Appendix A5
Hydropower, Energy Grid, and Export Energy Analyses

A5.1 Introduction

This appendix describes the methods and results for estimating energy effects of changes in hydrology and changes in water supply associated with implementation of the Sacramento/Delta update of the Bay-Delta Plan, including hydropower generation in the Sacramento River watershed and Delta eastside tributaries regions (Sacramento/Delta), an analysis of grid reliability, and energy required for conveyance of Central Valley Project (CVP) and State Water Project (SWP) exports.[1]

Section 7.2, *Description of Alternatives*, provides a description of the alternatives. This appendix describes energy calculations for baseline conditions and for the specific modeled scenarios (35, 45, 55, 65, and 75) that inform the analyses for the proposed Plan amendments (45 to 65 scenarios) and the low and high flow alternatives.

Changes in hydrology include changes in reservoir operations and surface water diversions, which could affect the associated timing and amount of hydropower generation and the energy needed to export water from the Delta. The energy analyses described in this appendix rely on the monthly results from the Sacramento Water Allocation Model (SacWAM). SacWAM results for reservoir elevation, reservoir releases, and Delta exports were used in the hydropower calculations and estimates of energy for Delta exports.

In this appendix, *powerhouse, power plant,* and *hydropower facility* are used interchangeably. Hydropower generation at a powerhouse depends on the flow through the powerhouse as well as the powerhouse head. The *head* is the elevation difference between the reservoir water surface and the channel that carries water away from the powerhouse turbines (i.e., the tailrace). Tailrace elevation at the powerhouse outlet is generally constant unless releases are high, such as during flood-control releases. In addition, reservoir water surface elevation may have little effect on energy generation if reservoir levels are held relatively constant (as what might occur at the small reservoirs formed by diversion dams) or if there is a large vertical drop through a pipeline to the powerhouse.

Hydropower generation was estimated for the 47 largest facilities expected to be affected by the proposed Plan amendments, which represent most of the generating capacity in the Sacramento/Delta.

In general, hydropower generation is expected to increase in spring and decrease in summer as a result of changes in hydrology. To evaluate the potential impacts of reduced summer hydropower generation on the electric grid, a power flow assessment was performed to check grid reliability under peak load (i.e., during peak demand for electricity) and outage contingency scenarios. To further consider grid reliability, the circumstances that led to brief periods of electrical energy

[1] The Sacramento/Delta terminology is used here for brevity even though no hydropower generation occurs in the Delta. Hydropower generation in the Sacramento/Delta occurs upstream of the Delta in the Sacramento River watershed and Delta eastside tributaries region.

shortages that resulted in power curtailments, or blackouts, during August 14 and 15, 2020, are also considered.

Changes in water supply include reduced Sacramento/Delta supply that is exported from the Delta through the CVP and SWP. Conveyance of Delta exports requires operation of pumping plants to move water uphill. Energy use at a pumping plant depends on the flow through the pumping plant and the vertical distance the water is being moved. Because export of Delta water, particularly conveyance of SWP water to southern California, requires much energy, the potential reduction in energy use associated with reduced exports was evaluated. Some of the energy required to convey water over mountains can be recaptured at hydropower facilities on the other side of the mountains. However, the recaptured energy represents only a portion of the total amount used and is included in the estimates of net export energy effects.

Interlinkages between SacWAM, the various analyses described in this appendix, and the resource evaluations are shown on Figure A5-1. SacWAM results provided input to the hydropower calculations and the calculations of energy needed for Delta exports. Power values from the hydropower calculations were used in the power flow assessment of grid reliability for July, a peak demand month with the largest hydropower effects expected from the proposed Plan amendments. The July power values were increased by a peaking fraction to represent the difference between average and peak power during a summer day. The results from the power flow assessment and the results from the calculations of energy from hydropower and energy for exports were used in Section 7.8, *Energy*, and Section 7.10, *Greenhouse Gas Emissions*.

A5.2 Hydropower Generation in the Sacramento/Delta

Each powerhouse may have multiple turbine-generator units, and each of these units may be operated at a range of flows or at full capacity for part of the day for peaking power. Although powerhouse flows and efficiencies may vary hour by hour, calculations based on monthly averages can generally be used to calculate monthly hydropower generation for monthly analysis of reservoir operations.

Two types of calculations were used to estimate monthly hydropower generation at the 47 facilities—flow-and-head-based calculations and flow-based calculations. Flow-and-head-based calculations were used for the four largest facilities expected to be most affected by the proposed Plan amendments due to changes in head and flow. Flow-based calculations were used for the other 43 facilities. The flow-based calculations do not include elevation effects. Elevation was not included for these 43 facilities for the following reasons.

- Many of these facilities are smaller and/or not expected to be affected substantially.
- Many of these facilities do not experience much variability in powerhouse head.
- This analysis is designed to capture the main effects of changes in hydrology under the proposed Plan amendments rather than precise changes that would occur at all affected facilities.

The appropriate use of SacWAM results is described in Chapter 6, *Changes in Hydrology and Water Supply*, and in Appendix A1, *Sacramento Water Allocation Model Methods and Results*. Correspondingly, for the hydropower analysis, actual hydropower operations may vary from the

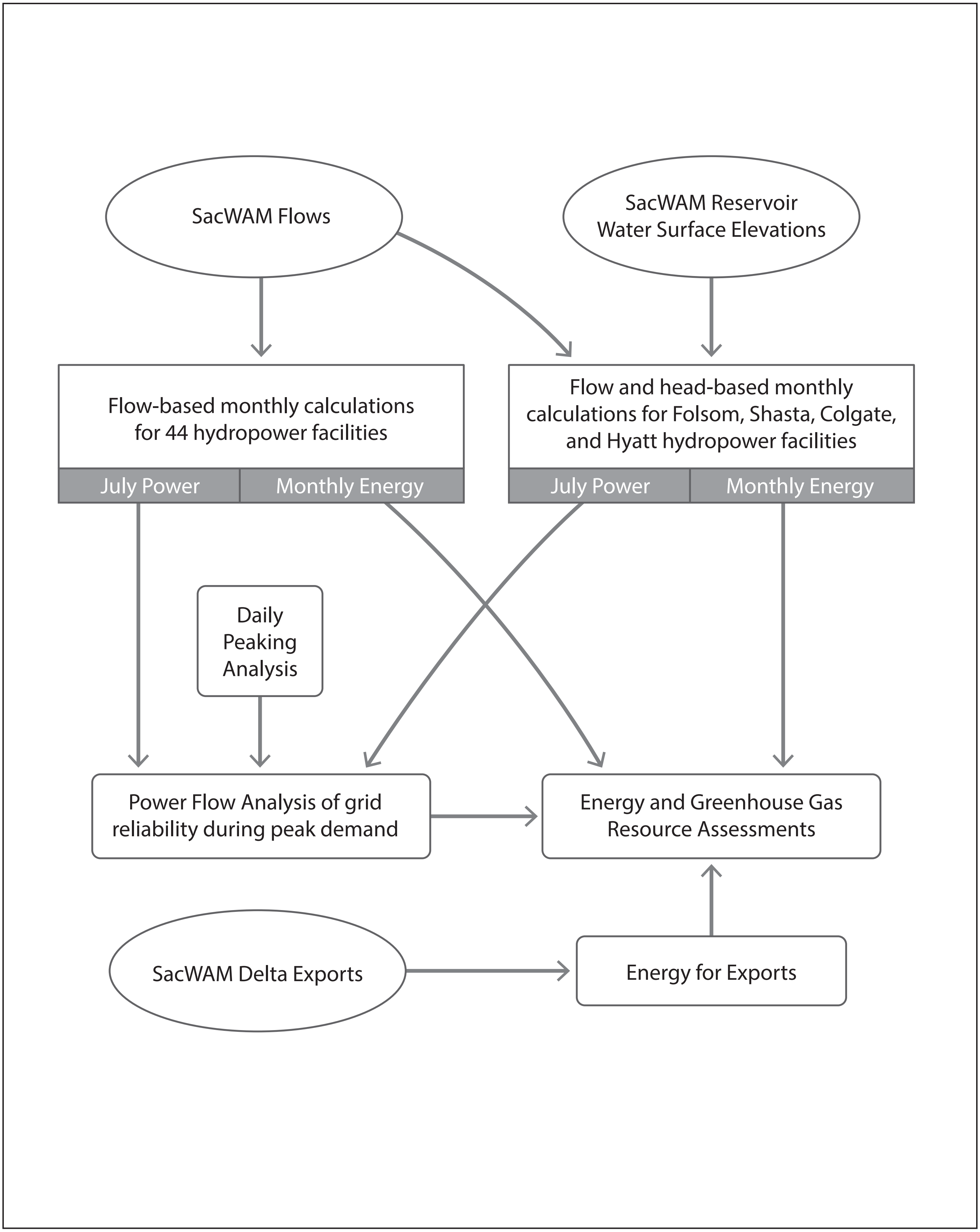

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Figure A5-1
Flowchart of Hydropower Analysis Linkages

modeled operations used to estimate changes in hydropower generation. Real-world operations may differ from simulated operations (e.g., due to equipment failure, flow requirements, or responses to grid demand). In addition, actual hydropower generation may differ from modeled hydropower generation because of inaccuracies in equation parameters or the use of a monthly time step for the analysis; some daily flows may exceed powerhouse capacity when monthly average flows would not. Nevertheless, model results are useful despite inaccuracies because they are good tools for comparing scenarios for relative impacts and they provide insight into the general magnitude and mechanisms of potential effects of changing conditions. For this hydropower assessment, the goal is to estimate changes in hydropower generation in order to assess large-scale effects such as grid reliability. Inaccuracies in results for some facilities do not affect the basic conclusions.

A5.2.1 Hydropower Facilities in the Sacramento/Delta

The proposed Plan amendments could affect hydrology within the Sacramento/Delta and result in changes to hydropower generation. Numerous hydropower generation facilities are located in this area. Figure A5-2 shows the locations of the largest hydropower facilities in the Sacramento/Delta and differentiates those that are eligible for the California Renewables Portfolio Standard (RPS) (described in Section A5.2.1.1, *Hydropower Facilities Included in the California Renewables Portfolio Standard*) from those that are not. Facilities with a summer capacity of 10 megawatts (MW) or less are not shown in the figure and were not included in the hydropower modeling because, although there are many such facilities, they contribute little to overall hydropower generation. Ten MW is also a threshold for the Federal Energy Regulatory Commission (FERC); FERC allows exceptions from licensing for certain hydropower facilities with less than or equal to 10-MW capacity (FERC 2018).

Hydropower generation facilities can be classified as *run-of-the-river powerhouses* or *reservoir powerhouses*. Run-of-the-river powerhouses divert river flow to the turbine and release it downstream, with little or no storage. Reservoir powerhouses use water from a reservoir and release it downstream; the reservoir allows high runoff to be stored and released through the powerhouse. In some cases, run-of-the-river facilities are associated with water interbasin diversions, and the powerhouse may release water to a watershed that is different from the point of origin.

Based on the expected changes in operations, the powerhouses most likely to experience large changes in energy generation in response to the scenarios are the large facilities associated with rim dams and the facilities affected by interbasin diversions. The rim dam powerhouses that generate the most electricity are those associated with Shasta Dam (Shasta Power Plant), Folsom Dam (Folsom Power Plant), Oroville Dam (Edward C. Hyatt Power Plant), and New Bullards Bar Dam (Colgate Powerhouse).

Within the Sacramento/Delta, hydropower facilities are described as being in the lower watershed (extending from the valley floor into the foothills, including the rim reservoirs), in the upper watershed (watersheds above the valley floor, including areas upstream of the rim reservoirs but excluding areas upstream of Shasta Dam), facilities dependent on Trinity River imports (Judge Francis Carr facility and Spring Creek Power Plant), and upstream of Shasta Dam. The facilities are grouped in this manner because the proposed Plan amendments may affect each of these regions differently.

Table A5-1 through Table A5-4 list the hydropower facilities that are in the lower watershed, in the upper watershed, dependent on Trinity River imports, and upstream of Shasta Dam, respectively, sorted by their summer capacity to generate electricity in MW for facilities with capacities greater than 10 MW. Capacity values presented in these tables represent the power that can be generated with full flow and elevation drop (head). These values represent summer capacity, which is generally similar to winter capacity and somewhat different from nameplate capacity, which is the capacity designation from the manufacturer. Summer and winter capacity are estimates of actual capacity under real operation and thermal conditions. Energy generation in megawatt hours (MWh) is an expression of actual power produced through time. The total capacity from facilities with capacities greater than 10 MW is 5,821 MW in the Sacramento/Delta. Many smaller facilities in the Sacramento/Delta have a combined capacity of 232 MW, bringing the total capacity to 6,053 MW (approximately 6 gigawatts [GW]). These smaller facilities are generally not required to obtain FERC licenses.

Table A5-1. Hydropower Facilities in the Lower Watershed with Capacity Greater than 10 Megawatts

Powerhouse	Summer Capacity (MW)	Percent of Power Capacity in Lower Watershed [a]	Tributary	Location Relative to Rim Dams
Hyatt (Lake Oroville)	743	31.4	Feather River	Rim dam
Shasta	714	30.2	Sacramento River	Rim dam
Colgate (New Bullards Bar Reservoir)	315	13.3	Yuba River	Rim dam
Folsom	215	9.1	American River	Rim dam
Keswick	117	4.9	Sacramento River	Downstream
Thermalito	116	4.9	Feather River	Downstream
Narrows 1 and 2	67	2.8	Yuba River	Downstream
Pardee	28	1.2	Mokelumne River	Rim dam
Nimbus	17	0.7	American River	Downstream
Coleman	13	0.5	Battle Creek	Downstream
Monticello	13	0.5	Putah Creek	Rim dam
Camanche	10	0.4	Mokelumne River	Rim dam
Capacity at the four largest facilities	1,987	83.8		
Total capacity in lower watershed	2,368	100.0		

Source: Summer capacity from ^ABB 2017.
Numbers may not total correctly because of rounding.
MW = megawatt
[a] Percent of power capacity values are calculated values based on the summer capacity of each hydropower facility.

Table A5-2. Hydropower Facilities in the Upper Watershed with Capacity Greater than 10 Megawatts

Powerhouse	Summer Capacity (MW)	Percent of Power Capacity in Upper Watershed [a]	Tributary [b]
White Rock	241	10.5	South Fork American River
Caribou No. 1 and No. 2	196	8.6	North Fork Feather River

Powerhouse	Summer Capacity (MW)	Percent of Power Capacity in Upper Watershed [a]	Tributary [b]
Jaybird	156	6.8	Silver Creek/South Fork American River
Camino	156	6.8	Silver Creek/South Fork American River
Poe	138	6.0	North Fork Feather River
Rock Creek	126	5.5	North Fork Feather River
Middle Fork	122	5.3	Rubicon River to Middle Fork American River
Belden	119	5.2	North Fork Feather River
Drum 1 and 2	104	4.5	Yuba and American Rivers to Bear River
Electra	99	4.3	North Fork Mokelumne River
Ralston	86	3.8	Middle Fork American River
Loon Lake	74	3.2	Gerle Creek/Middle Fork American River
Cresta	70	3.1	North Fork Feather River
Bucks Creek	65	2.8	North Fork Feather River
Tiger Creek	62	2.7	North Fork Mokelumne River
Woodleaf	59	2.6	South Fork Feather River
Salt Springs	44	1.9	North Fork Mokelumne River
Chicago Park	42	1.8	Bear River
Butt Valley	40	1.7	North Fork Feather River
Union Valley	39	1.7	Silver Creek/South Fork American River
Forbestown	36	1.6	South Fork Feather River
Dutch Flat No. 2	27	1.2	Bear River
Robbs Peak	26	1.1	Middle Fork American River (Rubicon Basin) to South Fork American River (Silver Creek)
Grizzly	23	1.0	Bucks Creek/North Fork Feather River
Dutch Flat No. 1	22	1.0	Bear River
De Sabla	19	0.8	Feather River to Butte Creek
Wise	17	0.8	Bear River to Auburn Ravine and American River
French Meadows	15	0.7	Middle Fork American River to Rubicon River
Forks of Butte	14	0.6	Feather River to Butte Creek
West Point	14	0.6	North Fork Mokelumne River
Halsey	14	0.6	Bear River to Auburn Ravine and American River

Powerhouse	Summer Capacity (MW)	Percent of Power Capacity in Upper Watershed [a]	Tributary [b]
Rollins	12	0.5	Bear River
Newcastle	12	0.5	Bear River to American River
Total capacity in upper watershed	2,290	100.0	

Source: Summer capacity from ^ABB 2017.
Numbers may not total correctly because of rounding.
MW = megawatt
[a] Percent of power capacity values are calculated values based on the summer capacity of each hydropower facility.
[b] The addition of “to” in a tributary description indicates that the powerhouse occurs along a conduit that conveys water from one major watershed to another.

Table A5-3. Hydropower Facilities Dominated by Trinity River Imports

Powerhouse	Summer Capacity (MW)	Percent of Power Capacity [a]	Tributary [b]
Spring Creek	180	50.4	Clear Creek, although much of the water originates from the Trinity River
Judge Francis Carr	177	49.6	Trinity River to Sacramento River
Total capacity dependent on Trinity River	357	100.0	

Source: Summer capacity from ^ABB 2017, page ref. n/a.
Numbers may not total correctly because of rounding.
MW = megawatt
[a] Percent of power capacity values are calculated values based on the summer capacity of each hydropower facility.
[b] The addition of “to” in a tributary description indicates that the powerhouse occurs along a conduit that conveys water from one major watershed to another.

Table A5-4. Hydropower Facilities Upstream of Shasta Dam with Capacity Greater than 10 Megawatts

Powerhouse	Summer Capacity (MW)	Percent of Power Capacity Upstream of Shasta Dam [a]	Tributary
James B. Black	169	21.6	Pit River
Pit 5	164	20.1	Pit River
Pit 7	110	14.0	Pit River
Pit 4	102	11.9	Pit River
Pit 6	79	10.0	Pit River
Pit 3	70	8.6	Pit River
Pit 1	64	7.9	Pit River
Muck Valley	30	3.7	Pit River
Hat Creek No. 1 and No. 2	17	2.2	Hat Creek/Pit River
Total capacity of facilities upstream of Shasta Dam	805	100.0	

Source: Summer capacity from ^ABB 2017.
Numbers may not total correctly because of rounding.
MW = megawatt
[a] Percent of power capacity values are calculated values based on the summer capacity of each hydropower facility.

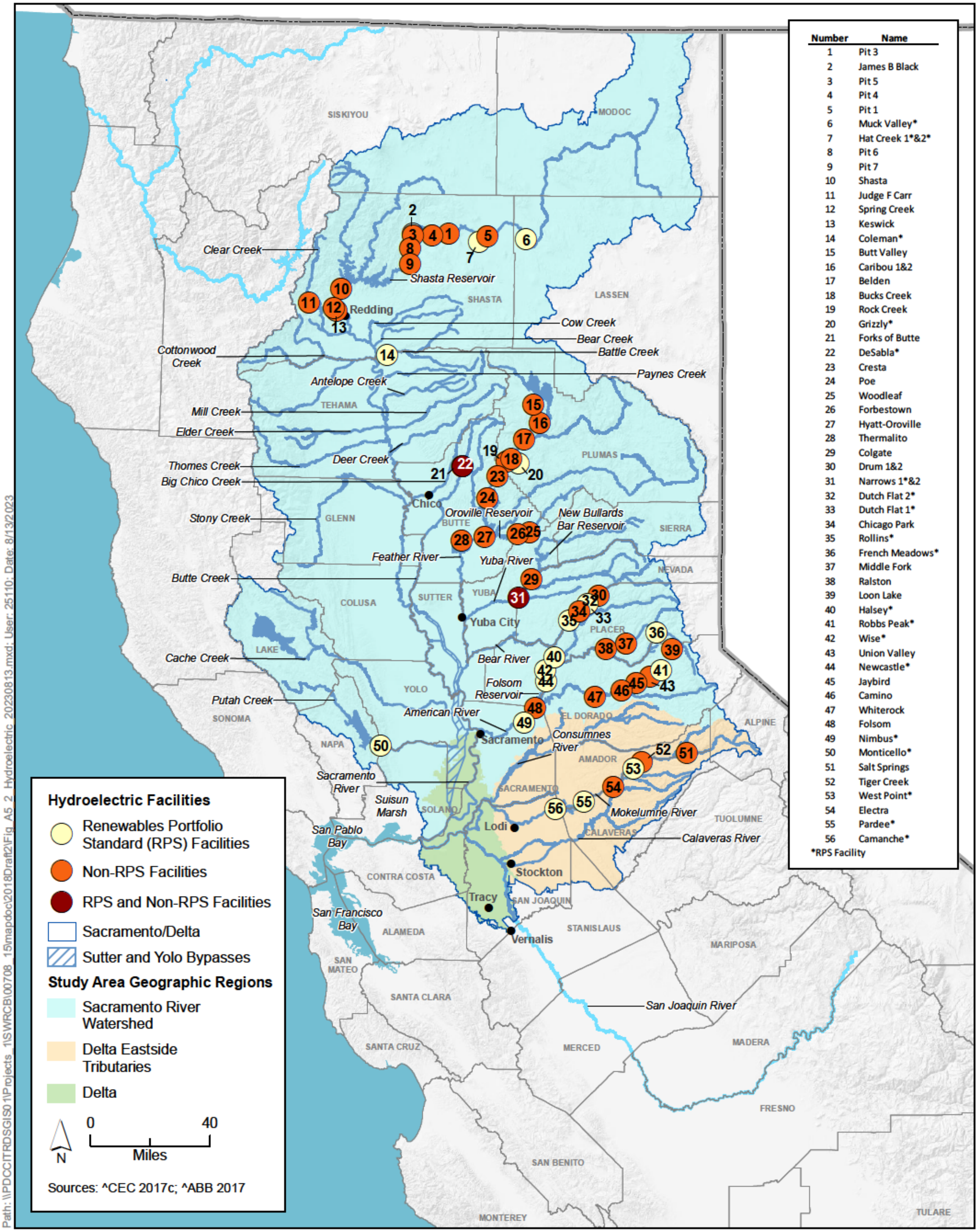

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Figure A5-2
The Largest Hydroelectric Facilities in the Sacramento/Delta

A5.2.1.1 Hydropower Facilities Included in the California Renewables Portfolio Standard

The California Public Utilities Commission (CPUC) administers the RPS, which was established in 2000. With the passage of Senate Bill (SB) 100 (De León), Statutes of 2018, amended Public Utilities Code sections 399.11, 399.15, and 399.30, 60 percent of California's electricity is required to be supplied by renewable energy by 2030. Only certain small hydropower facilities are included in the renewables portfolio. Facilities with more than 30 MW of generation capacity are called *large hydropower facilities*; facilities with less than 30 MW of generation capacity are considered *small hydropower facilities* and are part of the RPS (^CEC 2017b, ^CEC 2017c). Twenty of the hydropower facilities listed in Table A5-1 through Table A5-4 are approved sources of renewable energy under the RPS (Table A5-5). SB 100 and SB 1020 (Laird)[2] also include a provision that 100 percent of electricity should be carbon free by 2045. SB 1020 further requires state agencies to rely on 100 percent renewable energy and zero-carbon resources to serve their own facilities by 2035. Other carbon-free energy sources such as large hydropower facilities that are not part of the RPS can contribute to the attainment of these goals.

The small hydropower facilities listed in Table A5-5 represent a 343.3-MW total summer capacity, corresponding to about 6 percent of the 5,821-MW total summer capacity of the hydropower facilities in the Sacramento/Delta with summer capacity greater than 10 MW. In addition, all the hydropower facilities in the Sacramento/Delta with less than a 10-MW summer capacity (with a combined summer capacity of 232 MW) are RPS-approved. As described in Section A5.2.1.2, *Hydropower Facilities Modeled*, none of these smaller facilities were included in the hydropower modeling, but all of the facilities in Table A5-5 except Coleman and Forks of Butte were included. Coleman and Forks of Butte were not included because they are not represented in SacWAM. In the discussion of estimated changes in hydropower generation for RPS facilities, consideration is given to the facilities that were not modeled.

Table A5-5. California Renewables Portfolio Standard-Approved Hydropower Facilities in the Sacramento/Delta with Capacity Greater than 10 Megawatts

Powerhouse	Nameplate Capacity (MW)	Summer Capacity (MW)
Camanche	10.8	10.3
Coleman	12.2	13
De Sabla	18.5	19
Dutch Flat No. 2	24.57	27
Dutch Flat No. 1	22	22
French Meadows (Placer County Water Agency)	15.3	17
Grizzly	17.66	23
Halsey	12	14
Hat Creek No. 1	10	8.5
Hat Creek No. 2	10	8.5
Monticello (Solano Irrigation District)	11.9	13

[2] This act amended Government Code section 7921.505, amended Health and Safety Code section 38561, amended Public Utilities Code sections 454.53 and 583, added Public Utilities Code sections 454.59 and 739.13, and added Water Code Division 27.5 (commencing with section 80400).

Powerhouse	Nameplate Capacity (MW)	Summer Capacity (MW)
Muck Valley	29.9	30
Narrows 1	9.4	12
Newcastle	12.7	12
Nimbus	15	17
Pardee	23.6	28
Robbs Peak	29.5	26
Rollins	12.15	12
West Point	13.6	14
Wise	12	17
Total capacity	322.78	343.3

Sources: ^CEC 2017c; ^ABB 2017.
Numbers may not total correctly because of rounding.
MW = megawatt
Seventy-three additional facilities with a combined net summer capacity of 232 MW are present in the Sacramento/Delta; these facilities are Renewables Portfolio Standard-approved and have capacity less than or equal to 10 MW. Fifteen of these facilities, with a combined capacity of 31 MW, are located upstream of Shasta Dam.

A5.2.1.2 Hydropower Facilities Modeled

The analysis of hydropower effects focused on the 47 largest facilities expected to be affected by changes in hydrology. The 47 facilities consist of the following.

- 12 facilities listed in Table A5-1 (all except Coleman).
- 34 facilities listed in Table A5-2 (all except Forks of Butte).
- Spring Creek, which is listed in Table A5-3.

The power capacity of these facilities represents 79.4 percent of the total hydropower capacity in the Sacramento/Delta.

Approximately 16.8 percent of the remaining hydropower capacity is at facilities not expected to be affected by the type of hydrologic changes likely to occur with the proposed Plan amendments. These facilities include the Judge Francis Carr facility, which is powered by imports from the Trinity River watershed, and the facilities upstream of Shasta Dam. Operations upstream of Shasta Dam are not included in SacWAM because hydrology and hydropower generation in this area are not expected to change much in response to the proposed Plan amendments, as explained in Chapter 2, *Hydrology and Water Supply*.

The remaining 3.8 percent of the hydropower capacity in the Sacramento/Delta is at facilities that might be affected by the type of hydrologic changes modeled by SacWAM but were not included in SacWAM because of their small size, including facilities with capacities of 10 MW or less; Coleman Powerhouse on Battle Creek (capacity of 13 MW); and Forks of Butte Powerhouse on Butte Creek (capacity of 14 MW). Effects associated with changes in hydropower generation at these facilities are unlikely to affect any conclusions because of their small contribution to total hydropower and because changes at these facilities are somewhat less likely than at other facilities since many are run-of-the-river facilities or are in waterbodies unlikely to be affected by the proposed Plan amendments. These small facilities are considered in the evaluation of RPS facilities described in

Section A5.2.5.3, *Effects at Small Hydropower Facilities that Contribute to the California Renewables Portfolio Standard*.

A5.2.2 Flow-and-Head-Based Calculations

For the four largest facilities expected to be most affected by changes in hydrology, changes in flow and reservoir storage and hydropower generation were calculated based on flow through the turbines, powerhouse efficiency, and head. This approach was used for Folsom, Shasta, Hyatt (Lake Oroville), and Colgate (New Bullards Bar) Power Plants. Total power capacity at these four facilities is 1,987 MW, or approximately 33 percent of the total hydropower capacity in the Sacramento/Delta (based on summer capacity values from ^ABB 2017).

The overall powerhouse efficiency includes the turbine efficiency (converting potential energy to mechanical energy) and the electrical generator efficiency (converting mechanical energy to electrical energy). Most powerhouse efficiencies are greater than 75 percent and some powerhouse efficiencies may approach 95 percent. Although daily reservoir releases are quite variable during some months, such as during flood-control operations, the powerhouse flow was assumed to be the monthly average release flow, until the monthly flow is greater than the powerhouse flow capacity. The powerhouse flow capacity can be calculated from the energy generation capacity (MW), the maximum head, and the average efficiency. Although the generation efficiency of each turbine-generator unit generally declines with reduced flow, the powerhouse efficiency was assumed to remain constant at lower flows because the units would normally be operated at full capacity for several hours each day to optimize efficiency and increase generation during periods of peak demand for electricity.

The logic for calculating the hydropower generation as water moves downhill or the energy required for pumping water uphill (relevant to the export pumping energy analysis in Section A5.4, *Energy Use for SWP and CVP Export Pumping*) is based on the potential energy of water that is lifted or lowered a specified elevation (feet). The fact that raising 1 thousand acre-feet (TAF) of water 1 foot in elevation requires 1.024 MWh leads to the following general flow-and-head-based equation that is applicable to all hydropower facilities or pumping plants:

Energy (MWh) = 1.024 (MWh/feet*TAF) x Head (feet) x Volume (TAF) x Efficiency.

For facilities with a substantial distance between the dam and the powerhouse, the friction in the tunnel and/or penstock can be represented as a head loss, which is subtracted from the total water elevation difference (head). For example, the Colgate Powerhouse on the Yuba River is about 5 miles downstream of New Bullards Bar Reservoir. At full ratedcapacity of about 3,400 cubic feet per second (cfs), the tunnel and penstock are reported to have a head loss of about 80 feet (YCWA 2014). A head loss of 30 feet was used in the hydropower calculations because it produced a better overall match with measured hydropower generation.

The efficiency can be measured for each powerhouse unit at a range of flows and heads; the overall efficiency of a powerhouse can be estimated by comparing the energy to the head and the water volume:

Efficiency = Energy (MWh) / (Head [feet] x Volume [TAF] x 1.024 [MWh/feet*TAF]).

A powerhouse generates less electrical energy than the potential energy of the released water (i.e., efficiency is always less than 100 percent), and pumping plants are less efficient than powerhouses. Overall efficiency of a pumped-storage cycle ranges from 60 to 80 percent (CEC 2016). Efficiency changes over the range of turbine flows and heads and for different turbines (e.g., Pelton wheel, Francis turbine, Kaplan turbine), but the average efficiency at the maximum head and maximum flow can be used to compare units.

Normal powerhouse operations attempt to maximize the generation by operating units at relatively high flows for part of each day (peaking power); therefore, the daily average powerhouse efficiencies are often nearly constant. As a result, the energy generated at each powerhouse generally can be accurately estimated using a flow-and-head-based equation.

Some constraints on energy generation are incorporated into the calculations. Installed capacity (MW) at a powerhouse is indicative of energy generation at the facility because the turbines have been selected to generally match the available head and release flows. However, reservoir releases during some months could exceed the powerhouse turbine capacity because of flood-control releases. The energy generation can be calculated from monthly average head and monthly average release flow, with the constraint that flood-control releases causing flows greater than powerhouse capacity do not produce energy above the maximum capacity. In addition, no energy is generated when reservoir elevation is too close to the powerhouse intake elevation. Storage may drop below this elevation during drought operations if there is a river outlet at a lower elevation than the penstock; these releases would bypass the powerhouse. The flow-and-head-based energy calculation method includes a minimum elevation for energy generation; the minimum elevation for energy generation is the penstock intake elevation plus a submergence depth to prevent entrainment of air bubbles or debris that could damage equipment.

The next sections describe development and validation of flow-and-head-based equations for Folsom, Shasta, Colgate, and Hyatt Power Plants. These equations are compared with the more complex energy calculations in the CVP Long-Term Generation (LTG) monthly model for Folsom Power Plant and Shasta Power Plant and the energy calculations in the SWP monthly model for the Hyatt Power Plant at the Oroville Dam on the Feather River. In addition, the performance of the flow-and-head-based equations is further evaluated by comparing energy calculated using historical hydrologic data with historical energy measurements. Evaluating the performance of the calculations is important primarily for checking the accuracy of the components of the equation. Comparing equation results with results from other energy models or measured data is useful for checking that assumptions about efficiency, reservoir elevation as a function of storage, tailrace elevation, maximum turbine flow, and restrictions on generation at low reservoir elevations are reasonable.

A5.2.2.1 CVP Long-Term Generation Energy Model and SWP Energy Model

Flow-and-head-based equations for Shasta, Folsom, and Hyatt (Lake Oroville) Power Plants were developed using information from spreadsheet models developed by the California Department of Water Resources (DWR) and U.S. Bureau of Reclamation (Reclamation). These spreadsheets were originally developed by Surface Water Resources, Inc., for the Western Area Power Administration (WAPA), Reclamation, and DWR. These CalSim energy post-processors were a part of the common model package used by state and federal agencies, and similar analyses used by public agencies, engineering firms, and water districts, to support local water planning and environmental studies (Bates 2010). These models were developed to estimate CVP and SWP energy generation and pumping based on monthly reservoir storage and flow results from the CalSim hydrologic model. The CVP LTG energy spreadsheet model includes the CVP pumping plants (electrical motors and pumps) as well as the energy generation facilities (turbines and electrical generators). The SWP energy spreadsheet includes the energy generation and energy use at SWP facilities. Other California hydropower facilities and water pumping plants are not included in the CVP and SWP energy computation spreadsheets.

The flow-and-head-based equations use the same method for estimating tailrace elevation as the LTG and SWP models. In the LTG model, tailrace elevations for Folsom and Shasta Power Plants vary as a function of flow because high flows result in deeper water below the dam. Some effects of higher flows on the tailrace elevation occur at the Hyatt Power Plant, but these effects were not included in the SWP power model. Variation in tailrace elevation has little effect on power generation because variation in reservoir elevation is much greater than variation in tailrace elevation and because flood-control releases, which have the most effect on tailrace elevation, generally coincide with high reservoir storage.

The CVP LTG energy model, the SWP energy model, and the flow-and-head-based equations all use similar restrictions for estimating flow through the powerhouses. If the release flow is less than the highest potential powerhouse flow, the powerhouse flow is the release flow; if the release flow is greater than the highest powerhouse flow, the powerhouse flow is the highest potential powerhouse flow, and the remainder of the release flow is spill. The differences between daily operations and monthly average operations are usually small, except in months with flood-control releases. In these months, the daily powerhouse flows may be less than the highest potential powerhouse flows until flood-control releases are made. Generally, the energy generation calculated with monthly average flows is close to the energy generation calculated with daily flows.

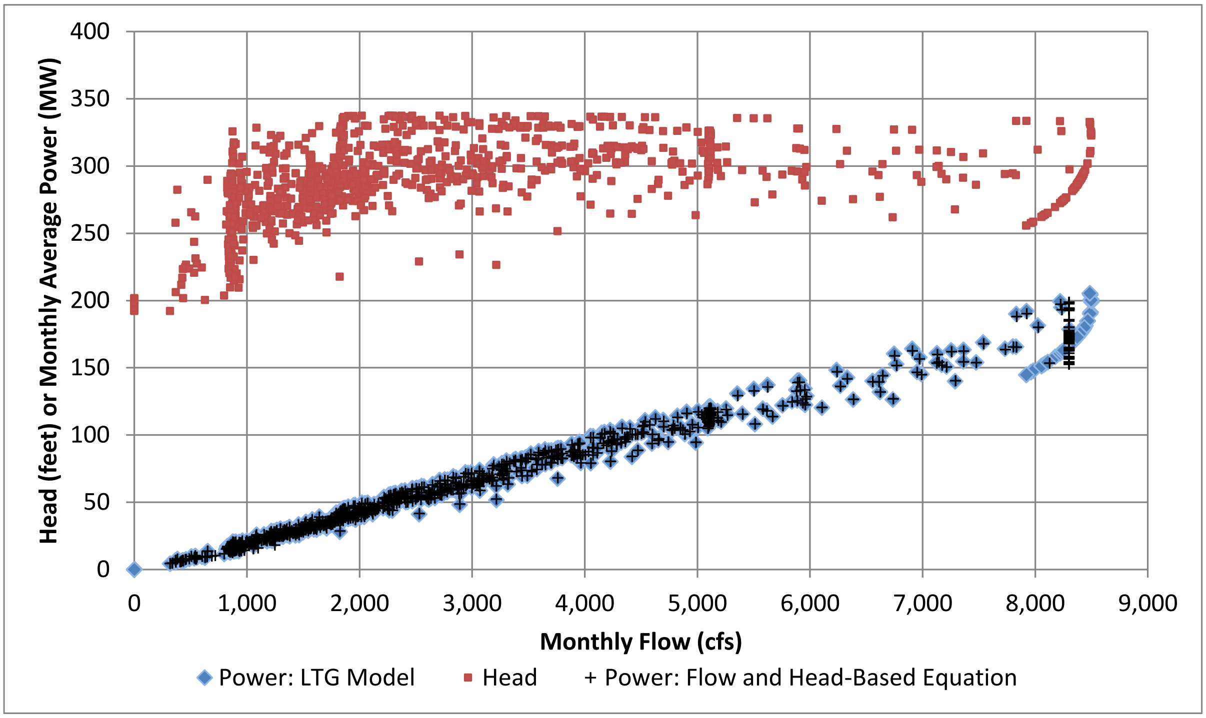
Some differences exist between the estimates of maximum possible flow through turbines. In the CVP LTG model, the highest potential powerhouse flow depends on head, whereas the flow-and-head-based equations use a constant value. However, the maximum powerhouse flow rarely limits monthly energy during months with low storage because reservoir release flows tend to be lower when the reservoir elevation is lower.

The calculations in the LTG and SWP spreadsheets are more complex than flow-and-head-based equations, primarily because efficiency is variable in the LTG and SWP spreadsheets. However, a comparison of results from these spreadsheets to results from flow-and-head-based equations indicates that the flow-and-head-based equations can generate results similar to the spreadsheets. Using the simpler flow-and-head-based equations for Shasta, Folsom, and Hyatt Power Plants is, therefore, preferred. Simpler equations not only lead to the same basic conclusions as the more complex analysis while being easier to use, but they are also compatible with the simple-equation approach used for other hydropower facilities analyzed in the Sacramento/Delta that did not have complex analysis spreadsheets available.

A5.2.2.2 Folsom Power Plant Energy Calculations

The 1922–2003 CalSim case in the LTG spreadsheet was used to compare the LTG energy calculations for Folsom Power Plant with the flow-and-head-based equation for Folsom Power Plant. The flow-and-head-based equation of Folsom Power Plant energy is similar to the more involved calculations of the CVP LTG model, but the efficiency is assumed to be constant at any head; the maximum energy generation capacity (power in MW) is assumed to decrease linearly with the head; and the maximum powerhouse flow is assumed to remain constant at any head. To cover concepts that do not need to be repeated for all reservoirs, this Folsom Power Plant evaluation is more detailed than the evaluations for Shasta and Hyatt Power Plants.

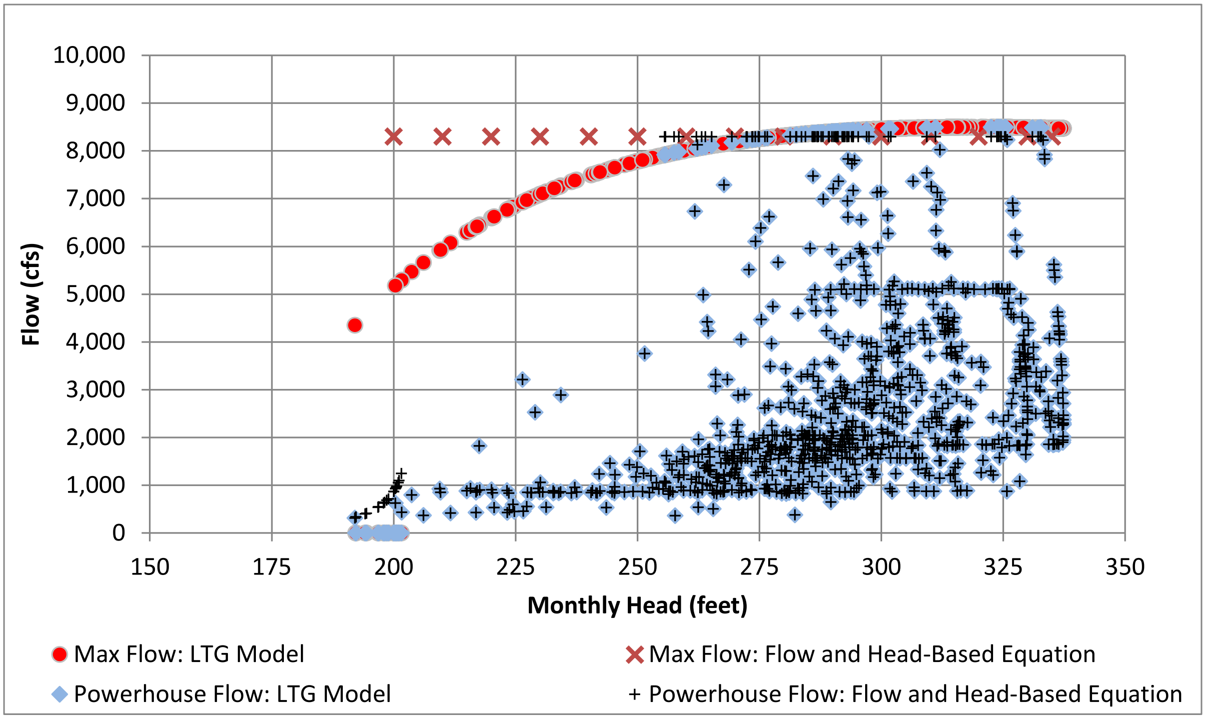
Figure A5-3 shows the monthly results from the CVP LTG model for the Folsom Power Plant, plotted as a function of the monthly average flow. The powerhouse flow varies from 0 cfs to about 8,500 cfs. At the highest flows, the effect of higher heads on the maximum turbine flow and power (and energy generation) is evident in the "arc" for head and power. Power calculated by the flow-and-head-based equation is also shown in Figure A5-3. The flow-and-head-based equation used a constant maximum possible flow of approximately 8,300 cfs (Table A5-6) without dependence on head, so no arc is present. The Folsom Power Plant operated at an overall average of 32 percent of capacity, which is a necessary trade-off for the wide range of runoff conditions in California. The installed capacity must be great enough to capture most of the release flows in most years.



Power calculations were made with both the LTG monthly model and the flow-and-head-based equation using 1922–2003 CalSim example hydrology.
cfs = cubic feet per second; LTG = Long-Term Generation; MW = megawatt

Figure A5-3. Calculated Monthly Average Power at Folsom Power Plant in Relation to Monthly Flow and Head

Figure A5-4 shows the monthly powerhouse flows from the CVP LTG model for the Folsom Power Plant, plotted as a function of the monthly average head. The maximum turbine flow in the LTG model decreases with the head, from a maximum of 8,500 cfs with a head of 300 feet or more, to about 7,000 cfs with a head of 225 feet, and to about 5,000 cfs at a minimum head of 200 feet. Because the Folsom Power Plant flow capacity is much greater than the average release flow, rarely were the powerhouse flows limited by the turbine flow capacity. Although the LTG model has a reduced maximum flow at lower heads and the flow-and-head-based energy model has a constant maximum flow, this difference is not important for the energy calculations because at lower storage levels, the release flows generally remain well below the maximum flow.

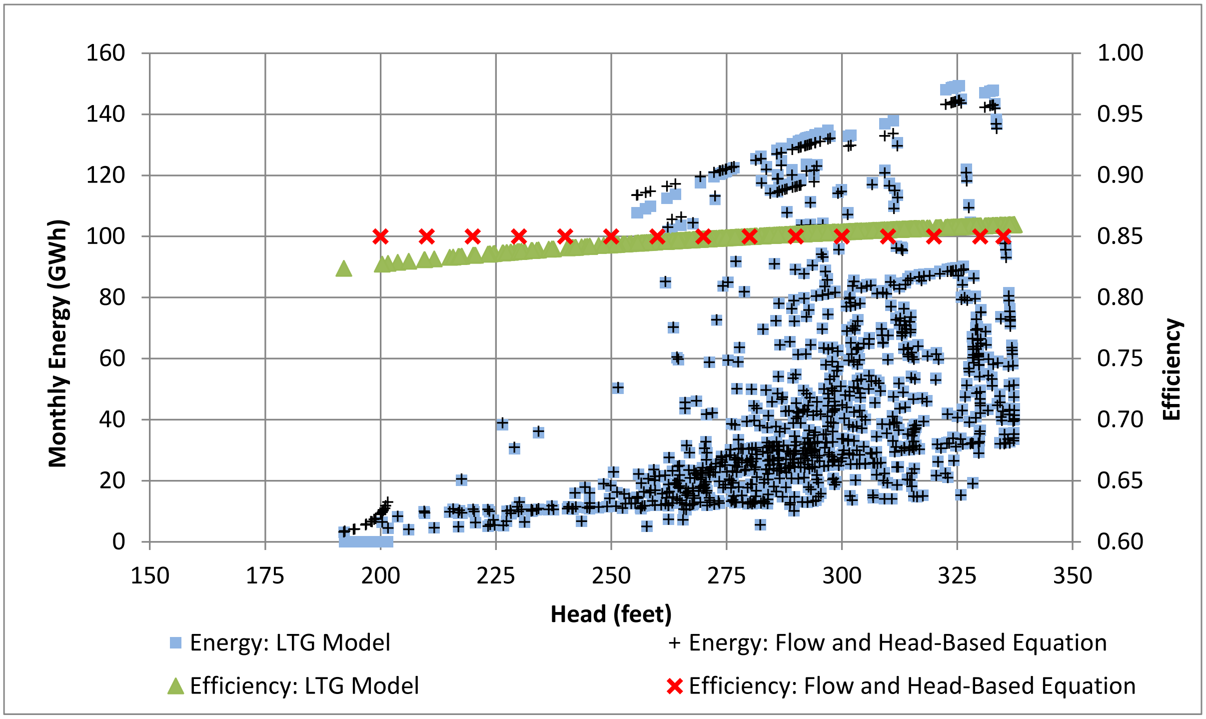


Powerhouse flow and maximum flow were calculated with both the LTG monthly model and the flow-and-head-based equation using 1922–2003 CalSim example hydrology.
cfs = cubic feet per second; LTG = Long-Term Generation; MWh = megawatt hour; TAF = thousand acre-feet

Figure A5-4. Calculated Folsom Power Plant Flow in Relation to Monthly Head

The LTG model has slightly reduced efficiencies at lower heads, while the flow-and-head-based equation uses a constant efficiency of 0.85, but this difference does not have a major effect on the calculated energy. Efficiency may be lower at low flows through the turbines, but powerhouses are typically operated to maintain high efficiency, either through peaking operations or reducing number of turbines in operation during periods of low flow.

Figure A5-5 shows the monthly energy calculated with the LTG model and the flow-and-head-based energy equation for the Folsom Power Plant, plotted as a function of the monthly average head. The monthly energy was determined primarily by the turbine flow, which can vary from less than 1,000 cfs to about 8,300 cfs. The CVP LTG Folsom Power Plant efficiency was calculated to vary from 0.84 at lower heads to 0.86 at higher heads. A constant efficiency of 0.85 was used for the flow-and-head-based energy equation.

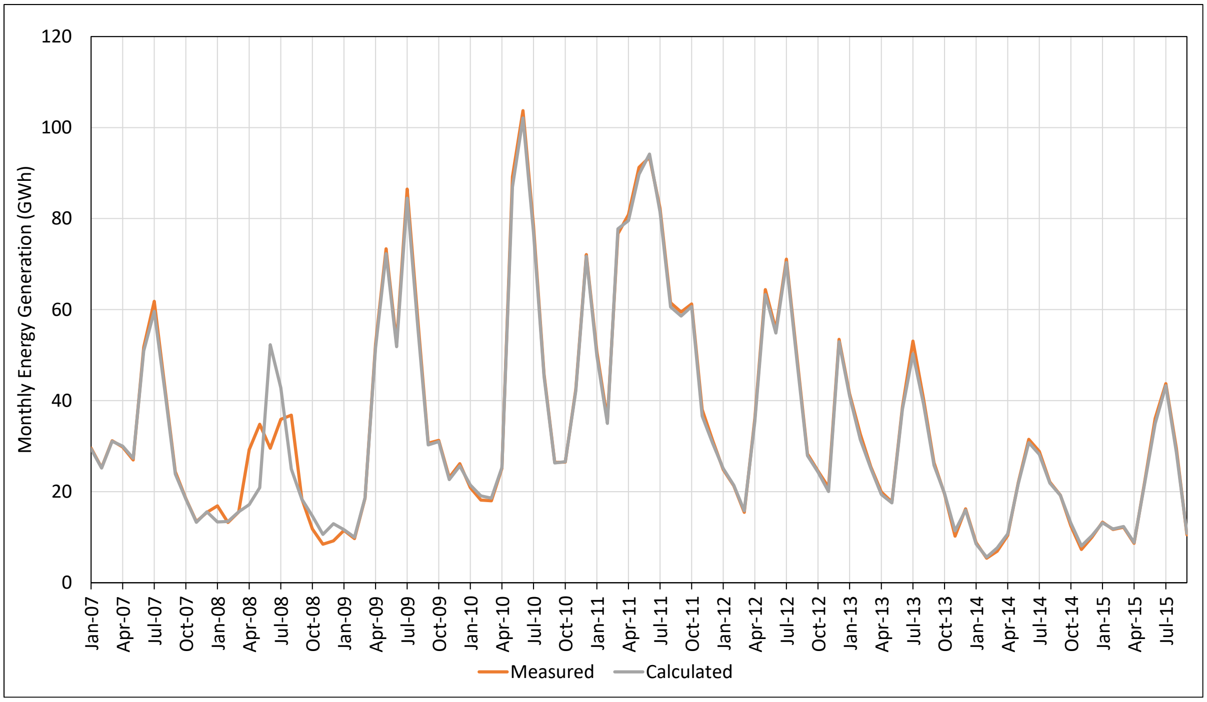


Energy was calculated with both the LTG monthly model and the flow-and-head-based equation using 1922–2003 CalSim example hydrology.
GWh = gigawatt hour; LTG = Long-Term Generation

Figure A5-5. Calculated Energy and Efficiency in Relation to Monthly Head at Folsom Power Plant

For the 1922–2003 CalSim case in the LTG spreadsheet, the results from the LTG spreadsheet calculations and the flow-and-head-based equation are nearly identical. The variations in efficiency and maximum turbine flow as a function of head that are included in the CVP LTG model are not necessary for the comparative evaluation of reservoir operations. Using the flow-and-head-based energy equation, average annual energy generation was 558 GW hours (GWh) per year (GWh/yr). This result was nearly equivalent to the CVP LTG energy model results of 560 GWh/yr. This comparison confirms that the flow-and-head-based energy equation is adequate for estimating the monthly energy generation at Folsom Power Plant.

As further confirmation of the approach for calculating hydropower generation at Folsom Reservoir, monthly measured hydropower generation for Folsom Reservoir was compared with values calculated using the flow-and-head-based equation, with monthly average measured reservoir elevation and flow through the powerhouse as input (Figure A5-6). The calculated values match the measured values well (root mean square error [RMSE] = 3.3 GWh), in part due to the availability of data for flow through the powerhouse. If powerhouse flows had not been available, the calculated values would have been based on reservoir release data and would have been higher than the measured values during times when the powerhouse was not used at full capacity.



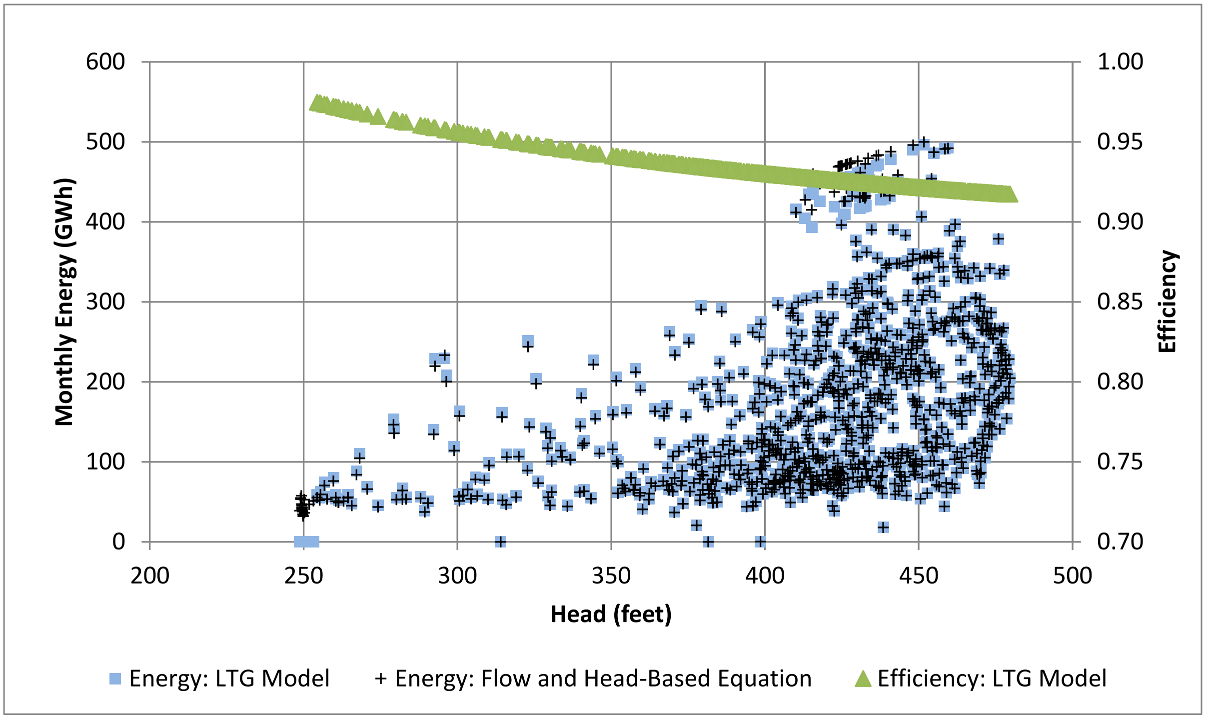
Sources: Hydropower generation from ^EIA 2017; reservoir elevation and powerhouse flow from DWR 2018.
GWh = gigawatt hour

Figure A5-6. Comparison of Measured and Calculated Hydropower Generation at Folsom Reservoir for 2007–2015

A5.2.2.3 Shasta Power Plant Energy Calculations

The 1922–2003 CalSim case in the LTG spreadsheet was used to compare the LTG energy calculations for Shasta Power Plant with the flow-and-head-based equation for Shasta Power Plant. Figure A5-7 shows the calculated monthly energy (GWh) for the CVP LTG model and for the flow-and-head-based energy equation, and the calculated powerhouse efficiency for the CVP LTG model as a function of the monthly head for the 1922–2003 hydrology. The flow-and-head-based equation used a constant efficiency of 0.92 (Table A5-6), whereas the CVP LTG model used a slightly variable efficiency (0.92–0.98).

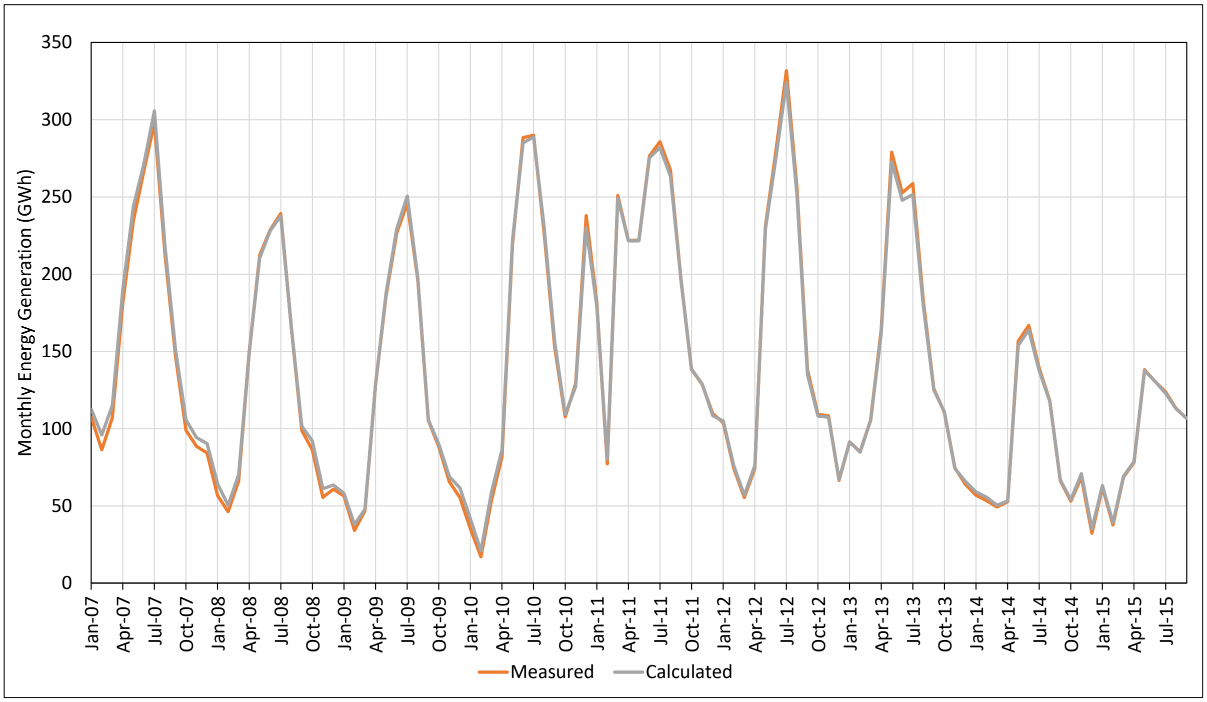
The differences in energy calculations were greatest at the highest energy values, when the CVP LTG energy values were slightly lower than the flow-and-head-based energy equation estimates. In general, however, the two methods of energy calculation were similar. For the 1922–2003 LTG case, the average annual energy for Shasta Power Plant calculated with the CVP LTG model was 2,106 GWh/yr. In comparison, the average annual energy for Shasta Power Plant calculated with the flow-and-head-based energy equation was 2,113 GWh/yr. The monthly variations in powerhouse flow and powerhouse head dominated the calculated Shasta Power Plant energy; variations from the powerhouse efficiency were minor.



Energy was calculated with both the LTG monthly model and the flow-and-head-based equation using 1922–2003 CalSim example hydrology.
GWh = gigawatt hour; LTG = Long-Term Generation

Figure A5-7. Calculated Energy and Efficiency in Relation to Monthly Head at Shasta Power Plant

As further confirmation of the approach for calculating hydropower generation at Shasta Reservoir, monthly measured hydropower generation for Shasta Reservoir was compared with values calculated using the flow-and-head-based equation, with monthly average measured reservoir elevation and flow through the powerhouse as input (Figure A5-8). The calculated values match the measured values well (RMSE = 3.7 GWh), in part due to the availability of data for flow through the powerhouse. If powerhouse flows had not been available, the calculated values would have been based on reservoir release data and would have been higher than the measured values during times when the powerhouse was not used at full capacity.



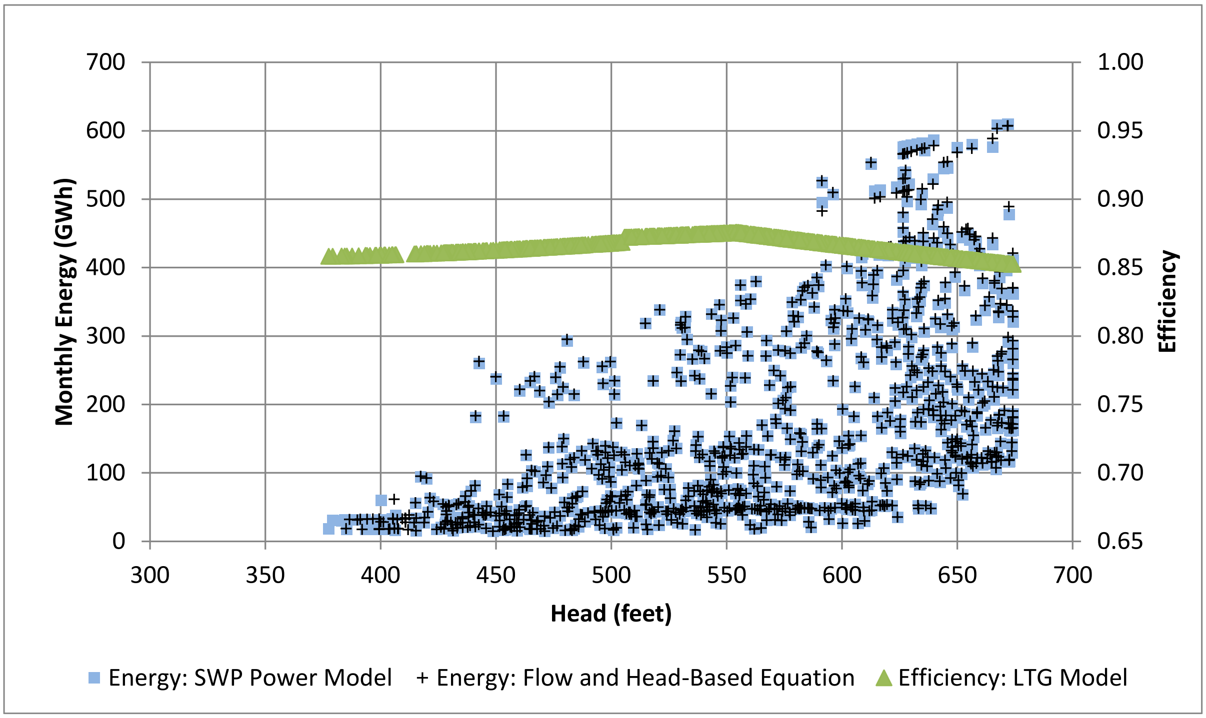
Sources: Hydropower generation from ^EIA 2017; reservoir elevation and powerhouse flow from DWR 2018.
GWh = gigawatt hour

Figure A5-8. Comparison of Measured and Calculated Hydropower Generation at Shasta Reservoir for 2007–2015

A5.2.2.4 Hyatt Power Plant Energy Calculations

The 1922–2003 CalSim case in the SWP power spreadsheet was used to compare the energy calculations in the SWP spreadsheet for Hyatt Power Plant with the flow-and-head-based equation for Hyatt Power Plant. Figure A5-9 shows monthly energy results for the SWP power model and the flow-and-head-based equation, along with powerhouse efficiency. In the SWP spreadsheet model, the efficiency varied from a maximum of 87.6 percent at a head of approximately 550 feet, near the middle of the head range, to a minimum of 85.2 percent at a head of approximately 675 feet, the maximum head. The flow-and-head-based equation used a constant average efficiency of 87.3 percent (Table A5-6).

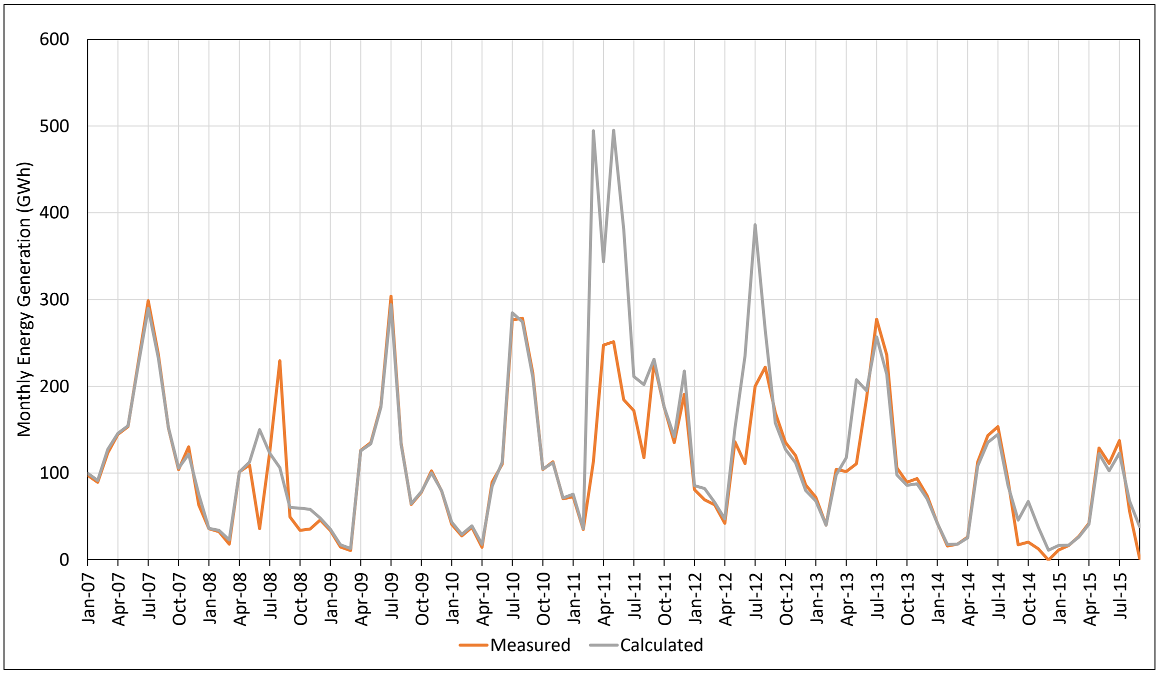
For the 1922–2003 CalSim case, the average annual energy for Hyatt Power Plant calculated with the SWP power model was 2,009 GWh/yr. The flow-and-head-based energy equation for Hyatt Power Plant calculated an average annual energy of 2,026 GWh/yr, nearly identical to the SWP power model. Evaluating the effects of alternative reservoir operations for a variety of runoff years can be based on these relatively simple calculations, using the monthly results from SacWAM.



Energy was calculated with both the LTG monthly model and the flow-and-head-based equation using 1922–2003 CalSim example hydrology.
GWh = gigawatt hour; LTG = Long-Term Generation

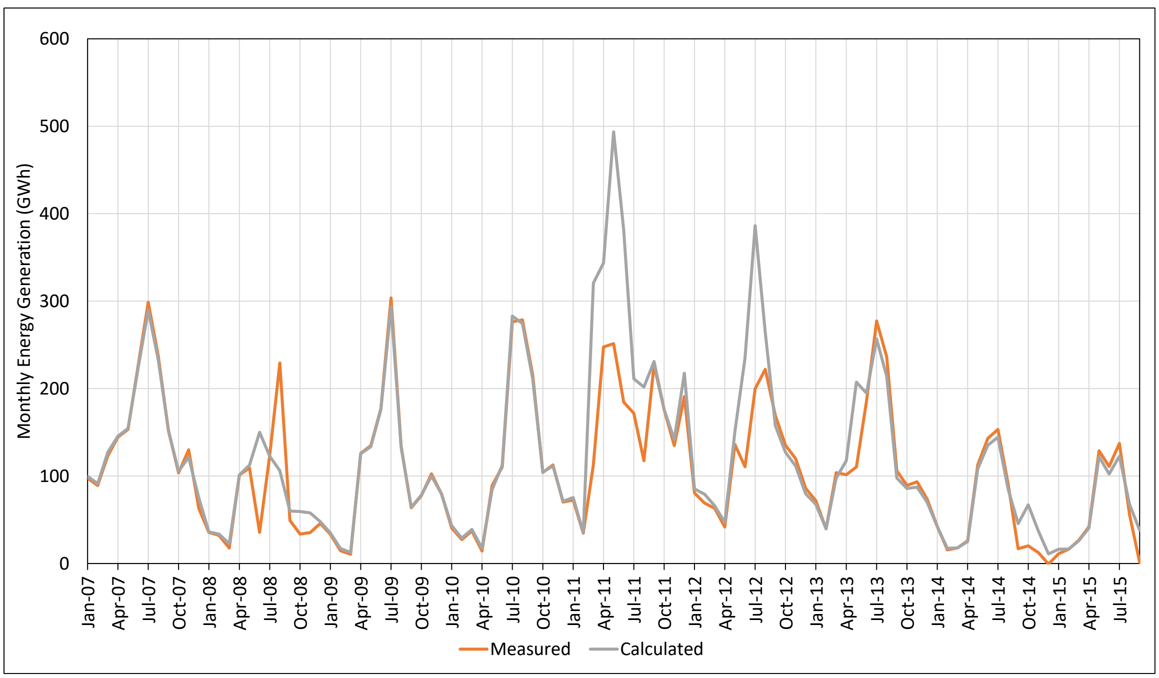
Figure A5-9. Calculated Energy and Efficiency in Relation to Monthly Head at Hyatt Power Plant

As further confirmation of the approach for calculating hydropower generation at Hyatt Power Plant, monthly measured hydropower generation for Lake Oroville was compared with values that were calculated using the flow-and-head-based equation, with measured monthly average reservoir elevation and reservoir release flows as input (Figure A5-10). In general, the calculated values match the measured values well. In some months, however, the calculated values were higher than the measured values. The flow-and-head-based equation limits flow through the powerhouse to the maximum capacity of the powerhouse, but the cap is applied on a monthly basis. This is a potential concern because although monthly average flow may not exceed the cap, on some days during storm events the cap could be exceeded and not all water could be used for generation. However, this possible occurrence is not a major source of mismatching between the measured and calculated energy values. Capping the daily flows to the powerhouse maximum prior to calculating monthly average flows removes only one of the high calculated values (Figure A5-11). The remaining instances of calculated values greater than the measured values are probably due to the powerhouse not being used to full capacity.



Sources: Hydropower generation from ^EIA 2017; reservoir elevation and powerhouse flow from DWR 2018.
GWh = gigawatt hour

Figure A5-10. Comparison of Measured and Calculated Hydropower Generation at Hyatt Power Plant for 2007–2015



Sources: Hydropower generation from ^EIA 2017; reservoir elevation and powerhouse flow from DWR 2018.
GWh = gigawatt hour

Figure A5-11. Comparison of Measured and Calculated Hydropower Generation at Hyatt Power Plant for 2007–2015 with Daily Flows Limited to Powerhouse Capacity

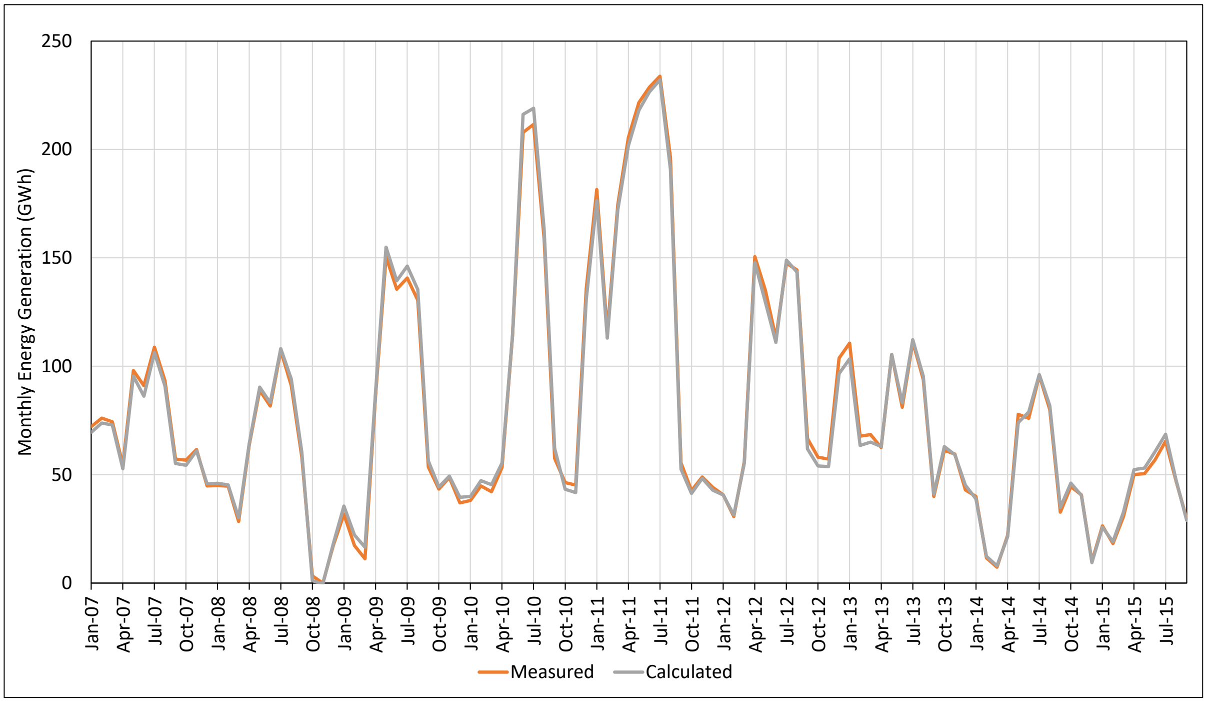
A5.2.2.5 Colgate Powerhouse Energy Calculations

New Bullards Bar Reservoir is located on the North Fork of the Yuba River. The FERC relicensing documents provide a general description of the reservoir operations and Colgate Powerhouse energy generation. The maximum New Bullards Bar Reservoir storage is 966 TAF at an elevation of about 1,955 feet, and the minimum reservoir storage is 230 TAF at an elevation of 1,730 feet. (YCWA 2014)

The Colgate Powerhouse is located about 5 miles downstream, with two large Pelton wheels at an elevation of 565 feet (YCWA 2014). The total head therefore ranges from 1,165 feet to 1,390 feet. Although the head loss in the 5-mile tunnel is reported to be the equivalent of about 80 feet at full capacity of 3,400 cfs (YCWA 2014), a head loss of 30 feet was used in this analysis because it generated a better match to measured hydropower generation over the full range of powerhouse flows evaluated. The efficiency can be roughly estimated based on the maximum capacity of 340 MW (8,160 MWh/day), the maximum flow of 3,430 cfs (6,800 acre-feet/day), and the maximum effective head of about 1,306 feet (YCWA 2014). Inserting these parameters in the efficiency equation provided at the beginning of Section A5.2.2, *Flow-and-Head-Based Calculations*, provides an estimated Pelton wheel efficiency of about 90 percent.

The Yuba County Water Agency FERC documents (YCWA 2009, 2014) suggest an annual energy generation of 1,225 GWh/yr with an average flow of 1,055 TAF/yr, suggesting an average energy factor of 1,160 MWh/TAF. However, because the documents do not specify an average head, the efficiency is uncertain. With an average powerhouse head of 1,250 feet assumed (the reservoir is generally full), the average efficiency would be 93 percent, slightly higher than the estimated efficiency of 90 percent. The approximate energy coefficients for Colgate Powerhouse are given in Table A5-6.

As confirmation of the approach for calculating hydropower generation at Colgate Powerhouse, monthly measured hydropower generation for Colgate Powerhouse was compared with values that were calculated using the flow-and-head-based equation, with measured monthly average reservoir elevation and powerhouse flows as input (Figure A5-12). The calculated values match the measured values well (RMSE = 3.0 GWh).



Sources: Hydropower generation from ^EIA 2017; reservoir elevation and powerhouse flow from DWR 2018; powerhouse flow from USGS 2018.
GWh = gigawatt hour

Figure A5-12. Comparison of Measured and Calculated Hydropower Generation at Colgate Powerhouse for 2007–2015

A5.2.2.6 Summary of Flow-and-Head-Based Calculations

These comparisons suggest that the flow-and-head-based energy equations can be used for each hydropower facility to provide an accurate evaluation of the monthly and annual energy production. Each of these powerhouses is operated efficiently, with average powerhouse efficiency of 85 to 92 percent by using a combination of peaking power (operating each unit at near-maximum capacity for some hours each day) and reducing the number of units operating on days with relatively low release flows. Equation components are listed in Table A5-6.

Table A5-6. Equation Components for Estimating Energy Generation at Folsom, Shasta, Hyatt, and Colgate Power Plants

Powerhouse	Tailrace Elevation (feet)	Minimum Reservoir Elevation for Generation (feet)	Efficiency	Maximum Powerhouse Flow (cfs)	Maximum Powerhouse Capacity (MW) [a]	Maximum Powerhouse Head (feet)
Folsom	Equation [b] (≈130)	329	0.85	8,299	200	335
Shasta	Equation [b] (≈590)	840	0.92	19,105	714	480
Hyatt	229	640	0.873	16,447	819	674
Colgate [c]	565	1,730	0.90	3,430	340	1,390

Sources: CVP LTG energy model; SWP energy model; ^ABB 2017; YCWA 2014; Reclamation 2005; Reclamation 2014; NMFS 2016; ^DWR and Reclamation 2016; Reclamation 2019; DWR 1999.
In some cases, the maximum powerhouse capacity used in the analysis differs from the ^ABB 2017 values based on information in the sources provided and comparisons with measured energy generation.
For Folsom, Shasta, and Hyatt, maximum powerhouse flow calculated from other parameters.
cfs = cubic feet per second; MW = megawatt; LTG = Long-Term Generation
[a] Used in calculation of capacity at a particular head.
[b] Equation depends on reservoir release flow.
[c] Head reduced by 30 feet to account for power loss in pipe.

A5.2.3 Flow-Based Calculations

For the other 43 facilities evaluated, hydropower generation was estimated by assuming that full powerhouse generating capacity could be attained when flows through the powerhouse are at the maximum flow capacity for the facility and that, during lower flows, the power would depend on the fraction of the full flow going through the facility. For example, if flow through a facility was at 50 percent of the maximum possible flow, then energy generation was assumed to be at 50 percent of the full powerhouse generating capacity.

Monthly hydropower generation was estimated as

> Energy = powerhouse capacity * hours in a month * (minimum of 1 or ratio of Flow to MaxFlow), where
>
> Powerhouse capacity is the capacity presented in Table A5-1, Table A5-2, and Table A5-3,
>
> MaxFlow is the maximum possible flow through the powerhouse, and
>
> Flow is the estimated flow through the powerhouse.

MaxFlow was initially estimated as the maximum powerhouse flow reported by the U.S. Geological Survey, maximum flow reported in documents, or other information sources. In many cases, the initial estimates were adjusted to improve the match between calculated and measured values.

Depending on the level of detail in SacWAM, flows through the powerhouses were generally estimated as one of the following.

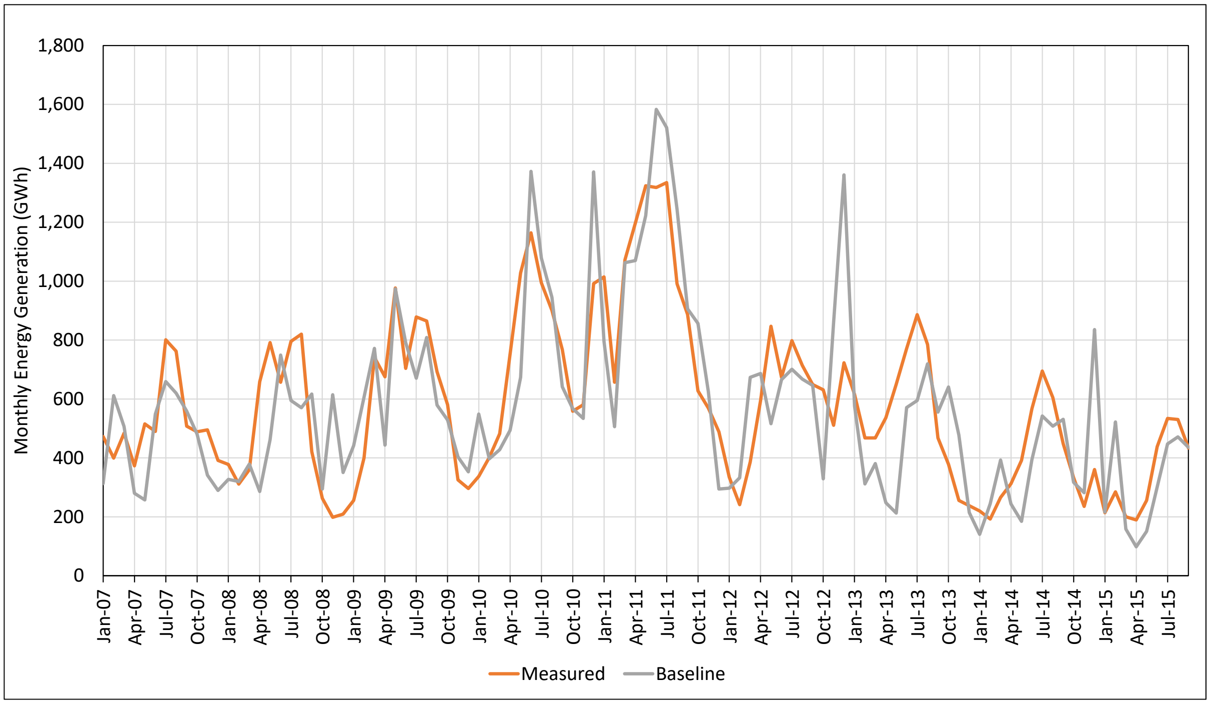
- SacWAM powerhouse penstock flow or flow in canal leading to the powerhouse.
- SacWAM reservoir release flow limited to the estimated maximum possible flow through the powerhouse.

Using this simplified approach, which does not account for reservoir head, is sufficiently accurate because most of the head at these facilities is unlikely to be substantially affected by the scenarios. Head is not likely to change greatly at most of these powerhouses because the powerhouse water comes from long pipes with large drops in elevation or because the elevations in the reservoirs supplying these facilities are not expected to change much. In only a few instances, the powerhouse is at a dam that could be affected by the scenarios. These facilities are typically small, and effects on the facilities would not cause large changes in overall hydropower generation and would not affect the conclusions of this policy-level analysis.

As confirmation of the flow-based approach for calculating hydropower generation, monthly measured energy generation was compared with generation calculated using measured flow either through the powerhouses or available to the powerhouses (with measured flow data from DWR 2017; USGS 2017). Most of the facilities had sufficient hydrologic data to make these comparisons. The measured hydropower generation generally matched the calculated hydropower, although some matches were better than others. Some of the comparisons matched well at an annual time step but not a monthly time step, likely due to imprecision in the month assignments for the measured generation.

Some of the mismatches may be related to inaccuracies in the equation parameters, but many of the discrepancies may result from lack of information about the actual flows running through the powerhouses. For many facilities, flow through the powerhouse was estimated based on flow available to the powerhouse. In addition, a complete comparison was not possible for Thermalito Powerhouse because Thermalito hydropower generation fell to zero in 2012 due to a fire that destroyed the facility.

Calculations were possible for all 43 facilities using SacWAM baseline condition results. To provide an overall evaluation of the flow-based calculation approach, the total hydropower generation calculated for all 43 facilities with flow-based calculations, excluding Thermalito, was compared with the total measured hydropower generation (Figure A5-13) (RMSE = 188 GWh). Considering the multiple potential sources of inaccuracies, including differences between SacWAM baseline condition flows and historical flows, this match is adequate and is an appropriate level of analysis to make a general assessment of possible project effects.



Source: ^EIA 2017.
Baseline energy generation was calculated with flows from SacWAM baseline condition results.
Thermalito is not included because measured values are incomplete due to a 2012 fire.
GWh = gigawatt hour

Figure A5-13. Comparison of Measured and Calculated Baseline Hydropower Generation for Facilities that Used the Flow-Based Calculation Approach

A5.2.4 SacWAM Inputs to Hydropower Calculations

Table A5-7 shows the SacWAM location labels for flow values used in the hydropower calculations for each of the 47 hydropower facilities evaluated quantitatively (note that calculations for Caribou 1 and 2 Power Plants are combined, as are those for Narrows 1 and 2 Power Plants and Drum 1 and 2 Power Plants). In addition to the flow results specified in Table A5-7, reservoir elevations were used to incorporate powerplant head in the calculations for Folsom, Colgate (New Bullards Bar), Hyatt (Oroville), and Shasta Power Plants.

Table A5-7. SacWAM Location Labels for Flow Results Used in Hydropower Calculations

Power Plant	SacWAM Flow Location Code
Belden	Belden Tunnel 0 \ Headflow
Bucks Creek	Bucks Creek Powerhouse 0 \ Headflow
Butt Valley	Prattville Tunnel 0 \ Headflow
Camanche	Mokelumne River 23 \ Camanche Reservoir
Camino	Camino Conduit 4 \ Reach
Caribou 1 & 2	Caribou Powerhouse 1 and 2 0 \ Headflow
Chicago Park	Chicago Park Flume 1 \ Operations Chicago Park Powerhouse
Colgate	Colgate Powerhouse 0 \ Headflow
Cresta	Cresta Tunnel 0 \ Headflow

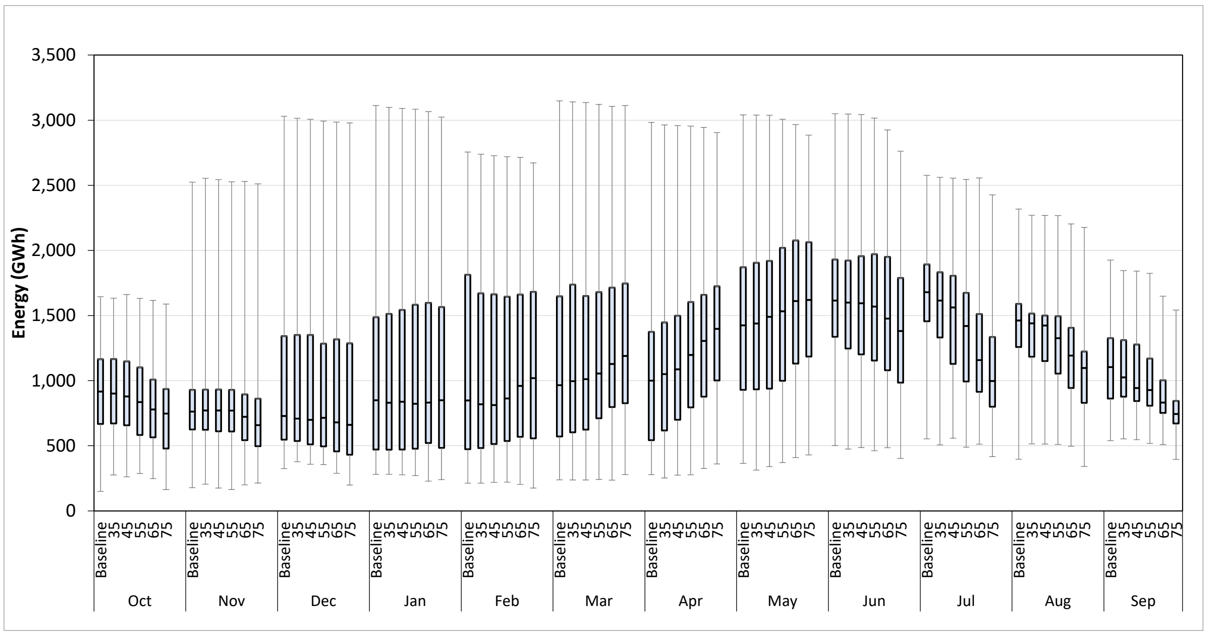
Power Plant	SacWAM Flow Location Code
De Sabla	Butte Creek 5 \ Toadtown Canal Inflow
Drum 1 & 2	Drum Canal 11 \ Operations Drum Canal
Dutch Flat 1	Dutch Flat Powerhouse No. 1 1 \ Operations Dutch Flat Powerhouse No. 1
Dutch Flat 2	Dutch Flat Flume 1 \ Operations Dutch Flat Powerhouse No. 2
Edward C Hyatt	Feather River 9 \ Oroville Reservoir
Electra	Electra Powerhouse Conduit 1 \ Operations Electra Powerhouse
Folsom	American River 11 \ SWRCB Folsom
Forbestown	Forbestown Powerhouse near Forbestown 1 \ Operations Forbestown Powerhouse
French Meadows	French Meadows Hell Hole Tunnel 0 \ Headflow
Grizzly	Buck Grizzly Tunnel 0 \ Headflow
Halsey	Bear River Canal 9 \ Operations Halsey Powerhouse
Jaybird	Jaybird Conduit 0 \ Headflow
Judge F Carr	Clear Creek Tunnel 0 \ Headflow
Keswick	Sacramento River 23 \ Keswick Reservoir
Loon Lake	Loon Lake Powerplant 0 \ Headflow
Middle Fork	Hell Hole Tunnel 3 \ Hell Hole Tunnel
Monticello	Putah Creek 11 \ SWRCB Lake Berryessa
Narrows 1 & 2	Narrows Powerhouse 1 and 2 0 \ Headflow
Newcastle	South Canal 9 \ Operations Newcastle Powerhouse
Nimbus	American River 15 \ Lake Natoma
Pardee	Mokelumne River 13 \ Pardee Reservoir
Poe	Poe Tunnel 0 \ Headflow
Ralston	Ralston Tunnel 0 \ Headflow
Robbs Peak	Robbs Peak Tunnel 0 \ Headflow
Rock Creek	Rock Creek Tunnel 0 \ Headflow
Rollins	Bear River 28 \ Reach
Salt Springs	North Fork Mokelumne River 8 \ Reach
Shasta	Sacramento River 17 \ SWRCB Shasta
Spring Creek	Spring Creek Conduit 0 \ Headflow
Thermalito	Power Canal 1 \ Operations Power Canal
Tiger Creek	Tiger Creek Powerhouse 1 \ Operations Tiger Creek Powerhouse
Union Valley	Union Valley Powerhouse 0 \ Headflow
West Point	West Point Powerhouse 0 \ Headflow
White Rock	White Rock Tunnel 0 \ Headflow
Wise	Wise Canal 9 \ Operations Wise Powerhouse
Woodleaf	Woodleaf Powerhouse 3 \ Operations Woodleaf Powerhouse

A5.2.5 Estimated Changes in Hydropower Generation

A5.2.5.1 Overall Effects

The main effect of the potential flow requirements on hydropower is an increase in generation during late winter/spring and a reduction during summer, resulting primarily from changes in flow (Figure A5-14).

In general, during late winter/spring, flows increase as a result of the flow requirements because unimpaired flows are high during late winter/spring. During summer, flows are reduced by the flow requirements because less water would be released from reservoirs for consumptive use. The largest increases in hydropower generation were estimated to occur during April, with the calculated hydropower generation increasing with each 10 percent increase in the flow scenario. The April median hydropower generation increases between approximately 50 GWh (for the 35 scenario) and 400 GWh (for the 75 scenario) over the baseline condition value of approximately 1,000 GWh for the facilities evaluated. The largest decrease in hydropower generation was estimated to occur during July, with median hydropower generation for the flow scenarios decreasing between approximately 65 GWh (for the 35 scenario) and 680 GWh (for the 75 scenario) relative to the baseline condition value of approximately 1,680 GWh for the facilities evaluated. Under baseline conditions, hydropower production in the Sacramento/Delta is greatest from May through August, when median generation at the evaluated facilities is more than 1,400 GWh per month. In contrast, for the higher flow scenarios, calculated generation drops below 1,400 GWh for July and August. For the 75 scenario, the calculated median generation for July and August is less than approximately 1,100 GWh.



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

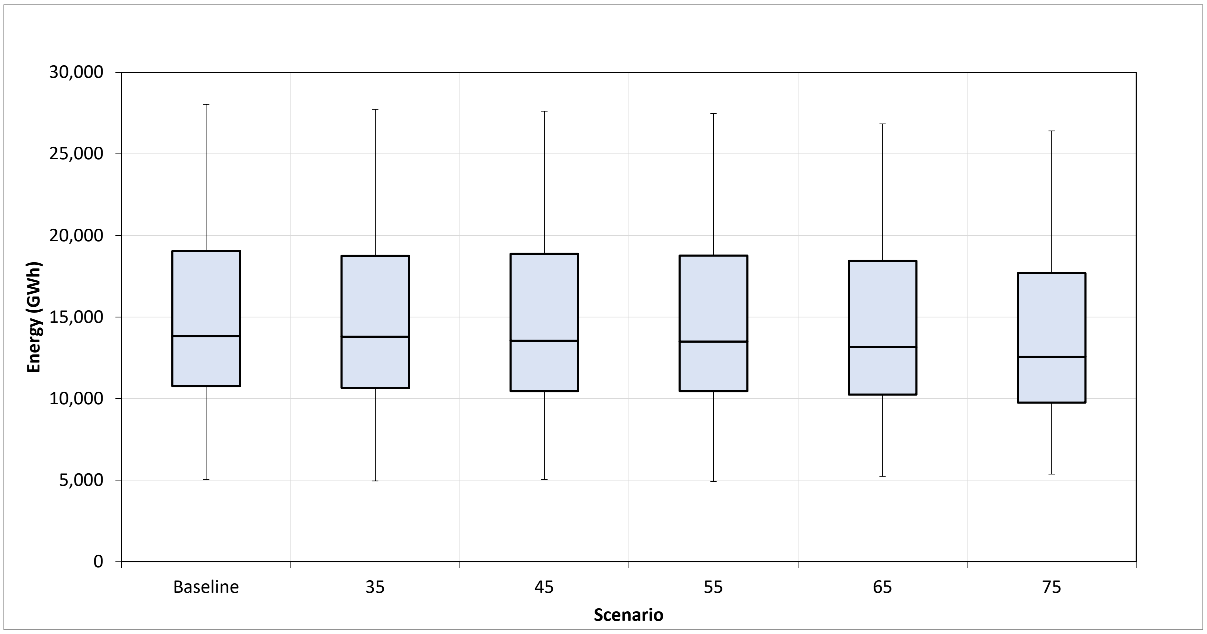
Figure A5-14. Monthly Changes in Hydropower Generation for Sacramento/Delta Facilities Potentially Subject to Changes in Flow

Annually, hydropower effects would be relatively small because the total volume of water running off the watersheds would not change, and reservoir storage is not expected to be greatly reduced (Figure A5-15 and Table A5-8). However, small annual changes may result from the following conditions.

- Increases in flow that may exceed the capacity of some hydropower facilities. These increases would occur primarily during wet years.
- Changes in reservoir water surface elevations.

- Changes in interbasin diversions, which would affect the total annual volume of water moving through some hydropower facilities.

Changes in annual hydropower generation range between a 7-percent increase in the driest water year (0th percentile) for the 75 scenario and a 14-percent reduction relative to baseline conditions under the 75 scenario for years with low hydropower generation (i.e., 10th percentile) (Table A5-8). For the 75 scenario, the reduction in average annual energy generation is 1,149 GWh, about 8 percent of the baseline average.



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

Figure A5-15. Annual Hydropower Generation for Sacramento/Delta Facilities Potentially Subject to Changes in Flow

Table A5-8. Cumulative Distribution of Annual Hydropower Generation—Baseline Conditions and Change from Baseline Conditions (gigawatt hour)

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

A5.2.5.2 Effects at Individual Facilities

Changes in hydrology simulated by SacWAM would result in a range of localized hydropower effects at the hydropower facilities in the Sacramento/Delta. The largest changes in hydropower are expected to occur at the rim reservoirs because of their large hydropower capacity and because rim reservoir operations will need to change to meet the flow objectives. Many facilities above the rim reservoirs are not expected to experience large hydrologic changes because consumptive use and reservoir storage in these areas are relatively small. Therefore, in general, large hydrologic changes would not be needed in these areas to meet the proposed flow requirements. In some cases, however, implementation of the flow requirements could result in a reduction of water diversions between watersheds, particularly for the higher flow scenarios. A reduction in interbasin diversions could reduce generation at facilities that depend on the diversions. Conversely, a few facilities may benefit from the retention of flows within a watershed.

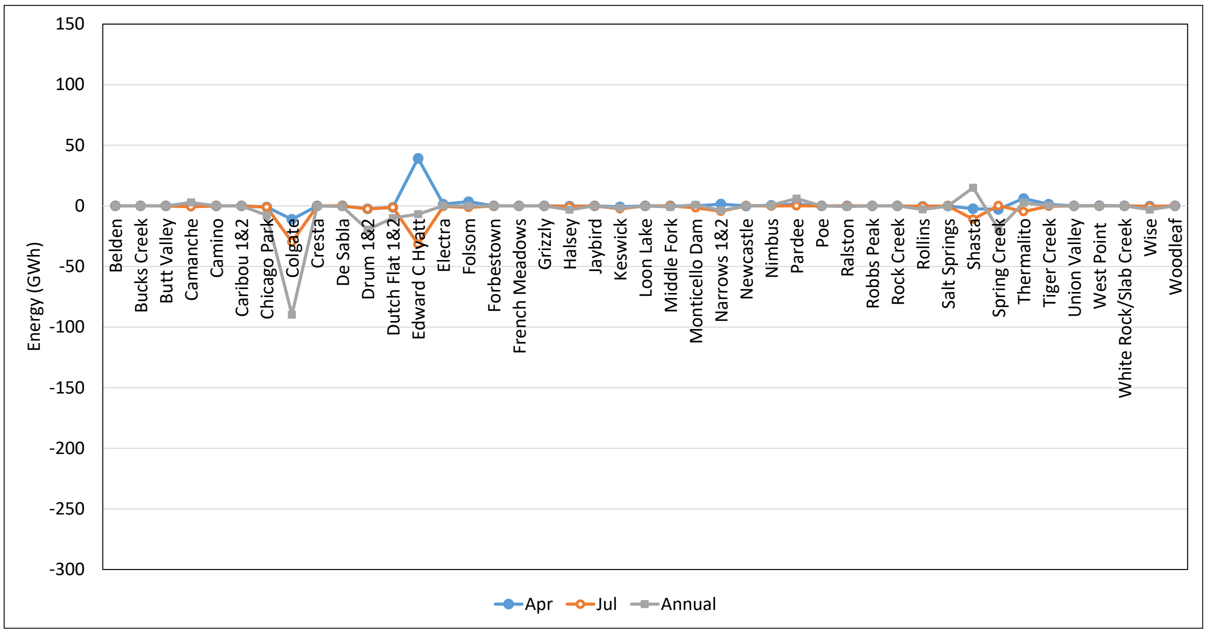
To show which facilities are most affected, a summary of average changes at all the facilities evaluated is provided for the 35 scenario (Figure A5-16), 45 scenario (Figure A5-17), 55 scenario (Figure A5-18), 65 scenario (Figure A5-19), and 75 scenario (Figure A5-20). The figures show results for April (the month with the largest increases in hydropower generation), July (the month with the largest decreases in hydropower generation), and the annual total. The higher flow scenarios show larger changes in hydropower generation. As expected, based on facility size and location, large changes occur at Shasta, Hyatt, Colgate, and Folsom Power Plants. In addition, the following rim reservoir facilities or facilities downstream of rim reservoirs showed large to moderate changes in hydropower generation.

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

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

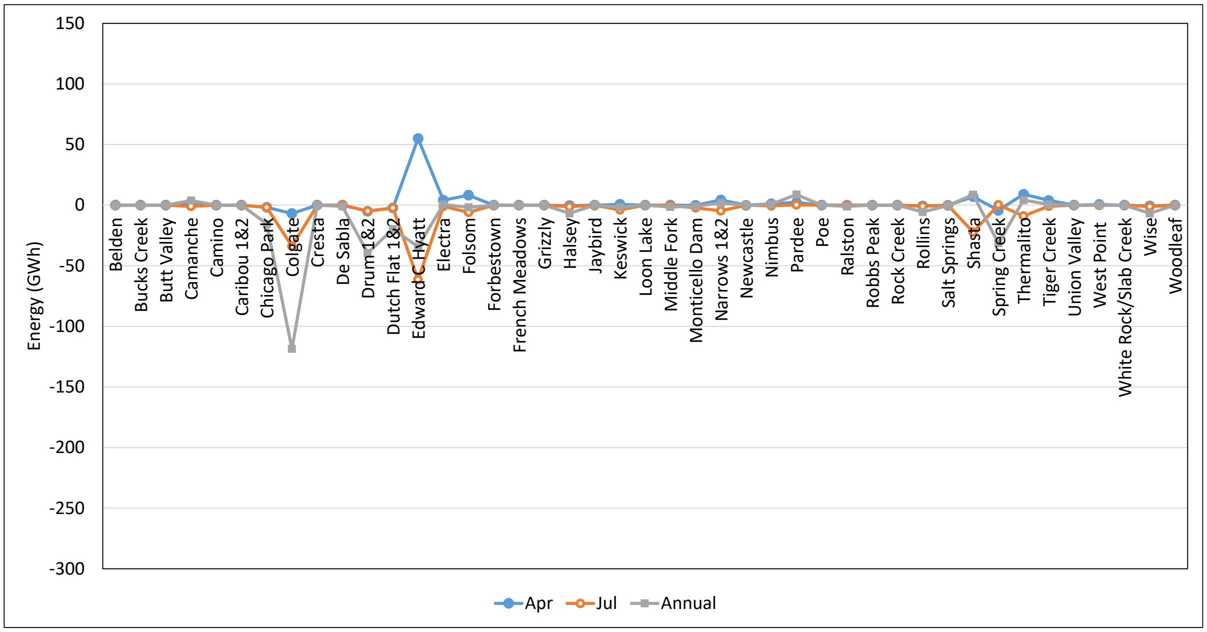
- **Drum 1 and 2 Powerhouses** (located along the conveyance between the Yuba and American Rivers to Bear River). Drum 1 and 2 Powerhouses have reduced generation caused by a reduction in diversions from the Yuba River to the Bear River.
- **Halsey and Wise Powerhouses** (located along the conveyance between the Bear River to Auburn Ravine and the American River). Halsey and Wise Powerhouses have reduced generation caused by a reduction in diversions from the Bear River to Auburn Ravine and the American River.

- **Chicago Park, Dutch Flat 1 and 2, and Rollins Powerhouses** (supplied by the Bear River). These powerhouses have reduced hydropower generation caused by a reduction in interbasin diversions to the Bear River.
- **Middle Fork and Ralston Powerhouses** (supplied by water in the Middle Fork American River basin, including the Rubicon River). Middle Fork and Ralston Powerhouses have small increases in hydropower in spring and reductions in summer caused by increases in releases from Hell Hole and French Meadows Reservoirs to meet instream flow requirements in spring followed by reductions in releases in summer. Occasional exceedances of power plant capacity in spring result in small reductions in net annual generation.
- **Tiger Creek and Electra Power Plants** (supplied by North Fork Mokelumne River). Tiger Creek and Electra Power Plants have small increases in hydropower in spring and reductions in summer caused by small increases in releases from upstream reservoirs to meet instream flow requirements in spring followed by reductions in releases in summer.



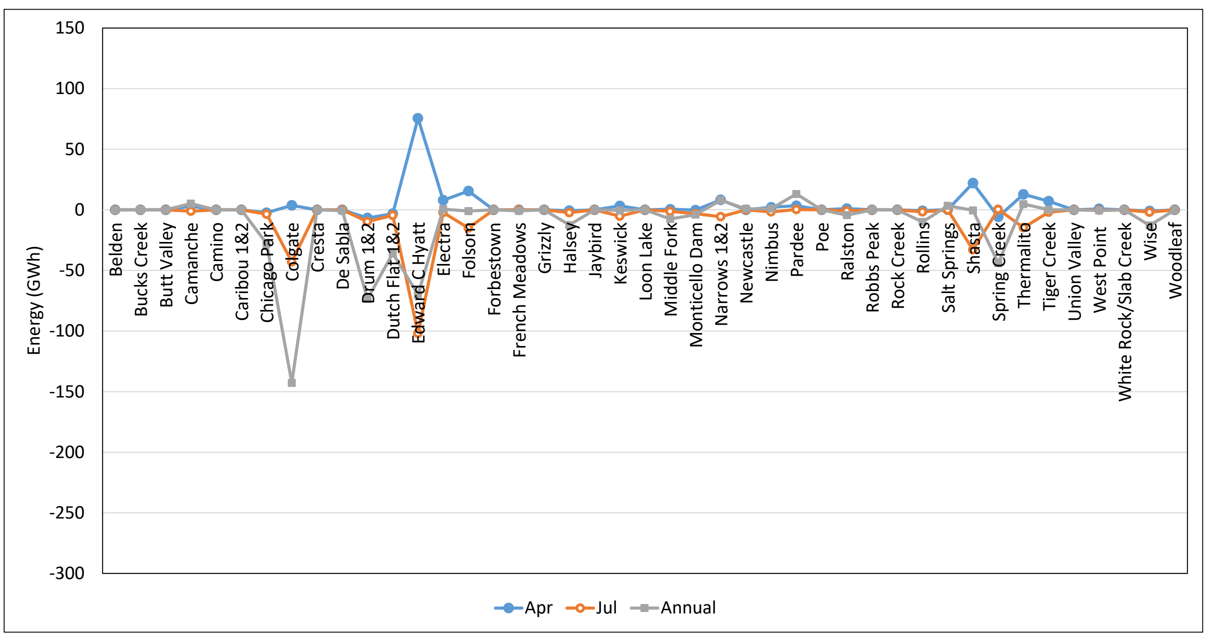
GWh = gigawatt hour

Figure A5-16. Estimated Average Change in Hydropower Generation for the 35 Scenario at Individual Hydropower Facilities



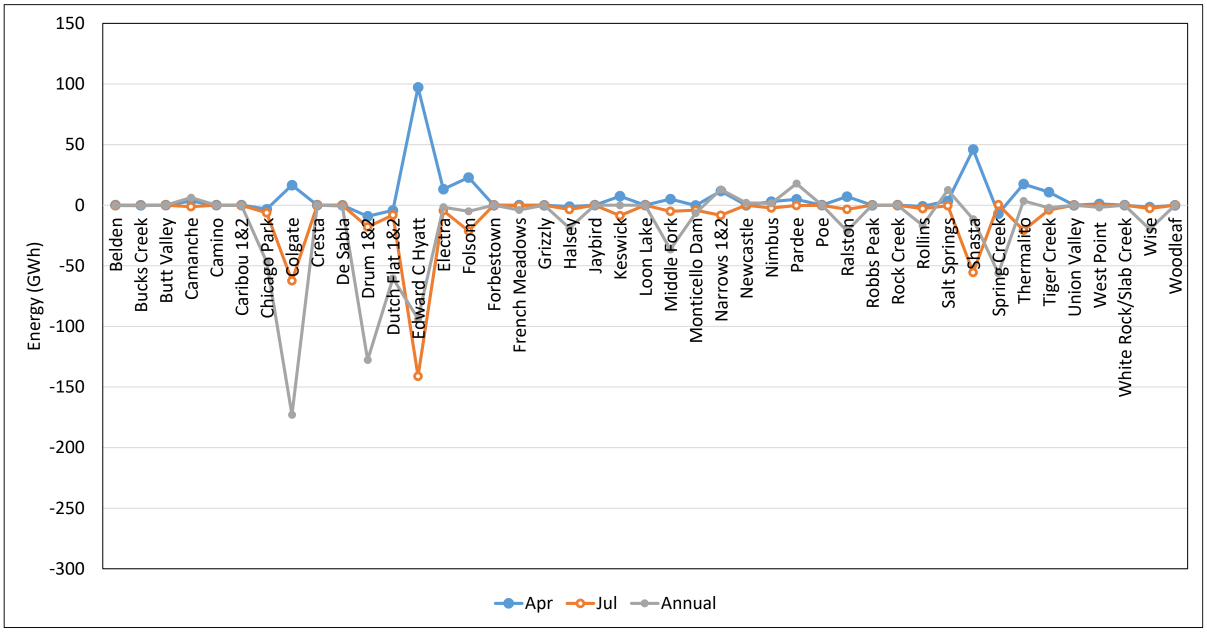
GWh = gigawatt hour

Figure A5-17. Estimated Average Change in Hydropower Generation for the 45 Scenario at Individual Hydropower Facilities



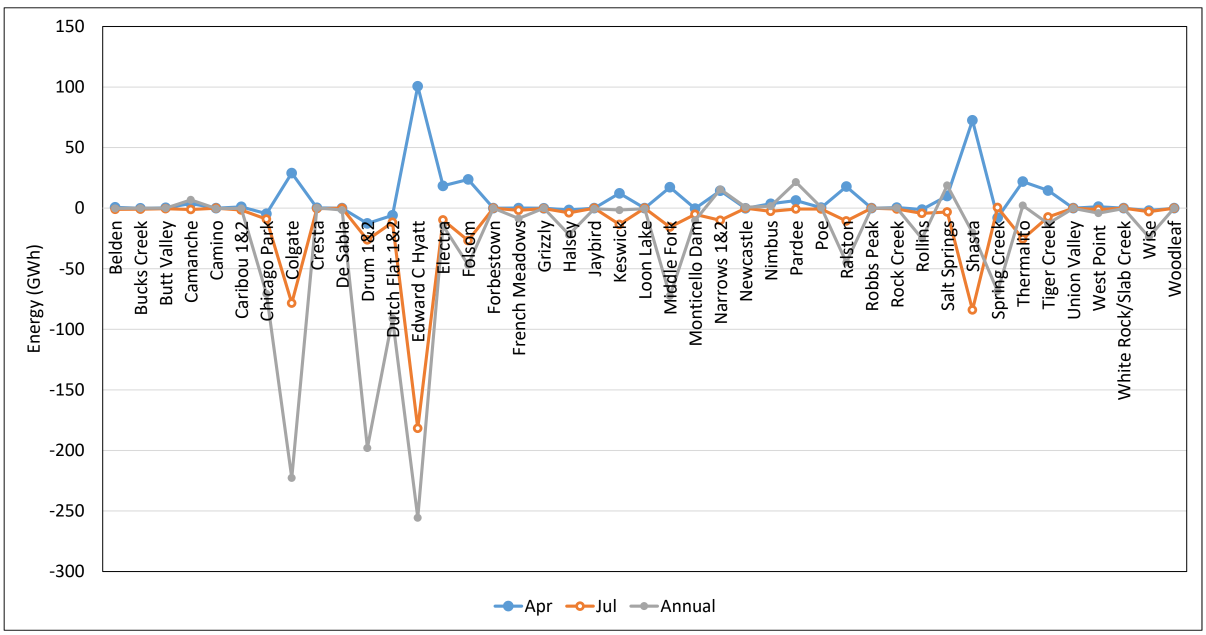
GWh = gigawatt hour

Figure A5-18. Estimated Average Change in Hydropower Generation for the 55 Scenario at Individual Hydropower Facilities



GWh = gigawatt hour

Figure A5-19. Estimated Average Change in Hydropower Generation for the 65 Scenario at Individual Hydropower Facilities



GWh = gigawatt hour

Figure A5-20. Estimated Average Change in Hydropower Generation for the 75 Scenario at Individual Hydropower Facilities

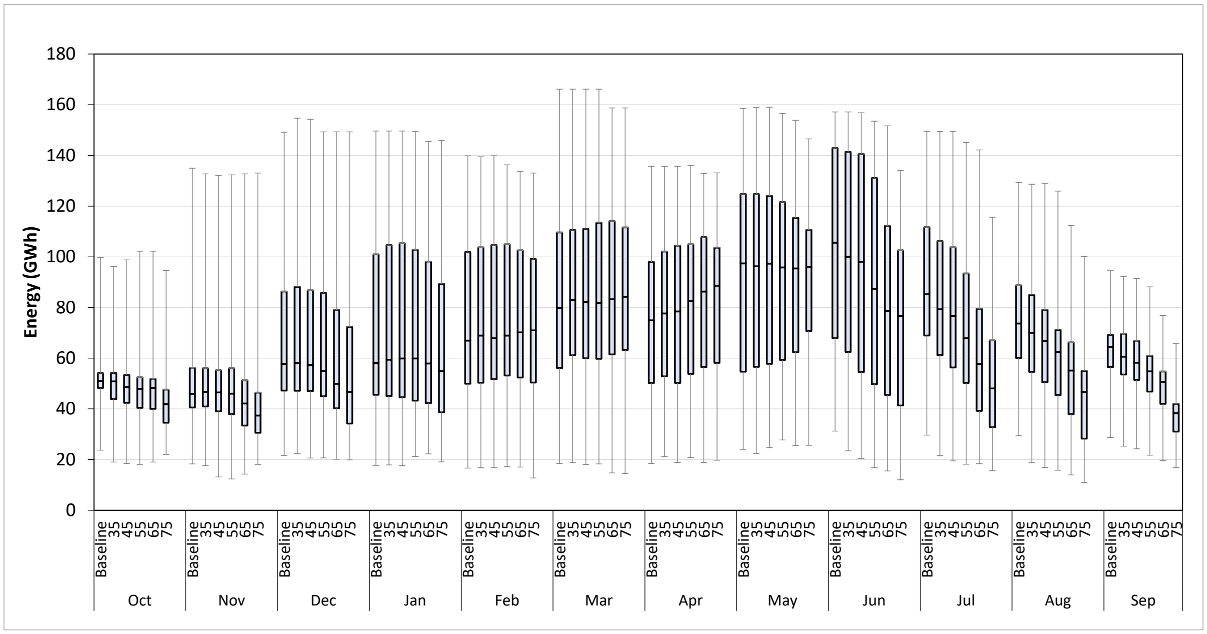
A5.2.5.3 Effects at Small Hydropower Facilities that Contribute to the California Renewables Portfolio Standard

Generation at 16 of the 20 small hydropower facilities that contribute to the RPS and have capacity greater than 10 MW (Table A5-5) were estimated with SacWAM results. These facilities have a total summer capacity of 282 MW, which represents about 57 percent of the capacity of small hydropower facilities in the portions of the Sacramento/Delta modeled by SacWAM. Three of the remaining four facilities listed in Table A5-5 are located above Shasta Dam and are not expected to be affected because they do not have a large effect on the flow regime (as explained in Chapter 2, *Hydrology and Water Supply*). Generation at the Coleman facility could be affected but is not represented in SacWAM.

Hydropower effects at these 16 powerhouses represented in SacWAM are shown in Figure A5-21, Figure A5-22, and Table A5-9. The monthly pattern of effect for the small hydropower facilities (Figure A5-21) is not quite the same as the monthly pattern of effect for all facilities combined (Figure A5-14). The small hydropower facilities show an increase in generation associated with the flow requirements mostly only during April, whereas the combined facilities show an increase during February through May. In addition, the percent reduction in average annual generation at these 16 facilities is expected to be greater under the flow scenarios than the percent reduction for all facilities combined.

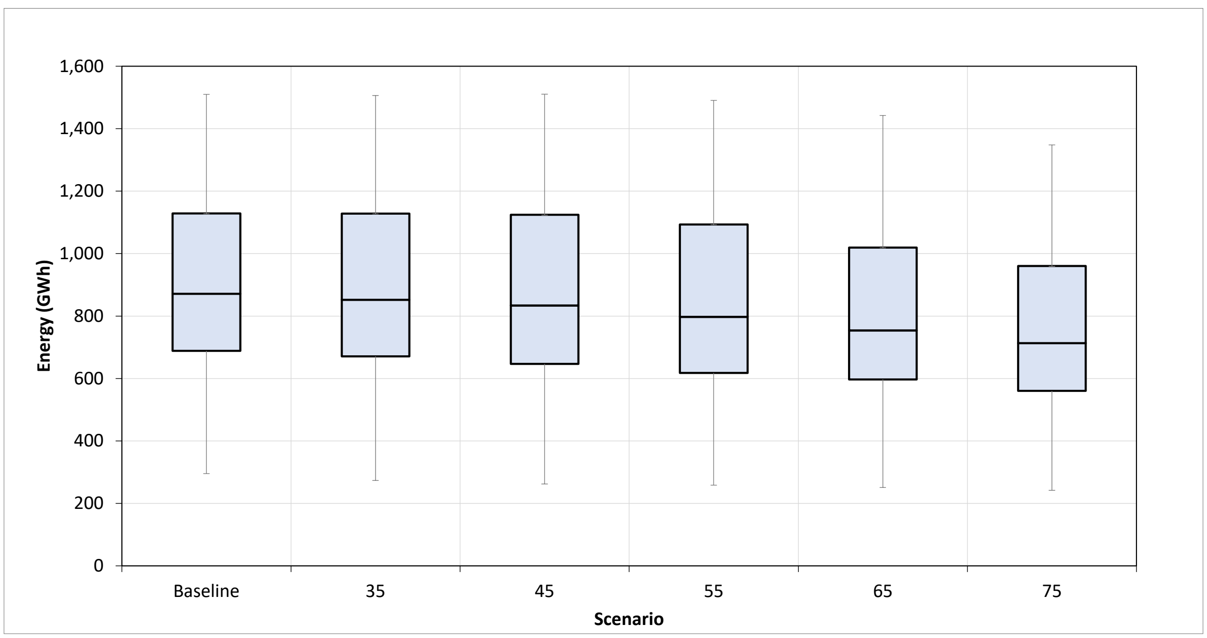
In terms of grid reliability, the small hydropower facilities are much less important than the larger hydropower facilities. Hydropower generation at the 16 small hydropower facilities is much less than the total generation that was modeled; average annual baseline condition generation for all modeled facilities was 14,701 GWh (Table A5-8), whereas average annual baseline condition generation for the 16 small hydropower facilities was only 904 GWh (Table A5-9). However, generation at the small hydropower facilities is important because it contributes to attainment of the RPS, whereas generation at the larger facilities does not. Reduced generation at small hydropower facilities would require compensation at other facilities that would increase generation to contribute to reaching the RPS objective.

The level of compensation needed for the potential reduction in energy at small hydropower facilities can be assessed by comparing the average annual reduction in hydropower at all the RPS-qualified facilities combined to the year-round output from a small hydropower facility. For example, for the 55 scenario, the average estimated reduction in generation for the 16 facilities evaluated was 56 GWh per year (Table A5-9). This number was then expanded to include an estimate of reduced generation at the other small hydropower facilities in the evaluation area that contribute to the RPS but were not modeled: Coleman Powerhouse and the 58 facilities with capacity less than or equal to 10 MW potentially affected by the proposed Plan amendments. The expansion assumes that these hydropower facilities would perform similarly to the modeled facilities relative to their capacity under baseline conditions and would experience the same percent reduction as the facilities that were modeled. The expanded average reduction in generation is about 100 GWh per year. In comparison, a single small hydropower facility with an average power output of 10 MW would generate about 88 GWh per year (10 MW x [24 x 365 hours per year] x [1/1,000 GW per MW]). Therefore, the average reduction in generation estimated for all the small hydropower facilities combined is similar to the amount of generation that could be attained from one small hydropower facility or from a small facility that uses a different type of renewable energy.



GWh = gigawatt hour

Figure A5-21. Monthly Changes in Hydropower Generation at Sixteen Renewables Portfolio Standard Facilities Potentially Subject to Changes in Flow



GWh = gigawatt hour

Figure A5-22. Annual Hydropower Generation at Sixteen Renewables Portfolio Standard Facilities Potentially Subject to Changes in Flow

Table A5-9. Cumulative Distribution of Annual Hydropower Generation at Sixteen Facilities that Contribute to the California Renewables Portfolio Standard (gigawatt hour)

		Scenario minus Baseline				
Percentile	Baseline	35	45	55	65	75
0th	295	-22	-33	-37	-45	-54
10th	562	-23	-43	-67	-90	-115
25th	688	-17	-42	-71	-91	-128
50th	871	-19	-37	-74	-117	-158
75th	1,129	-1	-4	-35	-110	-169
90th	1,271	-7	-13	-47	-110	-192
100th	1,510	-4	0	-19	-67	-162
Average	904	-10	-27	-56	-99	-153

A5.3 Energy Grid Analysis

A5.3.1 Overview of the Transmission System in California

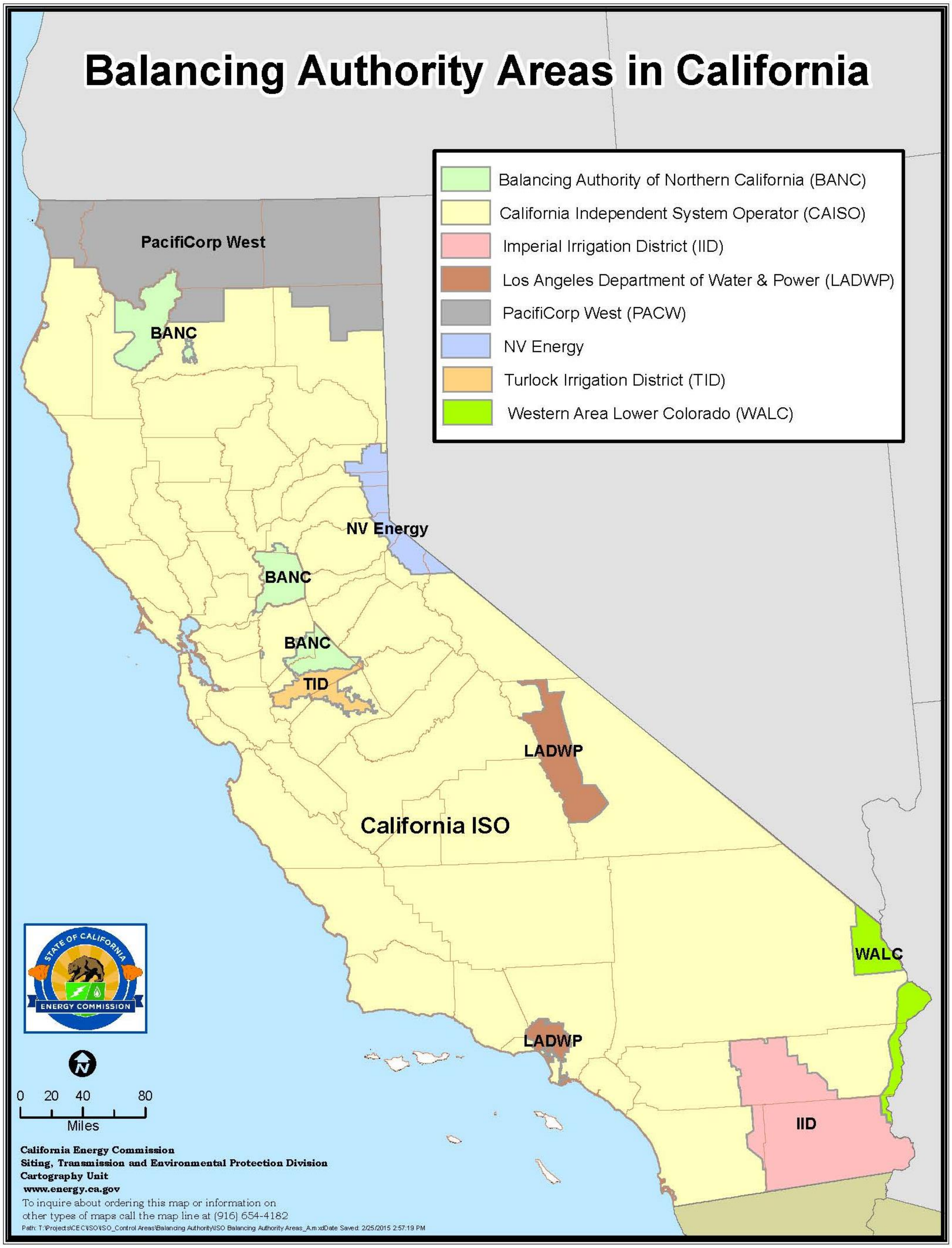
This section provides a brief overview of the California transmission system, with a focus on the area that includes the Sacramento/Delta hydropower facilities. The section describes the current state of the California electric grid, explains how shortages in local energy capacity can occur, and discusses the power flow assessment that was performed to analyze these shortages. The section also provides information about the robustness and interconnectedness of the transmission system that allows it to handle a reduction in hydropower generation.

A5.3.1.1 Balancing Authorities

Proper flow of electricity within and between areas is maintained by *balancing authorities*. Balancing authorities are entities responsible for maintaining load-generation balance in their area. *Load* is a term used to describe the total demand for electricity (i.e., the electrical power that must be provided to prevent grid failure).

California lies within the Western Interconnection, which is the electric grid that covers the western United States and western Canada. Electricity in the Western Interconnection is managed by the Western Electricity Coordinating Council (WECC), which works under the authority of the North American Electric Reliability Corporation (NERC). The California Independent System Operator (CAISO) is the largest of the 38 balancing authorities in the WECC. CAISO is also the largest balancing authority in California. It is an independent and regional transmission organization responsible for operating the transmission grid for about 80 percent of California and parts of Nevada (CAISO 2018). The CAISO service area encompasses major investor-owned utilities like Southern California Edison, Pacific Gas and Electric Company, and San Diego Gas and Electric and some municipal utility services.

In some areas in California, local public power companies manage and operate the transmission systems. These individual balancing authority areas are shown on Figure A5-23.



Source: CEC 2015.

Figure A5-23. Locations of Balancing Authority Areas in California

Of these smaller balancing authorities, the one most likely to be affected by changes in hydrology is the Balancing Authority of Northern California (BANC), which includes the Sacramento Municipal

Utility District (SMUD). Other small balancing authorities in California include PacifiCorp West, Los Angeles Department of Water and Power, Nevada Energy, Western Area Lower Colorado, Imperial Irrigation District, and Turlock Irrigation District.

A5.3.1.2 Western Area Power Administration

WAPA markets and transmits electricity from federal water projects in a 15-state region in the western United States. WAPA's Sierra Nevada Region (WAPA-SNR) covers much of northern and central California and parts of Nevada (WAPA 2016a), including the Sacramento/Delta area. In addition, California imports WAPA energy from outside WAPA-SNR over WAPA's share of the Pacific Northwest–Pacific Southwest Intertie and the California–Oregon Transmission Project 500-kilovolt (kV) lines linking northern and central California to the Pacific Northwest (WAPA 2015).

WAPA-SNR markets power from the CVP and Washoe Project under long-term contracts to approximately 80 preference customers in northern and central California and Nevada (82 Fed. Reg. 38675–38685). The energy available to customers is the amount of energy generated by the CVP and Washoe Project minus energy required for the projects (e.g., for pumping CVP Delta exports) and system requirements (e.g., capacity reserves and transmission losses). Customers for CVP power distributed by WAPA-SNR include municipal governments, public utility districts, irrigation districts, federal agencies, California state agencies (including CAISO, the California State University system, and California Department of Parks and Recreation), Native American tribes, and independent power marketers (WAPA 2016b). WAPA-SNR distributes power through WAPA-owned transmission lines and operates its own balancing authority in California under the umbrella of BANC, although almost half of the power distributed by WAPA-SNR in California (as of 2016) goes to customers within the CAISO area (^EE Online 2016).

A5.3.1.3 California Independent System Operator Capacity Conditions

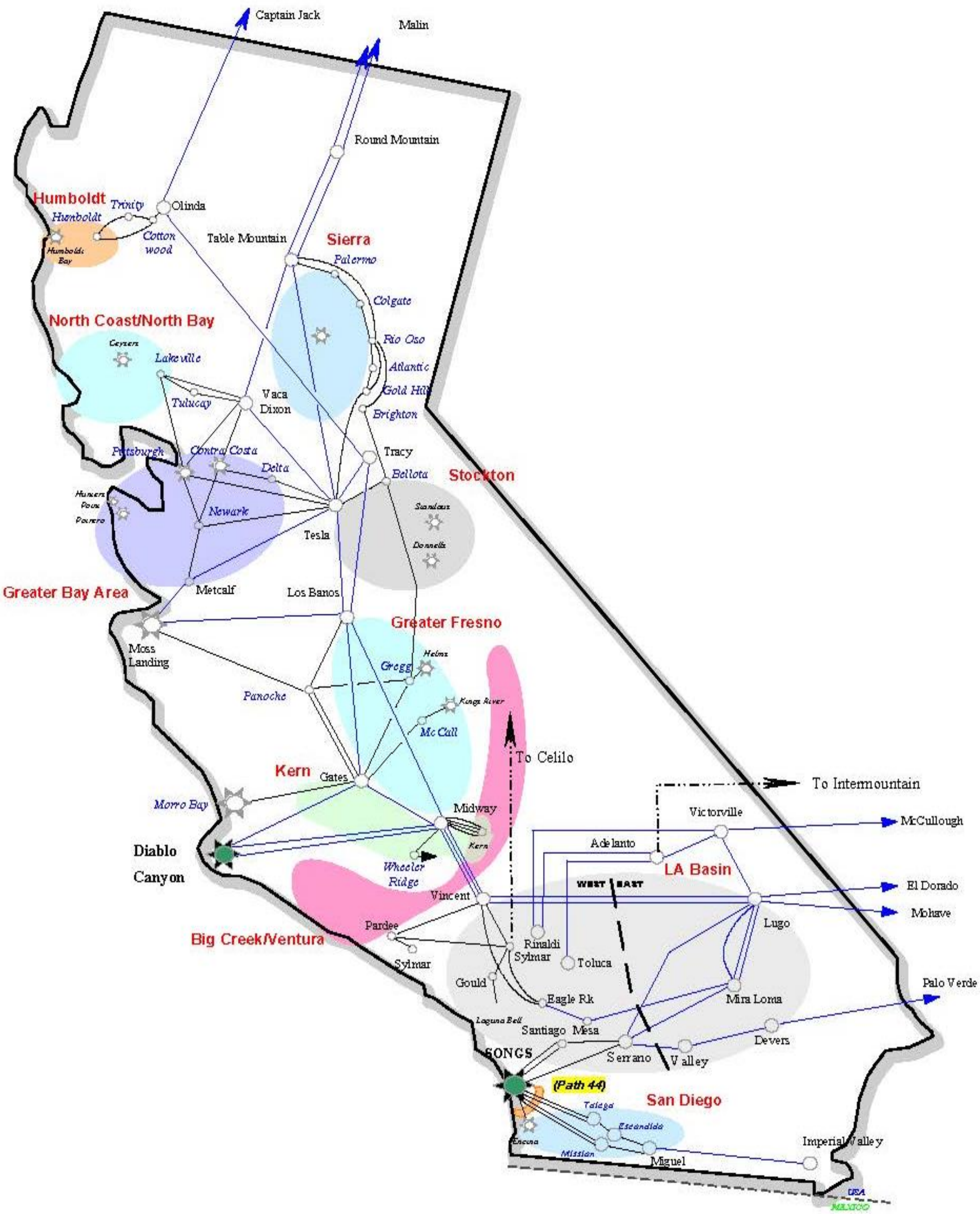
In general, electricity can readily flow from one part of the Western Interconnection to another. However, the electric grid is more reliable when local regions can generate their own electricity. CPUC adopted the resource adequacy (RA) program in 2004 with the twin objectives of providing sufficient resources to ensure the safe and reliable operation of the grid in real time and providing appropriate incentives for the siting and construction of new resources needed for reliability in the future (CPUC 2017). The RA obligations are applicable to all load-serving entities within CPUC's jurisdiction. As part of the RA program, each load-serving entity is required to procure enough resources to meet 100 percent of its total forecast load plus a 15-percent reserve. Some of the local areas have transmission constraints that may limit their ability to serve peak loads. Hence, in addition to region-wide capacity requirements, specific resource requirements exist for select local areas. These local transmission constraints may cause problems with grid reliability if a reduction in energy generation occurs.

Local Capacity Study

Each year, CAISO performs the Local Capacity Technical (LCT) Study to identify local capacity requirements (LCR) within its territory under normal and contingency system conditions. The results of this study are provided to CPUC for consideration in its RA program. These results are also used by CAISO for identifying the minimum quantity of local capacity necessary to meet NERC reliability criteria (CAISO 2021a, 2021b). The LCT Study is prepared for the upcoming year and the fifth year in the future (i.e., for the LCT Study cycle of 2021, the LCT Studies are prepared for 2022 and 2026). The results of these studies indicate whether the grid may be sensitive to reductions in energy generation.

Figure A5-24 shows the 10 LCR areas (Big Creek/Ventura, Fresno, Greater Bay, Humboldt, Kern, LA Basin, North Coast/North Bay, San Diego, Sierra, and Stockton) in CAISO. CAISO also identifies subareas within each larger LCR area. The subareas could be resource-deficient even though the larger area may have sufficient resources to meet its LCR. Because this appendix focuses on the Sacramento/Delta, the LCR requirements for the following LCR local areas are described further: Humboldt, Sierra, Stockton, North Coast/North Bay, Greater Bay, and Greater Fresno. For ease of reference, this set of LCR local areas is referred to as belonging to the Greater Sacramento area.

Table A5-10 shows the historical LCR, peak load, and total dependable local area generation for the Greater Sacramento area for 2021, 2022, 2025, and 2026, as determined in the 2022 and 2026 CAISO LCT studies (CAISO 2021a, 2021b). The table also shows the LCR as a percentage of the total dependable local generation. The CAISO LCT Studies for 2022 and 2026 found that several local areas in California, including Stockton (1,094 MW) and North Coast/North Bay (34 MW), were deficient overall in the 2022 and 2026 studies and that Greater Bay local area was found to be deficient in 2026 (305 MW) but not deficient in 2022. The North Coast/North Bay local area was found to be deficient overall in 2022 and 2026 because of limitations of the Tulucay–Vaca Dixon 230 kV transmission line. In addition to these local areas that were deficient overall, some of the subareas within the Sierra local area and some of the subareas within the Greater Fresno local area were found to be deficient.



Source: CAISO 2016.

Figure A5-24. Local Capacity Area Map of California Independent System Operator

Table A5-10. Local Capacity Requirements Compared with Peak Load and Local Area Generation for Local Areas in the Greater Sacramento Area

Year	Local Capacity Requirement (MW)	Peak Load 1-in-10 [a] (MW)	Local Capacity Requirement as Percent of Peak Load	Dependable Local Area Generation (MW)	Local Capacity Requirement as Percent of Total Area Generation
Humboldt					
2021	130	153	85%	191	68%
2022	111	144	77%	181	61%
2025	132	153	86%	191	69%
2026	128	161	80%	181	71%
North Coast/North Bay [b]					
2021	837	1,481	57%	842	99%
2022	834	1,509	55%	834	100%
2025	837	1,481	57%	842	99%
2026	834	1,489	56%	834	100%
Sierra					
2021	1,821	1,865	98%	2,108	86%[b]
2022	1,220	1,618	75%	2,092	58%[b]
2025	1,367	1,918	71%	2,108	65%
2026	1,690	1,880	90%	2,092	81%
Stockton [b]					
2021	596	1,113	54%	596	100%[b]
2022	562	1,027	55%	586	96%[b]
2025	619	950	65%	619	100%
2026	586	1,125	52%	586	100%
Greater Bay [b]					
2021	6,353	10,780	59%	7,418	86%
2022	7,231	10,746	67%	7,748	93%[b]
2025	6,110	10,743	57%	7,344	83%
2026	7,674	11,551	66%	7,674	100%
Greater Fresno					
2021	1,694	3,189	53%	3,392	50%[b]
2022	1,987	3,435	58%	3,370	59%[b]
2025	1,971	3,279	60%	3,392	58%
2026	2,314	3,571	65%	3,370	69%

Sources: CAISO 2021a, 2021b.
MW = megawatt
[a] "1-in-10" indicates that the peak load condition has a 1-in-10-year probability of occurring.
[b] Resource-deficient local area (or with one or more subareas that are deficient). A resource-deficient area implies that, to comply with the criteria, at summer peak, load must be shed immediately after the first contingency.

In the 2022 LCR assessment, local areas—including Sierra, Greater Bay, Greater Fresno, and Stockton—had subarea deficiencies. Local areas having subarea deficiencies are not necessarily deficient overall; conversely, local areas considered to be deficient overall might not have subarea deficiencies. Local areas with subarea deficiencies include the following.

- **Sierra:** Drum-Rio Oso Subarea (187 MW), Placer Subarea (30 MW), and Gold Hill-Drum Subarea (276 MW).
- **Greater Bay:** San Jose Subarea (141 MW).
- **Greater Fresno:** Coalinga Subarea (84 MW), Reedly Subarea (93 MW), and Wilson Subarea (248 MW).
- **Stockton:** Lockeford Subarea (3 MW) and Tesla-Bellota Subarea (813 MW).

All other local areas had sufficient resources overall to meet the projected needs. The Greater Bay local area, Greater Fresno local area, and Sierra local area are not identified as deficient in the 2022 LCR assessment (CAISO 2021a).

In the 2026 LCR assessment, three local areas—Stockton, North Coast/North Bay, and Greater Bay—had subarea deficiencies of 1,094 MW, 161 MW, and 305 MW, respectively. Resource deficiency values for these local areas result from a few deficient subareas. (CAISO 2021b). The Sierra and Greater Fresno local areas are not identified as deficient in the 2026 study (^CAISO 2022).

The Sierra Subarea is of particular interest because it contains Shasta Reservoir, Lake Oroville, Folsom Reservoir, and New Bullards Bar Reservoir areas. The 1-in-10 peak load for the local area was expected to be 1,618 MW in 2022 and 1,880 MW in 2026 (including losses and energy efficiency) (CAISO 2021a, 2021b). The CAISO LCT report for 2022 and the CAISO LCT report for 2026 define the list of transmission lines and substations in the area. The key subareas in the Sierra local area include Placerville, Placer, Pease, Gold Hill-Drum, South of Rio Oso, Drum-Rio Oso, and South of Palermo. The Placer Subarea and the South of Rio Oso Subarea are expected to have minor LCR deficiency in response to certain extreme contingencies. Overall, however, capacity in this CAISO region is expected to be sufficient in terms of availability of resources.

Recent California Independent System Operator Hydropower Assessments

To better understand the grid response to a reduction in hydropower, it is useful to review a summer assessment report for a drought year, when less water was available for hydropower generation. The 2015 summer assessment (CAISO 2015) was carried out during a period of statewide drought in California. The assessment found that renewable additions and imports from other regions could compensate for the loss of locally generated hydropower in the Greater Sacramento area, but mitigation procedures might be necessary in the San Joaquin Valley area. The 2015 assessment stated that hydropower generation reductions may affect power supply in the San Joaquin Valley area. Under the extreme low hydropower generation and high load scenario, this area may be subject to potential overloads under various contingencies. However, the report also pointed out that a mitigation procedure had been put in place to manage water resources to ensure that sufficient power supply exists during peak hours. The 2015 assessment did not find any specific reliability issues or concerns in the Greater Sacramento area under low hydropower conditions. If the overall CAISO-wide hydropower capacity derate (reduction) exceeds the limits assessed in the report (i.e., more than 2,733 MW), other systemwide or local reliability issues might emerge.

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

Power Curtailments during August 2020

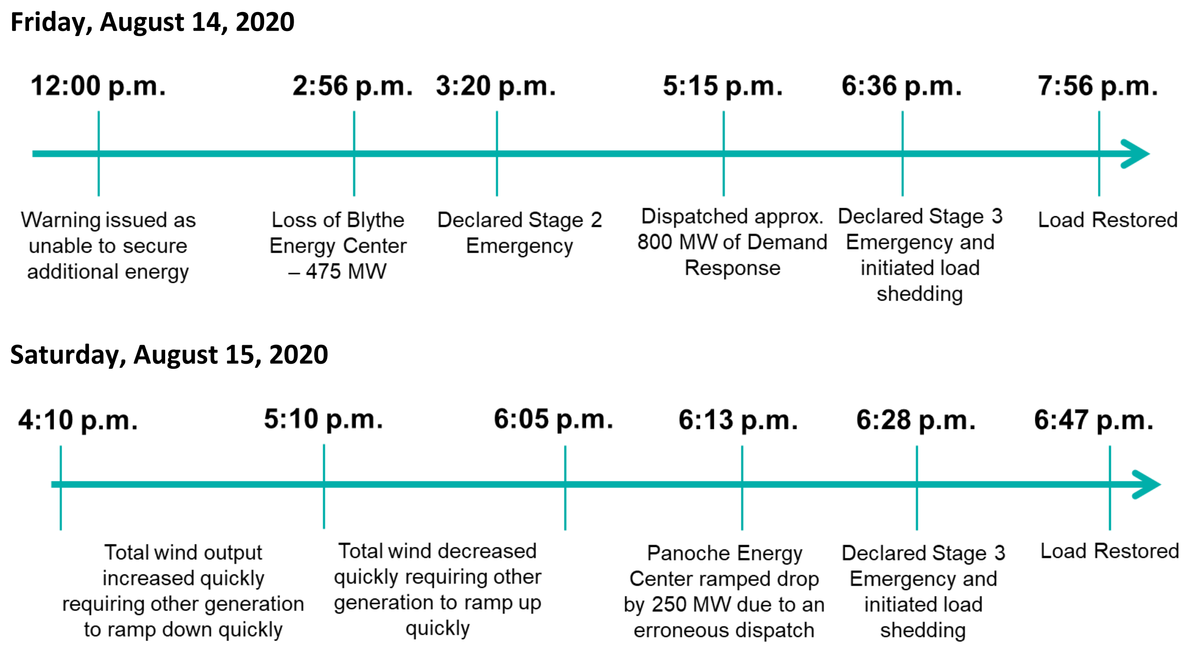
During the late afternoon on August 14 and 15, 2020, a record-breaking heat wave in California and the Southwest led to rolling blackouts, or power curtailments, in California. It should be noted that these power curtailments are different from Public Safety Power Shutoff measures, which are taken by electric power providers to prevent wildfires during periods of extreme fire danger. The Public Safety Power Shutoff measures occur due to extreme weather conditions, which would not be affected by the proposed Plan amendments. On the other hand, the power curtailments of August 2020 exposed the limitations of the reliability of California's electric grid and the RA planning processes. An increasing amount of intermittent electrical generation (e.g., solar and wind power) and the tightening of system supply by retiring facilities have reduced the margin of error for the California electric grid.

Factors leading to the rolling blackouts included the following.

- Various forms of supply shortages, resulting from unexpected low availability of electric generation from thermal facilities (mostly natural gas power plants) and intermittent resources under extreme weather conditions.
- Insufficient consideration of stressful scenarios in RA planning, which led to a lack of operating reserves relative to actual needs.
- Market practices in the day-ahead energy market that can lead to under-scheduled demand and excessive exports under extreme conditions (CAISO 2021c).
- Failure to secure sufficient resources for use in emergency situations (e.g., callable demand response resources), which contributes to limited flexibility in responding to emergencies.

Background

On August 14, 2020, CAISO declared a Stage 3 Electrical Emergency at 6:36 p.m. due to a regional heatwave-induced increase in demand for electricity and reduction in availability of imports along with an unexpected outage of the Blythe Energy Center in Riverside County, which is rated at 492 MW. A Stage 3 Electrical Emergency is declared when demand outpaces available supply. Notices are issued to utilities that they may need to reduce system demand for electricity (load) by implementing power-supply interruptions (load shedding). The emergency initiated rotating outages of about 1,000 MW throughout the state. On the following day, August 15, CAISO declared a Stage 3 Electrical Emergency again at 6:28 p.m. due to the high electricity demand, unexpected ramping down of power at the Panoche Energy Center in Fresno County, and loss of nearly 1,000 MW of wind power due to low wind. Rotating power interruptions of about 470 MW were initiated across the state. Figure A5-25 illustrates the timeline of events on August 14 and 15 based on CAISO's briefings on system operations (CAISO 2020a).



Source: CAISO 2020a.
MW = megawatt

Figure A5-25. Timeline of Events during August 2020 Power Curtailments

Planning Deficiency

The forced outage and erroneous dispatch of the two natural gas plants contributed to the rolling outages, but it is noteworthy that the power losses were less than the final load shed order by CAISO, which indicated additional shortages. The reason for additional energy shortages was partly related to the RA planning process. The objective of the RA obligations is to meet demand for electricity during the period of peak demand (gross peak demand). The requirement is to procure enough capacity to meet the demand of a 50/50 peak weather forecast, which means there is a 50-percent chance of actual demand being higher than the forecasted peak demand. The heat that spanned the western region on August 14 and 15, 2020, was a rare event that was not captured in the 1-in-2 forecast. CAISO's demand peaked at 46,777 MW on Friday, August 14, 2020, above the 1-in-2 peak forecast of 45,907 MW in the *CAISO 2020 Summer Loads and Resources Assessment* (CAISO 2020b). The RA methodology includes an additional 15-percent planning reserve margin above the 1-in-2 load forecast that is meant to cover a 6-percent contingency reserve for the grid operator, forced outages, and loads above forecasted values (CAISO 2021c). This RA methodology did not fully protect against energy shortages during the extreme weather conditions in August 2020. CAISO (2021c) now recommends that the RA process consider the period of a day after gross peak demand when solar energy declines but demand is still relatively high. This period may experience greater power deficits than may occur during the period of gross peak demand.

Various Forms of Supply Shortages

Further analysis showed that the available generation on August 14 and 15, 2020, was significantly lower than the planned RA requirements. Supply shortages took various forms as follows.

- **Thermal.** Unexpected outages at natural gas power plants were reported for both days during the outage hours. Total gas generation in California was only around 25 GW from 6 to 9 p.m. for both days. In contrast, in the CAISO August 2019 filing to CPUC (CAISO August 2019 RA Assessment [CAISO 2019), CAISO estimated that 28.7 GW of natural gas power would be available during system peak hours. Actual gas generation was roughly 13 percent lower than considered in the CAISO August 2019 RA Assessment.

- **Wind.** A loss of about 1 GW of wind generation was reported by CAISO to be one of the driving factors for the blackout on Saturday. In fact, the actual wind generation was around 1.3 GW lower from 6 to 9 p.m. on Friday and Saturday than was assumed in the CAISO August 2019 RA Assessment—about 50 percent below expectations due to the unique weather pattern.
- **Imports.** Less than 7 GW of imports were available between 6 and 7 p.m. for both days, while in the CAISO August 2019 RA Assessment, CAISO assumed that around 10.2 GW of import resources would be available to help the system meet annual peak demand. Because not all imports counted in the RA procurement have been secured by long-term contracts, the imports from non-CAISO regions could be reduced under systemwide extreme conditions similar to the conditions on August 14 and 15. In addition, the import capability depends greatly on the transmission availability. For example, the California–Oregon Intertie connecting the Pacific Northwest and California was derated through the month of August (i.e., operated at less than its maximum capacity).

CAISO took a slightly more conservative approach in the May 2020 Summer Loads and Resources Assessment (CAISO 2020b) by assuming that imports would be capped at 9.5 GW when demand approached 50 GW in its base-case modeling. This more conservative assumption considered that import resources might be limited when demand is high in neighboring states. However, this amount is still significantly higher than the imports that materialized during the August 2020 emergency condition (Table A5-11) (ICF 2020).

Table A5-11. Power Resources during Blackout Hours

Time		Market Performance (MW)			CAISO RA Assessment for 2020 (MW)			Difference (MW)				Difference (%)			
Date	Hour	Natural Gas	Wind	Imports	Natural Gas	Wind	Imports	Natural Gas	Wind	Imports	Total	Natural Gas	Wind	Imports	Total
8/14/20	18	24,962	810	5,855	28,689	2,694	10,193	(3,727)	(1,884)	(4,338)	(9,949)	-13	-70	-43	-24
8/14/20	19	25,278	1,045	6,887	28,689	2,876	10,193	(3,411)	(1,831)	(3,306)	(8,548)	-12	-64	-32	-20
8/14/20	20	25,220	1,025	7,217	28,689	2,828	10,193	(3,469)	(1,803)	(2,976)	(8,248)	-12	-64	-29	-20
8/15/20	18	24,320	2,033	4,521	28,689	2,694	10,193	(4,369)	(661)	(5,672)	(10,701)	-15	-25	-56	-26
8/15/20	19	25,781	1,436	5,480	28,689	2,876	10,193	(2,908)	(1,440)	(4,714)	(9,062)	-10	-50	-46	-22
8/15/20	20	25,880	2,114	5,751	28,689	2,828	10,193	(2,809)	(714)	(4,442)	(7,964)	-10	-25	-44	-19

Source: ICF 2020.
CAISO = California Independent System Operator
MW = megawatt; RA = resource adequacy

Reduced Power Availability during Extreme Weather

In addition to the outage at the Blythe Energy Center, which was one of the direct triggers of the blackout, a significant number of generation plants were not generating at their maximum capacity when the blackout occurred. August outage records from CAISO (CAISO 2020c) indicate that approximately 5,400 MW of generation capacity were not available when the rolling outages occurred on August 14, 2020. The outages and curtailments occurred for various underlying reasons, including general plant maintenance, plant malfunctioning, and hourly gas-burn limitations issued by the natural gas transmission pipeline operators. In addition to these outages, an additional 1.7 GW of generation capacity could not come online due to the extreme weather conditions. The unavailable capacity due to abnormal weather conditions might not have contributed to the supply shortage if it had been considered in the planning process.

Prevention of Subsequent Power Curtailments

Demand Reduction. On August 18 and 19, 2020, CAISO declared a Stage 2 Electrical Emergency. A Stage 2 Electrical Emergency is declared when all mitigating actions have been taken and the independent system operator is no longer able to provide its expected energy requirements. When this situation happens, independent system operator intervention in the market is required, such as ordering power plants online. According to a joint response issued by CAISO, the California Energy Commission, and CPUC to the Governor (CPUC et al. 2020), more power outages such as those the state experienced on August 14 and 15 would have occurred if conservation efforts had not cut demand by 2,000 to 3,000 MW and the state had not secured more power. In addition to the public call for energy conservation, the California Energy Commission coordinated with data centers in Silicon Valley to move approximately 100 MW of load to on-site backup generation. It also worked with the U.S. Navy and Marine Corps to "disconnect 22 ships from shore power, move a submarine base to backup generators, and activate several microgrid facilities resulting in approximately 23.5 MW of load reduction" (CPUC et al. 2020). Additionally, solar and battery storage companies, including Sunrun and Tesla, worked with their customers to change battery charging patterns so that they were maximizing power availability between 4 and 9 p.m.

Hydropower and Water Operation Adjustment. Adjustment of hydropower generation and pumping schedules helped to inject more power into the grid. The joint response (CPUC et al. 2020) reported that DWR and the Metropolitan Water District of Southern California shifted 80 MW of hydropower generation to peak demand times. DWR and Reclamation made changes in pumping schedules that secured another 72 MW, and Hetch Hetchy hydropower facilities were dispatched at their maximum output level to generate an additional 150 MW during peak demand periods. Additionally, starting August 18, 2020, Yuba Water Agency increased hydropower generation by an additional 20 MW (Yuba Water Agency 2020). With more intermittent resources coming online (e.g., solar and wind power), the flexible timing of power generation at some hydropower facilities could become increasingly useful for addressing unexpected energy supply shortages.

A5.3.1.4 Sacramento Municipal Utility District Capacity Conditions

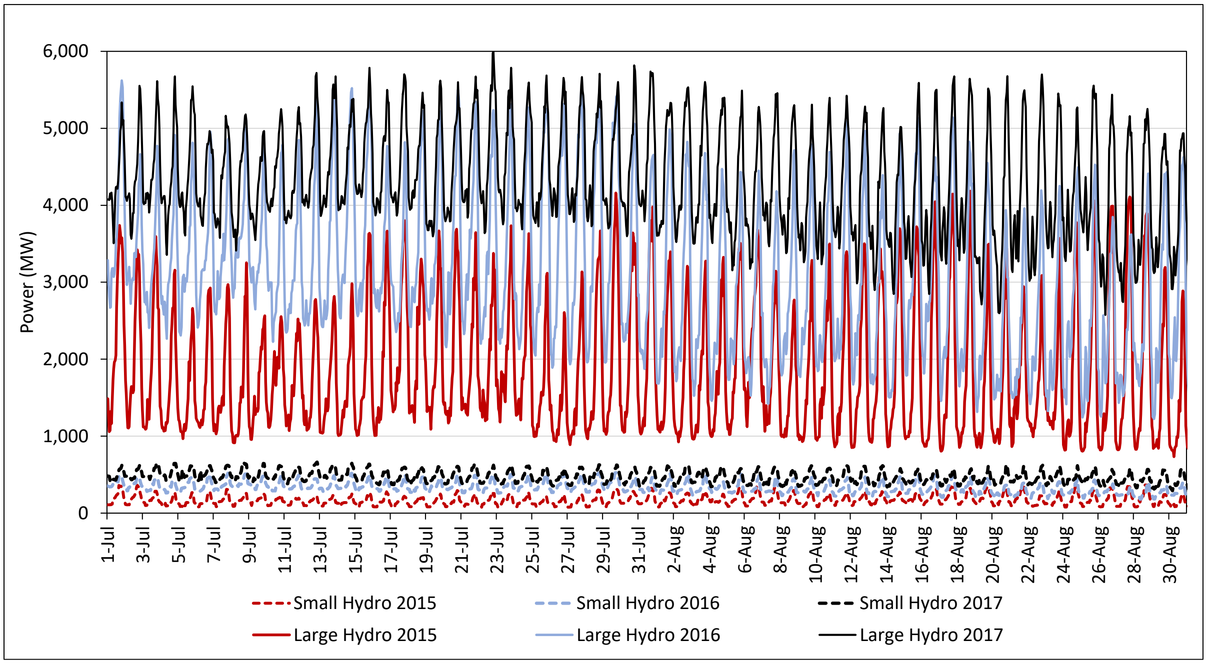
Because SMUD is located within the Sacramento/Delta and is part of the BANC balancing authority and not CAISO, SMUD energy resource assessments provide additional information about the electric grid within the Sacramento/Delta and how the area might be affected by reductions in hydropower.

SMUD carries out an annual 10-year transmission planning process to ensure that NERC and WECC reliability standards are met each year of the 10-year planning horizon (SMUD 2021). Major approved transmission projects were identified in the 2021 transmission plan for the near term (2021 through 2025) (SMUD 2021), including transmission line reconductoring, transmission rating increase, a new substation, and several new interconnections for solar energy/battery storage. These projects are expected to improve the reliability of SMUD's electric system as well as increase its load-serving capability, resulting in an electric grid that can better withstand reductions in hydropower. The SMUD Generator Interconnection Queue List of potential future projects includes six solar energy generation/battery storage interconnects totaling 1,594 MW generating capacity proposed to come into service between October 2023 and December 2024 (SMUD 2021).

A5.3.2 Peaking Operations

The ability to ramp power up and down during a day is an important tool to compensate for variations in demand and generation of electricity. This peaking ability is becoming more important due to increasing use of solar and wind power. Hydropower is one of the tools available for ramping power up and down as needed.

Hydrologic conditions may affect daily variations in hydropower generation through the day. Under wet conditions, hydropower facilities may operate close to full capacity throughout the day; during dry conditions, reductions in water availability may limit the ability to generate maximum power during periods of peak demand. However, flexibility persists under both dry and wet hydrologic conditions. Daily peaking operations can be seen in aggregated hydropower generation data collected by CAISO (hourly hydropower generation data for individual hydropower facilities are not available from CAISO). Hourly hydropower values for 2015 (a critically dry year) and for 2017 (a wet year) show that substantial peaking operations occur during both wet and dry years (Figure A5-26). The comparison shows that, as a percentage of average hydropower generation, peaking was greatest during the dry conditions of 2015 and smallest during the wet conditions of 2017. However, in terms of absolute values (in MW, not percent), peaking was greatest during 2017. These data show that hydropower can contribute to peak power demands under both wet and dry conditions.



Source: CAISO 2017, page ref. n/a.
MW = megawatt

Figure A5-26. Hourly Power from Small and Large California Independent System Operator Hydropower Facilities during Summer 2015, 2016, and 2017

A5.3.3 Power Flow Assessment Methods

Power Gem's Transmission Adequacy and Reliability Assessment (TARA) software was used for the power flow assessment in this study to examine any reliability violations[3] under normal system conditions as well as contingency (i.e., outage) conditions. TARA is a steady-state power flow software tool that provides robust and fast power flow calculations. It is widely used for reliability analysis, transfer limit calculation, preventive and corrective generation dispatch, critical facility identification, outage analysis, and region-wide generation deliverability analysis. TARA is licensed and used by all Regional Transmission Organizations/Independent System Operators in the country.

The TARA tool was used to simulate a base case (baseline conditions) and the 75 scenario. The 75 scenario was chosen for analysis because it has the largest instream flow requirement and would result in the largest reductions in reservoir storage (head) and the largest changes in flow for hydropower (see Section A5.2, *Hydropower Generation in the Sacramento/Delta*). Grid reliability for the 75 scenario was compared with baseline conditions. If this evaluation of worst-case conditions were to indicate reliability concerns, the lower flow scenarios would be evaluated.

[3] Reliability violations include *thermal violations*, which refer to the overloads at a transmission line or transformer where the loading of that transmission facility exceeds its normal rating under normal conditions or emergency rating under contingency conditions (i.e., outage events), and *voltage violations*, which refer to out-of-range voltage deviation from the normal operating values.

To assess grid reliability, loading on transmission facilities—including transmission lines and transformers as well as bus[4] voltages—was evaluated to identify any thermal violations (i.e., overload) or voltage violations under both normal and contingency conditions. Under normal conditions, all generation and transmission facilities are assumed to be in service. The contingency scenarios were ones defined by CAISO for reliability assessments. These CAISO contingency scenarios specify single or multiple outages. In some cases, multiple outages are associated with a substation bus bar that houses multiple transmission elements.

In general, if there is an undesired reduction in electricity generation, the shortage can be replaced by increased electrical generation at another facility on the electric grid. However, as described in Section A5.3.1, *Overview of the Transmission System in California*, some local areas may have transmission constraints that could limit their ability to serve peak load. A power flow assessment was performed to determine whether reduction in hydropower generation due to changes in Sacramento/Delta hydrology might affect grid reliability.

The TARA Load Flow model uses inputs developed by CAISO to represent 2021 electric grid conditions under heavy summer demand for the entire Western Interconnection, including detailed representation of the California electric grid. The model relied on transmission system data obtained from the 2021–2022 CAISO Reliability Assessment Base Case. ICF staff obtained the case through the Critical Energy/Electric Infrastructure Information process.

The power flow modeling includes all types of electricity-generating facilities, including natural gas, solar, hydropower (e.g., including all CVP and SWP hydropower), coal, and wind. The electric demand is modeled at each substation, and it includes all types of demand: residential, industrial, agricultural, and institutional (e.g., energy to move SWP and CVP Delta exports). The power flow analysis represents the electric grid under 2021 summer peak conditions. In this analysis, imports of electricity into California from other states were held constant at levels representative of 2021 conditions as received in the power flow base case from the 2021–2022 CAISO Reliability Assessment. Any shortages of electricity in the local area show up in the model results as a power overload on a transmission line or a violation of substation voltage requirements. To compensate for reduction in hydropower, generation at existing natural gas facilities in California was scaled up in the 75 scenario.

As an entity, WAPA is not specifically included in the power flow model for this study. However, federal hydropower generation marketed and transmitted by WAPA, as well as electricity used by WAPA customers, is included in the power flow modeling. Within California, WAPA brokers excess CVP hydropower energy that is not needed for pumping CVP Delta exports. In the power flow model, energy demand for pumping CVP Delta exports and CVP hydropower generation are included separately, which is appropriate because they do not occur in the same locations. Energy imports to California, which include WAPA imports, were held constant at levels representative of 2021 conditions.

The transmission line and transformer limits used in the study were the normal megavolt-ampere (MVA) rating and emergency MVA power ratings. Volt-ampere (VA) is a unit of measurement used in alternating current (AC) power systems to represent the apparent power of an electrical system, equivalent to the watts used in direct current (DC) power systems. In an AC system, apparent power

[4] A *bus* in a power system is defined as an interconnection point where several components of the power system—such as generators, loads, and feeders—are connected.

includes both real power, which refers to the actual power dissipated in the transmission system (measured in watts), and reactive power, which refers to the power oscillation between load and source that is inherent in an AC system (measured in Volt-Amperes Reactive [VAR]). An MVA is used to express the total power flow in an AC electrical system, and it equals the root sum square of real and reactive power. Under normal and contingency conditions, transmission line and transformer power should remain within the normal and emergency MVA ratings, respectively. The transmission line or transformer is considered thermally overloaded if power flow exceeds its rating.

Similarly, voltage limits were established relative to the normal voltages at the power flow buses. Under normal conditions, system operators regulate bus voltages within approximately 5 percent of their normal values. Under contingency conditions, this limit is relaxed to within approximately 10 percent of the normal value. Transmission upgrade or system adjustment is required if nodal voltages move outside of these defined limits.

If the flow scenario resulted in reliability criteria violations, redispatch solutions were identified to alleviate the violations. The redispatch solutions could include increasing generation at other facilities and adjustment of devices to control voltages and line flows. The redispatch solutions were not permitted to create new violations. If redispatch solutions could not be identified, the grid could be affected.

A5.3.3.1 Selection and Modification of Estimated Hydropower Values for Power Flow Modeling

The power flow assessment focused on energy effects associated with estimated reductions in summer hydropower in the Sacramento/Delta. Several other substantial energy effects might occur because of measures that could be taken in response to the proposed Plan amendments, including potential reductions in energy needed for Delta exports and potential increases in energy consumption to increase water supply. The decrease in energy needed for Delta exports is likely to be substantial, but this energy savings would likely be partially counteracted to an uncertain degree by measures such as groundwater pumping, water transfers, and desalination to replace reduced surface water supply. This topic is covered in more detail in Section A5.4, *Energy Use for SWP and CVP Export Pumping*, and Section 7.8, *Energy*. These other energy effects were not included in the power flow assessment because of the difficulty in predicting the actions people would take in response to reductions in water supply and because the net effect is unlikely to be large (see Section 7.8, *Impact EN-e*).

The hydropower facilities considered in the power flow assessment were the same as those included in the hydropower generation analysis described in Section A5.2, *Hydropower Generation in the Sacramento/Delta*. Electricity generation values for other facilities were the default values for 2021. Hydropower facilities' default generation is approximately 75 percent of the facilities' maximum capacity in the 2021 summer peak power flow case that was received from the 2021 FERC filing. This default generation in the power flow case is typically based on the historical operations during summer peak condition.

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

Because the power flow model simulates electricity during the daily period of peak demand, the monthly hydropower values estimated from SacWAM results were scaled up to represent the monthly average of daily peak power. Under both baseline conditions and the 75 scenario, hydropower peaking operations would still occur to maximize hydropower during the daily time of peak demand. Hydropower was estimated as the monthly hydropower derived from the SacWAM results increased by a fraction to represent typical peaking operations that would occur in the absence of a contingency.

To estimate peak hydropower relative to average hydropower, hourly CAISO data for July and August in 2015, 2016, and 2017 were evaluated to assess conditions during a range of hydrologic conditions (CAISO 2017). These values are provided for all CAISO hydropower facilities combined, as CAISO does not provide data for individual hydropower facilities. The degree of peaking operations varies from facility to facility and from day to day, but the use of the aggregated values is sufficient for estimating the effect of peaking operations and the adequacy of electric power supply to maintain grid reliability.

The data show that, as a percentage of average hydropower generation, peaking was greatest during the dry conditions of 2015 and smallest during the wet conditions of 2017 (Table A5-12, Figure A5-26), although in terms of absolute values (in MW, not percent), peaking was greatest during the more moderate year of 2016. These results are not surprising. During wet years, flow through the powerhouses may be so high that generation remains high throughout the day. During dry years, large daily fluctuations occur, but not enough water is present to maintain high average generation.

The peaking percentages of the more moderate year, 2016, were used in the power flow assessment to estimate that daily peak hydropower is 54 percent greater than the daily average hydropower under both the baseline conditions and 75 scenario for the normal and contingency power flow simulations. This percentage was used because it is a moderate value between the percentages seen in 2015 and 2017 and because 2016 was a below-normal year, which is the same year type chosen for the assessment because it represents conditions with the largest estimated reductions in hydropower. In reality, if average flows through the powerhouses were substantially reduced, the peaking percentage may increase somewhat to be more similar to operations during 2015. Because an increase in the peaking percentage could enhance grid reliability, the assumption of a constant peaking percentage is somewhat conservative, likely underestimating power availability during peak demand.

Table A5-12. Average July-to-August California Independent System Operator Hydropower Peaking

Year	Sacramento Valley Water Year Type	Average Hydropower (MW)	Average Daily Maximum Hydropower (MW)	Average Daily Increase in Hydropower to Help Meet Peak Demand	
				(MW)	(%)
2015	Critical	2,031	3,682	1,651	81
2016	Below normal	3,433	5,297	1,864	54
2017	Wet	4,782	6,057	1,275	27

Source: CAISO 2017.
MW = megawatt

In summary, power was calculated as

Power = Monthly Average Power derived from SacWAM results * (1 + Peaking fraction)

where

Monthly Average Power derived from SacWAM results = Monthly Energy derived from SacWAM results (Section A5.2, *Hydropower Generation in the Sacramento/Delta*), divided by the number of hours in the month

and

Peaking fraction = 0.54, based on 2016 data from CAISO.

The reservoir releases at some facilities can be increased on a short-term basis to maximize power and alleviate any reliability violations observed under contingency conditions. For this reason, if it appeared that the 75 scenario would result in a grid reliability issue under the contingency condition, hydropower could have been allowed to temporarily increase at some facilities to the maximum value possible, but this was not necessary.

For the following reasons, the power flow assessment represents a worst-case evaluation.

- The analysis compared the 75 scenario with baseline conditions because the change in hydropower is greatest under this scenario.
- The analysis used estimated hydropower generation for July of below-normal years because the largest reduction in summer hydropower generation in association with the 75 scenario occurred for this month and water year type.
- The analysis assumed no increase in peaking percent when there was a reduction in hydropower.

For these reasons, the power flow assessment likely overstates reduction in power for the proposed Plan amendments.

A5.3.4 Power Flow Assessment Results

The peak power generated by the 47 facilities represented in the analysis was approximately 3,552 MW for baseline conditions and 2,118 MW for the 75 scenario. To compensate for this difference in power, generation at existing natural gas facilities was scaled up proportionally in the 75 scenario analysis. Peak power generated under the other flow scenarios was higher than for the 75 scenario, confirming the conservative nature of the power flow analysis (2,449 MW for the 65 scenario, 2,872 MW for the 55 scenario, 3,218 MW for the 45 scenario, and 3,428 MW for the 35 scenario).

The 75 scenario did not cause out-of-limit bus voltage violations or transmission line or transformer thermal (MVA) loadings violations under normal system conditions. Under contingency conditions, the power flow assessment found that the 75 scenario caused no bus voltage violations but caused several thermal overloading issues across the CAISO system prior to applying any redispatch of generation, as summarized in Table A5-13. Locations of the monitored elements (transmission lines or transformers) presented in Table A5-13 are shown in Figure A5-27.

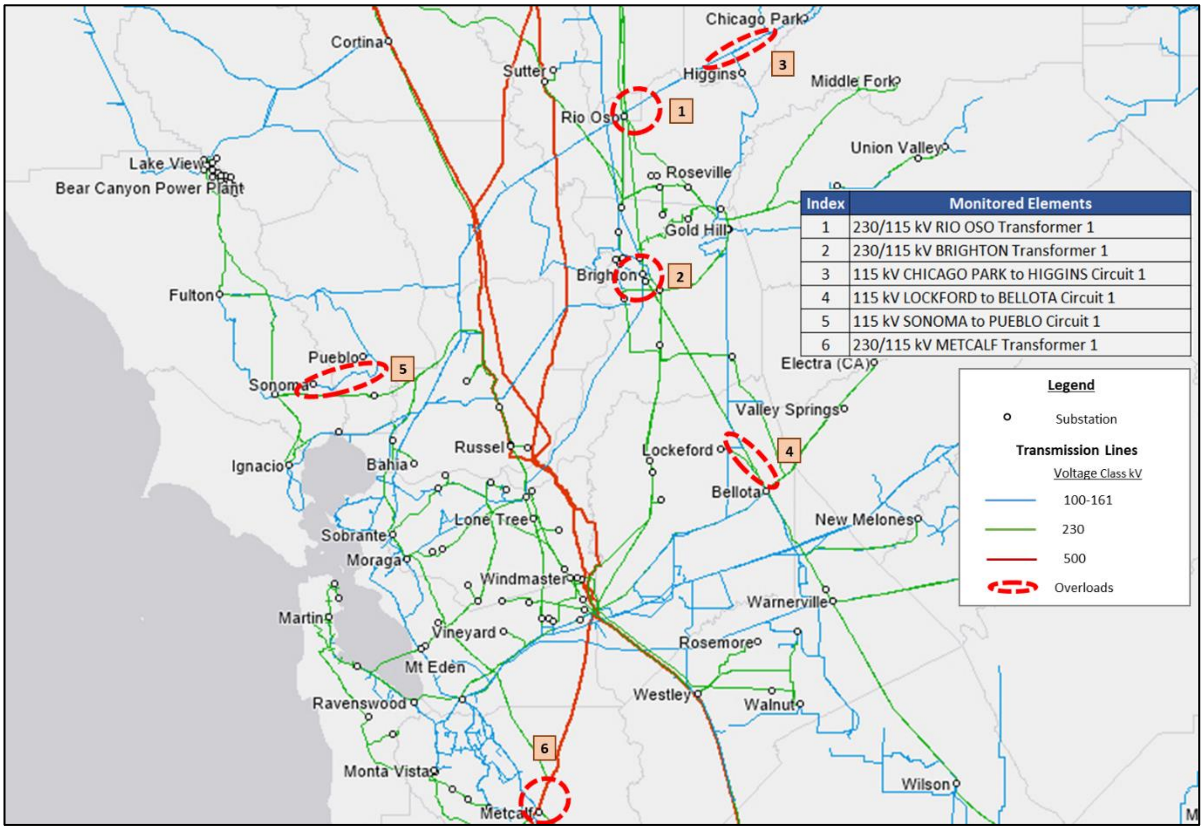
Table A5-13. Results from the Power Flow Assessment Showing the Most-Affected Transmission Facilities Prior to Generation Redispatch

Monitored Overloaded Element [a]	Contingency Element(s) [b]	Emergency Rating (MVA)	Loading in the Base Case (% of Rating)	Loading in the 75 Scenario (% of Emergency Rating)
230/115 kV Rio Oso Transformer 1	Outage of: 115 kV Brighton–Howard Junction 1&2&3 lines and 230/115 kV Brighton transformer 9	126.7	96.57	113.1
230/115 kV Rio Oso Transformer 1	Outage of: 115 kV Brighton–DPWT line, 115 kV Brighton–Howard Junction 1&2&3 lines, and 230/115 kV Brighton transformer 9	126.7	96.48	113.0
230/115 kV Brighton Transformer 1	Outage of: 115 kV UCD-Campus line and 115 kV Davis bus	239	92.09	103.6
115 kV Chicago Peak to Higgins Line 1	Outage of: 115 kV Goldhill–Placer 1 line and Goldhill–Flint 2 line	175.5	86.42	102.3
115 kV Chicago Peak to Higgins Line 1	Outage of: 230/115 kV Goldhill transformers 1&2, 115 kV Goldhill–Flint 1&2 lines, and Goldhill–Mizou 1&2 lines	175.5	86.37	102.2
115 kV Lockford to Bellota Line 1	Outage of: 115 kV Bellota–Riverbank Junction line, Riverbank Junction–Riverbank Substation line, 115 kV Lockford–Bellota line, and 230/115 kV Bellota transformer 1	102.4	99.07	101.6
115 kV Lockford to Bellota Line 1	Outage of: 115 kV Bellota–Riverbank Junction line, 115 kV Lockford–Bellota line, and 230/115 kV Bellota transformer 1	102.4	99.06	101.5
115 kV Sonoma to Pueblo Line 1	Outage of: 230/115 kV Fulton transformers 4&9, 230 kV Fulton–Ignacio line, 230 kV Fulton–T22 line, 230 kV Fulton–Geyser line, and 230 kV Fulton–Crit3 line	121.5	98.93	100.4
230/115 kV Metcalf Transformer 1	Outage of: 230 kV Metcalf–Cal Mec line, 230 kV Metcalf – Mosslanding 1&2 lines, Metcalf–Montavis line, and 230/115 kV Metcalf transformers 2&3	462	98.59	100.2
115 kV Sonoma to Pueblo Line 1	Outage of: 230/115 Fulton transformers 4&9, 115 kV Crit3–Geyser line, and 230 kV Fulton–Lakeville line	121.5	99.21	100.2

kV = kilovolt; DPWT = Department of Public Works and Transportation; MVA = megavolt-amperes; UCD = University of California, Davis

[a] The transmission element on which line loading is monitored under normal and contingency conditions.

[b] The element assumed to be lost for the contingency analysis.



kV = kilovolt

Figure A5-27. Location of Overloaded Transmission Facilities (Transmission Lines and Transformers) Prior to Generation Redispatch

With the redispatch of power from existing generators, all violations in Table A5-13 can be resolved. Therefore, the 75 scenario did not cause reliability criteria violations under normal system conditions and did not cause reliability criteria violations at the transmission lines or substation transformers under the contingency scenarios that could not be rectified with a temporary redispatch of generation. Electricity generation at other facilities was able to compensate for a reduction in hydropower in the Sacramento River watershed. Because reductions in hydropower generation for all other flow scenarios (35, 45, 55, and 65) are less than the reductions associated with the 75 scenario, these lower flow scenarios would also not be expected to cause any violations of reliability criteria.

A5.4 Energy Use for SWP and CVP Export Pumping

A large amount of energy is required to pump CVP and SWP Delta exports uphill, and only a portion of this energy can be recaptured when some of the water drops in elevation on its way to its final destination. Potential energy effects associated with changes in CVP and SWP exports from the Delta through the Jones and Banks Pumping Plants were estimated using energy factors that are estimates of the average energy needed to export a volume of water (MWh/TAF). These energy factors include the recapture of some energy along the downhill portions of the conveyance system.

The energy expenditure for CVP exports remains about the same regardless of the volume of the exports because most CVP exports have a destination that is beyond the three main CVP pumping facilities (Jones, O'Neill, and Gianelli pumping facilities). The energy needed to move the total volume of SWP exports depends on the fraction of the volume that is moved to each destination. However, because SWP water supply allocations are assigned based on a percent of full SWP contract values, the fraction of exports going to the various destinations changes little in response to changes in overall export volume. Because the distribution pattern of the exports relative to pump locations tends to be about the same regardless of the volume of water exported, the energy factor is not greatly affected by changes in the total volume of water exported.

This analysis did not include exports and diversions that require relatively little energy for conveyance, such as the East Bay Municipal Utility District diversions from the Mokelumne River and the North Bay Aqueduct diversions from the north Delta. Not only would energy effects associated with conveyance of water through these facilities be relatively small, but there would also be no effect on hydropower generation at the associated export reservoirs in the Bay Area because no hydropower facilities are present at these reservoirs (^ABB 2017).

A5.4.1 CVP Pumping Energy Use

This section describes the key pumping and hydropower facilities along the conveyance system for CVP Delta exports, with information derived from the CVP LTG energy spreadsheet (described in Section A5.2.2.1, *CVP Long-Term Generation Energy Model and SWP Energy Model*). The three main CVP facilities are Jones Pumping Plant, which lifts CVP water into the Delta-Mendota Canal (DMC), and O'Neill and Gianelli Pumping-Generating Plants, which are used to store water in San Luis Reservoir. Much of the energy required to pump water into O'Neill Forebay and San Luis Reservoir is regained when the water is released from these reservoirs. However, the process of moving water into and out of the reservoirs represents a net loss of energy.

Jones Pumping Plant is north of Tracy and consists of six pumps. The pumps are each rated at 22,500 horsepower (16.7 MW), for a maximum energy requirement of about 100 MW. The pumping plant has a maximum head of about 192 to 197 feet (depending on tide level) and a maximum flow of about 5,000 cfs. The pumping efficiency is about 78 percent; therefore, the pumping energy factor is about 252 MWh/TAF.

O'Neill Dam and O'Neill Pumping-Generating Plant are at the convergence of O'Neill Forebay and the DMC. O'Neill Pumping-Generating Plant uses six pumping units to lift water about 45 to 53 feet from the DMC to O'Neill Forebay, with head depending on water level in O'Neill Forebay. The pumping units have a maximum flow of 4,200 cfs and require about 27 MW of power. When water is released to the DMC, the six units have a maximum flow of about 6,000 cfs and generate 25 MW.

Gianelli Pumping-Generating Plant is a joint CVP/SWP facility between O'Neill Forebay and San Luis Reservoir. The pumping head ranges from 100 feet at minimum storage in San Luis Reservoir to about 320 feet at maximum storage. The plant has eight pumping-generating units that can pump a maximum of 11,000 cfs with a pumping energy factor of 412 MWh/TAF, an efficiency of about 78 percent, and an energy requirement of 380 MW. When releasing a maximum flow of 16,000 cfs from San Luis Reservoir to O'Neill Forebay, the eight units generate a maximum of 400 MW with an energy factor of about 300 MWh/TAF and an efficiency of about 94 percent.

For the California WaterFix Project, results from the CVP LTG monthly energy model for CVP exports were used to determine the average energy use for CVP exports, including the energy use at the

Jones, O'Neill, and Gianelli Pumping Plants. The average net energy factor for CVP exports was about 363 MWh/TAF. (^DWR and Reclamation 2016.).

A5.4.2 SWP Pumping Energy Use

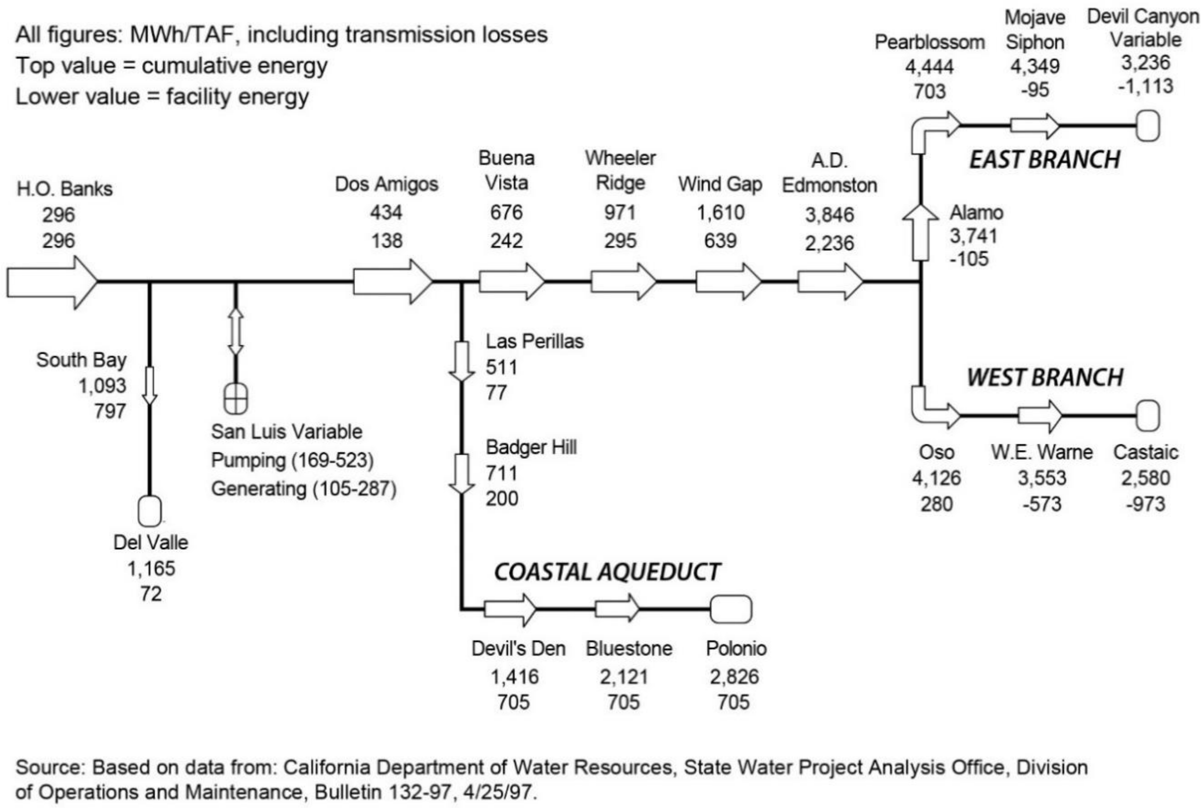
Energy required to transport SWP water that is exported at Banks Pumping Plant through the California Aqueduct system is higher than energy needed for CVP exports. The following text describes some of the key pumping and hydropower facilities along the SWP aqueduct system, with information derived from the SWP power spreadsheet (see Section A5.3, *Energy Grid Analysis*) and an SWP energy evaluation by Wilkinson (^2000). The SWP conveyance system is much more complex and requires much more energy for moving water south than does the CVP conveyance system.

The SWP network of pumping plants and generating powerhouses is shown in Figure A5-28 (^Wilkinson 2000). The figure summarizes the energy factors (MWh/TAF) required for pumping SWP water from Banks Pumping Plant near Tracy to various locations along the California Aqueduct. Positive numbers for *facility energy* indicate the amount of energy (in MWh) required to move 1 TAF through a pumping plant. Negative numbers for facility energy indicate the amount of energy that can be recaptured when that water moves downhill. *Cumulative energy* is the combined net energy factor for each location; it is the total amount of energy (in MWh) required to move 1 TAF from the Delta through each facility shown in the figure.

For example, the most energy-intensive destination would be somewhere between Pearblossom Pumping Plant and Mojave Siphon Power Plant. If the water were moved directly to this destination, without being stored in San Luis Reservoir, the energy cost would be an estimated 4,444 MWh/TAF. Storage in San Luis Reservoir would increase the energy requirement. Gianelli Pumping-Generating Plant, which lifts water from O'Neill Forebay to San Luis Reservoir, was described in the preceding section as one of the CVP pumping plants.

Banks Pumping Plant in the south Delta pumps water into the California Aqueduct. The pumping plant uses 11 pumps; two are rated at 375 cfs capacity, five at 1,130 cfs capacity, and four at 1,067 cfs capacity. The plant lifts the water about 252 feet from Clifton Court Forebay into the California Aqueduct. The maximum pumping capacity is about 10,670 cfs. The maximum energy requirement is about 246 MW. The pumping energy factor is about 296 MWh/TAF with an efficiency of 85 percent.

Some water is delivered to Kern County SWP contractors at a relatively low energy cost. The rest of the water is conveyed through the Coastal Aqueduct for deliveries along the central coast or continues in the California Aqueduct over the Tehachapi Mountains for delivery to southern California. The A. D. Edmonston Pumping Plant that moves California Aqueduct water over the Tehachapi Mountains is the highest lift pumping plant in the United States. The plant lifts water 1,926 feet and has a maximum flow of 4,480 cfs.



Source: Adapted from ^Wilkinson 2000.
Positive energy factors indicate energy cost of pumping, and negative energy factors indicate energy generation at hydropower facilities.
MWh = megawatts per hour
TAF = thousand acre-feet

Figure A5-28. Energy Factors for SWP Pumping Plants and Generating Powerhouses

The California Aqueduct continues over the Tehachapi Mountains into southern California and splits into two branches—the East Branch and West Branch. The West Branch delivers water to Lake Castaic and provides water to western Los Angeles County and the vicinity. The East Branch delivers water to the Antelope Valley, San Bernardino, and Riverside areas and eventually to Lake Perris near Hemet.

When export water moves downhill after passing over the mountains, some of the energy lost in pumping the water uphill can be recovered at hydropower facilities on the other side of the mountains (indicated by negative values for facility energy in Figure A5-28). However, the energy regained at these hydropower facilities is much less than the energy required to reach the facilities. The reason that energy used to move Delta exports cannot be fully recovered by hydropower facilities is twofold. One is that moving water up a certain vertical distance inherently requires more energy than can be recovered if the water drops the same vertical distance through a powerhouse. The other reason is that the hydropower facilities that are part of the SWP export conveyance system are at relatively high elevations and are not positioned to capture energy from a vertical drop equivalent to the maximum elevation attained by the exports.

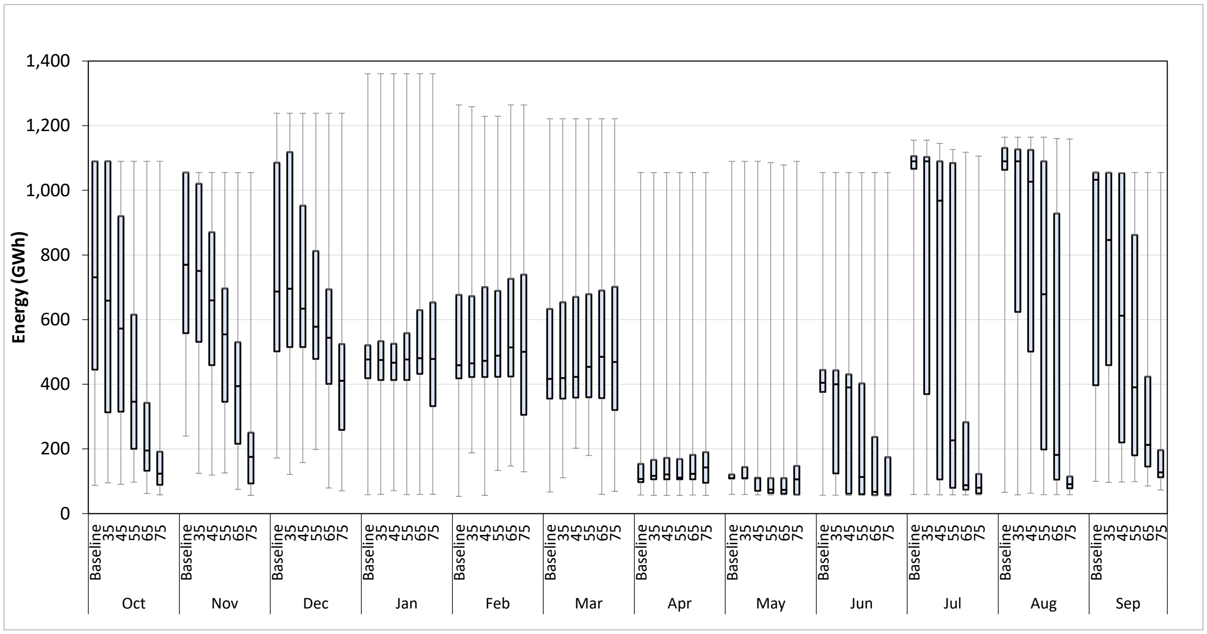
Energy recapture is part of the estimated energy factors. For example, the energy generated at Alamo, Mojave Siphon, Devil Canyon, W. E. Warne, and Castaic Power Plants (Figure A5-28) is incorporated into the net energy factor. For energy recapture at hydropower facilities associated with export reservoirs, the energy recapture assumes an average reservoir elevation. The recapture of energy could be somewhat reduced if reservoir elevations in the export reservoirs drop. Reduction in water supply could cause storage reduction in a few of the export reservoirs, but this reduction in storage is unlikely to have a substantial effect on the large energy savings expected with reduced pumping of SWP Delta exports.

The net energy factor for SWP deliveries can be calculated from the energy needed to convey water through the SWP system. For the California WaterFix Project, the energy required for SWP exports was determined from the results of the SWP energy model, using a CalSim simulation with existing facilities and operations. The energy model calculations included the individual pumping plants and deliveries from the California Aqueduct and included the energy generation at hydropower facilities south of the Delta. The average net energy factor for SWP exports was about 2,420 MWh/TAF. (DWR and Reclamation 2016.)

A5.4.3 Export Energy Results

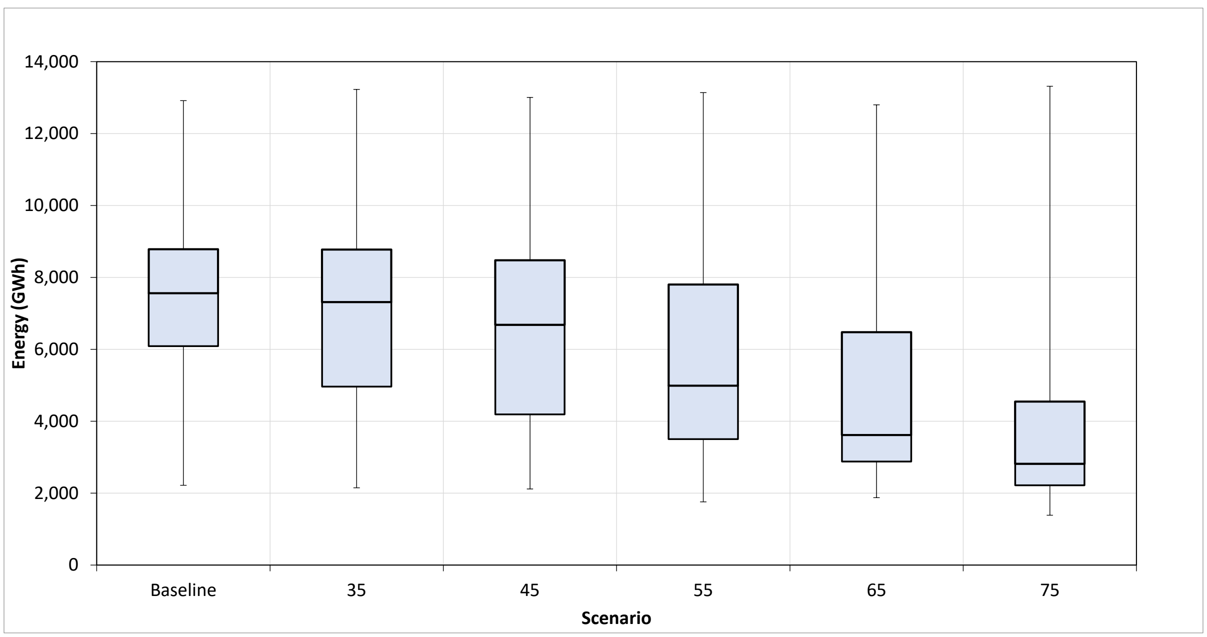
Reduction in CVP and SWP water exports would likely cause a substantial reduction in the amount of energy needed to move water to consumers. Change in energy for Delta exports was estimated using the net CVP energy factor of 363 MWh/TAF and the net SWP energy factor of 2,420 MWh/TAF, which were developed for the California WaterFix Project (^DWR and Reclamation 2016) (see Section A5.4.1, CVP *Pumping Energy Use*, and Section A5.4.2, *SWP Pumping Energy Use*). The energy evaluation shows that reductions in export energy are largest from June to December, which corresponds with the period during which SacWAM has estimated exports to be most affected (Figure A5-29). On an annual basis, reduction in energy use could be large, with calculated annual average net export energy being approximately 300 to 3,700 GWh less for the flow scenarios than for the baseline condition (Figure A5-30 and Table A5-14).

These annual average energy savings are much larger than the estimated annual average reduction in hydropower generation in the Sacramento/Delta. However, the reduction in energy use would be associated with a reduction in surface water supply. Depending on how water users react to the reduced water deliveries, energy used to replace reduced water supply could counteract the energy saved by providing less water. Reduction in water use would not require energy, but other types of responses, such as groundwater pumping, water transfers, water recycling, and desalination, could increase energy use. The potential energy expenditure for water replacement measures is discussed in Section 7.8, *Energy*.



GWh = gigawatt hour

Figure A5-29. Estimated Monthly Changes in Energy Required for CVP and SWP Exports



GWh = gigawatt hour

Figure A5-30. Estimated Annual Changes in Energy Required for CVP and SWP Exports

Table A5-14. Cumulative Distribution—Baseline Condition Energy for CVP and SWP Exports and Changes from Baseline Condition (gigawatt hour)

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

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