State Water Resources Control Board
California Environmental Protection Agency

DRAFT

APPENDIX X*: HYDROPOWER AND ELECTRIC GRID ANALYSIS OF LOWER SAN JOAQUIN RIVER FLOW ALTERNATIVES

February 2012

*Lettering of Appendix to be determined during the preparation of the Draft Substitute Environmental Document

Appendix X
DRAFT Hydropower and Electric Grid Analysis of Lower San Joaquin River Flow Alternatives

X.1 Table of Contents

X.2 Introduction

This appendix provides estimates of the potential effects on hydropower generation and electric grid reliability in the Lower San Joaquin River (LSJR) watershed caused by implementing the LSJR flow alternatives. The LSJR flow alternatives propose to alter the February through June flow on the Stanislaus, Tuolumne, and Merced Rivers (LSJR tributaries), which could affect reservoir operations and surface water diversions and the associated timing and amount of hydropower generation from the LSJR watershed.

This analysis relies on the State Water Resources Control Board (State Water Board) water supply effects model (WSE) to estimate the effects of the LSJR flow alternatives on reservoir releases and storage (elevations head) and allowable diversions to off-stream generation facilities, and then calculates the associated change in monthly and annual amounts of energy produced. This output then provides input to electric grid reliability modeling, which evaluates the potential for these changes to effect electric grid reliability under peak load and outage contingency scenarios.

There are three different LSJR flow alternatives, each consisting of specified percentage of unimpaired flow requirement for the Stanislaus, Tuolumne, and Merced Rivers. For a particular alternative, each tributary must meet the specified percentage of its own unimpaired flow at its mouth with the LSJR during the months of February through June. The percentage unimpaired flow requirements are 20%, 40% and 60% respectively for each alternative, but only apply when flows are otherwise below a specified trigger level. Also, flows must not drop below specified levels on each tributary, and together must maintain a minimum flow on the SJR at Vernalis. Specific trigger and minimum flow levels and other details of the LSJR flow alternatives are presented in Section 3.2 of the Substitute Environmental Document (SED), and are the basis for how the alternatives are modeled in this appendix.

Numerous hydropower generation facilities on the three LSJR tributaries are evaluated in this analysis. The major facilities potentially effected, however, are those associated with the New Melones Reservoir (New Melones Dam) on the Stanislaus River,[1] New Don Pedro Reservoir (New Don Pedro Dam) on the Tuolumne River, and Lake McClure (New Exchequer Dam) on the Merced River. Figure X-1 shows the location of these and other hydropower facilities in and around the LSJR watershed.

[1] The Tulloch reservoir and hydro power plant on the Stanislaus River could also be affected by the project. However, this is a relatively small facility, rated at 18 MW. Therefore, any impact associated with a reduction in its capacity on the California interconnected grid is likely to be minimal

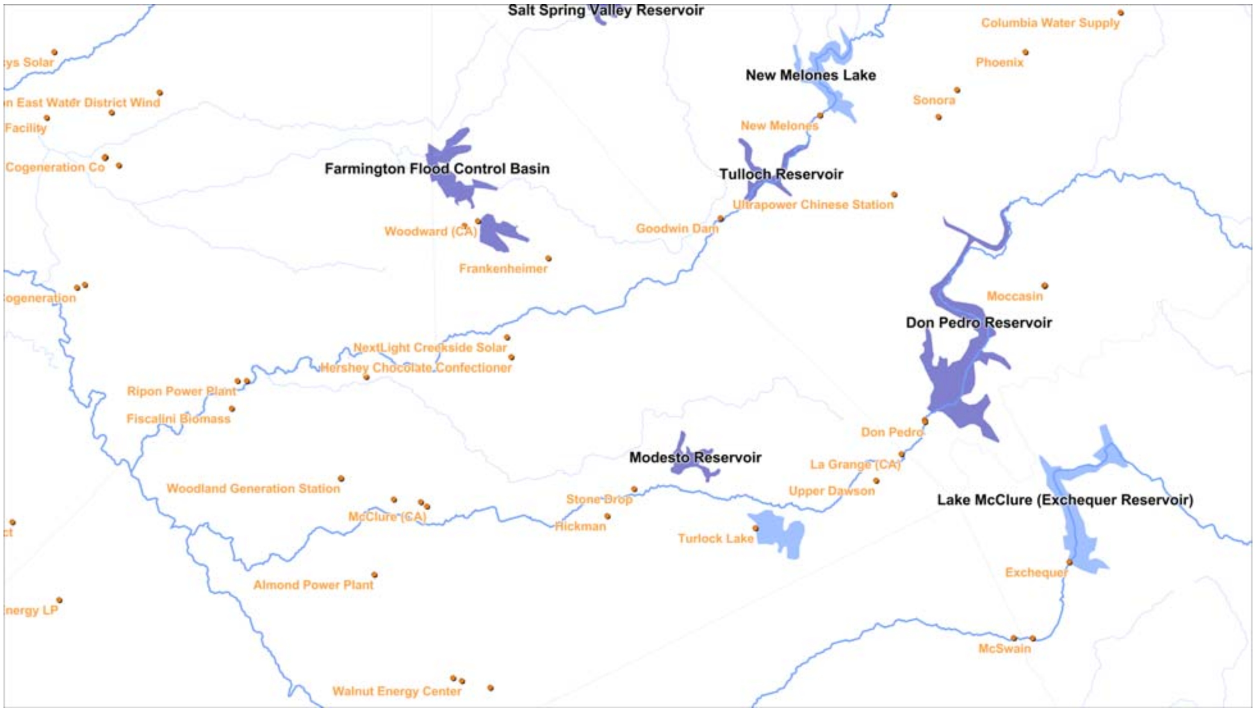


Figure X-1. Location of hydropower facilities in the LSJR watershed (Source: Ventyx)

X.3 Hydropower Generation Effects

The analysis in this section estimates the potential effects on timing and amount of hydropower generated by hydropower facilities on the LSJR tributaries caused by implementing the LSJR flow alternatives. These effects would be due to changes in the timing, rates of release, and elevation head at major reservoirs and changes to allowable diversions to off-stream facilities associated with meeting the percent unimpaired flow requirement of a particular alternative. Estimates of potential changes to reservoir releases, changes in reservoir elevations, and allowable off-stream diversions are provided by the State Water Board WSE model as described in Chapter 5 of Appendix X (draft technical report). The hydropower generation effects are presented as both annual and monthly changes from the baseline. The output from the modeling in this section provides input to the electric grid reliability analysis in the subsequent sections.

X.3.1 Methodology

For each of the LSJR flow alternatives, this analysis estimates the amount of hydropower that would be generated from the various facilities on the LSJR tributaries for comparison against the amount generated under baseline conditions. Baseline conditions are those from the "Current (2009) Conditions" CALSIM II model run from the California Department of Water Resource's State Water Project Reliability Report 2009.

Hydropower facilities on the LSJR tributaries were grouped into four categories for this analysis, based on where they are located relative to the three major tributary dams and whether they are in-stream facilities or off-stream. Table X-1 contains a list of the hydropower facilities on the LSJR grouped into these categories, along with some basic facility information.

Hydropower generated from in-stream facilities is estimated by inputting reservoir head and/or release rates obtained from the WSE model into the power equation presented below. As described in Chapter 5 of Appendix X (draft technical report) the WSE model provides estimates of reservoir operations and allowable surface water diversions associated with the different SJR flow alternatives. For simulation of each alternative the WSE model used diversion delivery rule (cutback) curves developed to match end-of-September (carryover) storage from the baseline CALSIM model run as closely as possible. Special attention was given to not exceeding the number of times reservoir storage dropped below set minimum levels of 300 thousand acre-feet (TAF), 500 TAF, and 200 TAF for New Melones, New Don Pedro, and Lake McClure, respectively. If different diversion delivery rule curves are used to model the LSJR flow alternatives, resulting reservoir storage levels and release rates, and associated amounts and timing of hydropower generated would also be different. In general, curves that maintain higher levels of diversion deliveries will result in lower reservoir levels and reduced overall hydropower generation.

Power generated from facilities at the major dams, or facilities in-stream and downstream of the major dams, was calculated using the following power equation on a monthly time step:

$$HP = \left(e_p \gamma Q h_g\right) \div 550$$

where HP is the total horsepower generated by the facility, e_p is the power plant efficiency, (80% in all facilities except New Melones), γ is weight of water, Q is the flow released from the reservoir and through the turbines, and h_g is the elevation head behind the dam. The reservoir release rates (Q) and reservoir elevations (h_g) are obtained from the WSE model output for each alternative and from CALSIM for the baseline condition. All hydropower facilities were assumed to operate within the constraints of the facility; spills causing flows greater than capacity do not produce energy above the maximum capacity. In-stream facilities located downstream of the major dams were assumed to have constant h_g equal to the maximum head of the reservoir as these facilities are generally run-of-the-river. Calculations for the New Melones facility use separate factors that allow the power plant efficiency (e_p) to change with respect to change in elevation head and flow rates (Medellin-Azuara, pers. comm. 2011). Horsepower obtained from the above equation is then converted to megawatts and multiplied by the number of hours in the month to result in megawatt (MW) hours of energy per month.

An off-stream facility is one supplied by diversions of surface water from the associated river. Power generated from off-stream facilities use the following equation to determine the effect of each alternative compared to the baseline on a monthly basis:

ΔPower = (TotD(alternative) – TotD(Baseline)) / TotD(baseline) x Nameplate Capacity

where the *ΔPower* is calculated in MW, *TotD* is the allowable surface water diversion from the WSE model for the associated tributary (for the respective alternative and baseline), and the nameplate capacity is the maximum generating capacity of the power facility. The amount of power produced in these facilities under baseline conditions is conservatively assumed to be the nameplate capacity.

Hydropower generated from facilities upstream of the major dams on the Stanislaus and Tuolumne Rivers is assumed to be unaffected by the LSJR flow alternatives. Storage capacity of the associated reservoirs as used to shift flows between spring and summer months is limited and much less than the capacity available downstream in the major reservoirs to make up any such difference. The Merced River has no major hydropower reservoirs upstream of Lake McClure (New Exchequer Dam).

Table X-1. List of hydropower facilities in the LSJR watershed (CEC 2012).

River Basin	Hydro-electric Power Plant Name	Nameplate Capacity (MW)	% of Power Capacity in Basin	Location Relative to Rim Dam
Stanislaus	Woodward	2.85	0.3%	Offline
	Frankenheimer	5.04	0.5%	Offline
	Tulloch	17.10	1.8%	Inline
	Angels	1.40	0.1%	Upstream
	Phoenix	1.60	0.2%	Upstream
	Murphys	4.50	0.5%	Upstream
	New Spicer	6.00	0.6%	Upstream
	Spring Gap	6.00	0.6%	Upstream
	Beardsley	9.99	1.1%	Upstream
	Sand Bar	16.20	1.7%	Upstream
	Donnells-Curtis	72.00	7.7%	Upstream
	Stanislaus	91.00	9.7%	Upstream
	Collierville Ph	249.10	26.5%	Upstream
	Collierville	253.00	26.9%	Upstream
	New Melones	300.00	32.0%	Rim Dam
	Upstream Capacity	710.79	75.7%	NA
	Affected Capacity	227.99	24.3%	NA
Tuolumne	Stone Drop	0.20	0.0%	Offline
	Hickman	1.08	0.2%	Offline
	Turlock Lake	3.30	0.5%	Offline
	La Grange	4.20	0.7%	Inline
	Upper Dawson	4.40	0.7%	Upstream
	Moccasin Lowhead	2.90	0.5%	Upstream
	Moccasin	100.00	16.6%	Upstream
	R C Kirkwood	118.22	19.6%	Upstream
	Dion R. Holm	165.00	27.4%	Upstream
	Don Pedro	203.00	33.7%	Rim Dam
	Upstream Capacity	390.52	64.8%	NA
	Affected Capacity	211.78	35.2%	NA
Merced	Fairfield	0.90	0.8%	Offline
	Reta - Canal Creek	0.90	0.8%	Offline
	Merced ID – Parker	3.75	3.2%	Offline
	Mcswain	9.00	7.6%	Inline
	Merced Falls	9.99	8.4%	Inline
	New Exchequer	94.50	79.4%	Rim Dam
	Upstream Capacity	0.00	0.0%	NA
	Affected Capacity	119.04	100%	NA

X.3.2 Results

Table X-2 contains a summary of the average annual hydropower generation change on each of the tributaries due to the alternatives. Generally, as the percent of unimpaired flow alternative increases, the amount of power generated annually is reduced. These changes are also represented as a percent of baseline generation in Table X-3. The monthly pattern of the average change (over 82 years of simulation) in hydropower generation from the entire LSJR watershed is presented in Figure X-2. This shows a general increase in energy being produced in May and June, as more flow is being provided in those months by the LSJR flow objectives when compared to baseline. A decrease during July and August is due to a corresponding reduction in reservoir releases during those months. These effects are more pronounced as the percentage of unimpaired requirement of the LSJR flow alternatives increases.

The corresponding relative effect on revenues from hydropower generation will be slightly greater as the price of energy is generally less during February through June when compared to July and August. An evaluation of the corresponding revenue loss and associated economic effects will be evaluated elsewhere in the SED (to be determined).

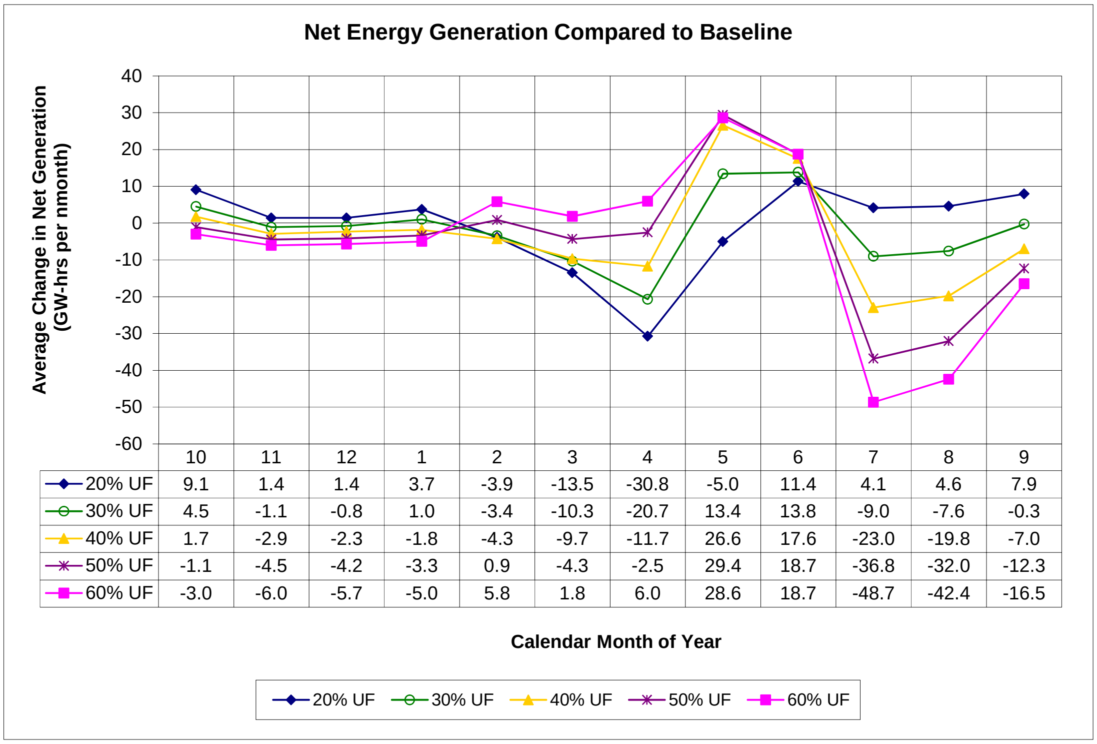
Table X-2. Average Annual Baseline Hydropower Generation and Difference from Baseline by Tributary.

Alternative	Stanislaus (GWh)	Tuolumne (GWh)	Merced (GWh)	Project Area (GWh)
Baseline	437	628	403	1,467
20% UF	-10	0	0	-10
40% UF	-19	-9	-9	-37
60% UF	-31	-18	-18	-66

GWh = gigawatt hours

Table X-3. Average Annual Hydropower Generation Difference as Percent Change from Baseline by Tributary.

Alternative	Stanislaus (% dif)	Tuolumne (% dif)	Merced (% dif)	Project Area (% dif)
Baseline	100%	100%	100%	100%
20% UF	-2%	0%	0%	-1%
40% UF	-4%	-2%	-2%	-3%
60% UF	-7%	-4%	-5%	-6%



	10	11	12	1	2	3	4	5	6	7	8	9
20% UF	9.1	1.4	1.4	3.7	-3.9	-13.5	-30.8	-5.0	11.4	4.1	4.6	7.9
30% UF	4.5	-1.1	-0.8	1.0	-3.4	-10.3	-20.7	13.4	13.8	-9.0	-7.6	-0.3
40% UF	1.7	-2.9	-2.3	-1.8	-4.3	-9.7	-11.7	26.6	17.6	-23.0	-19.8	-7.0
50% UF	-1.1	-4.5	-4.2	-3.3	0.9	-4.3	-2.5	29.4	18.7	-36.8	-32.0	-12.3
60% UF	-3.0	-6.0	-5.7	-5.0	5.8	1.8	6.0	28.6	18.7	-48.7	-42.4	-16.5

Figure X-2. Change in Average Monthly Hydropower Generation Across 82 Years of Simulation Associated with the LSJR Flow Alternatives When Compared to Baseline

X.4 Overview of the Transmission System in Central California

The following is a brief overview of the transmission systems and the balancing authorities in which the three hydropower plants, New Melones, New Don Pedro, and New Exchequer are located.[2] The balancing authorities are listed in Table X-4 and discussed in the sections below. This information is discussed to provide context for the capacity reduction calculation and power flow analysis discussed in Sections X.5 and X.6.

Table X-4. Balancing Authority of Power Plants Under Study

Power Plant	Balancing Authority
New Exchequer	California Independent System Operator (CAISO)
New Melones	Sacramento Municipal Utility District (SMUD)
New Don Pedro	Turlock Irrigation District (TID—68%) and SMUD—32%

Source: SNL Financial LC. Distributed under license from SNL

Note: Don Pedro Hydro Power Plant is jointly owned by TID and Modesto Irrigation District (MID). SMUD performs the Balancing Authority function for MID's portion of the plant while TID is the balancing authority for its portion.

X.4.1 California Independent System Operator

The California Public Utilities Commission (CPUC) adopted the Resource Adequacy (RA) program in 2004 with the twin objectives of (i) providing sufficient resources to the California Independent System Opera (CAISO) to ensure the safe and reliable operation of the grid in real time, and (ii) provide appropriate incentives for the siting and construction of new resources needed for reliability in the future (California Public Utilities Commission 2011). As part of the RA program, each Load Serving Entity (LSE) is required to procure enough resources to meet 100% of its total forecast load plus a 15% reserve. In addition, each LSE is required to file with the Commission demonstrating procurement of sufficient Local RA resources to meet their RA obligations in transmission constrained Local Areas. Each year CAISO performs the Local Capacity Technical (LCT) Study to identify local capacity requirements within its territory. The results of this study are provided to the CPUC for consideration in its RA program. These results are also be used by the CAISO for identifying the minimum quantity of local capacity necessary to meet the North American Electric Reliability Corporation (NERC) reliability criteria used in the LCT Study (California Independent System Operator 2010).

The LCT study identifies the Local Capacity Requirement (LCR) under normal and contingency system conditions. The three system conditions under which LCR is evaluated are given below:

- Category A : No Contingencies
- Category B : Loss of a single element (N-1)

[2] Entities responsible for maintaining load-generation balance in their area and supporting the frequency of the interconnected system.

- Category C: Category B contingency followed by another Category B contingency but with time between the two to allow operating personnel to make any reasonable and feasible adjustments to the system to prepare for the second Category B contingency.

For any given area or sub area the requirement for Category A, B and C are compared and the most stringent one will dictate that area's LCR requirement. Figure X-3 shows the 10 LCR areas in CAISO for study year 2012. The New Exchequer hydropower plant lies in the Greater Fresno LCR area. Greater Fresno LCR area is therefore discussed briefly below.

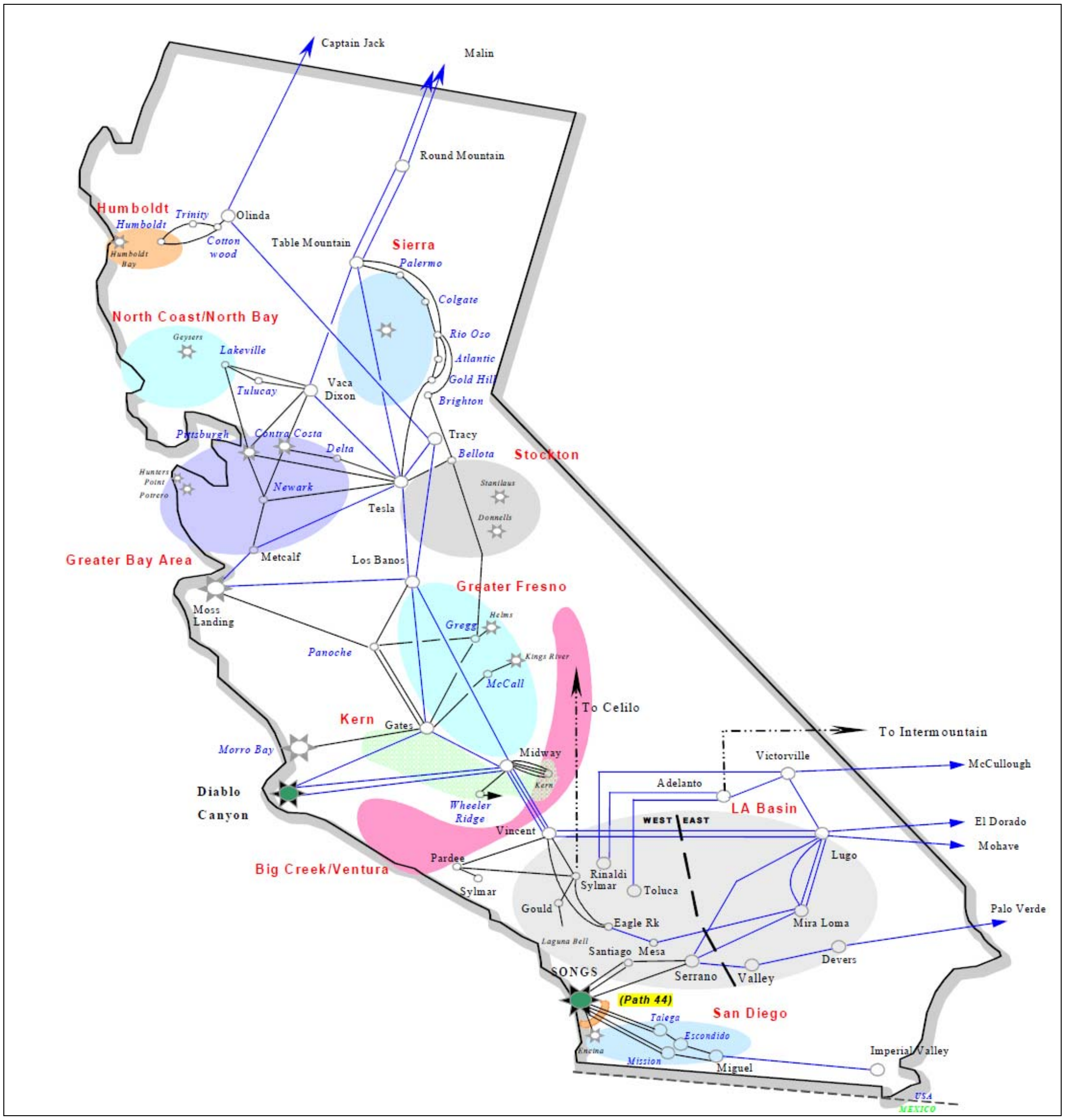


Figure X-3. Local Capacity Area Map of CAISO (Source: 2012 Local Capacity Technical Analysis, CAISO)

Locational Capacity Requirement in Greater Fresno Area

Table X-5 shows the historical LCR, peak load, and total dependable local area generation for the Greater Fresno area. The exhibit also shows the LCR as a percentage of the total dependable local generation. For example, in 2011, the LCR in Greater Fresno was 2,448 MW while the peak load stood at 3,306 MW, or, the LCR was 74% of the peak load. At the same time, the total dependable generation stood at 2,919 MW which meant that the LCR was 84% of the total dependable generation. In other words, in 2011 Greater Fresno had sufficient local resources available to meet its LCR requirements.

Table X-5. Local Capacity Needs vs. Peak Load and Local Area Generation for Greater Fresno Area

Year	LCR (MW)	Peak Load (MW)	LCR as % of Peak Load	Dependable Local Area Generation (MW)	LCR as % of Total Area Generation
2006	2837	3117	91%	2651	107%
2007	2219	3154	70%	2912	76%
2008	2382	3260	73%	2991	80%
2009	2680	3381	79%	2829	95%
2010	2640	3377	78%	2941	90%
2011	2448	3306	74%	2919	84%

Source: Year 2006 to 2011 Local Capacity Technical Analysis, CAISO

CAISO also identifies sub-areas within the larger LCR area. It is possible that the sub-areas are resource deficient although the larger area may have sufficient resources to meet its LCR requirement. For 2011, Greater Fresno LCR area was divided into three sub-areas: Wilson, Herndon, and Henrietta. While Wilson and Herndon had sufficient resources to meet their LCR requirement, Henrietta showed a deficiency of 4 MW under Category C contingency conditions.

The Wilson sub-area largely defined constraints on importing power into Fresno. For year 2011, the most critical contingency was the loss of the Melones—Wilson 230 kilovolt (kV) line overlapped with one of the Helms units out of service. The worst overload under this contingency occurred on the Warnerville-Wilson 230 kV line and established a LCR of 1,997. A number of generation units in the Wilson sub-area were found to be capable of reducing the overload on this line with varying degree of effectiveness. Exchequer was one of these units.

In 2011, the most critical contingency for the Herndon sub-area was the loss of the Herndon #1 230/115 kV transformer overlapped with Kerckhoff II generator out of service, which established a LCR of 1132 MW in 2011 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

In the Henrietta sub-area, the two most critical contingencies, (i) loss of Henrietta 230/70 kV transformer bank #4 and GWF Power unit, and (ii) loss of Henrietta 230/70 kV transformer bank #4 and one of the Henrietta-GWF Henrietta 70 kV line, together established a local capacity need of 57 MW in 2011 as the minimum capacity necessary for reliable load serving capability within this sub-area. However, under the category C contingency, the LCR in Henrietta exceeded the total dependable generation by 4 MW for the year 2011 implying that load would need to be shed if the most critical category C contingency were to happen.

Transmission Expansion Plans and New Generator Additions

In the board approved 2010/2011 transmission plan, CAISO identified a number of transmission upgrades that are needed in the Greater Fresno area to maintain system reliability between 2011 and 2020. PG&E proposed a number of projects to mitigate these reliability violations during the 2010 request window (CAISO 2011). A list of major PG&E projects that were found to be needed by CAISO for maintains system reliability in the Greater Fresno Area is given in Table X-6.

Table X-6. Reliability Based Transmission Projects in Greater Fresno

Transmission Project Name	Purpose	In-Service Date
Kerckhoff PH #2—Oakhurst 115 kV Line Project	Relieve expected overload on the Corsgold To Oakhurst 115 KV line under 2016-2020 system conditions	2015
Wilson 115 kV Area Reinforcement Project	Relieve a number of reliability violations expected under 2015-2020 system conditions	2015
Oro Loma 70 kV Area Reinforcement Project	Relieve Overloads on lines and transformers in the Oro Loma Area under 2015-2020 system conditions	2015
Source: CAISO and PG&E		

A number of generators are also seeking interconnection in the Greater Fresno Area between now and 2014. Table X-7 provides a list of selected projects that are at an advanced stage of the interconnection process.

Table X-7. Expected New Generator Additions in Greater Fresno

Fuel Type	Interconnecting Sub-Station	Capacity	Expected In-Service Date	County
Natural Gas	Gates Substation 230 kV bus	600	6/1/2014	KINGS
Natural Gas	Henrietta Substation 70 kV bus	150	5/31/2013	KINGS
Solar	Jacobs Corner Substation 70 kV bus	20	4/2/2012	KINGS
Solar	Jacobs Corner Substation 70 kV bus	20	5/1/2012	KINGS
Solar	Jacobs Corner Substation 70 kV bus	20	6/1/2012	KINGS
Solar	Arco Substation 70 kV bus	20	6/30/2013	KINGS
Solar	Corcoran- Kingsburg #1 115 kV line	20	8/1/2013	KINGS
Solar	Henrietta-Guernsey 70 kV	20	12/31/2011	KINGS
Solar	Oro Loma 115 kV	20	12/25/2011	MERCED
Solar	Dairyland—Legrand 115 kV	20	1/1/2012	MADERA
Solar	Henrietta-Tulare Lake 70 kV	20	12/31/2012	KINGS
Solar	Henrietta Sub 70 kV Bus	20	12/31/2012	KINGS
Solar	Arco 70 kV	20	1/15/2013	KINGS
Source: CAISO Generator Interconnection Queue				

X.4.2 Sacramento Municipal Utility District

The Sacramento Municipal Utility District (SMUD), established in 1946, is the nation's sixth largest community-owned electric utility in terms of customers served (approximately 590,000) and covers a 900 square mile area that includes Sacramento County and a small portion of Placer County. The service territory of SMUD is shown in Figure X-4.

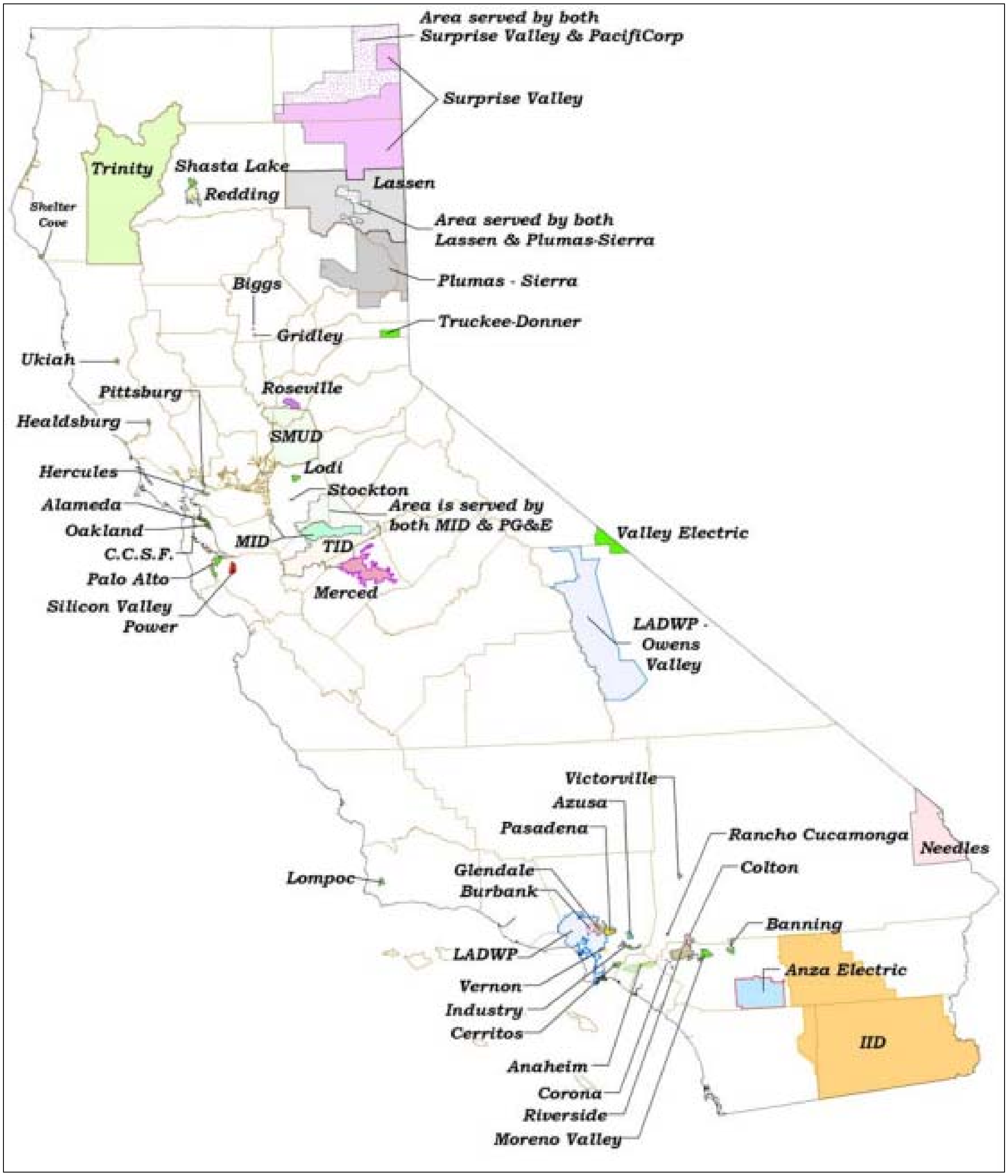


Figure X-4. SMUD Service Territory in California (Source: California Energy Commission 2012)

As part of the biennial resource adequacy and resource plan assessments for publically owned utilities, California Energy Commission (Commission) published its biennial report in November 2009 detailing the need and availability of generation resources to meet the future load and planning reserve margin requirements within the territory of publically owned utilities (California Energy Commission 2009). The report indicates that SMUD will be able to meet its resource adequacy requirements in the near term; however, in 2018 SMUD's generation resources may not be sufficient to meet its load and planning reserve margin obligations. The deficiency expected in 2018 is estimated at 347 MW, but the Commission does not expect this to be an issue due to the lead time available to resolve the expected deficiency.

Transmission Expansion Plans and New Generator Additions

SMUD also carries out an annual 10 year transmission planning process to ensure that NERC and Western Electricity Coordinating Council (WECC) Reliability Standards are met each year of the ten year planning horizon. Major projects that have been proposed in 2010 transmission plan for the 2016 to 2020 time period are listed in Table X-8 (Sacramento Municipal Utility District 2010). These projects are expected to improve the reliability of SMUD's electric system as well as increase its load serving capability.

Table X-8. Proposed Transmission Upgrades in SMUD from 2016–2020

Project Name	Project Description	Expected In-Service Date
Franklin 230/69 kV Substation	New Distribution Substation	May 31, 2016
O'Banion-Sutter 230 kV Double Circuit Transmission Line Conversion	Add circuit breakers to convert O'Banion-Sutter line to double circuit tower line	May 31, 2016
Installation of 200 MVAr transmission capacitors	Install transmission capacitors	May 31, 2019
400 MW Iowa Hill Pump Storage Facility	New Hydropower Plant in the Upper American River Project	May 31, 2020
Lake-Folsom 230 kV and Folsom - Orangevale 230 kV Reconductoring	Reconductor the Lake-Folsom – Orangevale 230 kV Lines	May 31, 2020

The New Melones Power Plant physically resides in the CAISO Balancing Authority Area. However, Sierra Nevada Region (SNR)[3], SMUD and the CAISO operate New Melones as a pseudo-tie generation export from CAISO into the SMUD Balancing Authority Area (Western Area Power Administration 2010). This arrangement implies that New Melones is electronically and operationally included as part of the SMUD Balancing Authority Area. For purposes of Qualifying Capacity, SNR has designated the New Melones Power Plant as part of the Central Valley Project (CVP) resource in the SMUD Balancing Authority Area. The location of New Melones is also shown in Figure X-5.

[3] Western, Sierra Nevada Region (SNR), is a certified scheduling coordinator and an LSE for certain loads and resources within the CAISO Balancing Authority Area.

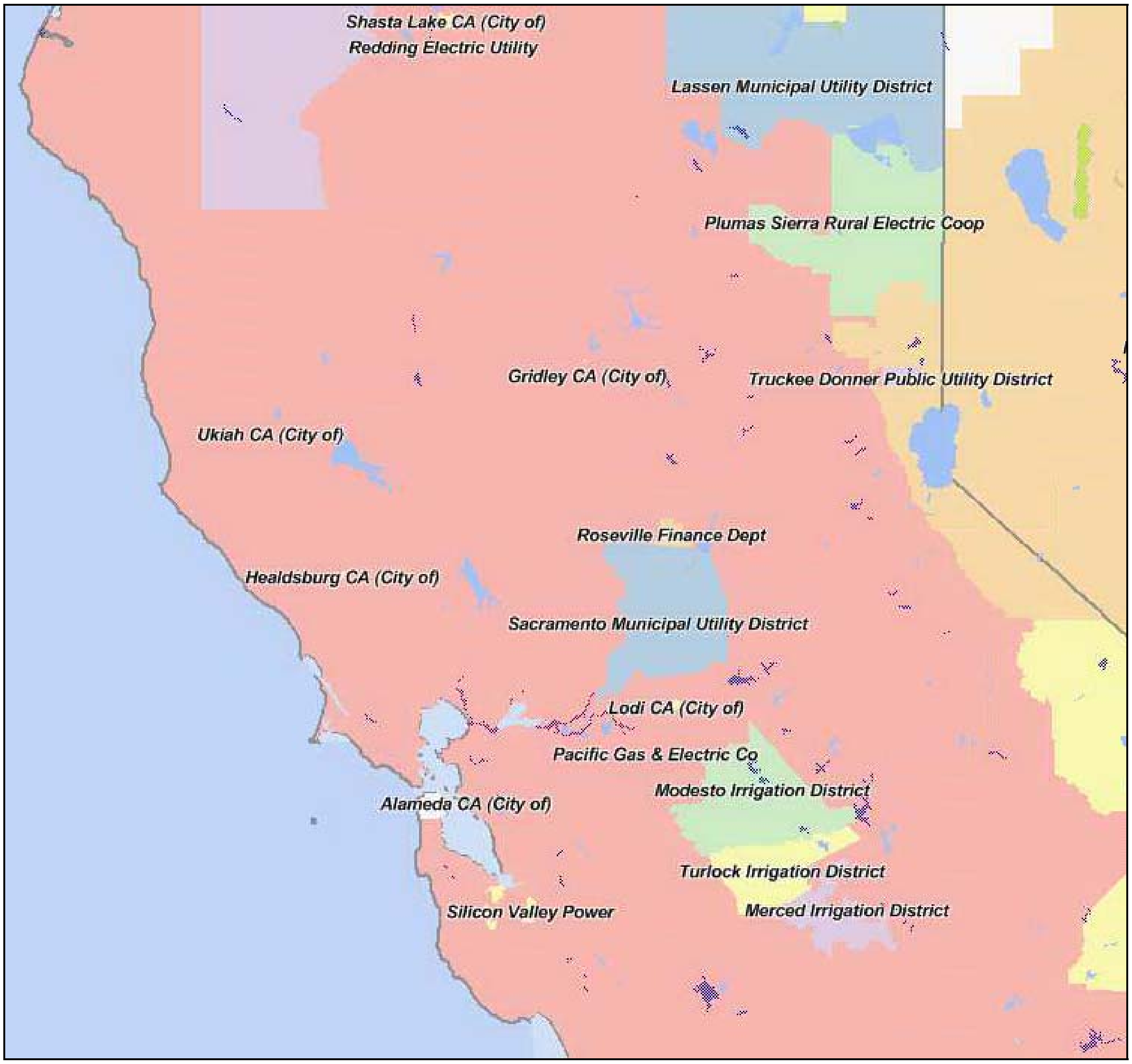


Figure X-5. Location of New Melones and Proposed 400 MW Iowa Hill Hydro Plant (Source: Ventyx)

X.4.3 Turlock Irrigation District

The Turlock Irrigation District (TID) operates as a Balancing Authority located between Sacramento and Fresno in California's central valley (California Transmission Planning Group). Westley 230 kV and Oakdale 115 kV lines provide import access for TID. The TID BA incorporates all 662 square miles of TID's electric service territory (Figure X-6) as well as a 115 kV loop with three 115 kV substations owned by the Merced Irrigation District (Merced ID). The Merced ID facilities are interconnected to TID's August and Tuolumne 115 kV substations and are located just south of TID's service territory and north of the City of Merced. TID is the majority owner and operating partner of the Don Pedro Hydroelectric Project with 68.46% ownership and MID has a 31.54% ownership.

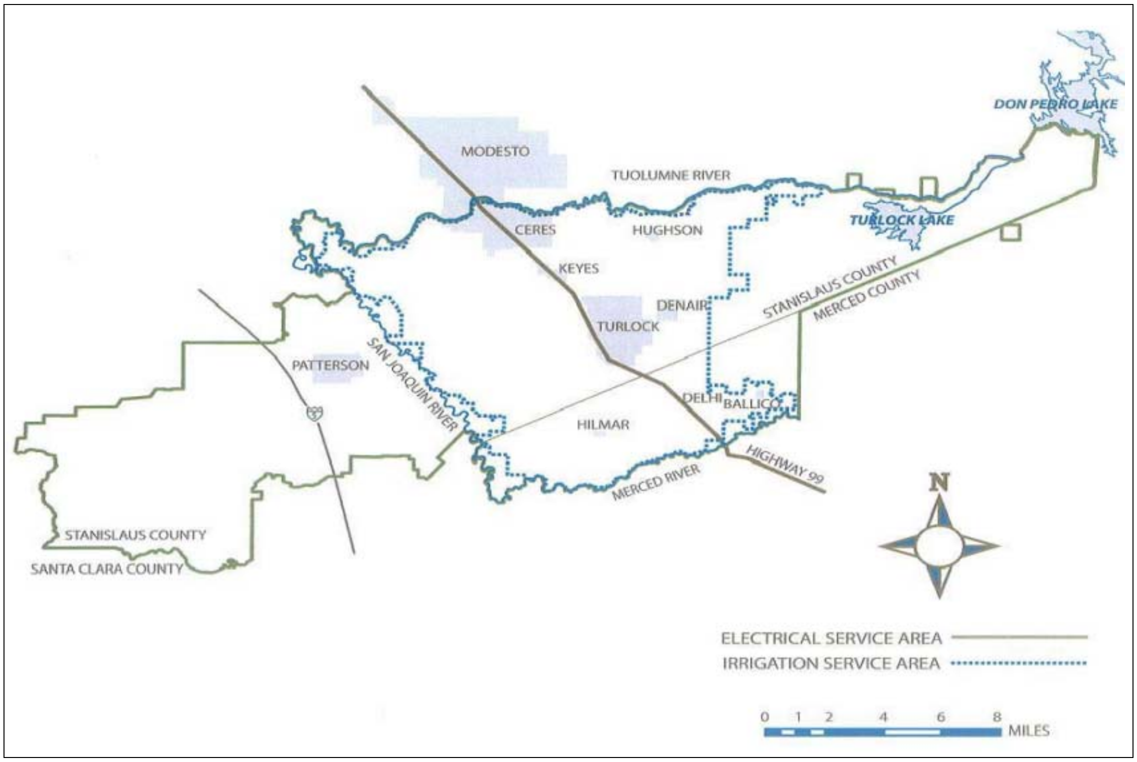


Figure X-6. Turlock irrigation District Service Area (Source: California Transmission Planning Group 2011)

Transmission Expansion Plans and New Generator Additions

TID is currently working on two major generation projects. One of these, the Almond 2 Power Plant has been approved by the Board of Directors while the Red Mountain Bar Pumped Storage Power Plant project is in the study phase. Key characteristics and benefits of these projects are summarized in Table X-9 (Turlock Irrigation District 2011).

Table X-9. Summary of Almond 2 and Red Mountain Bar Power Plants

Project Name	Key Characteristics	Project Objective(s)	Expected In-Service Date
Almond 2 Power Plant (174 MW)	Natural-gas fired simple-cycle peaking power generation facility. Located in Stanislaus county.	Meet reliability obligations as a Balancing Authority. Improve the economy, efficiency, and flexibility of the District's electrical system including the integration of intermittent renewable resources.	2012
Red Mountain Bar Pumped Storage (880 MW)	Joint project with MID. Located near Sonora in Tuolumne County.	Proposes to use the existing Don Pedro Reservoir as the lower pool from which to pump water to a newly constructed upper reservoir. Improve reliability of the electric grid by quickly replacing solar and wind generated electricity that could vary significantly with weather conditions.	Study Phase

X.5 Capacity Reduction Calculation and Power Flow Analysis

The implementation of one of the alternatives could increase the hydropower generation at New Melones, New Don Pedro and New Exchequer in the months of February through June because additional water would be released from the reservoirs during that time to meet the unimpaired flow objective alternative. But it could reduce the hydropower generation during the summer months of July through September because less water would be stored during those months in the reservoirs as a result of being released earlier in the year (e.g., February through June). Since the California grid is most stressed during summer months due to high demand for electricity, a reduction in hydropower capacity during this time has the potential of stressing the grid even further.

To assess the impact of different unimpaired flow alternatives on California's electric grid, the operation of the electric grid under peak summer demand conditions was simulated. First, the operation of the grid assuming the hydropower capacity reductions would not occur was examined. Next, the analysis is repeated, but assumed the hydropower capacity reductions were implemented. By comparing the results of the two sets of analyses, the effect of the Project on the electric grid are determined. The 20% unimpaired flow alternative would lead to negligible power capacity reduction for the three hydropower plants, while the total output of the three plants would reduce by 5% and 8% under 40% and 60% unimpaired flow alternatives, respectively. However, the capacity reductions under the 40% and 60% unimpaired flow alternatives do not result in reliability violations that could not be relieved by simple generation re-dispatch. The methodology and models are described in detail below.

X.5.1 Capacity Reduction Calculation Methodology

The 'Water Supply Effects Model—SJR Tributaries' developed by State Water Resource Control Board of California was used to estimate the impact of 20%, 40%, and 60% unimpaired flow alternatives on power generation of the three affected hydropower plants. It simulated the effects of the unimpaired flow alternatives on monthly flow rates and reservoir storage for each month of the 82 year period between water years 1922 and 2003. The model also translated reservoir storage into available head for generating electric power. Exhibit 3-1 shows the head, which is the difference between the maximum elevation and tail-water elevation, and the corresponding maximum capacity for New Melones, Don Pedro and Exchequer. Since the power generation capacity in MW is directly proportional to the available head, the monthly capacity (MW) of affected hydropower plants under each unimpaired flow alternative was estimated by prorating the maximum plant capacity by the available head estimated from the model. For example, if for any month, the model estimated available head for New Melones was 500ft, then using the head and maximum capacity values from Table X-10, its capacity for that month was estimated at 256 MW (300 MW X [500 feet/585feet]).

Table X-10. Existing Maximum Capacity

Power Plants	Maximum Elevation (Feet)	Tail-water Elevation (Feet)	Head (Feet)	Maximum Capacity (MW)
New Melones	1,088	503	585	300
Don Pedro	830	310	520	203
Exchequer	867	400	467	95

The impact of the reduced capacity of the three hydropower facilities on the reliability of the California grid under summer system conditions was evaluated. California's electric grid is most stressed during the summer months of June to August, with peak demand typically occurring in the month of July. Therefore, for each month of July during the 82 year period, the total MW capacity of the three facilities was calculated, separately for baseline, 20%, 40%, and 60% unimpaired flow alternatives.[4] Next, the percentage change in total MW capacity from the baseline was determined for the three unimpaired flow alternatives, and the maximum percentage reduction was selected for modelling the three hydropower plants in the power flow. The percentage change in capacity from baseline capacity for each July month between 1922 and 2003 is shown in Figures X-7, X-8, and X-9, for the 20%, 40%, and 60% unimpaired flow alternatives respectively. Negative values indicate a reduction in MW capacity compared to baseline. The minimum negative percentage change, or maximum reduction in capacity, for the 20% unimpaired flow alternative is negligible. However, the maximum reduction in capacity is 5% and 8 % for 40% and 60% unimpaired flow alternatives respectively. Therefore, power flow analysis is conducted for 40% and 60% unimpaired flow alternatives only.

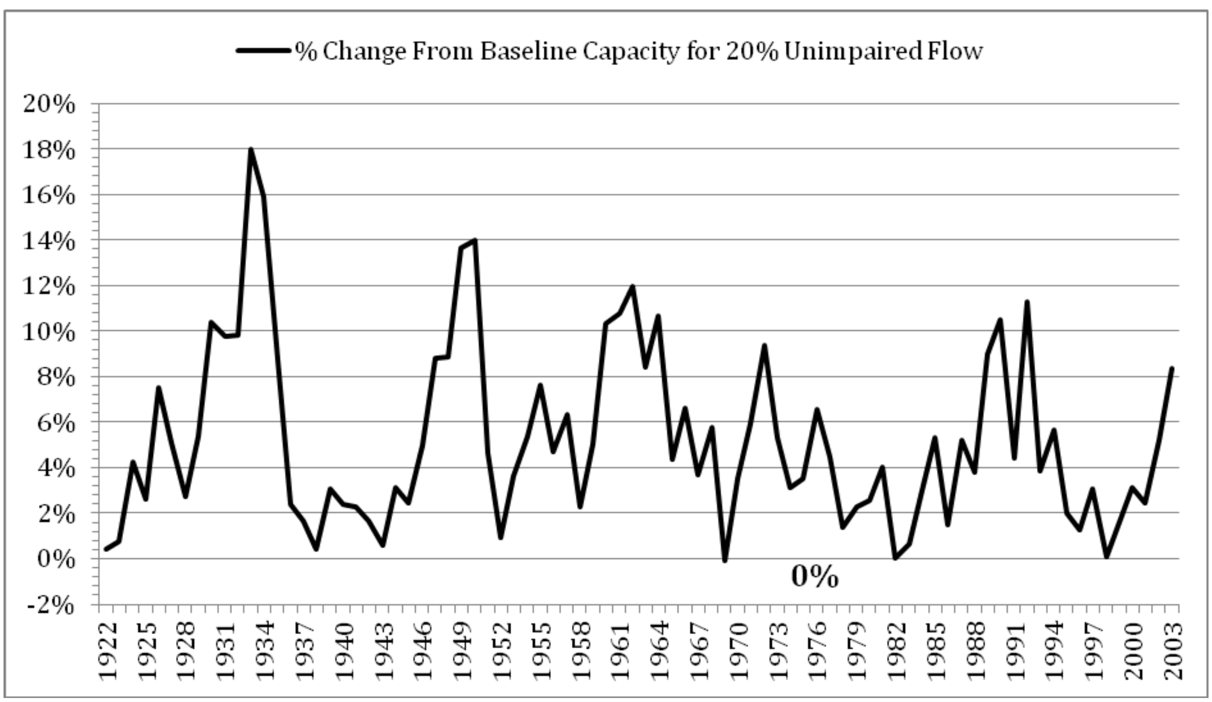


Figure X-7. Percentage Change in Power Capacity from Baseline for July under 20% Unimpaired Flow Alternative

[4] Baseline refers to the flow scenario as it exists today without implementation of the unimpaired flow alternatives.

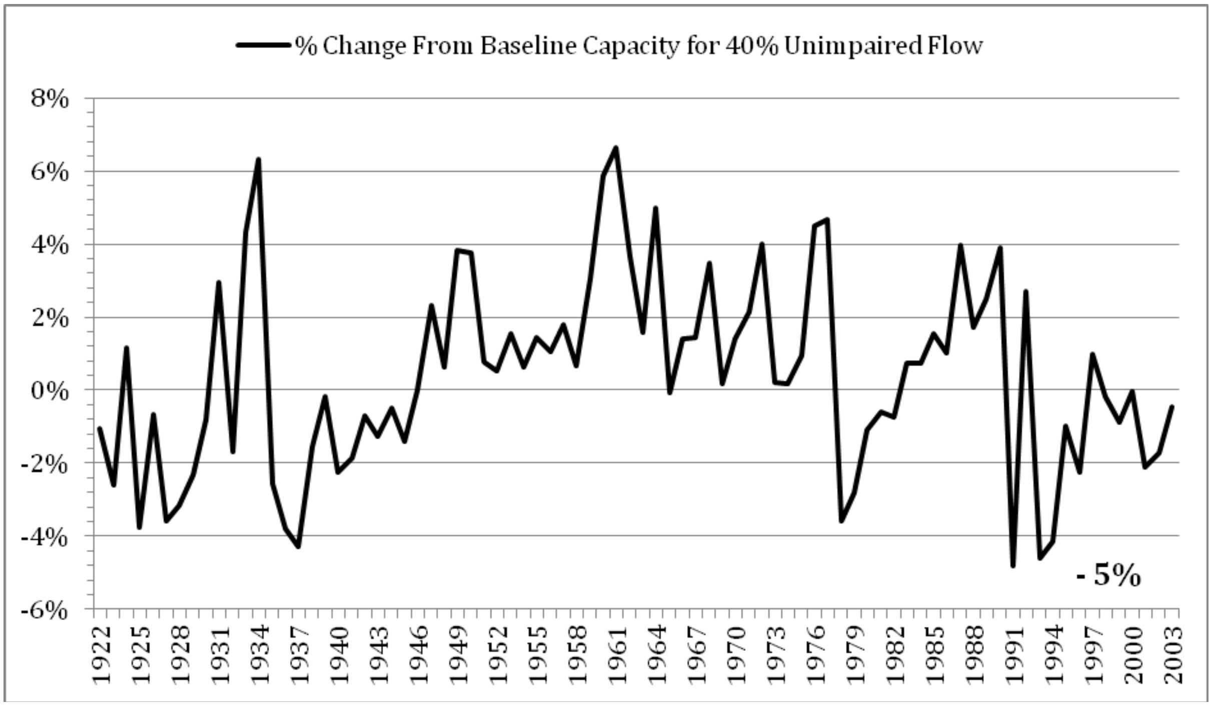


Figure X-8. Percentage Change in Power Capacity from Baseline for July under 40% Unimpaired Flow Alternative

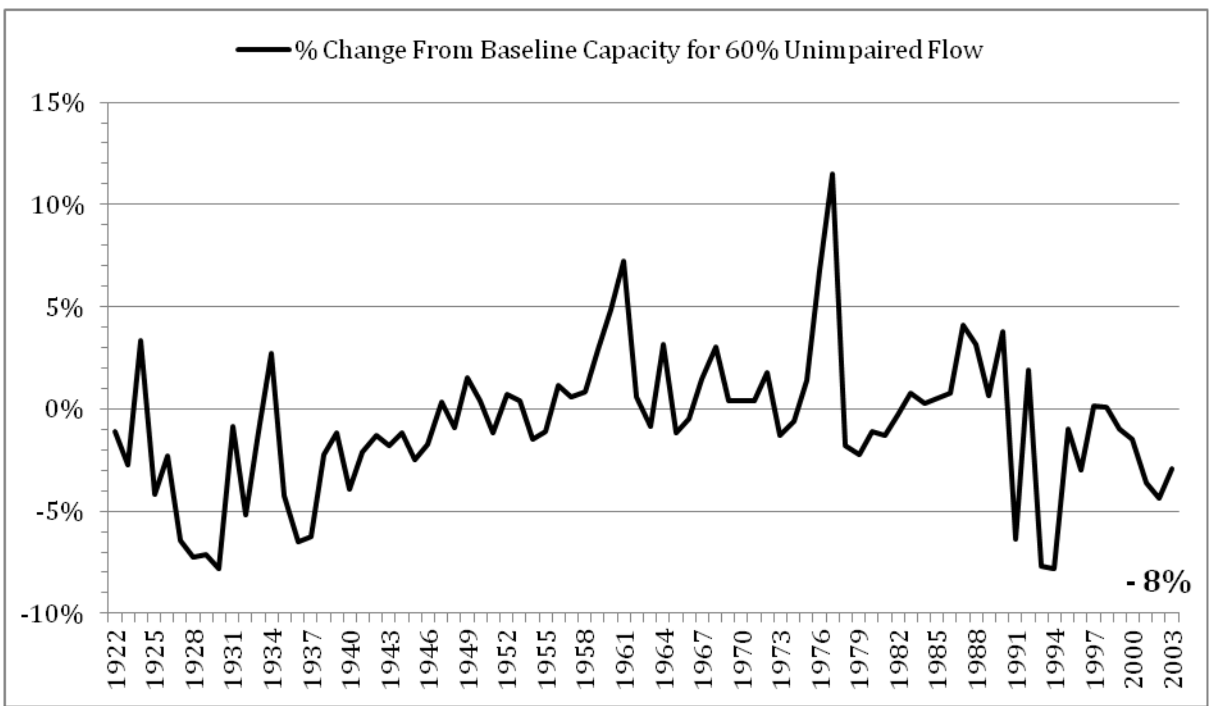


Figure X-9. Percentage Change in Power Capacity from Baseline for July under 60% Unimpaired Flow Alternative

X.5.2 Power Flow Assessment Methodology

According to NERC, reliability of an electric system comprises of two interrelated elements—adequacy and security. Adequacy refers to the amount of capacity resources required to meet peak demand and security refers to the ability of the system to withstand contingencies or other system disturbances, such as the loss of a generating unit or transmission line. Both of these reliability aspects can be gauged from sub-station voltages and transmission line loadings. A steady state power flow assessment of the California grid was performed to check if reduction in hydropower capacities of the three dams would adversely impact the grid reliability as defined by NERC.[5]

The power flow assessment was a multi-step process. These steps are listed below and detailed further below.

- Prepare a Base Case (California electric grid model under normal and contingency conditions assuming the facility is in normal operation).[6]
- Prepare separate Change Cases (California electric grid model under normal and contingency conditions assuming reduced output of the facilities) for 40% and 60% unimpaired flow alternatives.[7]
- Develop criteria for selection of generator and transmission contingencies.
- Develop criteria for voltage and thermal limits.
- Select the areas where transmission line/transformer loadings and sub-station voltages would be monitored.

Base and Change Case Development

The Base Case was the latest 2011 heavy summer (high summer power demand) electric grid model of the entire Western Interconnection developed by WECC. This case had a detailed representation of the California electric grid.

Using the capacity reductions calculated earlier, two Change Cases were developed for the hydropower generation facilities. One Change Case was prepared for the 40% unimpaired flow alternative with the output of each hydropower facility reduced by 5% of its value in the Base Case. Second Change Case was for the 60% unimpaired flow alternative where the hydropower facilities were generating 8% less than their output in the Base Case. Table X-11 summarizes the modeled cases.

---

[5] Power flow software models simulate the operation of the grid and calculate substation voltages and power flowing on transmission lines/transformers. These calculated values can then be compared with standard voltage limits and line/transformer thermal ratings to identify violations.

[6] Under normal conditions, all generation and transmission facilities are assumed to be in service. Contingency conditions refer to the unplanned outage of power system equipment.

[7] Under normal conditions, all generation and transmission facilities are assumed to be in service. Contingency conditions refer to the unplanned outage of power system equipment.

Table X-11. List of Cases Modeled

Case Description	Output of Hydro Units[a]	Normal Conditions	Contingency Conditions
Base Case	Normal	√	√
Change Case—40% Unimpaired Flow Case	Reduced by 5%	√	√
Change Case—60% Unimpaired Flow Case	Reduced by 8%	√	√

[a.] Units refer to New Melones, New Exchequer, and New Don Pedro Facilities

Contingency Selection Criteria

Base and Change Cases were analyzed for single contingency outage of all the transmission facilities rated 115 kV and above within the balancing authority of the generating facilities and 230 kV and above in the neighboring balancing authorities or regions.[8] Single contingency outage of all generators rated 100 MW or above, both within the balancing authority of the facilities and in the neighboring balancing authorities, were also used to analyze the performance of electric grid under Base and Change Cases. In the power flow, all the facilities are shown to be a part of PG&E area with Southern California Edison, Northwest and Sierra as neighboring regions.

Voltage and Transmission Line Limits

The transmission line limits used in the study were the normal and Long-Term Emergency (LTE) ratings. Under normal and contingency conditions transmission line flows are expected to remain within the normal and long-term emergency ratings, respectively. Similarly, voltage limits were established relative to the nominal voltages. Under normal conditions system operators regulate nodal voltages within ±5% of their nominal values. Under contingency conditions, this limit is relaxed to ±10% of the nominal value.

Criteria for Monitoring Transmission Elements

Within the Balancing Authority of the facilities, the following criteria for monitoring transmission line/transformer loadings and sub-station voltages:[9]

- All transmission lines with nominal voltage greater than 115 KV.
- All transformers with both nominal primary and secondary voltage greater than 115 KV.

In the neighboring Balancing Authorities, the following criteria for monitoring transmission/transformer loadings and sub-station voltages:

- All transmission lines with nominal voltage greater than 230 KV.
- All transformers with both primary and secondary voltage greater than 230 KV.

[8] In the context of this analysis, neighboring region or neighboring Balancing Authority is defined as a region which has a direct transmission link with the region in which the facility is located.

[9] The loading of a transmission line or transformer measured as a ratio of the actual flow across the facility in amperes or mega-volt amperes to the rated value of current. In this analysis, only those lines/transformers are recorded whose loading exceeds 90% of the applicable rating.

The WECC paths in California (referred to as "Interfaces" hereafter) were also monitored. These are listed in Table X-12.[10]

Table X-12. WECC Paths Monitored

WECC Path Number	WECC Path Name	Location
15	Midway-Los Banos	Between Central and Southern California within the PG&E system and South of Los Banos substation
24	PG&E-Sierra	Between Northern California and Nevada
25	PacifiCorp/PG&E 115 kV Interconnection	Southern Oregon/Northern California
26	Northern-Southern California	Between PG&E and Southern California Edison
52	Silver Peak-Control 55 kV	Southwestern Nevada/Central Eastern California
60	Inyo-Control 115 kV Tie	The 115 kV phase shifter between SCE and LDWP
66	COI	Between Oregon and northern California
76	Alturas Project	between northeastern California and western Nevada
Source: WECC Path Rating Catalog		

X.5.3 Power Flow Simulation Tools

The GE® Positive Sequence Load Flow (PSLF) model was used for this analysis. PSLF is ideal for simulating the transfer of large blocks of power across a transmission grid or for importing or exporting power to neighboring systems. The model can be used to perform comprehensive and accurate load flow, dynamic simulation, short circuit and contingency analysis, and system fault studies. Using this tool, engineers can also analyze transfer limits while performing economic dispatch. PSLF can simulate large-scale power systems of up to 80,000 buses.[11]

X.5.4 Assumptions for Facilities

The assumptions for the generation facility characteristics and interconnection substations are shown in Table X-13. Other assumptions, including transmission facility normal and long-term emergency ratings, transmission line impedances, and substation nominal voltages were defined in the WECC power flow cases used for the assessment.

Table X-13. Unit Assumptions for the Engineering Assessment

Unit Name	Unit Bus Number in WECC Power Flow Case	Interconnection Voltage (kV)
New Melones	37561, 37562	230
Don Pedro	38550, 38552, 38554	69
Exchequer	34306	115
Source: WECC Power Flow Case and SNL.		

[10] WECC Paths refer to either an individual transmission line or a combination of parallel transmission lines on which the total power flow should not exceed a certain value for maintain system reliability.

[11] In Power Flow modeling a "bus" represents all the sub-station equipment that is at the same voltage level and is connected together.

X.5.5 Results and Conclusions

Thousands of transmission lines, nodal voltages, and interfaces under normal system conditions and contingency outages of hundreds of transmission lines and generators were monitored under the Base and Change cases. The Base Case sub-station voltages and line/transformer loadings were then compared with those of the Change Cases. If the comparison showed that sub-station voltages or transmission line/transformer loadings are within limits in the Base Case, but outside the limits in the Change Cases (i.e., the 5% and 10% identified in Section 3.2.2), the unimpaired flow alternatives could be considered to have an adverse impact on the reliability of California's electric grid. Results of the power flow assessment are discussed below.

Comparison between Base and Change Case Line/Transformer Loadings under Normal Conditions

Under normal operating conditions, no transmission line or transformer was found that violated the ratings exclusively in the Change Cases.

Comparison between Base and Change Case Line/Transformer Loadings under Line/Transformer Contingencies

When Base and Change Cases were studied under transmission line and transformer contingencies, no line/transformer limit violation was found for the Base Case and the 40% unimpaired flow alternative. However, for the 60% unimpaired flow alternative, the 230 kV line between "Borden" and "Gregg" substations showed a minor violation under the outage of the 230 kV line between "Gregg" and "Storey" substations. This violation was easily mitigated through a re-dispatch of the three "Helms" generator units (Helms Unit 1, 2, and 3). The new loading of the monitored element after this re-dispatch was 99.81%.

Comparison between Base and Change Case Line/Transformer Loadings under Generator Contingencies

Under generator contingencies, no line/transformer limit violations were found that could be exclusively attributed to the 40% and 60% unimpaired flow alternatives.

Comparison between Base and Change Case Substation Voltages under Normal and Line/Transformer/Generator Contingencies

No voltage violations were found that could be exclusively attributed to the reduced hydropower capacity in the Change Cases.

Comparison between Base and Change Case Interface Loadings under Normal and Line/Transformer/Generator Contingencies

No Interface limit violations were found that could be exclusively attributed to the reduced hydropower capacity in the Change Cases.

In conclusion, an engineering assessment was performed to determine if implementation of the unimpaired flow alternatives on the tributaries, and the resulting change in hydropower generation at the hydropower plants, would adversely impact the reliability of California's electric grid.

Using the 'Water Supply Effects Model—SJR Tributaries' it was determined the 20% unimpaired flow alternative would lead to negligible power capacity reduction for the three hydropower plants, while the total output of the three plants would reduce by 5% and 8% under 40% and 60% unimpaired flow alternatives, respectively. The capacity reductions for 40% and 60% unimpaired flow alternatives were then applied to the summer electric grid model of the Western Interconnection and system performance was evaluated under both normal and single contingency conditions. There were no reliability violations that could be attributed to the unimpaired flow alternatives, or which could not be relieved by simple generation re-dispatch.

Based on the results of this study, the San Joaquin River Flow Objectives project would not adversely impact the reliability of California's electric grid.

X.6 References

California Energy Commission. 2009. An Assessment of Resource Adequacy and Resource Plans of Publicly Owned Utilities in California", California Energy Commission, November. Available at: < http://www.energy.ca.gov/2009publications/CEC-200-2009-019/CEC-200-2009-019.PDF> Accessed: November 2011.

California Energy Commission. 2012. California Power Plant Database (Excel File) at:. http://energyalmanac.ca.gov/electricity/index.html#table. Accessed February 2012.

California Independent System Operator. 2010. 2011 Local Capacity Technical Study-Final Report and Study Results. April. Available at: http://www.caiso.com/planning/Pages/ReliabilityRequirements/LocalCapacityRequirements.aspx. Accessed: November 2011.

CAISO. 2011. 2010-2011 Transmission Plan. May 18. Available at: <http://www.caiso.com/2b88/2b8872c95ce10.pdf>. Accessed: November 2011.

California Public Utilities Commission. 2011. Available at: http://www.cpuc.ca.gov. Accessed: November 2011.

California Transmission Planning Group. 2011. Available at: <http://www.ctpg.us/images/stories/ctpg-plan-development/2011/07-Jul/2011-07-18_TID_min_gen_req.pdf.>. Accessed: November 2011.

Medellin-Azuara, J. 2011. Personal communication. University of California, Davis, CA

Sacramento Municipal Utility District (SMUD). 2010. Ten-Year Transmission Assessment Plan. December 22. Available at: <http://westconnect.com/filestorage/2010_SMUD_10YearPlan_Final.pdf> Accessed: November 2011.

Turlock Irrigation District. 2011. Available at: <http://www.tid.org/power/projects.> Accessed: November 2011.

Ventyx Velocity Suite. Licensed mapping database.

Western Area Power Administration (Western). 2010. Final Resource Adequacy (RA) Plan, Federal Register 72 FR 41317; SMUD Comments to CAISO March 10, 2010 Dynamic Transfer Straw Proposal. Available at: <http://www.caiso.com/276c/276cbecb37360.pdf.> Accessed: November 2011.