31. Power Production and Energy

31.1 Introduction

This chapter describes the existing electrical generation and transmission infrastructure, the electricity market structure, the electricity demand forecast for California, and the potential effects of the Sites Reservoir Project (Project) operations on future power production and use in the Extended, Secondary, and Primary study areas. Descriptions and maps of these three study areas are provided in Chapter 1 Introduction.

Permits and authorizations for power production and energy resources are presented in Chapter 4 Environmental Compliance and Permit Summary. The regulatory setting for power production and energy resources is presented in Appendix 4A Environmental Compliance.

This chapter focuses on the potential impacts to electric power demand and production that could result from operation of the Project. To the extent possible, these discussions are separated into the Extended, Secondary, and Primary study areas. However, due to the highly interconnected nature of the electric grid in the Western Interconnection (made up of all or parts of 14 states, two Canadian provinces, and part of Mexico), the effects of the Project on the delivery and use of electric power in that region are not necessarily limited to the defined geographic study areas but rather can affect areas throughout the western U.S. Other energy uses for the Project, including diesel use by construction machinery and electricity use at the Project's recreation facilities, are also discussed (associated impacts to air quality from emissions are discussed in Chapter 24 Air Quality and Chapter 25 Climate Change and Greenhouse Gas Emissions).

31.1.1 Environmental Setting/Affected Environment Extended Study Area

The Extended Study Area for this analysis includes all areas potentially affected by the changes to power grid operations caused by operation of the Project. The Project is located in Northern California; therefore, the initial affected power system is comprised of primarily Pacific Gas & Electric (PG&E), Western Area Power Administration (WAPA), and Transmission Agency of Northern California (TANC) transmission systems, numerous generation facilities located in this area and the distribution systems of various entities interconnected to that portion of the Bulk Electric System (BES). The Extended Study Area also includes all or portions of 14 western U.S. states, two Canadian provinces, and the northern portion of Baja California Norte in Mexico that currently comprise the Western Interconnection.[1]

The Western Electricity Coordinating Council (WECC) is the Regional Entity responsible for coordinating and promoting BES reliability in the Western Interconnection. In addition, WECC provides an environment for coordinating the operating and planning activities of its members as set forth in the WECC Bylaws. The Balancing Authority (BA) is a key entity charged with complying with many of the reliability standards that WECC implements. The North American Electric Reliability Corporation (NERC) glossary of terms defines BA as the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time. The California Independent System Operator (CAISO) is the largest BA in Northern California. The Balancing Authority of Northern California (BANC) is an

[1] The Western Interconnection is one of three synchronized interconnections in the United States where electricity can flow freely between various parts of the power system, only limited by transmission capacity and operational constraints.

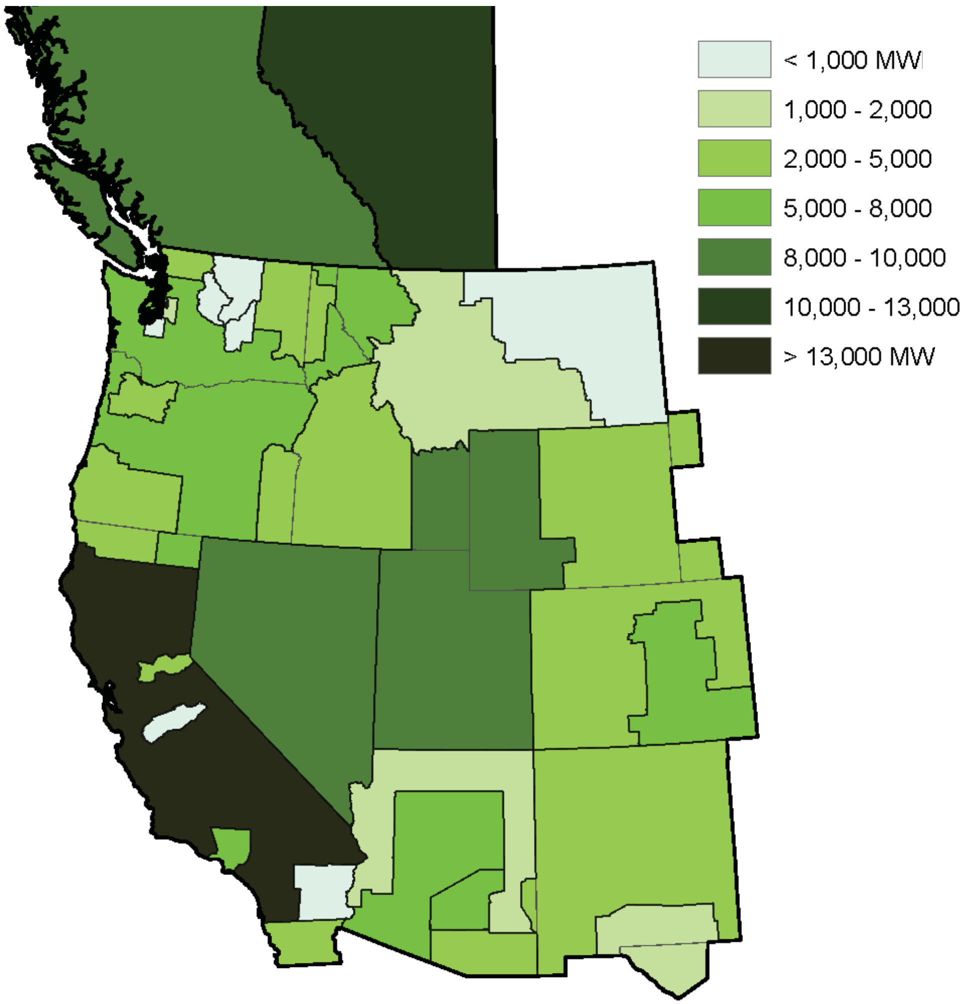
important municipal BA that includes WAPA as a sub BA. Both WECC and CAISO have ongoing efforts to plan for the reliable integration of significant amounts of intermittent renewable generation into the grid.

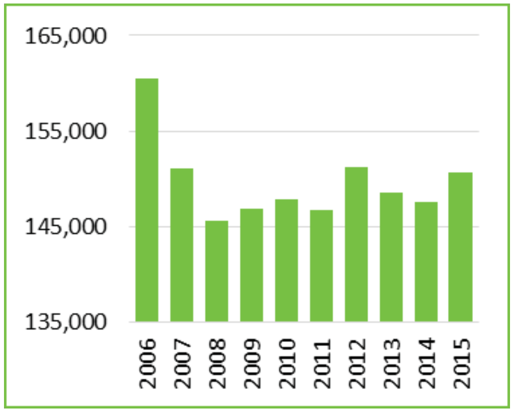
The states and provinces comprising WECC, along with the 2015 peak electric energy demand of each BA area within each state and province, are shown in Figure 31-1. WECC data show that, of the 127,700 circuit-miles[2] of high-voltage transmission lines in use throughout the WECC region in 2015, approximately 26,000 circuit-miles are located within California (WECC, 2015; CAISO, 2015a). The electric power grid in California is highly interconnected via high-voltage electric transmission lines with many WECC subregions. The grid is used to move power from a generator in one location to power users in another location; at any one time, millions of customers and hundreds of generators are using the grid for electricity service. The Western Interconnection offers many advantages, such as added system stability due to the inertia contributed by the hundreds of generators connected to the grid at any one time. System inertia is a product of the rotational velocity and mass of the rotors of all generators connected to the grid. The greater the system inertia, the greater ability the system has to mitigate disturbances to the grid, such as a generator shutting down unexpectedly. Some types of renewable generation such as solar photovoltaics do not use rotors to generate electricity and so do not provide inertia to the power system. The interconnected nature of the grid also adds stability due to its inherent tendency to cancel out load variability. For example, when one large load is started in one region, it is probable that the resultant instability put into the interconnected grid would be cancelled by the shutdown of one or more loads in another area. In addition, interconnected grids have the benefit of a more efficient bulk transfer of power and make it possible to serve load at the lowest available marginal cost of generation, provide supply reliability, and provide better outage management. The benefits provided by the interconnected grid have limits, however, especially as power flows on the grid reach maximum capacity and create congestion or bottlenecks that limit the ability to move power from one region to another.

The grid in the Western U.S. and Canada is highly interconnected north and south, such that hydroelectric generation in British Columbia can be delivered to California, and vice versa. Seasonal exchanges[3] without firm transmission rights were once common, but have been mostly crowded out of the market due to congestion in the electric transmission grid. This same congestion can also exacerbate the rare times when faults occurring in one area, such as the sudden loss of a generator or transmission line segment, ripple through vast areas of the West, creating widespread blackouts, such as a 1996 incident in which a downed transmission line in Montana led to a cascading outage across the western U.S., including large parts of California (Venkatasubramanian and Li, 1996), or a September 2011 incident in which a series of electrical faults in Arizona and Mexico led to a blackout for more than 5 million people in California (California Energy Markets, 2011). Interconnection to the eastern WECC subregions, as well as to other BAs in the U.S. and Canada, has always been limited by a relative lack of infrastructure, due to population trends and the difficulties and expense of constructing and maintaining electric transmission lines across the Rocky Mountains and other mountain ranges in the West.

[2] A circuit-mile is 1 mile of a single circuit, which for alternating current circuits are generally three-phase and, therefore, have three separate conductors making up a single circuit. Direct current circuits consist of two phases and have two conductors per single circuit.

[3] Seasonal exchanges occur when winter-peaking utilities in the north send power south during the summer, and summer-peaking utilities in the south send power north during the winter.





WECC Coincident Peak

Many factors drive peak demand, including sustained periods of hot weather. The 2015 WECC coincident peak occurred on June 30 as a result of an earlier-than-usual heatwave across the Interconnection.[5] West-wide hot weather was a major driver of the WECC all-time high peak demand in 2006.

The economy also affects demand. Peak demand in 2008 was more than 5,000 MW lower than in the year before, in part due to adverse economic conditions.

Source: Western Electric Coordinating Council (2016)

FIGURE 31-1
Western Electricity Coordinating Council, 2015 Non-coincident Peak Demand by Balancing Authority Area
Sites Reservoir Project EIR/EIS

Contractual agreements, the evolving regional and State energy market, and electric reliability requirements guide the movement of power over the grid. Changes in supply and demand in any given time period can have both direct physical effects on the grid that can affect system reliability, and effects on the economics and contractual instruments that drive the use and operation of the grid. Short-term effects, such as a decrease in supply due to idling of a large power plant for maintenance, are reflected primarily in the cost of electricity, and in the cost of the fuels used to produce that electricity. Longer term effects, such as the introduction of a new large load, new generation, transmission or market products/design can all cause the need to upgrade the impacted system or region.

31.1.2 Secondary Study Area

The Secondary Study Area includes the Balancing Authority areas of CAISO and BANC, from which Project-related transmission services, power sales, and purchases would occur.

31.1.2.1 Electrical Generation

California's electrical infrastructure is a complex grid of energy generation connected by high-voltage electric transmission lines and lower-voltage distribution lines. Table 31-1 shows the breakdown of sources for electric power generation in the State in 2014 and 2015, and Figure 31-2 shows electric generation capacity by resource type. California produces approximately two-thirds of its electricity from sources within the State. Approximately one-third of California's power supply is imported electricity from the Pacific Northwest and the American Southwest. In 2015, the total electricity imported was 99,210 gigawatt-hours (GWh), up slightly from 97,869 GWh in 2014 (California Energy Commission [CEC], 2016). From 2015 to 2016, total in-State solar generation increased 31 percent (4,737 GWh), and wind energy increased by approximately 11 percent (1,320 GWh), and large hydroelectric energy increased by 111 percent (12,841 GWh) during the same period. Nuclear generation also increased by 2 percent (406 GWh) between 2015 and 2016; nuclear energy combined with large hydroelectric and renewable energy accounted for nearly 40 percent of California's in-State electric generation in 2015, but that percentage surged to 50 percent in 2016 as a result of increased renewable energy generation (CEC, 2015; CEC, 2017c). Both demand and total energy use in the State declined slightly from 2014 to 2015 because of federal appliance energy efficiency standards and increased self-generation, including roof-top photovoltaic solar power systems. The combination of increased energy efficiency and photovoltaic self-generation is slowly reducing traditional system electric generation (CEC, 2016).

Table 31-1
2016 and 2015 Total System Electric Generation

Fuel Type	California In-State Generation (GWh)	California In-State Generation (%)	Northwest Imports (GWh)	Southwest Imports (GWh)	California Power Mix[a] (GWh)	California Power Mix (%)
2016 Total System Electric Generation						
Coal	324	0.16	373	11,310	12,006	4.13
Large Hydro[b]	24,410	12.31	3,367	1,904	29,681	10.21
Natural Gas	98,831	49.86	41	7,120	105,992	36.48
Nuclear	18,931	9.55	0	7,739	26,670	9.18
Oil	37	0.02	0	0	37	0.01
Other[c]	394	0.20	0	0	394	0.14

Fuel Type	California In-State Generation (GWh)	California In-State Generation (%)	Northwest Imports (GWh)	Southwest Imports (GWh)	California Power Mix[a] (GWh)	California Power Mix (%)
Renewables[d]	55,300	27.90	11,710	6,952	73,961	25.45
Biomass	5,868	2.96	659	25	6,553	2.26
Geothermal	11,582	5.84	96	1,038	12,717	4.38
Small Hydro[e]	4,567	2.30	229	1	4,796	1.65
Solar	19,783	9.98	0	3,791	23,574	8.11
Wind	13,500	6.81	10,725	2,097	26,321	9.06
Unspecified Sources of Power[f]	N/A	N/A	26,888	14,937	41,825	14.39
Total	198,227	100.00	42,378	49,963	290,567	100.00
2015 Total System Electric Generation						
Coal	538	0.3	294	16,903	17,735	6.0
Large Hydro[b]	11,569	5.9	2,235	2,144	15,948	5.4
Natural Gas	117,490	59.9	49	12,211	129,750	44.0
Nuclear	18,525	9.4	0	8,726	27,251	9.2%
Oil	54	0.0	0	0	54	0.0
Other[c]	14	0.0	0	0	14	0.0
Renewables[d]	48,005	24.5	12,321	4,455	64,781	21.9
Biomass	6,362	3.2	1,143	42	7,546	2.6
Geothermal	11,994	6.1	132	757	12,883	4.4
Small Hydro[e]	2,423	1.2	191	2	2,616	0.9
Solar	15,046	7.7	0	2,583	17,629	6.0
Wind	12,180	6.2	10,855	1,072	24,107	8.2
Unspecified Sources of Power[f]	N/A	N/A	20,901	18,972	39,873	13.5
Total	**196,195**	**100.0**	**35,800**	**63,410**	**295,405**	**100.0**

[a]Total of in-State and imported generation by fuel type.

[b]Defined as equal to or greater than 30 megawatts (MW) generating capacity.

[c]Includes other non-renewable fuels, such as petroleum coke.

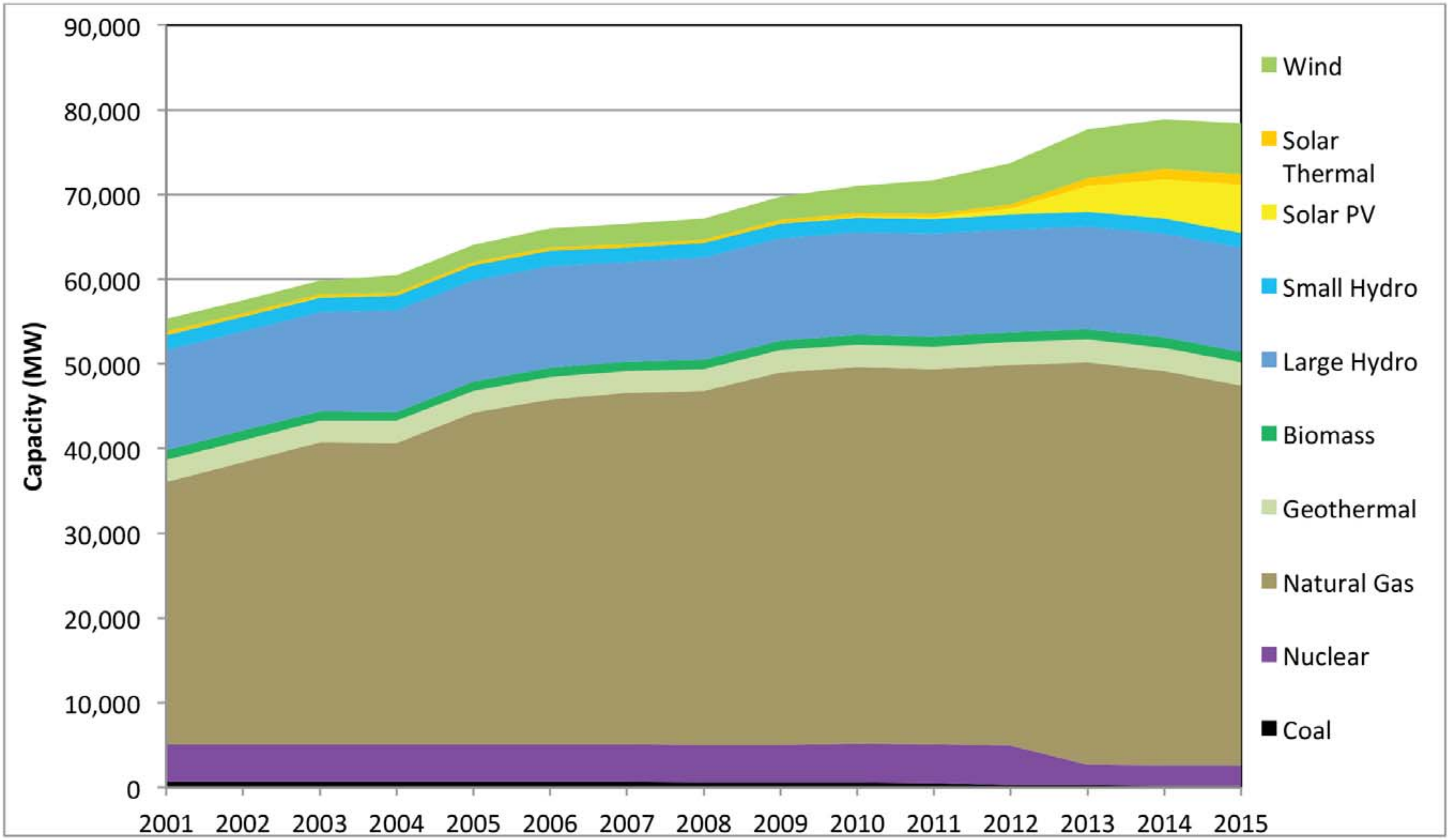
[d]Includes wind and solar generation.

[e]Defined as less than 30 MW in generating capacity.

[f]As of December 2011, the California Air Resources Board has been assessing the fuel sources of all imported power. Fuel source for imported power was not previously reported and, therefore, is categorized as "Unspecified."

Source: CEC, 2015; 2016

Since 1983, in-State natural gas electric generation has increased by more than 250 percent, accounting for approximately 60 percent of all in-State electric generation in 2015, compared to 36 percent in 1983 (CEC, 2016). The natural gas-fired power plants typically consist primarily of either (1) simple-cycle, gas turbine, peaking power plants generally used for meeting peak power demands or to compensate for sudden changes in demand, or (2) combined-cycle power plants used as intermediate or "load-following" power plants that can ramp power production up or down to meet demand through the day (CEC, 2003; CEC, 2012). Gas-fired power plants are more efficient than other fossil-fueled plants. They are easier to



Source: California Energy Commission (2016)

FIGURE 31-2
Installed In-State Electric Generation Capacity by Fuel Type
Sites Reservoir Project EIR/EIS

site, operate, and permit than other options, and are cleaner than other combustion sources. California's fleet of gas-fired power plants, however, is aging. Nearly one-third of the State's natural gas-fired generation capacity is produced by facilities that are categorized by CEC as "aging," meaning that they were constructed before 1980 (CEC, 2014b). The older gas-fired power plants are being modernized, and some older generation plants are being retired.

A total of 268 small (under 30 MW) and large (30 MW or higher) hydroelectric facilities in California provides a capacity of 14,000 MW (CEC, 2017a). However, hydroelectric output is highly variable year to year. In dry years, such as 2015, which concluded a 5-year drought, hydroelectricity contributed only 7 percent of the State's total power (when combining both in-State and out-of-State generation), the lowest recorded since CEC began tracking this information in 1983. Conversely, in wet years (e.g., 1983), hydroelectricity contributed nearly 47 percent of the State's power (CEC, 2016). Although hydroelectric output as a percentage of total in-State generation has ranged from 7 to 47 percent over the 33-year record maintained by the CEC, the annual average has been approximately 19 percent (CEC, 2016).

This variability must be accounted for in long-term planning. The seasonal nature of its generation, such as the increased levels of generation that occur during spring runoff, can create difficulties in moving the excess power to markets that can use it, but can also greatly affect the electric power marketplace by reducing the price for both on-peak and off-peak power, potentially to negative values, during high runoff periods when hydroelectric projects would otherwise spill water rather than send it through the powerhouse. These trends are further exacerbated by the increased penetration of renewable energy generation facilities in the California electricity market. Hydroelectricity production in wet years, combined with production from other renewable energy sources, is creating overgeneration patterns in the middle of the day to the point that power prices are negative, and reliability of the grid is challenged. However, hydroelectricity generation can be highly useful as a resource that can quickly ramp power operations up or down to compensate for sudden changes in demand or in generation such as that caused by the variable nature of solar and wind generation.

Hydroelectric production – both conventional and pumped-storage – can be used as a "firming" resource that can augment production from other renewable sources to provide a more reliable energy portfolio. Given the current carbon reduction mandates and renewable development incentives, the use of hydroelectricity for this purpose is appropriate. The following are current California mandates regarding renewables growth:

- In November 2008, Governor Arnold Schwarzenegger signed Executive Order S-14-08 to raise the State's renewable portfolio standard (RPS) to 33 percent by 2020, requiring electricity retail sellers to serve 33 percent of their load with renewable energy by 2020.
- In 2009, Governor Arnold Schwarzenegger issued Executive Order S-21-09 directing the California Air Resources Board, under its Assembly Bill 32 authority, to adopt regulations consistent with Executive Order S-14-08 by July 31, 2010.
- In 2011, Governor Edmund G. Brown, Jr. signed Senate Bill X1-2 to codify 33 percent by 2020 RPS.
- In 2015, Governor Edmund G. Brown, Jr. signed Senate Bill 350 to codify 50 percent by 2030 RPS.

In addition to these mandates, federal tax incentive legislation promoting the installation of renewable energy production facilities, namely wind and solar, has been approved in recent years. The Business Energy Investment Tax Credit, which provides a 30 percent tax credit for residential and commercial solar systems, was implemented in 2006 and has been amended several times, most recently in 2015 when the credit was extended through 2022, albeit with decreasing credit percentages commencing in 2019 (energy.gov, 2017a). The Renewable Electricity Production Tax Credit program was initially approved in 1992 and has also been amended and extended numerous times, including, most recently, a 2016-approved extension to 2019. The purpose of the program as it exists today, with only credit for wind energy but not for other forms of renewables, is to provide incentives for implementing wind energy production facilities through an inflation-adjusted, per-kilowatt-hour tax credit (energy.gov, 2017b). These programs remain catalysts for further growth in the renewable energy industry.

Compared to all other energy sources, renewable energy production, including solar, wind, geothermal, and biomass, has seen the most significant growth since 1983, particularly during the last 10 years. In 1983, renewable energy accounted for only 6 percent of the State's electric generation; however, by 2015, that number had increased to more than 23 percent, and the total generation from renewables had increased nearly 600 percent (CEC, 2016). Despite the significant surge that has occurred, renewable energy resources continue to be, by nature, intermittent. Solar is only available during daytime hours when the sun is shining, and wind is only available when the wind is blowing. These characteristics, and particularly the diurnal nature of solar, have reshaped the demand curve and have also resulted in a greater need for flexible ramping of assets to ensure reliable grid operation and to ensure outages do not occur when solar and wind resources are unavailable.

Financial incentives implemented to spur the development of solar and wind energy have allowed those resources to bid into the CAISO market at zero marginal cost, driving down locational marginal prices and making it more difficult for existing generators to derive profit from market participation. There are many instances where the CAISO's day-ahead hourly price is lower than what independent power producers require to meet operating and capital recovery costs, let alone make a return of its investment. This difficulty has been further exacerbated by the once-through cooling forced retirement rule and the establishment of the carbon cap-and-trade program, which have increased unit costs for electricity generation at existing facilities. In response to the grid reliability concerns, CAISO has implemented or proposed market enhancements such as the creation of the flexible ramping product, deeper regional coordination, and improvements to allow participation of energy storage and demand response in wholesale energy markets. How CAISO decides to address concerns regarding grid reliability adds another layer of uncertainty.

Electric transmission grid operators have a limited set of technologies that can be deployed to quickly respond to the uncertainty as net demand changes on the grid; most of them have limited capacity or energy. Hydroelectric pumped-storage is the oldest form of grid-scale energy storage and continues to be a leading alternative because of its large capacity and ability to generate revenue by storing energy from low-cost, off-peak electric power and selling the electricity back to the grid during peak hours (CEC, 2017d). An important distinction has to be made between "standalone" pumped-storage assets and those assets capable of pumped-storage that are an integral component of a conventional hydropower setup. The difference between the two is the limited dispatchability of the latter because of the need to sustain the water delivery objective that a specific project was built to serve in the first place. It is also important to note that the current uncertainties in market design will have little negative impact on "standalone" pumped-storage assets because the pumped-storage is not a net generation or net load energy participant. Cycle efficiency and the spread between certain periods in electricity prices are the only factors that can substantially impact the viability of pumped-storage assets.

Renewable integration is the concept of making available, deploying, and operating generation and/or load resources that are flexible and controllable to ensure the reliability of the electric grid, in response to the inherent variability and uncertainty of renewable generation resources (wind and solar). Nationally, there are ongoing efforts to assess the needs and costs of integrating renewable energy resources as they are developed and deployed, and as they penetrate different electricity grids. In California, electricity market participants, regulatory agencies, and grid operators are collaborating on developing methodologies and models to identify the State's resources need for renewable integration. Options such as adding gas turbines to compensate for the variability of renewable energy are being considered, but these are the least favorite solutions because they diminish the benefits and purpose of deploying renewable energy resources. Other options such as energy storage, curtailments, distributed resources, and smart grids are also being considered.

Pumped-storage, batteries, compressed air, and flywheels are among the different energy storage technologies available, being developed, and deployed today. Some storage technologies are better suited for short-term and fast response "capacity" applications (batteries, flywheels) that could be used to manage grid imbalances and volatility through regulation services. Others, such as pumped-storage and compressed air, are better suited for long-term and intermediate response "energy" applications needed to firm up highly variable wind and solar generation. Energy storage allows for increasing efficiency of renewables and solving existing problems, such as the abundance of supply and limited demand during mid-day. The complementary deployment of storage options, in conjunction with renewables, is a recent and important trend that enhances the value of using renewable energy, and innovation in this field will continue to be a key strategy moving forward (Center for Sustainable Energy, 2017).

Pumped-storage projects can quickly ramp up power operation by releasing water from the upper reservoir (forebay) to the lower reservoir (afterbay) during high-demand periods. Water is then pumped back up from the lower reservoir to the upper reservoir during off-peak hours, often taking advantage of very low wholesale power prices for power available during off-peak periods. Major pumped-storage facilities in California include:

- PG&E's 1,212-MW Helms Pumped Storage Project in Fresno County (standalone)
- Department of Water Resources (DWR) 644-MW Edward C. Hyatt (Butte County), 126-MW Thermalito (Butte County), and 424-MW San Luis/W.R. Gianelli (Merced County) Pumped-Storage Projects (integral to DWR's Lake Oroville)
- Los Angeles Department of Water and Power's (LADWP) 1,331-MW Castaic Pumped Storage Project in Los Angeles County, which takes advantage of SWP deliveries into Castaic Lake (integral to LADWP's water system)
- Southern California Edison's (SCE) 200-MW Eastwood project in Fresno County (standalone)

31.1.2.2 Electric Transmission System

California's high-voltage electric transmission system connects the different regions of the State to each other, to varying degrees, as well as to the transmission systems of the surrounding western states, Canada, and Mexico. The degree to which areas are interconnected depends upon the availability of transmission capacity between the areas. These interconnected electric transmission systems allow power purchases and sales to extend beyond State and national borders. More than 300,000 miles of electrical transmission or distribution lines currently cross California, including more than 32,000 miles of high-voltage electric transmission lines (CEC, 2011).

Originally, California's electric transmission system was built by the utility companies to connect their major load centers to the generation sources. Some generation sources were built close to the load centers, requiring relatively short transmission lines; others, such as hydroelectric plants, were located far from the metropolitan areas they serve. The investor-owned utilities (IOUs) – primarily PG&E, San Diego Gas & Electric (SDG&E), and SCE – built much of the electric transmission lines throughout the State to serve their customers. The federal government, through WAPA, also built major electric transmission systems to deliver power from federally owned hydroelectric dams to load centers throughout the west. These public and private electric transmission systems were operated independently of each other, with some ties to the consumer-owned utilities. An example is LADWP, which developed its own transmission system to connect generation in California, Nevada, Arizona, and New Mexico to load centers in the City of Los Angeles. Over time, as development of new power generation close to the load centers became more difficult, the IOUs and the federal government built high-voltage electric transmission systems connecting California to neighboring states – primarily to import less expensive hydroelectricity from the northwest and thermal power from the southwest.

This network of conductors, switchgear, and transformers allows long-distance sales and purchases of power, with deliveries across the grid paid for through tariffs charged by the electric transmission system owners. When a new load or generator comes on line, power flows over the grid must be reconfigured to accommodate the increase in demand or generation. The physical process of inserting or withdrawing additional power from the grid can reduce reliability and may warrant construction of additional infrastructure, such as upgrading an existing electric transmission line to handle more power, or constructing a new power plant in areas where transmission upgrades are not feasible.

The California electric transmission grid is shown in Figure 31-3. As shown, both the northern and southern regions of the State have an extensively developed grid system. These two areas are connected primarily through one high-voltage line known as "Path 15." Path 15 is often congested, hampering the ability to transfer power between northern and Southern California. The electric transmission system in Northern California is owned largely by the federal government (through WAPA) and PG&E. Transmission system planning is driven by Federal Energy Regulatory Commission (FERC) orders 890 and 1000, WECC economic transmission planning through the Transmission Expansion Planning Policy Committee (TEPPC) and California Transmission Planning Group (CTPG) that was formed in 2009 to jointly plan and coordinate transmission planning activities. The CAISO planning process includes both a grid reliability planning process and a more long-term transmission system planning process for all transmission facilities within its control area, which consists of the service territories of the State's three largest investor-owned utilities. The reliability planning process compares projected load growth against projected generation reserve margins in all areas within the CAISO control area, identifies potential local reliability problems where available generation may not be able to meet maximum local loads, and identifies where the electric transmission system may be too congested to compensate for a system disturbance, such as an unexpected loss of a major generator or transmission line. The short-term solution to any one reliability problem may be to contract for additional generation capacity within the local area, or to construct additional transmission facilities that would allow more remote generation to serve the local load (CAISO, 2011a).

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FIGURE 31-3
California Electric Transmission System
Sites Reservoir Project EIR/EIS

The longer term electric transmission planning identifies transmission upgrades needed to serve future loads, as well as to compensate for changes in generation patterns, such as the renewable power generation being introduced into the grid to meet RPSs, which pursuant to State law require that 20 percent of retails sales of all utilities in the State come from renewable resources by the end of 2013, to 25 percent by the end of 2016, 33 percent by the end of 2020, and 50 percent by the end of 2030. California legislators have expressed a continuing interest in expanding statewide renewable mandates and have been actively contemplating increasing the renewable mandate beyond the 50 percent standard established in SB 350. However, a bill authorizing an increase in the 50 percent renewable portfolio standard has yet to be enacted. Identified reliability-related transmission projects from the reliability planning process are also considered during the transmission system planning process. When needed, transmission system projects are identified during the California Public Utilities Commission (CPUC) transmission planning process which includes CAISO transmission planning process. The transmission system owner then seeks approval for the project through the appropriate regulatory authority, which for PG&E is the CPUC. As one of four power marketing agencies under the Department of Energy, WAPA has its own approval process for upgrading its transmission facilities, although the rates it charges to recover the cost of improvements are approved by FERC.

Reliability planning is also conducted on a wider scale by WECC. As designated by the NERC, WECC is the regional entity that was delegated responsibility to implement NERC’s mandatory reliability standards in the Western Interconnection, and provides an environment for coordinating the operating and planning activities of its members. WECC works closely with PG&E and other California utilities to gather data regarding projected future generation reserve margins and planned transmission upgrades to ensure that reliability standards are met throughout the region.

As part of any proposed project (including the Project), transmission service would be required to support the energy pumping requirements of the off-stream storage reservoir. As part of that effort, a study would need to be undertaken to identify whether transmission lines could be used to provide power and to determine additional requirements for reinforcing and/or upgrading existing transmission infrastructure in the local area and region. The study will be used to ensure that other transmission infrastructure owners and/or stakeholders are not adversely affected by the addition of the Project to the electric grid.

31.1.2.3 Demand Forecast

The increasing demand for electrical energy is based on growth in both population (i.e., households) and commerce (commercial and industrial businesses). Weather can also significantly influence electricity demand. California’s peak load was 46,232 MW of electric power in 2016 (CAISO, 2017). For that year, the commercial sector accounted for approximately 44 percent of the State’s electricity demand, followed by the residential sector, which accounted for approximately 36 percent, and the industrial sector, at approximately 20 percent (CEC, 2017b). Residential demand is projected to grow by 17 percent from 2017 to 2027, spurred by population growth, rising disposable income, and continued population shifts to warmer regions with greater cooling requirements. Commercial sector electricity demand is projected to increase by 11 percent over that same period, led by the service industries. Industrial electricity demand is projected to decline by less than 1 percent, slowed by increased competition from overseas manufacturers and a shift of U.S. manufacturing toward consumer goods that require less energy to produce and are produced by increasingly energy efficient equipment (CEC, 2016). Increased use in the residential sector will come both from an increased average use per household (i.e., larger homes, more homes with air conditioning, and increased home electronics) and a population increase. Historically, the amount of electricity used per household increased by approximately 0.7 percent per year. This trend is expected to continue, with the decrease in electricity use for home lighting, refrigeration, air conditioning, and heating use as the efficiency of these products improve, balanced against the increase in popularity of consumer electronics (U.S. Department of Energy [DOE], 2011). Recent and projected growth trends are presented in Table 31-2.

Table 31-2
California Energy Demand Update, 2016 Forecasts of Statewide Electricity Demand

Years	Low Energy Demand	Mid Energy Demand	High Energy Demand
Consumption (GWh)			
1990	227,606	227,606	227,606
2000	261,036	261,036	261,036
2015	281,334	281,334	281,334
2020	291,477	294,474	297,280
2026	302,603	315,683	328,559
2027	304,639	319,256	333,100
Average Annual Consumption Growth Rates (%)			
1990-2000	1.38	1.38	1.38
2000-2015	0.50	0.50	0.50
2015-2020	0.71	0.92	1.11
2015-2026	0.66	1.05	1.42
2015-2027	0.67	1.06	1.42
Non-coincident Peak (MW)			
1990	47,123	47,123	47,123
2000	53,529	53,529	53,529
2016[a]	60,543	60,543	60,543
2020	60,332	61,444	62,644
2026	58,750	63,275	67,072
2027	58,370	63,501	67,772
Average Annual Non-coincident Peak Growth Rates (%)			
1990-2000	1.28	1.28	1.28
2000-2015	0.77	0.77	0.77
2015-2020	-0.09	0.37	0.86
2015-2026	-0.30	0.44	1.03
2015-2027	-0.33	0.43	1.03

[a]Weather normalized: California Energy Demand Updated Forecast 2016 uses a weather-normalized peak value derived from the actual 2016 peak for calculating growth rates during the forecast period.

Note:

Shaded = historical values

Source: CEC, 2017b

The 2017 forecast developed by the CEC projected that electricity demand in the State would increase at a rate of 0.89 percent per year from 2017 to 2027 (CEC, 2017b). However, economic and climatic conditions have the potential to affect electricity consumption in the State, particularly among residential users. For example, the downturn in the economy from 2008 to 2010 had a significant effect on electricity use in the State, such that the projected maximum demand for the summer of 2011 was actually 2 percent lower than the projected maximum demand for the summer of 2010 (CEC, 2011). Additionally, above average winter temperatures in 2016 resulted in a decrease in residential electricity demand in California of 0.73 percent when compared with 2015 data (WECC, 2016; CEC, 2017b). Across the WECC region, the 2015 total regionwide demand of 728,896 GWh is projected to increase by 7.4 percent to 782,546 GWh, an average of 0.67 percent annually by 2026 (U.S. Energy Information Administration, 2017).

Although electricity use is expected to increase over the long term, since the economic recession, the growth of distributed generation, coupled with the deployment of energy efficient appliances and other devices, has significantly reduced the rate of growth from previous years' projections. California has led the nation in efficiency gains for decades. California's 196 million British thermal units (Btu) per capita energy consumption in 2014 was substantially lower than the national average of 309 million Btu per capita, ultimately ranking 49th out of 51, including Washington D.C., behind only Rhode Island (194 million Btu) and New York (190 million Btu) (U.S. Energy Information Administration, 2014). Despite two states using less total energy per capita than California, the American Council for an Energy-Efficient Economy (ACEEE) continues to rank California at or near the top of their annual State Energy Efficiency Scorecard, based on state-led programs and policies towards energy efficiency. Most recently, California tied for first with Massachusetts in the 10th annual State Energy Efficiency Scorecard (ACEEE, 2016).

Demand for electricity in Northern California can ebb and flow dramatically, both within each year and from year to year, as can available generation. Demand is highest during heat waves[4] and is generally lowest at night during spring and fall, when heating and cooling demand is low. Competition for off-peak power purchases is much more robust during summer months, as is reflected in the considerably higher market prices. Northern California's summer peak demand, however, has fallen below forecasts for the last several years. The last year that Northern California summer peak demand met the projected forecast was 2010, exceeding the forecast by 0.3 percent. Since then, peak summer demand in Northern California has been 7.7 percent, 2.7 percent, 1.9 percent, 9 percent, and 2 percent below forecast demand in the years 2011 to 2015, respectively (CAISO, 2011b; 2012; 2013; 2014; 2015b; 2016). Furthermore, despite above average temperatures and a multi-year drought, regional peak demand has declined by approximately 3.6 percent since 2010, when peak summer demand was 21,218 MW to 20,462 MW in 2015 (CAISO, 2011b; 2016).

31.1.3 Primary Study Area

The Primary Study Area is limited to those areas that would be most directly affected by Project power operations, including the specific transmission lines that the Project would connect to, and other Central Valley Project (CVP) and State Water Project (SWP) projects that would be re-operated by the alternatives. The Primary Study Area includes the service territories of entities that currently purchase power from the SWP and CVP.

31.1.3.1 Central Valley Project

The Central Valley Project, one of the Nation`s major water conservation developments, extends from the Cascade Range in the north to the plains along the Kern River in the south. The CVP is managed by the

[4] Heat waves are defined as three or more days of greater than 100-degree temperatures.

Bureau of Reclamation (Reclamation). Initial features of the project were built primarily to protect the Central Valley from water shortages and floods, but the CVP also improves Sacramento River navigation, supplies domestic and industrial water, generates electric power, conserves fish and wildlife, creates opportunities for recreation, and enhances water quality. The CVP is comprised of 20 dams and reservoirs, 39 pumping plants, 11 power plants, and 500 miles of major canals manage nearly 9 million acre-feet of water annually, delivering water to customers from Redding to Bakersfield. The CVP includes four major canals: the Tehama-Colusa, the Contra Costa, the Delta-Mendota, and the Friant-Kern. CVP also includes storage reservoirs on the Trinity, Sacramento, American, Stanislaus, and San Joaquin rivers, and offstream storage at San Luis Reservoir.

San Luis Reservoir is part of both the CVP and SWP; it is a pumped-storage operation that takes water from, and makes deliveries to, both the California Aqueduct and the Delta-Mendota Canal, provides storage for later use, and generates up to 424 MW of power. The federal-only portion of the San Luis Unit includes the O'Neill Pumping-Generating Plant and Intake Canal, Coalinga Canal, Pleasant Valley Pumping Plant, and San Luis Drain. The C.W. "Bill" Jones Pumping Plant (formerly the Tracy Pumping Plant) lifts Delta water 197 feet up and into the Delta-Mendota Canal, and moves water through the canal to San Luis Reservoir. Each of the six pumps at the plant is capable of pumping 767 cfs. Farther south, Dos Amigo Pumping Plant, a joint CVP and SWP facility located 17 miles south of O'Neill Forebay, lifts water 113 feet to permit gravity flow to the end of San Luis Canal at Kettleman City. The plant contains six pumping units, each capable of delivering 2,200 cfs at 125 feet of head (WAPA, 2004).

Of the water conveyed by the CVP, approximately 5 million acre-feet (MAF) are delivered to farms in Northern California, and approximately 600,000 acre-feet is delivered to municipal and industrial users (Reclamation, 2017). The CVP is a net energy producer. The CVP's hydroelectric facilities produce a net of approximately 4,800 GWh of electricity annually. The capacity and annual generation at CVP facilities is presented in Table 31-3.

Production capacity and pumping power vary significantly from year to year and day to day, depending upon hydrological conditions, reservoir levels, and operational constraints such as fish protection measures. For example, for the 1-year period beginning in October 2015, the projected effective generating capacity of the CVP was expected to vary between a low of 30 GWh (April 2016) and a high of 150 GWh (November 2016) (Reclamation, 2016).

CVP power is marketed by WAPA to preference power customers, which are primarily consumer-owned or government entities, including municipal utilities, irrigation districts, public utility districts, Native American tribes, and government facilities, such as Department of Energy laboratories. As with all power produced by federally-owned hydropower facilities, consumer-owned and government entities are given preference to CVP power sales. Approximately 85 preference power customers purchased CVP power in 2015, although 65 percent was allocated to just six customers: Sacramento Municipal Utility District, the City of Redding, Silicon Valley Power (City of Santa Clara), the City of Roseville, the City of Palo Alto and the U.S. governmental facilities in the San Francisco Bay Area (Henn, 2017, pers. comm.).

Table 31-3
Central Valley Project Power Plants, Capacities, and Historical Annual Generation

CVP Power Plant	Capacity (MW)	Net Annual Generation (MWh)										Average Annual Generation (MWh)
		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	
Shasta Power Plant	710	2,082,200	1,901,983	2,648,324	1,914,177	1,465,825	1,435,033	1,840,062	2,357,123	1,827,640	1,794,553	1,926,692
Trinity and Lewiston Power Plants	140	582,909	404,582	653,441	364,535	396,154	247,731	320,532	455,391	434,340	449,912	430,953
Judge Francis Carr Power Plant	171	479,847	234,149	617,029	291,941	305,345	180,901	175,961	344,441	332,379	423,713	338,571
Spring Creek Power Plant	180	562,699	344,369	822,234	271,581	305,925	220,836	323,354	408,600	324,713	352,400	393,671
Keswick Power Plant	117	452,205	395,563	531,169	419,597	373,541	344,875	378,585	441,318	371,796	383,662	409,231
Folsom Power Plant	215	457,396	755,952	894,289	371,559	259,964	474,265	566,962	762,649	465,839	341,902	535,078
Nimbus Power Plant	17	51,987	72,316	77,729	41,263	34,413	58,752	59,699	81,000	57,041	45,661	57,986
New Melones Power Plant	383	335,354	372,876	910,223	469,682	365,676	357,107	339,801	705,425	439,711	410,547	470,640
O'Neill Pumping/ Generating Plant	14	5,964	56	28	5,404	8,932	5,936	1,624	28	3,752	7,840	3,956
William R. Gianelli Pumping/Generating Plant (Federal Share)	202	176,083	116,744	130,719	126,409	157,320	66,634	111,856	73,172	165,568	104,048	122,855
TOTAL	**2,149**	**5,186,644**	**4,598,590**	**7,285,185**	**4,276,148**	**3,673,095**	**3,392,070**	**4,118,436**	**5,629,147**	**4,422,779**	**4,314,238**	**4,689,633**

Note:

MWh = megawatt-hours

Source: Reclamation, 2014

CVP power allocations are based on predicted hydrological conditions, using a long-term generation model that determines available capacity and energy, and the needed reserve margin. Energy available after meeting CVP obligations is called the Base Resource, which is allocated to customers on a percentage of generation basis pursuant to long-term contracts for each year. Base Resource is determined by this formula:

> Base Resource = Gross Generation – Project Use – First Preference Customer Load – Maintenance – Reserves – System Losses – Ancillary Services[5]

Customers are generally divided into three groups for the marketing plan: base resource, variable resource, and full load service customers. Base resource customers are those customers that will only receive base resource energy from WAPA. Variable resource customers are customers that opt for base resource firming service and/or supplemental energy from WAPA in addition to their base resource. These first two categories of customers receive approximately 86 percent of the base resource. Full load service customers are customers that will have their total load met by WAPA through a combination of their base resource and additional purchases by WAPA on their behalf. This category of customers receives approximately 14 percent of the base resource.

31.1.3.2 State Water Project

The SWP is a complex network of 34 storage facilities, reservoirs, and lakes; 20 pumping plants; four pumping-generating plants; five hydroelectric power plants; and approximately 701 miles of open canals and pipelines designed to move water from the Feather River basin and Lake Oroville in Northern California to users in the Central Valley and Southern California. It is the nation’s largest state-built water and power development and conveyance system, and the largest electricity user in the State. DWR manages the SWP to deliver water to its 29 long-term water contractors and their member water agencies. The service areas of these contracting agencies extend from Plumas County in the north to San Diego County adjacent to the Mexican border. These contractors’ service areas comprise almost one-quarter of California’s land area and more than two-thirds of its population. SWP facilities also provide flood control, recreation, and fish and wildlife enhancement. The SWP contractors repay all costs related to project construction and operation, with annual repayments of approximately $1 billion per year (based on 2014 data). Of that amount, operation and maintenance costs account for 34 percent; capital costs account for 36 percent; and variable costs account for 30 percent. (DWR, 2017).

The SWP has a net energy use of approximately 4,600 GWh, making it the largest single consumer of electric power in California, consuming approximately 2.5 percent of the State’s total electric energy production. In 2014, energy used at the SWP pumping and generating plants totaled 2.79 GWh (DWR, 2017). SWP energy use and production is highly variable, depending on hydrologic and storage conditions. For example, over the period 1990 to 2001, net energy use varied from a low of 3,421 GWh in 1998 (a very wet year with high hydroelectric production) to a high of 8,171 GWh in 1990 (in the middle of the 1987 to 1992 drought).

The SWP’s hydroelectric plants (Hyatt, Thermalito, Gianelli, Warne, Alamo, Thermalito Diversion, Mojave, and Devil Canyon) have a total generating capacity of approximately 1,475 MW. In Northern California, the Hyatt Pumping/Generating Plant pumps water from the Thermalito Afterbay to Lake

[5] Pursuant to the Trinity River Act of 1955, 25 percent of the power delivered from the CVP’s Trinity River Division must be reserved for customers within Trinity County. Similarly, the Rivers and Harbor Act of 1962 authorizing the New Melones Project specified that up to 25 percent of the energy resulting from that project is reserved for customers in Calaveras and Tuolumne counties. Customers receiving energy pursuant to these authorizations are referred to as “First Preference” customers.

Oroville, in pumping mode, and also produces power when water is released from the lake to the afterbay. Hyatt has three pumping/generating units, each producing 173,000 horsepower and up to 1,870 cfs of flow in pumping mode, and 113 MW (at 615 feet of static head and 2,850 cfs flow) in generating mode; and three generating units, each capable of producing 106 MW (at 615 feet of static head and 2,800 cfs flow). In total the Hyatt plant has generating and pumping flow capacities of 16,950 cfs and 5,610 cfs, respectively, and can generate up to 645 MW of power. Just downstream, the 114-MW Thermalito Pumping-Generating Plant is designed to operate in tandem with the Hyatt Pumping-Generating Plant and has generating and pumped-storage flow capacities of 17,400 cfs and 9,120 cfs, respectively. Thermalito Diversion Dam, 4 miles downstream of Oroville Dam, creates a tailwater pool for the Hyatt Pumping-Generating Plant and is used to divert water to the 10,000-foot-long Thermalito Power Canal designed to convey generating flows up to 16,900 cfs to Thermalito Forebay and pumped-storage flows to the Hyatt Pumping-Generating Plant. Storage in Thermalito Forebay and Thermalito Afterbay is used to generate power and maintain uniform flows in the Feather River downstream of the Oroville Facilities. Thermalito Afterbay storage also can be used for pump-storage operations, which in total may consume about 390,000 MWh of energy annually. Generation provided by pumped-storage activity has the potential to contribute approximately 6 or 7 percent to the total annual Oroville Facilities generation of approximately 2.08 GWh per year[6] (DWR, 2012).

Further south (as described above) is the San Luis Unit, part of both the CVP and SWP, consisting of the O’Neill Dam and Forebay, B.F. Sisk San Luis Dam, San Luis Reservoir, William R. Gianelli Pumping-Generating Plant, Dos Amigos Pumping Plant, Los Banos and Little Panoche Reservoirs, and San Luis Canal from O’Neill Forebay to Kettleman City. O’Neill Pumping-Generating Plant takes water from the Delta-Mendota Canal and discharges it into the O’Neill Forebay, where the California Aqueduct (a SWP feature) flows directly. The William R. Gianelli Pumping-Generating Plant lifts water from O’Neill Forebay using eight 63,000 horsepower pumps and discharges it into San Luis Reservoir. During releases from the reservoir, these plants can generate up to 424 MW of electric power by reversing flow through the turbines. Water for irrigation is released into the San Luis Canal and flows by gravity to Dos Amigos Pumping Plant, where the water is lifted more than 100 feet to permit gravity flow to the end of San Luis Canal at Kettleman City.

Moving water through the California Aqueduct is a series of large pumping plants, starting with the Harvey O. Banks Pumping Plant, located 2.5 miles southwest of the Clifton Court Forebay on the California Aqueduct. Farther south along the California Aqueduct, the Chrisman, Edmonston, and Pearblossom pumping plants historically consumed the highest amount of energy. The Chrisman and Edmonston pumping plants provide 524 and 1,970 feet of lift, respectively, to convey California Aqueduct water across the Tehachapi Mountains. The Pearblossom Pumping Plant lifts water approximately 540 feet and discharges the water 3,479 feet above mean sea level, the highest point along the California Aqueduct.

Using gravity on the downhill side of the Tehachapis, flows through the Alamo Power Plant, Mojave Siphon Power Plant, Devil Canyon Power Plant, and Warne Power Plant, together with generation from the William R. Gianelli Plant (located north of the Tehachapis), generated 1.99 GWh of electric energy in 2007, approximately one-fifth of the total energy used by the SWP. The Alamo Power Plant uses the 133-foot head between Tehachapi Afterbay and Pool 43 of the California Aqueduct to generate electricity. The Mojave Siphon Power Plant generates electricity from water flowing downhill after its

6 This value is the average generation from 1982 to 2001.

540-foot lift by the Pearblossom Pumping Plant. The Devil Canyon Power Plant generates electricity with water from Silverwood Lake with more than 1,300 feet of head, the highest water head in a power plant in the SWP system. The Warne Power Plant uses the 725-foot drop from the Peace Valley Pipeline to generate electricity (DWR, 2012).

SWP manages its loads and generation resources to maximize off-peak pumping load and peak generation to minimize water delivery costs. The SWP's power resources portfolio also includes contracts for power purchases, sales, and exchanges. The SWP is operated as an independent bulk power entity and is interconnected with the PG&E, Southern California Edison (SCE), and WAPA transmission systems. DWR dispatches the SWP's own loads and resources and coordinates its power operations through CAISO. The SWP makes yearly projections for energy needs to ensure it has enough power to make scheduled deliveries. SWP-related pump load is met through SWP generation, long-term, mid-term, and short-term contracts and purchases.

31.1.3.3 Northern California Transmission System

The transmission system in Northern California consists of dozens of high-voltage (230-kilovolt [kV] to 500-kV) transmission circuits, most aligned north and south, which connect the region's diverse network of power plants to load centers throughout the State. PG&E, WAPA, and TANC[7] each own major transmission lines in the region, including in the immediate vicinity of the Project. PG&E has more than 18,600 circuit-miles of transmission lines and 141,000 miles of distribution lines connecting its customers from Eureka to Bakersfield. WAPA's 856 circuit-miles of high-voltage transmission lines can deliver power from the Oregon border as far south as the San Luis Reservoir.

As shown in Figure 31-4, four high-voltage transmission lines are located in western Colusa County in the vicinity of Project facility locations, and the Project could interconnect with any or all of these lines. These are:

- A 230-kV WAPA transmission line extending from the Olinda (Vic Fazio) Substation in Shasta County, south through Tehama, Glenn, Colusa, Yolo, Solano, Contra Costa, and Alameda counties to connect to the Jones Pumping Station at the Tracy Substation, and farther south to other pumping plants along the Delta-Mendota Canal. This line distributes power from CVP facilities to federally owned pumping stations.
- Two 230-kV transmission lines owned by PG&E, which roughly parallel the WAPA-owned transmission line along most of its Northern California route, including in Glenn, Colusa, Yolo, Solano, Contra Costa, and Alameda counties. These lines are part of PG&E's 230-kV network, which interconnects PG&E's hydroelectric facilities and various other power plants to load centers throughout Northern California.
- The COTP, a 500-kV transmission line owned by a consortium of public and private utilities, including TANC, which is comprised of the COTP manager, PG&E, WAPA, the City of Redding, and the Carmichael and San Juan water districts. The COTP extends from the Bonneville Power Administration's Captain Jack Substation in Southern Oregon south to WAPA's Tracy Substation near the CVP's and SWP's delta pumping plants, and on to PG&E's Tesla Substation. It is interconnected with and parallel to the Pacific Intertie, and consists of three segments: a

[7] TANC is a joint powers agency created in 1984 by a group of publicly-owned utilities to plan and construct the California-Oregon Transmission Project (COTP).

148.5-mile-long Northern Segment between the Captain Jack Substation and the Olinda (Vic Fazio) Substation in Tehama County; the 190-mile-long CVP Upgrade Segment between the Olinda Substation and the Tracy Substation in San Joaquin County, near the Tracy Pumping Station; and the Tesla Bypass Segment, a 7-mile-long double circuit from the Tracy Substation to an interconnection with the Pacific AC Intertie on PG&E's 500-kV transmission line between the Tesla and Los Banos substations. The COTP also includes the Maxwell Compensation Station, located approximately 6 miles south of the Funks Reservoir, which helps condition the power on the 500-kV line.

In addition to the large hydroelectric projects of the CVP and SWP, more than 200 power plants are located in the Primary Study Area; most are smaller than 50 MW. Most of the larger power plants in Northern California are located near Sacramento or the San Francisco Bay areas. Only a few power plants of any size are located in the five counties surrounding the Project (Tehama, Glenn, Colusa, Lake, and Mendocino counties), the largest of which is PG&E's 660-MW Colusa Generating Station, located approximately 3 miles north of the proposed Sites Reservoir site (CEC, 2012). The Colusa Generating Station, which began commercial operations in December 2010, interconnects to the two 230-kV PG&E transmission lines described above, and takes water from the Tehama-Colusa Canal for plant use (CEC, 2007).

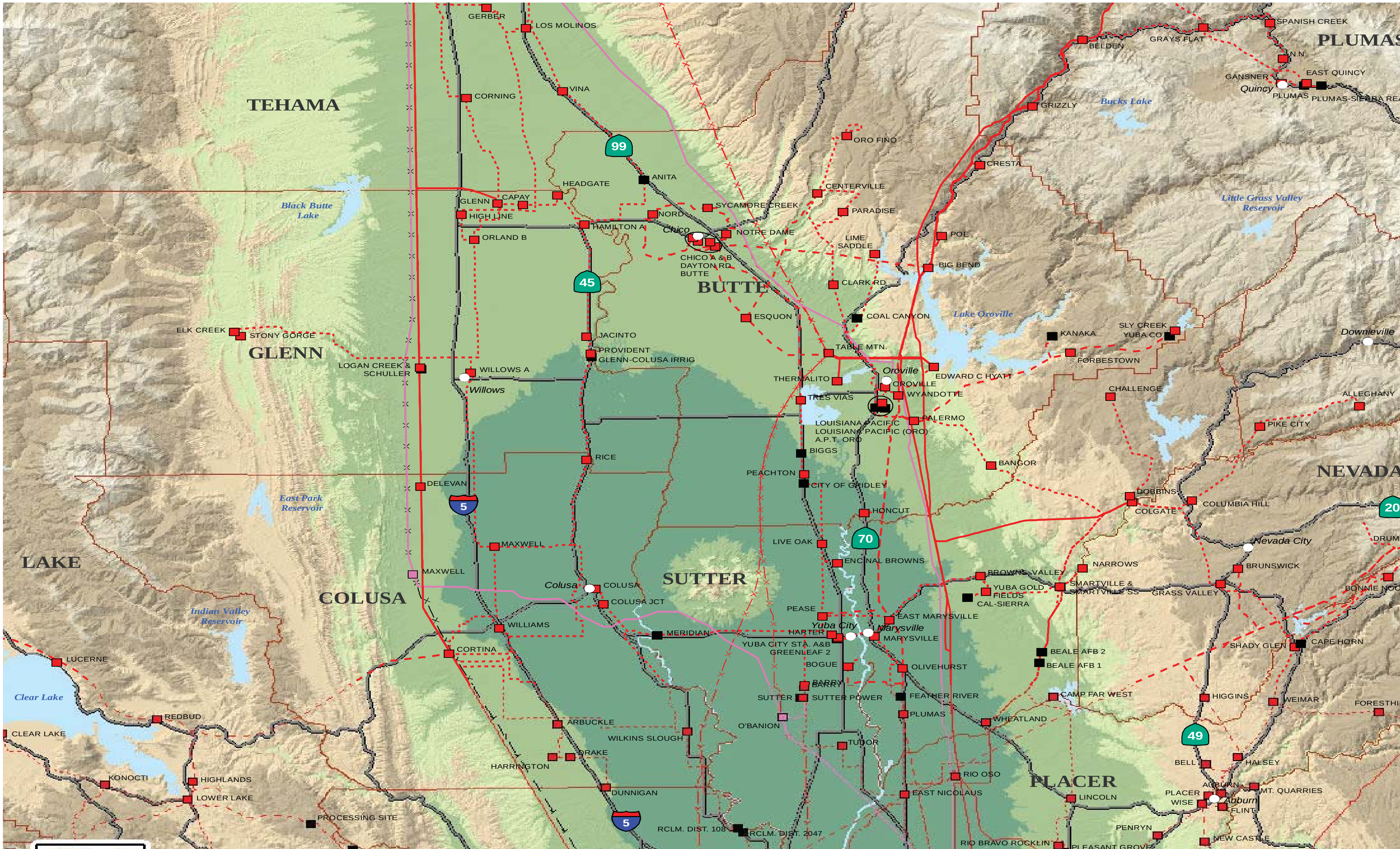
31.2 Environmental Impacts/Environmental Consequences

The following identifies the anticipated environmental impacts/consequences associated with implementation of Alternatives A, B, C, and D; Alternative C_1 would not result in the generation of power.

31.2.1 Project Operational Scenario

31.2.1.1 The Project as an Energy Storage Asset

Energy storage is the concept of storing excess (and/or low cost) energy during low demand periods for later use during high energy demand (and/or high cost) periods. Energy storage technologies, their capital installation costs, and their electricity grid applications vary significantly from one technology to another and from one market to another. Today, pumped-storage is considered to be one of the most viable forms of energy storage, due its high potential capacity and energy (100s MW and 1,000s MWh), and long discharge time (minutes to hours). In assessing the viability of the Project, it is important to consider the excess capacity in the California energy markets. Specifically, the promulgation of enhanced mandatory renewable standards has significantly affected the ability of independent power producers to recover all of their costs in the CAISO energy markets. The historical value difference that some market participants received by arbitraging the difference between peak and off-peak prices has been greatly reduced by the penetration of renewables, which for the most part recover their costs through the retail markets, as opposed to wholesale producers and/or consumers who recover their costs through the CAISO wholesale market. Other available energy storage technologies include, but are not limited to, batteries, compressed air, capacitors, and flywheels. Most of these technologies are limited by capacity and/or discharge (time of sustained generation).



LEGEND

Substation

- Pacific Gas & Electric (PG&E)
- Western Area Power Administration (WAPA)
- All Other Substations *

Transmission Line
(Color according to Utility Ownership)

- 33 - 92KV
- 110 - 161KV
- 220 - 287KV
- 345 - 500KV
- 500KV - DC

Other Features

- City
- Major Roads
- Dry Lake
- Water Body
- County Line

FIGURE 31-4
Regional Transmission Lines and Substations
Sites Reservoir Project EIR/EIS

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Typically, pumped-storage setup includes lower and upper reservoirs, interconnected through hydraulic conveyance/conduit, and a pumping-generating plant. The pumping-generating plant would be interconnected to the electrical grid via a switchyard and transmission lines. Sizing the different components of a pumped-storage setup is a complex multidisciplinary exercise (e.g., engineering, economics, and environmental) that is beyond the scope of this chapter. Operating a pumped-storage facility entails pumping the water from the lower reservoir into the upper reservoir when excess and/or low cost energy is available. The consumed energy (minus losses) would be transformed to potential energy through the hydrostatic head of the water stored in the upper reservoir. When there is a need for energy, capacity, and/or ancillary services (including renewable integration services), water would be released from the upper reservoir into the lower reservoir through the hydraulic turbines to generate electricity. The energy (in MWh) generated from releasing a unit volume of water relative to the energy consumed to pump that unit volume of water into the upper reservoir would be the cycle efficiency (or recovery rate) of that specific pumped-storage plant. Cycle efficiency varies with the net head across the pumping-generating units and the discharge of the water at the time of pumping and generation (subject to water surface elevation in the upper and lower reservoirs, and plant efficiencies). Average cycle efficiency of a pumped-storage setup (which would be site- and technology-specific) may range between 70 percent and 80 percent (with new pumping-generating technology units cycle efficiencies are approaching 85 percent).

The Project is being planned as a multi-objective project, and one of these objectives would be pumped-storage operations (for all alternatives other than Alternative C_1). Another objective for the Project would be potential participation in providing renewable integration services to the electrical grid. The Project would perform as an energy storage asset either through daily time-shifting (from off-peak to on-peak hours), or through seasonal-shifting (from low spring demand to high summer demand). The Project’s benefits in this context would be numerous, including economic incentives, greenhouse gas (GHG) emissions reduction, renewable energy integration, system reliability, and transmission support. The Project, through its water diversion and release cycles from the Sacramento River (seasonal-shifting), and/or daily pumped-storage operations (time-shifting) would perform as an energy storage asset that could support the State’s electrical grid.

31.2.1.2 Project Operations

The Project is expected to operate in a similar manner to the San Luis Reservoir/O’Neil Forebay/Gianelli Powerhouse complex without the limitation of age and design of these facilities that do not allow them to operate in a daily pumped-storage manner. A detailed description of this daily pumped-storage operation and the associated benefits is provided in the following paragraphs. On a seasonal basis, water would be pumped from the Sacramento River through the existing Tehama-Colusa Canal and Glenn-Colusa Irrigation District (GCID) Main Canal and/or the proposed Delevan Pipeline into Holthouse Reservoir, where it would be lifted as much as 328 feet by the Sites Pumping/Generating Plant into Sites Reservoir throughout the winter and spring months for storage. Water releases from the Project would be coordinated with releases from CVP and SWP facilities to provide a variety of ecosystem, agricultural, and municipal and industrial benefits.

For Project operations, the base assumptions and scenarios used in developing the CALSIM II model were maintained for the different Project components. The CALSIM II model was used to simulate the operations of the Project, as a component of the integrated SWP and CVP operations. The CALSIM II model is a tool that was setup to emulate the operations strategy set forth for the Project, and to help determine many of the Project benefits and impacts. More details on the CALSIM II model formulation are available in Section 31.3.4.2.

For the purpose of modeling the power operations of the Project, three modes for Project operations were identified: diversion mode (pumping from the Sacramento River to fill up Sites Reservoir); release mode (generation) from Sites Reservoir to meet Project water release objectives; and a pumped-storage mode to better use residual capacities of the different Project components. The Project pumped-storage mode is intended to enhance the Project economics by capturing opportunities offered by the energy market (energy price differentials between on-peak and off-peak hours), and to provide the support/products needed to integrate renewable energy (e.g., wind, solar).

In modeling the power needs for the diversion mode for all alternatives, an optimization strategy was developed toward shifting pumping operations (i.e., pump load) to off-peak hours, when excess renewable and/or lower GHG emissions energy is available. This approach was focused on minimizing energy costs of pumping operations, reducing GHG emissions resulting from pumping operations, and potentially providing renewable integration services, yet, maintaining Project water operations objectives. Flat monthly pumping operations were assumed to be maintained (where/when applicable, 24 hours a day, 7 days a week) for all three diversion points along the Sacramento River, so the Project would maintain its primary objective of capturing excess water in the Sacramento River. Once water was diverted from the Sacramento River into Holthouse Reservoir, the rest of the diversion operations (i.e., pumping into Sites Reservoir) is intended to be optimized to better use Sites Pumping Plant capacity and the available storage in Holthouse Reservoir. Operations would retain the on-peak diversions from the Sacramento River in Holthouse Reservoir (as scheduled) and pump that water into Sites Reservoir in the off-peak hours (on a daily basis) to the degree possible. The intent of reshaping the diversion mode would be to allow the Project to participate in providing renewables integration services, and avoiding on-peak high electricity costs to the extent possible. This shift in operations would allow generating facilities (for all alternatives other than Alternative C_1) to operate during the on-peak hours (through a controlled water release from Sites Reservoir into Holthouse Reservoir), and provide an opportunity to superimpose the pumped-storage mode on the Project diversion mode. In an optimized mode and in the on-peak (or super-peak) hours, the Sites Pumping/Generating Plant would be available for generation. In the off-peak hours, the residual pumping capacity would be available to pump the water back into Sites Reservoir.

For the water release mode (i.e., generation) of the Project, an optimization strategy was developed to shift water releases and generation to the on-peak hours, to provide integration services to renewable generation, and to maximize generation revenues from the Project's generation facilities. For this strategy, and to the extent physically possible, all intended daily water releases from Sites Reservoir into Holthouse Reservoir would occur during the on-peak hours (or super peak hours). Incidental to the on-peak releases from Sites Reservoir into Holthouse Reservoir, water would be released into the Terminal Regulating Reservoir (TRR), Tehama-Colusa Canal, and the Sacramento River up to the capacities of these facilities (and within the planned limits for the water release). The residual water in Holthouse Reservoir (from the on-peak Sites Reservoir releases) would be released during the off-peak hours to satisfy water delivery obligations of the Project. A key requirement for this strategy to be effective is that Holthouse Reservoir's active storage would be made available before the beginning of the next on-peak cycle (i.e., next day's cycle). Optimizing the release mode would better use Sites generation capacity (through shifting renewable generation from off-peak hours, providing renewable integration services, and maximizing revenues) and provide an opportunity to superimpose a pumped-storage operation cycle on the release mode.

The Project, through its water diversion and release cycles from the Sacramento River and/or daily pumped-storage operations would perform as a renewable integration and an energy storage (resource-shifting) asset that could support the State's electrical grid. If the Project were to deploy variable speed pumping-generating units (a decision would be made during the design stage), then the Project would be able to provide integration services needed to firm up highly variable wind and solar generation. In the pumping mode, some of the Project's pumping load (subject to physical and operational constraints) would follow the variable wind generation (mostly in off-peak hours). In the generation mode, some of the generation capacity would be offered to provide regulation services needed to firm up wind and solar generation (mostly in on-peak hours).

A desired result from the Project's operations from a hydroelectric generation capability perspective is to provide an additional source of renewable energy in a manner that supports the electrical grid, including use/generation during off-peak hours to the on-peak hours. In addition, and if properly equipped with variable-speed units, the Project could provide renewable integration services, thereby displacing single-cycle combustion turbines and combined-cycle gas turbines; otherwise, it would be needed to firm up renewable energy resources. Although the Project is anticipated to be a net energy consumer, optimized operations are anticipated to have a positive impact through its ability to assist in resource shifting, renewable integration, and minimization of potential GHG emissions.

A third component of the Project power operations is a daily pumped-storage operation. For periods when the Project is in neither diversion nor in release modes, Sites Reservoir pumping and generation facilities could operate in a pure pumped-storage mode to participate in shifting excess renewable energy resources (excess wind energy) from off-peak to on-peak hours, provide renewable integration services needed to firm-up renewable energy resources in both the on-peak and off-peak hours, and reduce overall GHG emissions for the California electrical grid. In a pure pumped-storage operation mode, water would be released from Sites Reservoir into Holthouse Reservoir during the on-peak (or super peak) hours to generate energy and would be pumped back into Sites Reservoir in the off-peak hours to complete the pumped-storage cycle. The pumped-storage operation could be superimposed on the diversion and release modes when the energy market economics relative to the Sites Pumping/Generating Plant's efficiency (cycle efficiency) are conducive to do that. At the proposed Sites Reservoir, the extent of the pure pumped-storage operations, and pumped-storage incidental to the Project diversion and release modes, would be driven by market economics, pumping-generating cycle efficiency, residual pumping capacity, residual generation capacity, and residual storage capacity in Holthouse Reservoir.

Project power operations would be incidental to water delivery objectives, and residual pumping–generating capacity could be offered in the energy and/or in the ancillary markets (including renewable integration services) as available.

Power delivered to or taken from the Project would be transmitted over the interconnected transmission system through one or more interconnection points. The proposed interconnection points and facilities are identified in Chapter 3 Description of the Sites Reservoir Project Alternatives. A transmission system impact study, conducted by the transmission system owner or owners, would be conducted as necessary to determine the optimal interconnection costs, as well as to identify potential reliability problems that may be caused by the interconnection, and potential system upgrades needed to mitigate the impact of the new interconnection.

Because of the already highly limited capability of transferring additional power between Northern and Southern California, the effects of Project operations would occur primarily north of the Path 15 transmission line in central and Northern California. This region also effectively represents the service area of the CVP. However, as is shown in the modeling conducted to date as part of analyzing the effects of Project operations on the overall power system, detailed in Section 31.3.4.2, the water operation of the Project would also have a ripple effect on energy use in all of California.

For example, the Project would act as an additional storage facility, up to 1.8 MAF, much like the 2-MAF San Luis Reservoir. During drought years especially, the increased storage would increase operations of several pumping plants as water would be released to the Sacramento River and into the Delta, where it would be pumped into the California Aqueduct and the Delta-Mendota Canal, and on through the SWP or CVP pumping stations to projects' service areas throughout central and Southern California. Any increased storage in Northern California would have the same effect: increased flexibility and quantity in storage would allow or cause increased operations of all pumping plants, including at the SWP's Lake Oroville/Thermalito Complex, where the increased storage of the Project may allow increased pumped-storage operations there. Increased storage would lead to increased pumping throughout the SWP because of the increased amount of water available to help meet demand while operating within existing environmental restrictions. Increased storage could also lead to increased generation from the SWP and CVP powerhouses from water releases in general.

The diversions from the Sacramento River into Holthouse Reservoir would occur when water is available for diversion. Pumping into Sites Reservoir from Holthouse Reservoir would occur mostly during off-peak hours. From a power perspective, the Project's pumping load would use excess renewable energy (wind energy), and/or excess capacity from fossil generation units. As a result, the Project would shift renewable energy generated during off-peak hours to on-peak hours. As the modeling for the Project shows, Project pumping and generation for water delivery objectives would be seasonal, with high pumping demand in winter months (December through February) and high generation in summer months.

Pumped-storage operations would be superimposed on Project operations during periods when the Project is not being operated to meet water delivery objectives, or excess capacities are available and could be better used. The intent would be to optimize Project operations to meet water delivery objectives, and to provide integration services to renewable energy generation plants. The Project represents a medium-sized generator (either 127.6 MW, 130.8 MW, or 141.6 MW, depending upon the alternative), with operations optimized to meet scheduled water releases, and to provide valuable renewable integration services As shown in Tables 31-4 and 31-5, the Project in isolation would represent a large, but mostly off-peak electric load (210 MW to 276 MW, depending upon alternative). This load includes pumping for the water diverted from the Sacramento River to Holthouse Reservoir, including at the Tehama-Colusa Canal (where two new 250-cfs pumps would be installed at the Red Bluff Pumping Plant), and at the proposed Delevan Pipeline Intake/Discharge Facilities. During maximum pumping operations, the Project would have the potential to increase total demand in Northern California by as much as 276 MW (181.35 MW at the Sites Pumping/Generating Plant, 65.65 MW at the Delevan Pipeline Intake/Discharge Facilities, 19.68 MW at the TRR, 6 MW at the Red Bluff Pumping Plant Intake, and 3.39 MW at the GCID Main Canal Intake).

Table 31-4
Project Maximum Pumping Demand by Alternative

Location	Alternative A (MW)	Alternative B (MW)	Alternatives C and C_1 (MW)	Alternative D (MW)
Sites Pumping/Generating Plant	158	181.35	181.35	181.35
Delevan Pipeline Intake/Discharge Facilities	65.65	0	65.65	65.65
Terminal Regulating Reservoir	19.68	19.68	19.68	19.68
Red Bluff Pumping Plant	6	6	6	6
GCID Main Canal Intake	3.39	3.39	3.39	3.39
Total	**252.72**	**210.42**	**276.07**	276.07

Table 31-5
Project Maximum Generating Capacity by Alternative

Generating Plant	Alternative A (MW)	Alternative B (MW)	Alternative C (MW)	Alternative C_1 (MW)	Alternative D (MW)
Sites Pumping/Generating Plant	107	121	121	0	121
Delevan Pipeline Intake/Discharge Facilities	10.8	0	10.8	0	10.8
Terminal Regulating Reservoir	9.8	9.8	9.8	0	9.8
Total	**127.6**	**130.8**	**141.6**	**0**	141.6

Pumped-storage operations would involve the daily procurement of excess renewable energy and relatively low GHG emissions in the off-peak hours (relatively inexpensive power sources) to pump water from the Holthouse Reservoir up to Sites Reservoir and release water during peak hours to generate power and displace energy with relatively higher GHG emissions. Also, Pumped-storage operations provide flexible load and generation, and would be used to compensate for rapid changes in electric power demand as well as for changes in power production from variable renewable power sources. Although water delivery and power production are given equal weight in the planning goals for the Project, pumped-storage power operations would likely be secondary to water delivery operations because of the various restrictions on water operations from contracts and from environmental restrictions, but would be optimized within those restrictions to produce the greatest value to support the California electricity grid through providing renewable energy integration services. Pumped-storage operations from the afterbay to the forebay of each of the two or three (depending upon the chosen alternative) Project pumping/generating facilities would be possible, but only the Sites Pumping/Generating Plant would be used for daily pumped-storage operations because of the operational limitations placed on the smaller forebays and afterbays of the other Project pumping/generating facilities.

Table 31-6 shows a summary of a preliminary level analysis performed to assess the benefits from optimizing the Project's hydropower operations, including pumped-storage operations, so it can participate as an energy storage and renewable integration asset using three renewable integration scenarios, and sustain its intended water delivery objectives.

Table 31-6
Summary of Project Optimized Hydropower Operations, including Pumped-storage Operations

	Operational Mode	Average Annual Load-Gen (MWh)	Wind or Solar Used or Shifted (MWh)	Baseload Used or Displaced (MWh)	Firming Energy Displaced (MWh)
Alternative A					
Scenario 1					
Excess Wind (80%) + Integration Service (20%)	Pumping	398,677	318,941	0	79,735
Resource Shifting (80%) + Integration Service (20%)	Generation	242,568	194,054	0	48,515
Scenario 2					
Excess Wind (50%) + Baseload (30%) + Integration Service (20%)	Pumping	398,677	199,338	119,603	79,735
Resource Shifting (80%) + Integration Service (20%)	Generation	242,568	121,284	72,770	48,515
Scenario 3					
Baseload (80%) + Integration Service (20%)	Pumping	398,677	0	318,054	79,735
Resource Shifting (80%) + Integration Service (20%)	Generation	242,568	0	194,054	48,515
Alternative B					
Scenario 1					
Excess Wind (80%) + Integration Service (20%)	Pumping	365,728	292,583	0	73,146
Resource Shifting (80%) + Integration Service (20%)	Generation	241,830	193,464	0	48,366
Scenario 2					
Excess Wind (50%) + Baseload (30%) + Integration Service (20%)	Pumping	365,728	182,864	109,718	73,146
Resource Shifting (80%) + Integration Service (20%)	Generation	241,830	120,915	72,549	48,366
Scenario 3					
Baseload (80%) + Integration Service (20%)	Pumping	365,728	0	292,583	73,146
Resource Shifting (80%) + Integration Service (20%)	Generation	241,830	0	193,464	48,366
Alternative C					
Scenario 1					
Excess Wind (80%) + Integration Service (20%)	Pumping	421,237	336,990	0	84,247
Resource Shifting (80%) + Integration Service (20%)	Generation	261,060	208,848	0	52,212
Scenario 2					
Excess Wind (50%) + Baseload (30%) + Integration Service (20%)	Pumping	421,237	210,619	126,371	84,247
Resource Shifting (80%) + Integration Service (20%)	Generation	261,060	130,530	78,318	52,212
Scenario 3					
Baseload (80%) + Integration Service (20%)	Pumping	421,237	0	336,990	84,247
Resource Shifting (80%) + Integration Service (20%)	Generation	261,060	0	208,848	52,212
Alternative C_1					
Scenario 1					
Excess Wind (80%) + Integration Service (20%)	Pumping	421,237	336,990	0	84,247
Resource Shifting (80%) + Integration Service (20%)	Generation	0	0	0	0
Scenario 2					
Excess Wind (80%) + Integration Service (20%)	Pumping	421,237	210,619	126,371	84,247
Resource Shifting (80%) + Integration Service (20%)	Generation	0	0	0	0

	Operational Mode	Average Annual Load-Gen (MWh)	Wind or Solar Used or Shifted (MWh)	Baseload Used or Displaced (MWh)	Firming Energy Displaced (MWh)
Scenario 3					
Baseload (80%) + Integration Service (20%)	Pumping	421,237	0	336,990	84,247
Resource Shifting (80%) + Integration Service (20%)	Generation	0	0	0	0
Alternative D					
Scenario 1					
Excess Wind (80%) + Integration Service (20%)	Pumping	330,677	264,542	0	66,135
Resource Shifting (80%) + Integration Service (20%)	Generation	215,542	172,434	0	43,108
Scenario 2					
Excess Wind (50%) + Baseload (30%) + Integration Service (20%)	Pumping	330,677	165,338	99,203	66,135
Resource Shifting (80%) + Integration Service (20%)	Generation	215,542	107,771	64,663	43,108
Scenario 3					
Baseload (80%) + Integration Service (20%)	Pumping	330,377	0	264,542	66,135
Resource Shifting (80%) + Integration Service (20%)	Generation	215,542	0	172,434	43,108

Note:

Load-Gen = Load and Generation

The maximum direct potential adverse effect on the Northern California grid from future Project operations would be the instability of the grid caused by simultaneous starting of all Project pumps at a time when insufficient additional generation and transmission capacity would be available to compensate for the resultant instability put into the grid. When started, motors often initially draw 10 or more times their running current as the motor comes up to speed. Motor control designs and pumping management procedures would ensure that pumps are started sequentially, allowing each to come up to speed before the next pump is started, thus reducing the amount of starting current, and resultant instability. Soft-start and motor-generator technology, such as those used at SWP pumping plants, could also be used to reduce starting currents to minimal levels.

Therefore, with appropriate motor control designs and operating procedures in place, the effective maximum adverse direct effect of the Project would most likely be during periods of maximum pumping when generation reserve margins[8] in Northern California are low. Indirectly, during times of high demand for water in Southern California, Project water releases would cause increased pumping energy use throughout the SWP, especially during drought periods. Low generation reserve margins can occur during summer months when heat waves cause large increases in air conditioning loads, but also during spring and fall months when many generators are off-line for maintenance, reducing the pool of generators available to meet sudden increases in demand or to compensate for other system disturbances, such as the unexpected loss of a transmission line or large generator.

The indirect effects of Project operations on power and energy use, especially during times of high demand for CVP and SWP water releases, are more difficult to identify and assess because of the difficulty in predicting the mix of generating resources that would be available to meet increased power and energy demand, as well as to provide ancillary services to help maintain reliability standards. However, as load increases, less-efficient generation would be added to the mix, to the point that during

[8] Reserve margin is defined as the difference in percentage between the maximum generating capacity available to serve load in the region, and the total power demand in that region.

periods of very high demand, all available power plants would be made available to maintain resource adequacy, including those that are so inefficient that they otherwise remain idle for all but a few days per year. Inefficient power plants also tend to be the oldest and most polluting plants available, and significantly increase systemwide air emissions per MWh when operating.

To help assess the range of potential systemwide effects of the alternatives, several modeling efforts were commissioned that simulate system operations under various scenarios. The modeling conducted regarding the effect of the Project on power operations throughout the CVP and SWP (primarily Appendix 31B CVP-SWP Power Modeling, as well as 31A Power Planning Study [Power and Risk Office or PARO]) show that the increased storage offered by the Project would:

- Increase the flexibility of water operations throughout the year
- Increase operations of all pumped-storage projects in the SWP
- Increase operations of SWP pumping plants due to the increased water releases from the Project

This increased energy use (from the last bullet above) would be offset somewhat by the increased generation available from the Project and from other projects within the CVP and SWP because of the overall increase in water releases. Any overall increase in energy use indirectly caused by the increased storage offered by the Project could be partially offset by the energy or cost savings offered by releasing Project water from storage. Similarly, the increased systemwide flexibility provided by the Project may also allow increased pumped-storage operations at other facilities, such as at Lake Oroville/Thermalito Complex and San Luis Reservoir/Gianelli.

31.2.2 Evaluation Criteria and Significance Thresholds

Significance criteria represent the thresholds that were used to identify whether an impact would be potentially significant. Appendix G (Environmental Checklist Form) of the *CEQA Guidelines* does not include evaluation criteria related to power production and energy. Appendix F (Energy Conservation) of the *CEQA Guidelines* requires a discussion of the potential energy impacts of proposed projects, with particular emphasis on avoiding or reducing inefficient, wasteful, and unnecessary consumption of energy.

Appendix F includes the following goals:

- Decreasing overall per capita energy consumption
- Decreasing reliance on fossil fuels, such as coal, natural gas, and oil
- Increasing reliance on renewable energy sources

The evaluation criteria used for this impact analysis represent a combination of the Appendix F criteria and professional judgment that considers current regulations, standards, and/or consultation with agencies, knowledge of the area, and the context and intensity of the environmental effects, as required pursuant to the National Environmental Policy Act (NEPA). An adverse effect on power production and energy would occur if an alternative resulted in a substantial expenditure of energy that was not balanced by corresponding beneficial effects (or would result in a wasteful use of energy), or if it would reduce production of renewable energy within the Extended, Secondary, or Primary study areas. Therefore, for the purposes of this analysis, an alternative would result in a potentially significant impact if it would result in any of the following:

- Inefficient, wasteful, or unnecessary consumption of energy during construction, maintenance, and recreation activities.

- Inefficient, wasteful, or unnecessary consumption of energy during operational activities.
- A substantial reduction in the generation of renewable energy.

Various thresholds have been used in previous NEPA and California Environmental Quality Act (CEQA) investigations of SWP- or CVP-related projects in determining significance. For this analysis, an adverse effect would potentially occur if the construction, operation, or maintenance activities result in a net energy use that exceeds 5 percent of the Existing Conditions/No Project/No Action Condition energy use for CVP and SWP pumping. The average combined CVP and SWP energy use for pumping and delivery of water from the Delta, including storage in San Luis Reservoir, pumping over the Tehachapi Mountains, and recovery of some of this energy at generating stations along the California Aqueduct, is approximately 7,000 GWh per year. Therefore, a 5 percent increase would be approximately 350 GWh.

Although all facilities for each alternative would be constructed, operated, and maintained to minimize the energy required to pump and transport water through the CVP and SWP, each would require energy. An increase in joint CVP and SWP pumping energy use of more than 5 percent would suggest a substantial use of energy resources to move water supplies through the CVP and SWP; however, the increased energy use must be balanced against the beneficial attributes of the flexible generation provided by each alternative (other than Alternative C_1, which would not generate power). The 5 percent threshold is, therefore, considered a trigger that would require additional analysis of adverse and beneficial effects to determine overall power use significance.

31.2.3 Impact Assessment Assumptions and Methodology

Combinations of Project facilities were used to create Alternatives A, B, C, C_1, and D. In all resource chapters, the Authority and Reclamation described the potential impacts associated with the construction, operation, and maintenance of each of the Project facilities for each of the five action alternatives. Some Project features/facilities and operations (e.g., reservoir size, overhead power line alignments, provision of water for local uses) differ by alternative and are evaluated in detail within each of the resource areas chapters. As such, the Authority has evaluated all potential impacts with each feature individually, and may choose to select or combine individual features as determined necessary.

31.2.3.1 Assumptions

The following assumptions were made regarding Project-related impacts (construction, operation, and maintenance impacts) to power production and energy use:

- Direct Project-related construction, operation, and maintenance activities would occur in the Primary Study Area.
- Direct Project-related operational effects would occur in the Secondary Study Area.
- The only direct Project-related construction activity that would occur in the Secondary Study Area is the installation of two additional pumps into existing bays at the Red Bluff Pumping Plant.
- No direct Project-related construction or maintenance activities would occur in the Extended Study Area.
- Direct Project-related operational effects that would occur in the Extended Study Area are related to San Luis Reservoir operation; increased reliability of water supply to agricultural, municipal, and industrial water users and ecosystem uses; and the provision of an alternate Level 4 wildlife refuge

water supply. Indirect effects to the operation of certain facilities that are located in the Extended Study Area, and indirect effects to the consequent water deliveries made by those facilities, would occur as a result of implementing the alternatives.

- The Authority would operate the Project primarily as a water storage and delivery project, with an additional primary purpose of providing electric power services within the contractual and legal obligations that restrict water operations.
- To the extent possible within constraints imposed by water delivery operations, power operations would be conducted in such a way as to provide maximum value to the California power system. Pumped-storage power operations would be limited to the Sites Pumping/Generating Plant.
- The direct Project-related adverse impacts on power production and energy use would primarily relate to its demand on electric power, which would be at least in part offset by its beneficial effects of producing flexible generation to integrate renewable power on demand and/or on-peak energy.
- Indirect Project-related impacts on power production and energy use include both the displaced energy used for Project pumping and the energy use associated with the changes in water storage and conveyance from Project implementation. For instance, although the Project could increase demand for electric power for its pumping operations, provision of surface water could reduce the need for energy use associated with the pumping of groundwater.

31.2.3.2 Methodology

Existing Conditions and the future No Project/No Action Alternative were assumed to be similar in the Primary Study Area given the generally rural nature of the area and limited potential for growth and development in Glenn and Colusa counties within the 2030 study period used for this EIR/EIS, as further described in Chapter 2 Alternatives Analysis. As a result, within the Primary Study Area, it is anticipated that the No Project/No Action Alternative would not entail material changes in conditions as compared to the existing conditions baseline.

With respect to the Extended and Secondary study areas, the effects of the proposed action alternatives would be primarily related to changes in available water supplies in the Extended and Secondary study areas and the Project’s cooperative operations with other existing large reservoirs in the Sacramento watershed, and the resultant potential impacts and benefits to biological resources, land use, recreation, socioeconomic conditions, and other resource areas. The DWR has projected future water demands through 2030 conditions that assume the majority of CVP and SWP water contractors would use their total contract amounts and that most senior water rights users also would fully use most of their water rights. This increased demand in addition to the projects currently under construction and those that have received approvals and permits at the time of preparation of the EIR/EIS would constitute the No Project/No Action Condition. As described in Chapter 2 Alternative Analysis, the primary difference in these projected water demands would be in the Sacramento Valley. As of the time of preparation of this EIR/EIS, the water demands have expanded to the levels projected to be achieved on or before 2030.

Accordingly, Existing Conditions and the No Project/No Action alternatives are assumed to be the same for this EIR/EIS and as such are referred to as the Existing Conditions/No Project/No Action Condition, which is further discussed in Chapter 2 Alternatives Analysis. With respect to applicable reasonably foreseeable plans, projects, programs and policies that may be implemented in the future but that have not yet been approved, these are included as part of the analysis of cumulative impacts discussed in Chapter 35 Cumulative Impacts.

This analysis examines both adverse and beneficial effects of each alternative, and makes a determination of whether an impact would be potentially significant using the significance criteria listed above, and whether feasible mitigation could avoid, eliminate, reduce, or compensate for a potentially significant impact. To determine overall effects, potential adverse effects were balanced with the potential beneficial effects. To help quantify these effects, modeling of the alternatives was conducted to assess the potential benefits and impacts of each, including the No Project/No Action Alternative. The modeling conducted to date for this analysis focused on Project-related operations and the resulting direct and indirect effects within the CVP and SWP systems. The modeling did not attempt to predict all power operations in the WECC, or in all of California, for any alternative.

Whether the alternatives would result in potentially significant impacts associated with power production and energy (including secondary impacts to the environment) was determined based on an assessment of:

- Energy requirements and energy use efficiencies for each stage of the alternative.
- The effects on local and regional energy supplies and on requirements for additional capacity.
- The effects on demands for electricity and other forms of energy.
- The effects of the alternative on other energy resources in particular renewable resources.
- A comparison of the alternatives in terms of overall energy consumption and in terms of reducing wasteful, inefficient, and unnecessary consumption of energy.

To examine the range of potential effects of Project operations on the electric power system in the western U.S., computer modeling of CVP, SWP, and Project power and energy use over a wide range of hydrological conditions was conducted, including multiple dry years as well as wet years. This modeling was used in a preliminary analysis of the direct and indirect effects of future Project operations on power and energy use in the Extended, Secondary, and Primary study areas.

The power analysis used spreadsheet post-processors to evaluate the power impacts of flow scenarios from CALSIM II operations studies on a monthly time step. CALSIM II is a planning model developed by DWR and Reclamation that simulates operations of the SWP and CVP and areas tributary to the Sacramento-San Joaquin Delta. CALSIM II provides quantitative hydrologic-based information to those responsible for planning, managing, and operating the SWP and CVP. CALSIM II is typically the system model that is used for any interregional or statewide analysis in California.

The following tools used the monthly output from CALSIM II as input to perform power production and benefits analyses; the tools evaluate facility-specific and systemwide generation, load, and net generation:

- LTGen: analyzes CVP facilities
- SWP_Power: analyzes SWP facilities
- NODOS_Power: analyzes existing and Project facilities
- PLEXOS power generation benefits tool

These tools estimated average annual energy generation and use at SWP and CVP facilities and at Project generation and pumping facilities, including existing facilities that would be operated differently if the Project is constructed. For generation facilities, the tools estimated average annual energy generation, as well as average annual peaking power capacity, based on projected reservoir levels. For pumping facilities, the tools estimated average annual energy requirements. The tools also checked to determine whether off-peak energy use targets were met. Transmission losses were estimated for both pumping and generation facilities. The methods, assumptions, and results of the LTGen, SWP_Power, and NODOS_Power spreadsheet models are described in Appendix 31B CVP-SWP Power Modeling. A summary description of flow and storage conditions associated with the alternatives, based on the CALSIM II model results, is in Chapter 6 Surface Water Resources. The CALSIM II model description and detailed results are included in Appendix 6B Water Resources System Modeling.

Additionally, DWR's PARO performed two initial power evaluation studies. The first phase study (Phase 1) was completed in 2009, in which the designed capacities and the corresponding operational scenarios for the Project's components were analyzed, and some design modifications were recommended to increase the power generation capabilities of the Project. The second phase study (Phase 2) analyzed the three original Project alternatives (Alternatives A, B, and C). The Phase 2 effort focused on the potential to optimize power operations with sustained water operations to better capture opportunities within the power market and use the inherent excess capacities resulting from hydrology swings. The full Phase 1 and Phase 2 reports are included in Appendix 31A Power Planning Study (PARO). Although these evaluations included projections into future conditions and identify key factors that would influence generation capability and maximizing potential benefits, additional evaluations would be required prior to Project implementation. These evaluations are included as reference only and were not used to identify potential adverse impacts of the Project.

The analysis of each alternative also included consideration of direct adverse and beneficial effects from Project operations on electric power use and production. Adverse effects include:

- Displaced use of CVP or SWP power for Project pumping operations.
- Increased pumping throughout the CVP and SWP system, especially during drought years, due to the increased storage available at Sites Reservoir.

Increased competition for off-peak network power purchases for Project pumping operations at times. At other times the flexible load available through daily pumped-storage operations may avoid problems with over generation. Beneficial effects include:

- Increased use of excess renewable energy (especially wind energy) to serve Project's pump loads during off-peak hours.
- Increased peak power generation and flexibility from Project pumped-storage power production during peak hours.
- Increased availability of ancillary services from Project operations, including firming other renewable power resources, such as wind and solar power, as well as spinning and non-spinning reserves, frequency support, voltage support, and load-following.
- Increased flexibility of water operations throughout the SWP and CVP may allow increased use of pumped-storage operations at other facilities to maximize revenues, increasing the ability to meet contract obligations while maintaining required environmental standards, and the potential for increased generation from increased SWP and CVP storage (including in dryer years).

It should be recognized that the analyses do not account for the many project participants that are anticipated to use Sites Reservoir Project water in lieu of their current water supplies, including groundwater and water from other sources. Current uses, in some cases, may require a relatively greater energy usage and/or cost to obtain or convey. As such, the overall system energy demands identified should be viewed as conservative.

31.2.4 Topics Eliminated from Further Analytical Consideration

No Project facilities or topics that are included in the significance criteria listed above were eliminated from further consideration in this chapter.

31.2.5 Impacts Associated with Alternative A

31.2.5.1 Extended and Secondary Study Areas – Alternative A

Construction, Operation, Maintenance, and Recreation Impacts

Impact Power-1: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Construction, Maintenance, and Recreation Activities

Implementation of Alternative A would require no Project construction, maintenance, or recreation activities within the Extended Study Area, resulting in **no impact** when compared to the Existing Conditions/No Project/No Action Condition. Additionally, no Project recreation areas would be constructed within the Secondary Study Area if Alternative A is implemented, resulting in **no impact** from recreation area construction, operation, or maintenance in the Secondary Study Area when compared to the Existing Conditions/No Project/No Action Condition.

The only use associated with the Project that would occur in the Secondary Study Area is that associated with the installation and operation of two pumps at the Red Bluff Pumping Plant. Installing the proposed pumps into existing bays at the existing Red Bluff Pumping Plant would require the direct and indirect use of energy resources. Direct energy use would involve using petroleum products and electricity to operate construction and maintenance equipment, as well as fuel use by workers commuting to and from the Project site. Indirect energy use would involve the consumption of energy to extract raw materials to manufacture the pump and construction/maintenance equipment and vehicles, and to transport the pump. These activities would require the use of gasoline and diesel fuel.

Project construction activities would temporarily result in a very minor increase in energy consumption during the Project construction period when compared to the Existing Conditions/No Project/No Action Condition. No substantial long-term energy use would be required for the installation of the pump as part of Alternative A. Also, it is not anticipated that such energy use would be inefficient, wasteful, or unnecessary. This impact is considered to be **less than significant** when compared to the Existing Conditions/No Project/No Action Condition**.** In addition, energy use for Project maintenance would also be very minor, and not inefficient, wasteful, or unnecessary because it would ensure that the pump would continue to operate properly for its designed life cycle. As such, impacts to power and energy use related to Project maintenance would be **less than significant** when compared to the Existing Conditions/No Project/No Action Condition.

Impact Power-2: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Operational Activities

The Project's water operation and pumped-storage operations would be optimized to the extent possible to support the most efficient use of the Project's pumping and generating assets. Most pumping from Holthouse Reservoir into Sites Reservoir would be done during off-peak hours when power demands and, subsequently, power prices are low. During these periods, it is anticipated that there would generally be an excess in wind generation and there would be a need for load to keep combined cycle gas generation units (low GHG emissions) at the minimum allowed generation. Water stored in Sites Reservoir would represent stored energy in the context of power operations of the Project. Stored water (i.e., energy) would be released through Project generating facilities during on-peak and super-peak hours to the extent possible, either on a seasonal basis to meet water delivery objectives, or on a daily basis to meet pumped-storage power operations objectives. In general, generated power from the Project would likely displace single-cycle gas generation units. Although the Project would be a net energy consumer, Project operations, when optimized, would have a positive effect in integrating renewable energy resources and lowering the energy market's GHG emissions.

By making up to 1.3 MAF of additional storage available to the water system, water releases from Alternative A would lead to increased use of energy for pumping the released water as far as Southern California. When compared to the entire Western Interconnection, this increase in demand or generation would not be substantial, with Alternative A's power operations having very minor effects across the Western Interconnection. Such effects would primarily occur in California, related to operational effects on CVP and SWP operations.

As shown in Table 31-7, the modeling results associated with implementation of Alternative A indicate relatively modest effects on generation reserves and modest increases in energy use of the CVP and SWP as a result of adding the Project facilities to their systems, as would be expected for any increase in water storage in Northern California. Table 31-7 does not show the increase in ancillary service production, which would increase system reliability. When considered alone, the energy use under Alternative A would not be substantial compared to the Existing Conditions/No Project/No Action Condition.

Table 31-7
CVP, SWP, and Proposed Project Facilities Energy Use (in GWh)[a] – Alternative A

Parameter	Long-Term Average or Dry and Critical Water Year Type Average	Existing Conditions/ No Project/ No Action Condition	Alternative A	Difference between Alternative A and Existing Conditions/No Project/No Action Condition[b]
CVP Facilities				
Energy Generation	Long-Term[c]	4,701	4,711	11
	Dry and Critical[d]	3,513	3,500	-13
Energy Use	Long-Term	1,116	1,152	36
	Dry and Critical	878	902	24
Net Generation[e]	Long-Term	3,585	3,560	-25
	Dry and Critical	2,635	2,598	-37
SWP Facilities				
Energy Generation	Long-Term	4,386	4,491	105
	Dry and Critical	2,909	3,143	234
Energy Use	Long-Term	8,088	8,442	354
	Dry and Critical	6,013	6,768	755
Net Generation	Long-Term	-3,702	-3,951	-249
	Dry and Critical	-3,104	-3,625	-521

Parameter	Long-Term Average or Dry and Critical Water Year Type Average	Existing Conditions/ No Project/ No Action Condition	Alternative A	Difference between Alternative A and Existing Conditions/No Project/No Action Condition[b]
Project Facilities[e]				
Energy Generation	Long-Term	0	126	126
	Dry and Critical	0	129	129
Energy Use	Long-Term	13	229	216
	Dry and Critical	12	184	172
Net Generation	Long-Term	-13	-103	-90
	Dry and Critical	-12	-54	-43
All Facilities (CVP, SWP, and Project)[f]				
Energy Generation	Long-Term	9,087	9,329	242
	Dry and Critical	6,422	6,771	350
Energy Use	Long-Term	9,214	9,818	604
	Dry and Critical	6,901	7,850	948
Net Generation	Long-Term	-132	-499	-367
	Dry and Critical	-482	-1,085	-603

[a]Results are estimated using LTGEN, SWP_Power, and NODOS_Power using data from the CALSIM II model.

[b]Due to rounding of the energy values to whole numbers, some differences may appear to be off by +/- one.

[c]Long-term is the average quantity for the calendar years 1922 to 2002.

[d]Dry and Critical is the average quantity for dry and critical years according to the Sacramento River 40-30-30 index.

[e]Project Facilities include Tehama-Colusa Canal and GCID Main Canal pumping facilities.

[f]Energy use and net generation for all facilities does not equal the sum of Energy Use and Net Generation for CVP, SWP, and Project facilities because energy use at Red Bluff Pumping Plant is included in both CVP and Project facilities. Results for Red Bluff Pumping Plant from LTGEN are subtracted from Energy Use and Net Generation for all facilities to avoid double-counting.

The net CVP, SWP, and Project energy generated under Alternative A (energy use minus energy production) would be as much as 367 GWh less than the Existing Conditions/No Project/No Action Condition over the long term, and 603 GWh during Dry and Critical water year types. When compared to the total in-State energy generation identified in Table 31-1 (198,227 GWh), the long-term change resulting from Alternative A would constitute less than 0.2 percent while the change during dry and critical water year types would be 0.3 percent. When compared to total electric demand in Northern California (20,462 GWh) (CAISO, 2016), the long-term reduction in net generation related to Alternative A would constitute an approximately 1.8 percent change; during dry and critical water year types, this number would increase to approximately 3.0 percent.

Power not generated by Alternative A project facilities but required for pumping operations, including power needed for pumped-storage operations, would be procured from CAISO or WAPA. The increased demand caused by Alternative A pumping would be partially offset by the generating capacity from Alternative A power operations. Based on normal load growth and the overall regional and statewide electric power generation and transmission capacity, this marginal increase in demand and subsequent reduction in net generation would be **less than significant** when compared to the Existing Conditions/No Project/No Action Condition.

Project modeling also indicates that Alternative A-related pumping would occur mostly in winter months, with lesser amounts into spring and early summer. Project power generation would occur mostly during summer months when water would be released to meet CVP and SWP obligations and power values are generally greater. This operation would be well-suited to Northern California's power system, which has peaks in power and energy use in summer months during periods of high air conditioning demand, and generally has significantly lower demand in winter months. This generation would be partially offset by pumping water through SWP canals and pumping stations to meet some Project participant needs.

Energy used to store water would not be considered an inefficient, wasteful, or unnecessary use of energy because it would be used to store water and potential electric energy for later use when needed. This would result in a **less-than-significant impact** when compared to the Existing Conditions/No Project/No Action Condition.

Impact Power-3: A Substantial Reduction in the Generation of Renewable Energy

In addition to the seasonal operational profile, pumping-generating assets would be optimized on a daily basis to the extent possible to better use and synchronize the Project's facilities with power market opportunities (e.g., prices, ancillary services). Optimized operations would shift pumping from Holthouse Reservoir to Sites Reservoir to off-peak and shoulder hours, and would shift water releases and incidental power generation to on-peak and super-peak hours to the extent possible. Regarding the power and energy use goals set forth in Appendix F of the *CEQA Guidelines*, Alternative A would not be anticipated to decrease per capita energy consumption in the Extended or Secondary study areas but would promote increased reliance on renewable resources, decreased reliance on fossil fuels, and reductions in GHG emissions by displacing high-emission peaking power plants through integration of renewable power resources, such as wind and solar. Therefore, Alternative A is expected to promote the use of renewable energy, would not cause a reduction in generation of renewable energy, and would thus result in a **less-than-significant impact** when compared to the Existing Conditions/No Project/No Action Condition.

31.2.5.2 Primary Study Area – Alternative A

Impact Power-1: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Construction, Maintenance, and Recreation Activities

The proposed modification or demolition of existing facilities and the construction of new facilities would require the direct and indirect use of energy resources. Direct energy use would involve using petroleum products and electricity to operate construction equipment, such as trucks, bulldozers, and tunnel boring equipment, as well as fuel use by workers commuting to and from the Project sites. Indirect energy use would involve consuming energy to extract raw materials, manufacture construction equipment and materials, and transport the goods necessary for construction and maintenance activities. These activities would require the use of gasoline and diesel fuel. Energy required during the temporary construction activities would not be used inefficiently, wastefully, or unnecessarily and, therefore, would result in a **less-than-significant impact** when compared to the Existing Conditions/No Project/No Action Condition.

Various types of fuel-consuming equipment would be necessary for maintenance of Project facilities, including routine inspections and repairs, sediment removal and dredging, and for maintenance and use of the recreation areas. Work conducted during maintenance activities would be relatively minor when compared to overall energy use in the Primary Study Area under the Existing Conditions/No Project/No

Action Condition, and the energy use would be temporary and intermittent. Impacts to power and energy use related to Project maintenance and recreational use would, therefore, be **less than significant** when compared to the Existing Conditions/No Project/No Action Condition.

A preliminary transmission interconnection feasibility analysis conducted in 2007 concluded that power flows expected for Alternative A, using the assumptions at that time, could be accommodated within the then-existing transmission system, with no upgrades, without creating reliability impacts in the Primary Study Area (Utility Systems Efficiencies, Inc., 2007). Three Interconnection Configuration Alternatives were considered for power flow analysis and cost estimating:

- Interconnect to PG&E's (then-proposed but now operating) Colusa 230-kV switching station via a 1-mile 230-kV transmission line
- Interconnect by looping onto PG&E's 230-kV transmission line from the then-proposed Colusa switching station to Vaca-Dixon 230-kV substation, Circuit 3
- Interconnect by looping onto WAPA's Olinda - Obanion 230-kV transmission line

Although constructing additional facilities would result in an increase in energy consumption when compared to the Existing Conditions/No Project/No Action Condition, expanding upon existing infrastructure within the Primary Study Area would substantially minimize inefficient, wasteful, or unnecessary energy use, resulting in a **less-than-significant impact**.

Impact Power-2: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Operational Activities

Other than for Project pumping, Primary Study Area energy use associated with Alternative A would be minimal, limited to lighting and potable water pumping proposed for the Stone Corral and Peninsula Hills recreation areas, and the lighting of Project facilities. These areas would use minimal amounts of energy on an ongoing basis when compared to Project pumping, and do not reach the trigger thresholds requiring additional analysis. Therefore, impacts to power and energy use at the Stone Corral and Peninsula Hills recreation areas, and the lighting of Project facilities would be **less than significant** when compared to the Existing Conditions/No Project/No Action Condition.

Impacts on energy production and demand associated with Alternative A, presented in Table 31-7, would primarily be encountered within the Extended and Secondary study areas because of the regional nature of electric power grids. However, these impacts could cause changes in energy production and transmission patterns that could lead to localized effects, such as a need to build additional infrastructure to compensate for changes in power flows. The net increase in power and energy demand related to implementation of Alternative A would be accommodated by proper planning, especially given the projected large generation margins in the region. Determining the future need for new infrastructure due to direct or indirect effects of Alternative A operations would be speculative, given the changes that are likely to happen before Alternative A could be operational. However, all future infrastructure additions would be subject to environmental review by the approving agency.

Impact Power-3: A Substantial Reduction in the Generation of Renewable Energy

As described for the Extended and Secondary study areas, Alternative A power capabilities would offer benefits to the electric grid system, including an increase in generation of renewable power resources within the Primary Study Area. Alternative A would not likely decrease per capita energy consumption within the Primary Study Area but would promote increased reliance on renewable resources and decreased reliance on fossil fuels because it integrates renewable power resources such as wind and solar. Operation of Alternative A would, therefore, result in a **less-than-significant impact** when compared to the Existing Conditions/No Project/No Action Condition.

31.2.6 Impacts Associated with Alternative B

31.2.6.1 Extended Study and Secondary Areas – Alternative B

Construction, Operation, Maintenance, and Recreation Use Impacts

Impact Power-1: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Construction, Maintenance, and Recreation Activities

The impacts associated with Alternative B as they relate to inefficient, wasteful, or unnecessary consumption of energy during construction, maintenance, and recreation activities would be the same as described for Alternative A for the Extended and Secondary study areas.

Impact Power-2: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Operational Activities

Table 31-8 summarizes the modeling results of the CVP and SWP systemwide effects of Alternative B, as well as those related specifically to Project facilities. Table 31-8 does not identify the increase in ancillary service production, which would serve to increase system reliability.

Table 31-8
CVP, SWP, and Proposed Project Facilities Energy Use (in GWh)[a] – Alternative B

Parameter	Long-Term Average or Dry and Critical Water Year Type Average	Existing Conditions/ No Project/ No Action Condition	Alternative B	Difference between Alternative B and Existing Conditions/No Project/No Action Condition[b]
CVP Facilities				
Energy Generation	Long-Term[c]	4,701	4,718	18
	Dry and Critical[d]	3,513	3,506	-6
Energy Use	Long-Term	1,116	1,147	32
	Dry and Critical	878	902	25
Net Generation[e]	Long-Term	3,585	3,571	-14
	Dry and Critical	2,635	2,604	-31
SWP Facilities				
Energy Generation	Long-Term	4,386	4,493	107
	Dry and Critical	2,909	3,128	220
Energy Use	Long-Term	8,088	8,464	376
	Dry and Critical	6,013	6,727	714
Net Generation	Long-Term	-3,702	-3,971	-269
	Dry and Critical	-3,104	-3,599	-494

Parameter	Long-Term Average or Dry and Critical Water Year Type Average	Existing Conditions/ No Project/ No Action Condition	Alternative B	Difference between Alternative B and Existing Conditions/No Project/No Action Condition[b]
Project Facilities[e]				
Energy Generation	Long-Term	0	104	104
	Dry and Critical	0	100	100
Energy Use	Long-Term	13	195	182
	Dry and Critical	12	106	95
Net Generation	Long-Term	-13	-91	-78
	Dry and Critical	-12	-6	6
All Facilities (CVP, SWP, and Project)[f]				
Energy Generation	Long-Term	9,087	9,316	229
	Dry and Critical	6,422	6,735	313
Energy Use	Long-Term	9,214	9,801	587
	Dry and Critical	6,901	7,732	830
Net Generation	Long-Term	-132	-498	-366
	Dry and Critical	-482	-1,004	-522

[a]Results are estimated using LTGEN, SWP_Power, and NODOS_Power using data from the CALSIM II model.

[b]Because of rounding of the energy values to whole numbers, some differences may appear to be off by +/- one.

[c]Long-Term is the average quantity for the calendar years 1922–2002.

[d]Dry and Critical is the average quantity for dry and critical years according to the Sacramento River 40-30-30 index.

[e]Project Facilities include Tehama-Colusa Canal and GCID Main Canal pumping facilities.

[f]Energy Use and Net Generation for all facilities does not equal the sum of Energy Use and Net Generation for CVP, SWP, and Project facilities because energy use at Red Bluff Pumping Plant is included in both CVP and Project facilities. Results for Red Bluff Pumping Plant from LTGEN are subtracted from Energy Use and Net Generation for all facilities to avoid double-counting.

As presented in Table 31-8, implementation of Alternative B would be anticipated to have similar impacts related to power production and energy use as those described for Alternative A, including total electric demand on CVP, SWP, and Project pumping operations (reductions of 17 GWh and 119 GWh over the long term and during dry and critical water year types, respectively, when compared to Alternative A), and generating capacity (reductions of 13 GWh and 36 GWh over the long term and during dry and critical water year types, respectively, when compared to Alternative A). When compared to Alternative A, the changes in CVP, SWP, and Project operations under Alternative B would result in a slightly reduced net generation over the long term (1 GWh) and a slightly larger reduction (81 GWh) during dry and critical water year types. The net change in generation caused by implementation of Alternative B would, however, be more substantial when compared to the Existing Conditions/No Project/No Action Condition (366 GWh over the long term and 522 GWh during dry and critical water year types). When considered independently, these impacts could be regarded as potentially significant; however, given that power production and energy use impacts are typically considered at the regional level, these changes would constitute approximately 0.2 and 0.3 percent of all generation within the State over the long term and during dry and critical water year types, respectively. In the context of Northern California, these reductions would constitute changes of approximately 1.8 and 2.6 percent, respectively.

When considered in conjunction with the benefits offered (including increased renewable generation and services to better integrate other sources of renewable energy into the grid), the adverse impacts related to power production and energy use associated with Alternative B operations within the Extended and Secondary study areas would be **less than significant** when compared to the Existing Conditions/No Project/No Action Condition.

Impact Power-3: A Substantial Reduction in the Generation of Renewable Energy

Similar to Alternative A, Alternative B would not likely decrease per capita energy consumption in the Extended and Secondary study areas but would promote increased reliance on renewable resources and decreased reliance on fossil fuels through integration of renewable power resources, such as wind and solar. Therefore, Alternative B is expected to promote the use of renewable energy, and would not cause a reduction in generation of renewable energy. Therefore, operation of Alternative B would result in a **less-than-significant impact** to power or energy use when compared to the Existing Conditions/No Project/No Action Condition.

31.2.6.2 Primary Study Area – Alternative B

<u>Construction, Operation, Maintenance, and Recreation Use Impacts</u>

Impact Power-1: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Construction, Maintenance, and Recreation Activities

The impacts associated with Alternative B as they relate to inefficient, wasteful, or unnecessary consumption of energy during construction, maintenance, and recreation activities would be the same as described for Alternative A for the Primary Study Area.

Impact Power-2: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Operational Activities

Despite the larger Sites Reservoir associated with Alternative B, because of the regional nature of electric power grids and potential impacts, and the speculative nature of localized impacts, the impacts associated with Alternative B as they relate to inefficient, wasteful, or unnecessary consumption of energy during operational activities would be the same as those described for Alternative A for the Primary Study Area.

Impact Power-3: A Substantial Reduction in the Generation of Renewable Energy

The impacts associated with Alternative B as they relate to the generation of renewable energy would be the same as those described for Alternative A for the Primary Study Area.

31.2.7 Impacts Associated with Alternative C

31.2.7.1 Extended and Secondary Study Areas – Alternative C

<u>Construction, Operation, Maintenance, and Recreation Use Impacts</u>

Impact Power-1: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Construction, Maintenance, and Recreation Activities

The impacts associated with Alternative C as they relate to inefficient, wasteful, or unnecessary consumption of energy during construction, maintenance, and recreation activities would be the same as described for Alternative A for the Extended and Secondary study areas.

Impact Power-2: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Operational Activities

As shown in Table 31-9, modeling indicates that the addition of Alternative C to the CVP and SWP would cause a net increase in energy consumption of 543 GWh over the long term and a net increase of 649 GWh during dry and critical water year types when compared to the Existing Conditions/No Project/No Action Condition. Table 31-9 does not show the increase in ancillary service production, which would increase system reliability.

Table 31-9
CVP, SWP, and Proposed Project Facilities Energy Use (in GWh)[a] – Alternative C

Parameter	Long-Term Average or Dry and Critical Water Year Type Average	Existing Conditions/ No Project/ No Action Condition	Alternative C	Difference between Alternative C and Existing Conditions/No Project/No Action Condition[b]
CVP Facilities				
Energy Generation	Long-Term[c]	4,701	4,715	14
	Dry and Critical[d]	3,513	3,479	-34
Energy Use	Long-Term	1,116	1,155	40
	Dry and Critical	878	901	24
Net Generation[e]	Long-Term	3,585	3,559	-26
	Dry and Critical	2,635	2,578	-58
SWP Facilities				
Energy Generation	Long-Term	4,386	4,496	110
	Dry and Critical	2,909	3,168	259
Energy Use	Long-Term	8,088	8,473	385
	Dry and Critical	6,013	6,848	834
Net Generation	Long-Term	-3,702	-3,977	-275
	Dry and Critical	-3,104	-3,679	-575
Project Facilities[e]				
Energy Generation	Long-Term	0	157	157
	Dry and Critical	0	173	173
Energy Use	Long-Term	13	278	265
	Dry and Critical	12	199	188
Net Generation	Long-Term	-13	-121	-108
	Dry and Critical	-12	-26	-15
All Facilities (CVP, SWP, and Project)[f]				
Energy Generation	Long-Term	9,087	9,368	281
	Dry and Critical	6,422	6,821	399
Energy Use	Long-Term	9,214	9,901	687
	Dry and Critical	6,901	7,945	1,043

Parameter	Long-Term Average or Dry and Critical Water Year Type Average	Existing Conditions/ No Project/ No Action Condition	Alternative C	Difference between Alternative C and Existing Conditions/No Project/No Action Condition[b]
Net Generation	Long-Term	-132	-543	-412
	Dry and Critical	-482	-1,131	-649

[a]Results are estimated using LTGEN, SWP_Power, and NODOS_Power using data from the CALSIM II model.

[b]Because of rounding of the energy values to whole numbers, some differences may appear to be off by +/- one.

[c]Long-Term is the average quantity for the calendar years 1922–2002.

[d]Dry and Critical is the average quantity for dry and critical years according to the Sacramento River 40-30-30 index.

[e]Proposed Project Facilities include Tehama-Colusa Canal and GCID Main Canal pumping facilities.

[f]Energy Use and Net Generation for all facilities does not equal the sum of Energy Use and Net Generation for CVP, SWP, and Project facilities because energy use at Red Bluff Pumping Plant is included in both CVP and Project facilities. Results for Red Bluff Pumping Plant from LTGEN are subtracted from Energy Use and Net Generation for all facilities to avoid double-counting.

As presented in Table 31-9, implementation of Alternative C would be anticipated to have similar impacts related to power production and energy use as those described for Alternative A, including total electric demand on CVP, SWP, and Project pumping operations (increases of 83 GWh and 94 GWh over the long term and during dry and critical water year types, respectively, when compared to Alternative A), and generating capacity (increases of 39 GWh and 50 GWh over the long term and during dry and critical water year types, respectively, when compared to Alternative A). When compared to Alternative A, the changes in CVP, SWP, and Project operations would result in a slight increase in net generation over the long term (45 GWh) and a similar increase (46 GWh) during dry and critical water year types. The net change in generation caused by implementation of Alternative C would, however, be more substantial when compared to the Existing Conditions/No Project/No Action Condition (412 GWh over the long term and 649 GWh during dry and critical water year types). As discussed under Alternatives A and B, when considered independently, these impacts could be regarded as potentially significant; however, given that power production and energy use impacts are typically considered at the regional level, these changes would constitute approximately 0.2 and 0.3 percent of all generation within the State over the long term and during dry and critical water year types, respectively. In the context of Northern California, these reductions would constitute changes of approximately 2.0 and 3.2 percent, respectively.

When considered in conjunction with the benefits offered (including increased renewable generation and services to better integrate other sources of renewable energy into the grid), the adverse impacts related to power production and energy use associated with Alternative B operations within the Extended and Secondary study areas would be **less than significant** when compared to the Existing Conditions/No Project/No Action Condition.

Impact Power-3: A Substantial Reduction in the Generation of Renewable Energy

Similar to Alternatives A and B, Alternative C would not likely decrease per capita energy consumption in the Extended and Secondary study areas but would promote increased reliance on renewable resources and decreased reliance on fossil fuels through integration of renewable power resources, such as wind and solar. Operation of Alternative C is, therefore, expected to result in a **less-than-significant impact** to power and energy use when compared to the Existing Conditions/No Project/No Action Condition.

31.2.7.2 Primary Study Area – Alternative C

Construction, Maintenance, and Recreation Use Impacts

Impact Power-1: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Construction, Maintenance, and Recreation Activities

The impacts associated with Alternative C as they relate to inefficient, wasteful, or unnecessary consumption of energy during construction, maintenance, and recreation activities would be the same as described for Alternative A for the Primary Study Area.

Impact Power-2: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Operational Activities

Despite the larger Sites Reservoir associated with Alternative C, because the regional nature of electric power grids and potential impacts, and the speculative nature of localized impacts, the impacts associated with Alternative C as they relate to inefficient, wasteful, or unnecessary consumption of energy during operational activities would be the same as those described for Alternative A for the Primary Study Area.

Impact Power-3: A Substantial Reduction in the Generation of Renewable Energy

The impacts associated with Alternative B as they relate to the generation of renewable energy would be the same as those described for Alternative A for the Primary Study Area.

31.2.8 Impacts Associated with Alternative C_1

31.2.8.1 Extended and Secondary Study Areas – Alternative C_1

Construction, Operation, Maintenance, and Recreation Use Impacts

Impact Power-1: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Construction, Maintenance, and Recreation Activities

The impacts associated with Alternative C_1 as they relate to inefficient, wasteful, or unnecessary consumption of energy during construction, maintenance, and recreation activities would be the same as those described for Alternative C for the Extended and Secondary study areas.

Impact Power-2: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Operational Activities

Table 31-10 summarizes the modeling results of the CVP and SWP systemwide effects of Alternative C_1, as well as those related specifically to Project facilities, but Table 31-10 does not identify the increase in ancillary service production, which would serve to increase system reliability.

Table 31-10
CVP, SWP, and Proposed Project Facilities Energy Use (in GWh)[a] – Alternative C_1

Parameter	Long-Term Average or Dry and Critical Water Year Type Average	Existing Conditions/ No Project/ No Action Condition	Alternative C_1	Difference between Alternative C_1 and Existing Conditions/No Project/No Action Condition[b]
CVP Facilities				
Energy Generation	Long-Term[c]	4,701	4,715	14
	Dry and Critical[d]	3,513	3,479	-34
Energy Use	Long-Term	1,116	1,155	40
	Dry and Critical	878	901	24
Net Generation[e]	Long-Term	3,585	3,559	-26
	Dry and Critical	2,635	2,578	-58
SWP Facilities				
Energy Generation	Long-Term	4,386	4,496	110
	Dry and Critical	2,909	3,168	259
Energy Use	Long-Term	8,088	8,473	385
	Dry and Critical	6,013	6,848	834
Net Generation	Long-Term	-3,702	-3,977	-275
	Dry and Critical	-3,104	-3,679	-575
Project Facilities[e]				
Energy Generation	Long-Term	0	0	0
	Dry and Critical	0	0	0
Energy Use	Long-Term	13	278	265
	Dry and Critical	12	199	188
Net Generation	Long-Term	-13	-278	-265
	Dry and Critical	-12	-199	-188
All Facilities (CVP, SWP, and Project)[f]				
Energy Generation	Long-Term	9,087	9,211	124
	Dry and Critical	6,422	6,647	225
Energy Use	Long-Term	9,214	9,901	687
	Dry and Critical	6,901	7,945	1,043
Net Generation	Long-Term	-132	-700	-569
	Dry and Critical	-482	-1,304	-823

[a]Results are estimated using LTGEN, SWP_Power, and NODOS_Power using data from the CALSIM II model.

[b]Because of rounding of the energy values to whole numbers, some differences may appear to be off by +/- one.

[c]Long-Term is the average quantity for the calendar years 1922–2002.

[d]Dry and Critical is the average quantity for dry and critical years according to the Sacramento River 40-30-30 index.

[e]Proposed Project Facilities include Tehama-Colusa Canal and GCID Main Canal pumping facilities.

[f]Energy Use and Net Generation for all facilities does not equal the sum of Energy Use and Net Generation for CVP, SWP, and Project facilities because energy use at Red Bluff Pumping Plant is included in both CVP and Project facilities. Results for Red Bluff Pumping Plant from LTGEN are subtracted from Energy Use and Net Generation for all facilities to avoid double-counting.

As presented in Table 31-10, implementation of Alternative C_1 would be anticipated to have slightly more significant impacts related to power production and energy use than those described for Alternative C, including the same total electric demand on CVP, SWP, and Project pumping operations, but reduced generating capacity, and thus net generation, of 157 GWh and 174 GWh over the long term and during dry and critical water year types, respectively, when compared to Alternative C. Consistent with all alternatives, the net change in generation caused by implementation of Alternative C_1 would be more substantial when compared to the Existing Conditions/No Project/No Action Condition (569 GWh over the long term and 823 GWh during dry and critical water year types). When considered independently, these impacts could be regarded as potentially significant; however, given that power production and energy use impacts are typically considered at the regional level, these changes would constitute approximately 0.3 and 0.4 percent of all generation within the State over the long term and during dry and critical water year types, respectively. In the context of Northern California, these reductions would constitute changes of approximately 2.8 and 4.0 percent, respectively.

When considered in conjunction with the benefits offered (including increased renewable generation and services to better integrate other sources of renewable energy into the grid),the adverse impacts related to power production and energy use associated with Alternative C_1 operations within the Extended and Secondary study areas would be less than significant when compared to the Existing Conditions/No Project/No Action Condition.

Impact Power-3: A Substantial Reduction in the Generation of Renewable Energy

Similar to all alternatives, Alternative C_1 would not likely decrease per capita energy consumption in the Extended and Secondary study areas, but it would promote increased reliance on renewable resources and decreased reliance on fossil fuels because it integrates renewable power resources such as wind and solar. Operation of Alternative C_1 is, therefore, expected to result in a **less-than-significant impact** to power and energy use when compared to the Existing Conditions/No Project/No Action Condition.

31.2.8.2 Primary Study Area – Alternative C_1

Construction, Maintenance, and Recreation Use Impacts

Impact Power-1: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Construction, Maintenance, and Recreation Activities

The impacts associated with Alternative C_1 as they relate to inefficient, wasteful, or unnecessary consumption of energy during construction, maintenance, and recreation activities would be the same as those described for Alternative C for the Primary Study Area.

Impact Power-2: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Operational Activities

As discussed under Alternatives B and C, despite the larger Sites Reservoir associated with Alternative C_1, because of the regional nature of electric power grids and potential impacts, and the speculative nature of localized impacts, the impacts associated with Alternative C_1 as they relate to inefficient, wasteful, or unnecessary consumption of energy during operational activities would be the same as those described for Alternative C for the Primary Study Area.

Impact Power-3: A Substantial Reduction in the Generation of Renewable Energy

The impacts associated with Alternative C_1 as they relate to the generation of renewable energy would be the same as those described for Alternative C for the Primary Study Area.

31.2.9 Impacts Associated with Alternative D

31.2.9.1 Extended Study Area – Alternative D

Construction, Operation, Maintenance, and Recreation Use Impacts

Impact Power-1: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Construction, Maintenance, and Recreation Activities

The impacts associated with Alternative D as they relate to inefficient, wasteful, or unnecessary consumption of energy during construction, maintenance, and recreation activities would be the same as those described for Alternative C for the Extended and Secondary study areas.

Impact Power-2: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Operational Activities

Table 31-11 summarizes the modeling results of the CVP and SWP systemwide effects of Alternative D, as well as those related specifically to Project facilities, but it does not identify the increase in ancillary service production, which would increase system reliability.

Table 31-11
CVP, SWP, and Proposed Project Facilities Energy Use (in GWh)[a] – Alternative D

Parameter	Long-Term Average or Dry and Critical Water Year Type Average	Existing Conditions/No Project/No Action Condition	Alternative D	Difference between Alternative D and No Project/ No Action Condition[b]
CVP Facilities				
Energy Generation	Long-Term[c]	4,701	4,718	18
	Dry and Critical[d]	3,513	3,485	-28
Energy Use	Long-Term	1,116	1,145	29
	Dry and Critical	878	895	17
Net Generation[e]	Long-Term	3,585	3,574	-11
	Dry and Critical	2,635	2,590	-45
SWP Facilities				
Energy Generation	Long-Term	4,386	4,486	100
	Dry and Critical	2,909	3,108	199
Energy Use	Long-Term	8,088	8,424	336
	Dry and Critical	6,013	6,659	645
Net Generation	Long-Term	-3,702	-3,937	-236
	Dry and Critical	-3,104	-3,551	-446
Proposed Project Facilities[e]				
Energy Generation	Long-Term	0	149	149
	Dry and Critical	0	163	163
Energy Use	Long-Term	13	258	245
	Dry and Critical	12	172	160
Net Generation	Long-Term	-13	-108	-95
	Dry and Critical	-12	-9	2

Parameter	Long-Term Average or Dry and Critical Water Year Type Average	Existing Conditions/No Project/No Action Condition	Alternative D	Difference between Alternative D and No Project/ No Action Condition[b]
All Facilities (CVP, SWP, and Project)[f]				
Energy Generation	Long-Term	9,087	9,354	267
	Dry and Critical	6,422	6,756	334
Energy Use	Long-Term	9,214	9,820	606
	Dry and Critical	6,901	7,721	820
Net Generation	Long-Term	-132	-477	-346
	Dry and Critical	-482	-973	-491

[a]Results are estimated using LTGEN, SWP_Power, and NODOS_Power using data from the CALSIM II model.

[b]Because of rounding of the energy values to whole numbers, some differences may appear to be off by +/- one.

[c]Long-Term is the average quantity for the calendar years 1922—2002.

[d]Dry and Critical is the average quantity for dry and critical years according to the Sacramento River 40-30-30 index.

[e]Proposed Project Facilities include Tehama-Colusa Canal and GCID Main Canal pumping facilities.

[f]Energy Use and Net Generation for all facilities does not equal the sum of Energy Use and Net Generation for CVP, SWP, and Project facilities because energy use at Red Bluff Pumping Plant is included in both CVP and Project facilities. Results for Red Bluff Pumping Plant from LTGEN are subtracted from Energy Use and Net Generation for all facilities to avoid double-counting.

As presented in Table 31-11, implementation of Alternative D would be anticipated to have similar impacts related to power production and energy use as those described for Alternative C, including total electric demand on CVP, SWP, and Project pumping operations (reductions of 81 GWh and 223 GWh over the long term and during dry and critical water year types, respectively, when compared to Alternative C), and generating capacity (reductions of 14 GWh and 65 GWh over the long term and during dry and critical water year types, respectively, when compared to Alternative C). When compared to Alternative C, the changes in CVP, SWP, and Project operations under Alternative D would result in a slight increase in net generation over the long term (66 GWh) and a slightly larger increase (158 GWh) during dry and critical water year types. As with other alternatives, the net change in generation caused by implementation of Alternative D would be more substantial when compared to the Existing Conditions/No Project/No Action Condition (346 GWh over the long term and 491 GWh during dry and critical water year types). When considered independently, these impacts could be regarded as potentially significant; however, given that power production and energy use impacts are typically considered at the regional level, these changes would constitute approximately 0.2 and 0.3 percent of all generation within the State over the long term and during dry and critical water year types, respectively. In the context of Northern California, these reductions would constitute changes of approximately 1.7 and 2.4 percent, respectively.

When considered in conjunction with the benefits offered (including increased renewable generation and services to better integrate other sources of renewable energy into the grid), the adverse impacts related to power production and energy use associated with Alternative D operations within the Extended and Secondary study areas would be **less than significant** when compared to the Existing Conditions/No Project/No Action Condition.

Impact Power-3: A Substantial Reduction in the Generation of Renewable Energy

Similar to all alternatives, implementation of Alternative D would not be anticipated to decrease per capita energy consumption in the Extended or Secondary study areas, but it would promote increased reliance on renewable resources and decreased reliance on fossil fuels through integration of renewable power resources, such as wind and solar. Operation of Alternative D is, therefore, expected to result in a **less-than-significant impact** to power and energy use when compared to the Existing Conditions/No Project/No Action Condition.

31.2.9.2 Primary Study Area – Alternative D

Construction, Maintenance, and Recreation Use Impacts

Impact Power-1: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Construction, Maintenance, and Recreation Activities

The impacts associated with Alternative D as they relate to inefficient, wasteful, or unnecessary consumption of energy during construction, maintenance, and recreation activities would be the same as those described for Alternative C for the Primary Study Area.

Impact Power-2: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Operational Activities

As discussed under Alternatives B, C, and C_1, despite the larger Sites Reservoir associated with Alternative D, because of the regional nature of electric power grids and potential impacts, and the speculative nature of localized impacts, the impacts associated with Alternative D as they relate to inefficient, wasteful, or unnecessary consumption of energy during operational activities would be the same as those described for Alternative C for the Primary Study Area.

Impact Power-3: A Substantial Reduction in the Generation of Renewable Energy

The impacts associated with Alternative C as they relate to the generation of renewable energy would be the same as those under Alternative C for the Primary Study Area.

31.3 Mitigation Measures

With continued effective planning for California transmission grid improvements and generation capacity additions, impacts to power production and energy use associated with the construction and operation of the Project would be **less than significant.** Therefore, no mitigation is required or recommended. Potential impacts to other resources such as land use, biological resources, and air quality are addressed in those specific chapters.

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