocean water would likely be limited; and other less energy-intensive methods, such as conservation, water recycling, and groundwater pumping, would be more common replacement methods. Desalination of brackish water could also occur as a less energy-intensive method; energy for desalination of brackish water depends on the level of salinity in the water. Groundwater pumping is more likely to occur in areas where groundwater levels are closer to the surface because in those areas pumping would be less expensive, less likely to be influenced by the Sustainable Groundwater Management Act, and less energy intensive.

The net effect of reductions in water supplies would largely be dictated by what occurs in the four regions that would be expected to experience the largest reductions in Sacramento/Delta water supplies: Southern California, the Sacramento River watershed, San Joaquin Valley, and the Bay Area (Table 7.8-5). Potential effects in these regions are evaluated for the purposes of considering overall energy effects, not to evaluate sub-impacts by region. A regional analysis helps provide understanding of potential overall effects because it considers which response actions could drive net energy effects in the areas with the largest estimated reductions in water supply.

- For Southern California—the region with the highest energy costs for conveyance of Delta exports—desalination of seawater is the only replacement mechanism that has energy costs higher than the energy savings associated with reduced exports (Table 7.8-5). To the extent that they would occur, water transfers would negate energy savings associated with reduced conveyance.
- In the Sacramento River watershed, energy requirements to convey water are low (Table 7.8-5). Although energy costs to replace reduced supply also would be low, replacement mechanisms could result in a net increase in energy use even though the most energy-intensive mechanism, seawater desalination, is not expected to occur.
- In the San Joaquin Valley, seawater desalination is infeasible, and most mechanisms to replace reductions in Sacramento/Delta supply would use similar or less energy than the energy savings associated with reduced conveyance (Table 7.8-5), with the possible exception of desalination of brackish groundwater.
- In the Bay Area, due to the large population, the energy savings associated with municipal water conservation could be substantial. The presence of a large population means there would likely be a willingness to pay a high price for transfers for municipal supply, which could negate some of the energy savings associated with reduced conveyance. The net energy effect of reduced conveyance and replacement of supplies in the Bay Area would likely be driven by decisions regarding desalination.

Due to uncertainty in the actions that would be taken to replace reduced Sacramento/Delta water supply in each region, it is difficult to know whether the total energy required for these actions would be greater than the total energy savings associated with reduced conveyance and indoor water conservation. There could be a net energy cost. The impact of this net energy cost combined with reductions in hydropower generation could exceed the energy savings associated with reduced exports and indoor water conservation, and this impact would be potentially significant.

Implementation of Mitigation Measure MM-EN-a–e: 1 through 7 can reduce the increased energy use associated with replacing Sacramento/Delta supplies. Water users can and should diversify their water supply portfolios to the extent possible, in an environmentally responsible manner and in accordance with the law. Water users and providers should consider the energy efficiency of other water supplies and pursue options that require less energy to the extent possible, including using energy from renewable sources. The State Water Board, DWR, CPUC, California Department of Food and Agriculture, and CEC will continue to implement the response plan to the Governor's Executive Order B-37-16 (May 9, 2016). The plan includes recommendations and an implementation timeline to (1) use water more wisely; (2) eliminate water waste; (3) strengthen local drought resistance; and (4) improve agricultural water use efficiency and drought planning. The State Water Board will continue to pursue the development of programs that continue to increase water use efficiency and conservation in order to maximize the beneficial use of Sacramento/Delta supplies, including through conditions on discretionary approvals for funding and other approvals, as appropriate.

In addition, implementation of greenhouse gas emission mitigation (Mitigation Measures MM-GHG-a and MM-GHG-b), as incorporated into Mitigation Measure MM-EN-a–e, will reduce energy impacts associated with other water management actions.

While the State Water Board has some authority to ensure that mitigation is implemented for some actions, other mitigation measures are largely within the jurisdiction and control of other agencies or depend on how water users respond to the proposed Plan amendments. Accordingly, the State Water Board cannot guarantee that measures will always be adopted or applied to fully mitigate potential energy impacts. Unless and until the mitigation is fully implemented, the impacts remain potentially significant.

Impact EN-f: The project's projected transportation energy use requirements and its overall use of efficient transportation alternatives

Changes in water supply could result in a reduction in agricultural water supply and subsequent reduced agricultural production in California's Central Valley. The effect of reduced agricultural production on overall transportation energy use is complex. Nearly all the affected production enters a national and international market because California is the dominant or sole commercial producer with few substitutes. As a result, on balance, this may cause a decrease in transportation energy use for moving agricultural products to the people of California. It may also cause a reduction in transportation of agricultural products from California to other states and countries. The magnitude of the energy effects depends on the amount of agricultural product currently consumed within California, the amount that is exported to other states or countries, the mode of transportation, and the distance of travel. The proposed Plan amendments could help promote local agriculture in areas that currently receive agricultural goods from California, which would result in a reduction in energy for transportation. However, another possibility is that people who previously relied upon California agricultural products, whether in California or in other locations, would end up buying goods from locations farther away than California. Because California exports more agricultural product than is used in-state, a reduction in water supply could therefore result in a net decrease in energy used for transportation. Determining the effect of the changes in water supply is speculative and would depend on farmers' responses to reduction in water supply and consumer responses to reduction in California agricultural product supply. However, it is unlikely that a reduction in California agricultural production would cause a substantial increase in energy use for transportation. This impact would be less than significant.

7.8.4 Mitigation Measures

MM-EN-a–e: Mitigate the project effects on energy resources

1. **Voluntary Implementation Plans:** The proposed program of implementation promotes voluntary implementation plans that could amplify the ecological benefit of new and existing flows with physical habitat restoration and other complementary ecosystem measures. These plans may also reduce the volume of water that needs to be dedicated for instream purposes, resulting in less change in hydropower generation. Water users are encouraged to work together to tailor approaches to meet the proposed Plan amendments in a manner that minimizes disruptions to hydropower production to the extent possible, including through sharing of responsibilities within and between tributaries.
2. **Temperature Control and Reservoir Management in the Sacramento/Delta:** The proposed Plan amendments include inflow and cold water habitat requirements that must be implemented together on regulated tributaries in a manner that preserves cold water for fish. Rim reservoir owners and operators must develop and implement long-term strategies and annual operations plans to meet the cold water habitat requirements that consider the unique structural, operational, and hydrological characteristics and species requirements in individual tributaries of the Sacramento/Delta. As determined by the Executive Director of the State Water Board, upstream reservoir operators may also be required to develop their own strategies if their reservoir operations are impacting achievement of the narrative objective for stream segments above the rim reservoirs. The proposed Plan amendments call for the cold water habitat measures to be implemented to the extent possible in a manner that avoids hydropower impacts.
3. **Coordination with Existing Requirements:** With the exception of federal facilities, reservoirs with hydropower operations are subject to regulation by FERC and have independent obligations to meet temperature and other instream flow requirements pursuant to FERC licenses and associated water quality certifications. Many reservoirs are also subject to other ESA and California Endangered Species Act requirements, including biological opinion provisions that include requirements that may dictate reservoir storage levels that affect hydropower production. To the extent possible, the proposed Plan amendments are proposed to be integrated with existing and new FERC licenses and associated water quality certification by the State Water Board as well as ESA, California Endangered Species Act, and other requirements. These requirements may help reduce impacts on hydropower production by coordinating regulatory requirements to the extent possible.
4. **Diversify Water Portfolios**: Water users can and should diversify their water supply portfolios to the extent possible, in an environmentally responsible manner and in accordance with the law. This includes sustainable conjunctive use of groundwater and surface water, water transfers, water conservation and efficiency upgrades, and increased use of recycled water.

Water users and providers should consider the energy efficiency of other water supplies and pursue options that require less energy to the extent possible.

i. Groundwater Pumping**:** Water users who utilize increased use of groundwater pumping to replace Sacramento/Delta water supplies should consider energy-efficient pumps and other equipment, including using energy from renewable sources.

ii. Groundwater Storage and Recovery: The State Water Board will continue efforts to encourage and promote environmentally sound recharge projects that use surplus surface water, including prioritizing the processing of temporary and long-term water right permits for projects that enhance the ability of a local or state agency to capture high runoff events for local storage or recharge. In processing water right applications that involve groundwater storage, the State Water Board will include conditions as appropriate to provide for the inclusion of energy efficiency measures in those projects.

iii. Water Recycling: The State Water Board will continue efforts to encourage and promote recycled water projects, including projects that involve use of recycled water for groundwater recharge, through expediting permit processes and funding efforts. When processing wastewater change petitions pursuant to Water Code section 1211, the State Water Board will include conditions as appropriate to provide for the inclusion of energy efficiency measures in those projects.

iv. Water Conservation: Water use is energy intensive because it requires energy for movement, heating, and treating. Water conservation measures help reduce energy associated with water use. For example, some urban conservation such as low-flow appliances are also more energy efficient by reducing hot water usage, thereby also saving energy. The following conservation measures will reduce water use and associated energy use.

- Pursuant to Water Code section 10826 et seq., agricultural suppliers that provide water to 10,000 acres or more are required to develop and implement agricultural water management plans that describe agricultural efficient water management practices that should result in reduced water supply demands and associated energy demands. Efficient water management practices include but are not limited to improvements to on-farm irrigation systems and water supplier delivery systems, such as installation of integrated supervisory control and data acquisition systems and canal automation; increased use of pressurized, drip, or microspray irrigation methods; and lining of canals.
- Grant programs, such as the Agricultural Water Use Efficiency Program and State Water Efficiency and Enhancement Program (^DWR 2018; CDFA 2018) could help to provide for the enhancement of agricultural water use efficiency and water conservation efforts that should reduce water supply demands and associated energy demands. These programs provide grants for on-farm improvements to address: (1) agricultural water use efficiency, conservation, and reduced demands; (2) greenhouse gas emission reductions; (3) groundwater protection; and (4) sustainability of agricultural operations and food production. Where appropriate, when funding water conservation–related activities, including for agriculture, the State Water Board will consider and other agencies should consider measures that would dedicate a portion of the conserved water to instream flows.

- Pursuant to the Urban Water Management Planning Act, municipal water suppliers are required to develop and implement urban water management plans every 5 years that include water conservation measures, programs, and incentives that prevent the waste of water and promote the reasonable and efficient use and reuse of available supplies that should result in reduced water supply demands and associated energy demands. Measures to increase water use efficiency and associated energy conservation include but are not limited to demand management measures; plumbing codes requiring more efficient fixtures; the Model Water Efficient Landscape Ordinance advances in irrigation technology; new technologies in the commercial, institutional, and industrial sectors; and mandates requiring that unmetered connections become metered.

5. **Increase Water Use Efficiency:** The State Water Board will continue to pursue various efforts that increase water use efficiency and conservation in order to maximize the beneficial use of Sacramento/Delta supplies. The following water efficiency measures will reduce water use and associated energy use.

   i. All municipal water suppliers and agricultural water users have an obligation to maximize water use efficiency and utilize conservation to the extent possible in conformance with the prohibition against waste and unreasonable use in the California Constitution. As directed by the Governor's Executive Order B-40-17 (April 7, 2017), the State Water Board is currently conducting a rulemaking process to prohibit wasteful water use practices. In addition, the State Water Board may implement the prohibition on waste and unreasonable use in exercising its discretionary authorities in its water right and water quality decision-making processes.

   ii. The State Water Board, DWR, CPUC, California Department of Food and Agriculture, and CEC will continue to implement their April 2017 response plan to the Governor's Executive Orders B-37-16 (May 9, 2016) and B-40-17 (April 7, 2017). The response plan includes actions and an implementation timeline to (1) use water more wisely; (2) eliminate water waste; (3) strengthen local drought resistance; and (4) improve agricultural water use efficiency and drought planning.

   iii. Conservation a California Way of Life: In 2018, the California State Legislature passed Assembly Bill (AB) 1668 and SB 606 that build on ongoing efforts to make water conservation a way of life in California and create a new foundation for long-term improvements in water. DWR and the State Water Board developed, *Making Water Conservation a California Way of Life – Primer of 2018 Legislation on Water Conservation and Drought Planning, Senate Bill 606 (Hertzberg) and Assembly Bill 1668 (Friedman)* outlining key authorities, requirements, timeline, roles, and responsibilities of State agencies, water suppliers, and other entities during implementation of actions described in the 2018 legislation. The State Water Board is developing the proposed regulation to implement the Making Conservation a California Way of Life framework. The formal rulemaking process is expected to begin (May 2023). DWR, Reclamation, and other water agencies should implement measures to design, construct, and refurbish water diversion infrastructure to increase energy efficiency.

   iv. As appropriate, the State Water Board will include provisions for water use efficiency and conservation when providing funding for water supply–related projects.

6. **Promote the Use of Renewable Energy:** The following renewable energy measures will help increase the degree to which the proposed Plan amendments comport with statewide energy

standards, including goals for renewable energy use. In addition, renewable energy measures will reduce impacts associated with energy production and use.

i. Energy providers are required to comply with existing and future state and local regulations and mandates requiring increased use of electricity from renewable energy resources and zero-carbon resources. Specifically, the 100 Percent Clean Energy Act of 2018 mandates achievement of a minimum quantity of 50 percent of electricity products from renewable resources by December 31, 2026, and a minimum of 60 percent by December 31, 2030.

ii. DWR, Reclamation, and other water providers should take actions to support and increase the use of renewable energy (OP-3 Renewable Energy Procurement Plan) (^DWR 2020).

iii. Implementation of Assembly Bill 2514 (Skinner), Statutes of 2010, amending Public Utilities Code section 9620 to promote the use of energy storage systems, requires the development of targets for energy storage that will enable increased use of renewable energy.

7. **Implement Greenhouse Gas Emissions Mitigation:** Implementation of Mitigation Measures MM-GHG-a and MM-GHG-b will reduce energy impacts associated with other water supplies.

7.8.5 References Cited

7.8.5.1 Common References

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