California Energy Commission

STAFF REPORT

SUMMER 2012 ELECTRICITY SUPPLY AND DEMAND OUTLOOK

CALIFORNIA
ENERGY COMMISSION

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ABSTRACT

The *Summer 2012 Electricity Supply and Demand Outlook* is the California Energy Commission staff's assessment of the adequacy of resources to meet California's 2012 summer peak electricity demand.

Keywords: Supply, planning reserve margin, loss of load, demand, forced outage, generation, net interchange, demand response, interruptible load

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EXECUTIVE SUMMARY

The *Summer 2012 Electricity Supply and Demand Outlook* (*Summer Outlook*) is the California Energy Commission staff's projection of the electricity system's capability to meet statewide peak electricity demand in California from June through September 2012. California is expected to have more-than-adequate electricity supplies to meet peak demand this summer, even if hotter-than-average temperatures occur. Staff bases its conclusions on existing planning reserve margins, the percentage total of projected generation capacity, demand resources and import capacity exceed the forecasted annual peak demand.

Two primary factors support this conclusion. First, additions of generation resources since last year and expected additions through August 2012 should result in a cumulative increase in generation capacity. Second, the current staff demand forecast predicts a modest increase in annual peak demand compared to forecasts of 2011; the 1-in-2 and 1-in-10 peak demand forecasts increase 1.3 percent and 0.6 percent respectively. These estimates of peak demand represent a normal peak demand exceeded in half the years and a higher than normal peak demand only exceeded once in 10 years. The combined result is that planning reserve margins remain robust through September 2012.

Reserve Margins

Statewide reserve margins for electricity are in **Table 1** and as shown remain robust. These margins indicate that there should be sufficient resources to cover most system contingencies, including high demand due to hotter-than-normal (1-in-10 year) weather conditions.

Table 1: Statewide 2012 Summer Outlook (MW)

Resource Adequacy Planning Conventions		June	July	August	September
1	Existing Generation	61,300	61,421	61,765	62,183
2	Expected Retirements	0	-44	0	0
3	Expected Additions	121	344	418	23
4	Net Imports	13,118	13,118	13,118	13,118
5	**Total Net Generation**	74,539	74,839	75,301	75,324
6	Demand Response / Interruptible / Curtailable Programs	2,860	3,132	3,073	3,039
7	**Total Net Supply**	77,399	77,971	78,374	78,363
8	1-in-2 Summer Demand	53,811	58,086	60,343	54,922
8a	**Reserve Margin (1-in-2 Demand)**	**44%**	**34%**	**30%**	**43%**
9	1-in-10 Summer Demand	57,944	62,557	64,936	59,173
9a	**Reserve Margin (1-in-10 Demand)**	**34%**	**25%**	**21%**	**32%**

Note: All capacities are dependable, not nameplate. Existing generation values for July, August, and September incorporate expected additions from previous months.
Components may not sum to totals because of rounding.
Source: Energy Commission staff.

Estimated monthly reserve margins for this summer compared to those reported in the *2011 Summer Outlook* for normal (1-in-2 year) and hotter-than-normal (1-in-10 year) peak weather conditions are about the same or slightly higher.[1] Values for August correspond with the time frame used by the California Independent System Operator (California ISO) in its *Summer Loads and Resources Operations Preparedness Assessment*[2] for its planning reserve margin estimates.

Supply

Energy Commission staff expects California will have added 2,236 megawatts (MW) of generation capacity in the one-year period from October 1, 2011, to October 1, 2012. This quantity is based on nameplate ratings or the intended technical full–load sustained output of the facility and is expected to yield 1,504 MW of dependable capacity. Dependable capacity is the estimated capacity that a unit or facility can provide to carry system load for a specified length of time and during the period of the typical ambient conditions.

1 *Summer 2011 Electricity Supply and Demand Outlook* (*2011 Summer Outlook*) *Table 1: California 2011 Summer Outlook (MW)*, p. 5. [http://www.energy.ca.gov/2011publications/CEC-200-2011-004/CEC-200-2011-004.pdf].

2 California ISO, *2012 Summer Loads and Resources Assessment,* March 15, 2012. Available at: http://www.caiso.com/Documents/Briefing_SummerLoads_ResourcesOperationsPreparednessAssessment-Report-MAR2012.pdf.

Adjustments to nameplate capacity are made for onsite loads and decrease in generating capacity due to the ambient conditions at the time of the peak. Retirements of 496 MW are expected, resulting in a net addition of 1,008 MW of dependable capacity.

Hydroelectric generation provides a significant portion of dependable capacity. Despite experiencing less-than-average water and snowfall so far this year, water conditions indicate that the in-state hydroelectric system will be able to operate at full capacity. Energy Commission staff expects load-serving entities in California will have at least 12,100 MW of dependable hydroelectric capacity available during the summer months in 2012.

Demand response and interruptible programs are considered as supply resources in the *Summer 2012 Electricity Supply and Demand Outlook*. These programs contribute slightly more than in 2011, adding a low of 2,860 MW in June to a high of 3,132 MW in July.

Demand

This report uses two forecasts of summer temperatures to estimate electricity demand. In the near term, the greatest uncertainty in the peak demand forecast is weather-related; air-conditioning loads increase rapidly as temperatures rise. To characterize the range of possible peak demand under varying temperatures, the staff forecast analyzes peak demand response to temperature. The 1-in-2 demand forecast represents expected demand at temperatures with a 50 percent probability of being exceeded due to hotter–than–normal weather, based on the historical distribution of annual maximum temperatures in each area. This forecast is an estimate of summer peak demand for a normal summer and represents peak demand during a peak temperature event occurring once in two years. The 1-in-10 peak demand forecast assumes temperatures at the 90th percentile of the historical annual peak temperature distribution and has a 10 percent probability of being exceeded. The 1-in-10 forecast represents peak demand during a peak temperature event occurring once in 10 years.

The statewide 1-in-2 peak demand forecast for summer 2012 is 770 MW, or 1.3 percent higher than the *2011 Summer Outlook* forecast for summer 2011. Although peak demand for summer 2011, after adjusting to 1-in-2 temperatures, was lower than previously forecast, projected increases in economic activity contribute to forecasted growth of 2.5 percent by summer 2012. This is based on the mid-case forecast from the most recent staff demand forecast, *Revised California Energy Demand Forecast 2012 – 2022.*[3]

3 California Energy Commission, *Revised California Energy Demand Forecast 2012-2022*, CEC-200-2012-001-SD-V1, February 2012. [http://www.energy.ca.gov/2012publications/CEC-200-2012-001/CEC-200-2012-001-SD-V1.pdf].

San Onofre Generating Station

Since January 2012, both San Onofre Generating Station (SONGS) Units 2 and 3 have been offline. Unit 2 was undergoing planned maintenance when Unit 3 experienced problems with steam generator tubing that resulted in the unit being taken offline. Whether one or both units will return to normal operations by the end of September is unknown. Energy Commission staff has determined that if Unit 3 were to remain out of service this summer, the largest reserve margin reduction would be in August. Under 1-in-2 conditions, the reduction would be from 29 to 27 percent, while under 1-in-10 conditions, the reduction would be from 20 to 18 percent. If both units remain out of service, the largest reduction would again be in August, going from 29 to 25 percent under 1-in-2 conditions, and from 20 to 16 percent for 1-in-10 conditions.

These determinations indicate that even with the loss of capacity from SONGS, the statewide planning reserve margin remains adequate, but this determination does not characterize local supply issues. The outages may present additional operational challenges in the Los Angeles Basin and San Diego areas. The California Independent System Operator (California ISO) is responding to and planning for the potential of SONGS remaining offline and is actively leading and coordinating efforts to reduce the risk of potential outages with the Governor's Office, the energy agencies, and other regulatory agencies and affected parties[4].

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4 See California ISO Memorandum to ISO Board of Governors "*Summer Readiness Briefings*", May 9, 2012, [http://www.caiso.com/Documents/LegislativeStateRegulatoryUpdate-Memo-May2012.pdf].

2012 Summer Supply and Demand Outlook

Overview

The Energy Commission's *Summer 2012 Electricity Supply and Demand Outlook (Summer Outlook)* along with the California Independent System Operator's (California ISO) *2012 Summer Loads and Resources Assessment*[5] (*Summer Assessment)* provide decision-makers and the public with projections of electricity supply adequacy during the critical period from June through September.[6] The *2012 Summer Outlook* encompasses all of the state's major balancing authority areas (BAAs). The balancing authorities are the entities that are responsible for integrating resource plans ahead of time, load, interchange, and generation within their area and interconnection frequency in real time. The BAA is the collection of generation, transmission, and loads within the metered boundaries of the balancing authority. The largest BAA is the California Independent System Operator (California ISO); the *Summer Assessment* produced by the California ISO focuses on supply and demand conditions within its area. The remainder of the state's system is largely served by four smaller balancing authorities: Los Angeles Department of Water and Power (LADWP), Balancing Area of Northern California[7] (BANC), Imperial Irrigation District (IID), and Turlock Irrigation District (TID).[8] Appendix A reports details reserve margins broad areas of the state and briefly compares the focus, scope, and method of this report and the California ISO's *Summer Assessment.* Appendices B and F provide supporting information to the report: existing generation, additions, retirements (Appendix B), hydroelectric resources (Appendix C), imports (Appendix D), demand response and interruptible programs (Appendix E), and peak demand (Appendix F).

Electricity use varies widely over the time of day and time of year. On a typical day, demand increases 60 percent from the midnight low to the afternoon high. For a small number of hours each summer, the generation capacity that sits idle for most of the year is needed to meet peak demand. Because air-conditioning loads drive peak demand, California sees its greatest demand during the summer months (June, July, August, and

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5 Ibid.

6 Energy Commission *Summer Outlook* reports do not include either an evaluation of the condition of the electricity market, specific contractual details, or the adequacy of any individual utility or local distribution system. For instance, failures of local-level distribution system components, such as transformers, were the causes of curtailments during the July 2006 heat storm. In-state generation and electricity imports were more than adequate to meet demand.

7 Formerly Sacramento Municipal Utility District.

8 Small portions of the state are in BAAs that lie primarily outside California, including PacifiCorp and Nevada Power. PacifiCorp is by far the largest of these, with a peak load of about 180 MW.

September). On a hot summer day, this swing can be 85 to 90 percent from the early morning trough to the peak demand in mid- to late afternoon.

Since 2005, resource adequacy requirements imposed by the California ISO on load-serving entities (LSEs) in its BAA have alleviated much of the concern over both monthly and year-ahead summer supplies. The LSEs are required to procure capacity sufficient to meet forecasted peak loads on both year-ahead and month-ahead bases. Municipal utilities serving load in the other BAAs have procured capacity in the form of utility-owned generation and long-term contracts sufficient to meet 95 percent or more of their forecasted peak demand. In addition, large quantities of energy, primarily from the Northwest, are available in near-term and spot markets to meet peak summer loads in California under even the most adverse of hydro conditions.

Reserve Margins

The Energy Commission studies potential long-term (10 years) electricity supply and demand conditions to ensure that California maintains a sustainable and reliable energy system well into the future. The Energy Commission also analyzes short-term market developments and a range of potential system variations to determine if there is a significant risk of supply shortfalls during the upcoming peak demand season. This analysis became particularly important following the 2000 – 2001 energy crisis.

A reserve margin is a measurement intended to indicate whether electricity supplies are adequate to meet system loads. The measurement is calculated as the percentage by which dependable supply resources (total of generation capacity, demand resources, and import capacity) exceed the 1-in-2 or 1-in-10 peak demand. This report provides reserve margins based on existing generation, availability of imports, expected retirements, and expected additions.

A specified reserve margin target is the level necessary to cover a particular range of possible system fluctuations, unplanned outages, and unexpected emergencies. The target has historically been based on the desire that loss of load would occur no more frequently than one day in 10 years, which with a 1-in-2 peak demand translates into a 15 to 17 percent reserve margin. This assumes that the cost of providing a higher degree of reliability, building additional generation capacity to ensure continued service even under the 1-in-30 year weather conditions that prevailed in July 2006, would be greater than society's willingness to pay for it.

In California, a planning reserve margin is a specific regulatory requirement imposed on California Public Utility Commission jurisdictional LSEs as part of resource adequacy requirements. It is based on a 1-in-2 peak demand forecast with specific counting rules for loads, reductions of load, and capacity. In contrast to the LSEs, each publicly owned utility defines and sets its own resource adequacy requirements.

A reserve margin of 15 to 17 percent over a 1-in-2 peak demand ensures that an adequate operating reserve margin can be maintained by the BAA. An *operating* reserve margin is the generation capacity available to the balancing authority in real time above that needed to meet the forecasted daily peak load. For the BAA to reliably serve load given near-term load forecasting error and the potential for the sudden failure of major system components (large generators and transmission lines), an operating reserve of 7 to 9 percent or more is typically required. The specific value depends upon the composition of the generation resources online, and the size of the largest system component. A share of this reserve must be synchronous to the grid ("spinning") and thus able to change output levels all but instantaneously; the remainder must be available within a few minutes.

Table 2 compares the supply of electricity with expected demand during the period June 1 through September 30, 2012.[9] It provides a deterministic assessment (a single point forecast) of expected peak demand, in-state generation, electricity imports, and reserves under average (1-in-2 year) and hotter-than-normal (1-in-10 year) weather conditions. The results for each month are expressed in terms of estimated reserve margins.

Table 2: Statewide 2012 Summer Outlook (MW)

Resource Adequacy Planning Conventions		June	July	August	September
1	Existing Generation	61,300	61,421	61,765	62,183
2	Expected Retirements	0	-44	0	0
3	Expected Additions	121	344	418	23
4	Net Imports	13,118	13,118	13,118	13,118
5	**Total Net Generation**	74,539	74,839	75,301	75,324
6	Demand Response / Interruptible / Curtailable Programs	2,860	3,132	3,073	3,039
7	**Total Net Supply**	77,399	77,971	78,374	78,363
8	1-in-2 Summer Demand	53,811	58,086	60,343	54,922
8a	**Reserve Margin (1-in-2 Demand)**	**44%**	**34%**	**30%**	**43%**
9	1-in-10 Summer Demand	57,944	62,557	64,936	59,173
9a	**Reserve Margin (1-in-10 Demand)**	**34%**	**25%**	**21%**	**32%**

Note: All capacities are dependable, not nameplate. Existing generation values for July, August, and September incorporate expected additions from previous months.
Components may not sum to totals because of rounding.
Source: Energy Commission staff.

Estimated reserve margins for this summer are about the same as those reported in the *2011 Summer Outlook* for normal (1-in-2 year) and above normal (1-in-10 year) peak weather conditions. Based on the 1-in-2 demand, the June and July reserve margins are somewhat

9 For the *2012 Summer Outlook*, Energy Commission staff considers demand reduction, interruptible programs, and curtailable programs as resources. Other documents, studies, and programs may consider these programs differently.

lower, while the August and September reserve margins differ from last year by less than 1 percent.[10] These margins indicate that there should be sufficient resources to cover most system contingencies, including high demand due to hotter-than-normal weather conditions. **Table 3** compares current August statewide reserve margins to comparable values from previous 2010 and 2011 *Summer Outlooks*.[11]

Table 3: Statewide August Reserve Margins 2010 to 2012 (MW)

Resource Adequacy Planning Conventions	August 2010 Summer Outlook	August 2011 Summer Outlook	August 2012 Summer Outlook
Generation Including Expected Additions and Retirements	61,100	61,362	62,183
Net Imports	13,118	13,118	13,118
Total Net Generation	**74,218**	**74,135**	**75,301**
Demand Response/Interruptible/Curtailable Programs	2,784	2,946	3,073
Total Net Supply	**77,001**	**77,081**	**78,374**
Expected 1-in-2 Normal Summer Temperature Demand	60,797	59,571	60,343
Reserve Margin (1-in-2 Demand)	**28%**	**29%**	**30%**
Expected 1-in-10 Unusually Hot Summer Temperature Demand	65,965	64,527	64,936
Reserve Margin (1-in-10 Demand)	**17%**	**19%**	**21%**

Source: Energy Commission staff.

Supply

Supply consists of in-state generation, including demand response and interruptible programs, and electricity imports. **Table 4** summarizes the estimated net capacity additions included in the *2012 Summer Outlook*. These figures are based on additions and retirements that were either not included in the *2011 Summer Outlook*, have occurred since October 1, 2011, or are believed to have a high probability of taking place before October 1, 2012.

10 *Summer 2010 Electricity Supply and Demand Outlook* (*2010 Summer Outlook*) *Table 1: Statewide 2010 Summer Outlook (MW)*, p. 5. [http://www.energy.ca.gov/2011publications/CEC-200-2011-004/CEC-200-2011-004.pdf].

11 *Summer 2011 Electricity Supply and Demand Outlook* (*2011 Summer Outlook*) *Table 1: California 2011 Summer Outlook (MW)*, p. 5 [http://www.energy.ca.gov/2011publications/CEC-200-2011-004/CEC-200-2011-004.pdf].

Table 4: Statewide Summary of Additions and Retirements

	Nameplate Capacity (MW)	Dependable Capacity (MW)
Additions	2,236	1,504
Retirements	496	496
Net Change	**1,740**	**1,008**

Source: Energy Commission staff.

This report uses the term *dependable capacity* to indicate net dependable capacity. Net dependable capacity is the estimated capacity that a unit or facility can provide to carry system load for a specified time interval and period based under ambient conditions. For example, a natural gas turbine's nameplate capacity based on its maximum output under test conditions would be derated or reduced by the amount of power used onsite and further because of the reduction in generation capacity during peak periods resulting from higher ambient temperatures during the summer.

The values reported in this report as dependable capacity correspond to the California ISO's value of net qualifying capacity (NQC) as defined by the California Public Utilities Commission for resource adequacy. Annually, the California Public Utilities Commission and the California ISO jointly report NQCs for facilities within the California ISO's balancing area. For new wind and solar facilities outside the California ISO or without California ISO-established values, the California ISO method used to establish initial NQC values was used. For other technologies, the reported dependable capacity was used, or, in cases where reported dependable capacities did not exist, the dependable capacity was estimated using the factors in **Table B-3**.

Existing generation includes additions and retirements to date as well as seasonal changes in the capacity of solar and wind generation. New generation totals 2,236 MW nameplate (1,504 MW dependable). Retirements totaling 496 MW are expected to take place during this period, for a net addition of 1,740 MW of nameplate capacity and 1,008 MW of dependable capacity. See Appendix B for a detailed presentation of additions and retirements.

Installed and available hydroelectric generating capacity in California is essentially unchanged from prior years in the California ISO and the other BAAs. Total hydroelectric nameplate capacity in California is 13,539 MW. Statewide, about 10,928 MW is considered dependable capacity for meeting summer peak loads,[12] based on dry 1-in-5 year hydrological conditions. When precipitation and water content in the Sierra snowpack are substantially below average, which is the case thus far this year, hydroelectric energy production will also be below average. However, the ability to generate electricity, even

12 Statewide summer peak loads most commonly occur in August, and August capacities are reported here. June through September values are reported in Appendix B.

during a few hours during peak summer demand, will not be diminished substantially during 1-in-10 dry year conditions. As of April 16, 2012, the state's largest 36 reservoirs were storing 110 percent of the average for this date.[13] Appendix C provides Energy Commission staff's analysis of this year's hydroelectric supply.

Imports of electricity provide about 13,000 MW of capacity on a statewide basis. These consist both of energy from out-of-state resources owned by or under contract to California LSEs, and energy purchased on short-term and spot markets at a price that is lower than the cost of generating it in California.

The net imports assumption represents a conservative estimate of the available electricity imports into each region, based on the western United States' system's capability to provide surplus generation during peak demand periods. The interconnected, interdependent wholesale power market provides reliability support and broad cost-reduction benefits. The Pacific Northwest has a diverse mix of surplus electricity resources and different load patterns, which create opportunities for sales of electricity to California on peak during the summer. In addition, surplus energy is frequently available from the Desert Southwest. See Appendix D for a more detailed presentation of imports.

Demand response and interruptible programs are considered as supply resources in the *2012 Summer Outlook*. These programs contribute a total of 3,075 MW in August, which is about 5 percent of statewide peak demand. Programs in August 2012 are expected to contribute 129 MW more than in 2011. Appendix E provides details on interruptible and demand response resources.

Demand

The 1-in-2 peak demand forecast for summer 2012 is 1.3 percent (770 MW) higher than the *Summer 2011 Outlook* forecast for summer 2011. Economic conditions in 2011 were worse relative to the assumptions underlying the previous load forecast, resulting in lower–than–predicted load in 2011. The economic projections for the current forecast indicate growth in 2012, so this forecast projects statewide peak demand growth of 2.5 percent over weather-adjusted 2011 demand. The forecast is documented in *Revised California Energy Demand Forecast 2012 – 2022*.[14] This outlook uses the mid-case forecast.

The greatest uncertainty in near-term demand forecasting is weather-related; air-conditioning loads increase rapidly as temperatures rise. To characterize the range of possible demands under varying temperatures, the forecast incorporates analysis of peak

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13 See http://cdec.water.ca.gov/cgi-progs/reservoirs/RES.

14 California Energy Commission, *Revised California Energy Demand Forecast 2012-2022*, CEC-200-2012-001-SD-V2, February 2012. See http://www.energy.ca.gov/2012_energypolicy/documents/2012-02-23_workshop/Mid_Case_LSE_and_Balancing_Authority_Forecast.xls for tables.

demand response to temperature. The 1-in-2 demand forecast represents expected demand at temperatures with a 50 percent probability of being exceeded due to hotter-than-average weather, based on the historical distribution of annual maximum temperatures in each area. The 1-in-10 peak demand forecast assumes temperatures at the 90th percentile of the historical annual peak temperature distribution and has a 10 percent probability of being exceeded. See Appendix F for the 1-in-2 and 1-in-10 forecasts by BAA.

San Onofre Generating Station

The San Onofre Generating Station (SONGS) is a nuclear power plant located on the coast of northern San Diego County and consists of two units, Units 2 (1,122 MW) and 3 (1,124 MW). Since January 2012, both San Onofre Generating Station (SONGS) Units 2 and 3 have been offline. Unit 2 was undergoing planned maintenance when Unit 3 experienced problems with steam generator tubing that resulted in the unit being taken offline. Whether one or both units will return to normal operations by the end of September is unknown. Energy Commission staff has determined that if Unit 3 were to remain out of service this summer, the largest reserve margin reduction would be in August. Under 1-in-2 conditions, the reduction would be from 29 to 27 percent, while under in 1-in-10 conditions, the reduction would be from 20 to 18 percent. If both units remain out of service, the largest reduction would again be in August, going from 29 to 25 percent under 1-in-2 conditions, and from 20 to 16 percent for 1-in-10 conditions as shown **Table 5**.

Table 5: Statewide Reserve Margins With SONGS Units 3, or Both 2 and 3 Offline

Scenario		June	July	August	September
Unit 3 Offline	**Total Net Supply**	**76,754**	**77,327**	**77,730**	**77,719**
	Unit 3 Outage	-1,124	-1,124	-1,124	-1,124
	Residual Net Supply	75,630	76,203	76,606	76,595
	1-in-2 Summer Demand	53,811	58,086	60,343	54,922
	Reserve Margin (1-in-2 Demand)	**41%**	**31%**	**27%**	**39%**
	1-in-10 Summer Demand	57,944	62,557	64,936	59,173
	Reserve Margin (1-in-10 Demand)	**31%**	**22%**	**18%**	**29%**
Units 2 and 3 Offline	**Total Net Supply**	**76,754**	**77,327**	**77,730**	**77,719**
	Units 2 + 3 Outage	-2,246	-2,246	-2,246	-2,246
	Residual Net Supply	74,508	75,081	75,484	75,473
	1-in-2 Summer Demand	53,811	58,086	60,343	54,922
	Reserve Margin (1-in-2 Demand)	**38%**	**29%**	**25%**	**37%**
	1-in-10 Summer Demand	57,944	62,557	64,936	59,173
	Reserve Margin (1-in-10 Demand)	**29%**	**20%**	**16%**	**28%**

Source: Energy Commission staff.

These determinations indicate that even with the loss of capacity from SONGS statewide PRM remain adequate, but this determination does not characterize local supply issues and does not approach the very real issue that California may face local reliability challenges if one or both SONGS units remain offline. The values reported in **Table 5** are statewide planning values, not operational values and do not reflect local needs.

The availability of capacity from SONGS directly affects the California ISO's operations in the Los Angeles Basin and San Diego areas. The California ISO is responding to and planning for the potential of SONGS remaining offline and means to reduce the risk of potential outages. In addition, the California ISO is actively leading and coordinating responses to these risks with the Governor's Office, California Air Resources Board, local air districts, the California Public Utilities Commission, the California Energy Commission, the affected utilities, and power generators. Potential actions include the bringing other generation that is currently offline back into service, transmission upgrades, demand response measures, and maintenance of existing generations. Information pertaining to California ISO is available on its website.[15]

15 See [www.caiso.com].

GLOSSARY

Acronym or Term	**Definition**
BAA	Balancing authority area
BANC	Balancing Authority Area of Northern California (formerly SMUD BAA)
California ISO	California Independent System Operator
CCSF	City and County of San Francisco
COI	California Oregon Intertie
CPUC	California Public Utilities Commission
CVP	Central Valley Project
Energy Commission	California Energy Commission
IEPR	*Integrated Energy Policy Report*
IID	Imperial Irrigation District
LADWP	Los Angeles Department of Water and Power
LSE	Load-serving entity
MW	Megawatt
NP 26	North of Path 26
NQC	Net qualifying capacity
OTC	Once-through-cooling
PG&E	Pacific Gas and Electric
PRM	Planning reserve margin
SDG&E	San Diego Gas & Electric
SMUD	Sacramento Municipal Utility District
SONGS	San Onofre Generating Station
SP 26	South of Path 26
TID	Turlock Irrigation District
USBR	U.S. Bureau of Reclamation
WECC	Western Electricity Coordinating Council
WAPA	Western Area Power Authority

APPENDIX A: Reserve Margins

This report does not attempt to address the questions of reserve margins for local areas, but because of California's size, reserve margins are reported here for three broad areas of the state. **Table A-1**, **Table A-2**, and **Table A-3** show reserve margins for North-of-Path 26 (NP 26), South-of-Path 26 (SP 26), and the aggregated areas outside the California ISO.

Path 26 consists of the three Southern California Edison (SCE) 500 kilovolt (kV) power lines that form SCE's intertie or link with Pacific Gas and Electric (PG&E) to the north. NP 26 is used to refer to the portion of the California ISO consisting of the PG&E service territory and adjacent municipal utility districts falling within the California ISO. SP 26 is used to refer to the portion of the California ISO consisting of the SCE and SDG&E service territories and adjacent municipal utility districts falling within the California ISO. Margins are reported here separately because the intertie can limit electricity interchange between the two regions under some load conditions. Although reserve margins might be sufficient overall, either or both of the regions could have insufficient resources. The remainder of the state's system outside the California ISO BAA is largely served by four smaller balancing authorities: Los Angeles Department of Water and Power (LADWP), Balancing Area of Northern California (BANC), Imperial Irrigation District (IID), and Turlock Irrigation District (TID). Aggregate reserve margins for these areas are reported **Table A-3**.

Table A-1: Reserve Margins NP 26, 2012 Summer Outlook (MW)

Resource Adequacy Planning Conventions		June	July	August	September
1	Existing Generation	26,394	26,342	25,905	25,352
2	Expected Retirements	0	0	0	0
3	Expected Additions	22	284	348	0
4	Net Imports	1,750	1,750	1,750	1,750
5	**Total Net Generation**	**28,166**	**28,376**	**28,003**	**27,102**
6	Demand Response/Interruptible/Curtailable Programs	612	684	649	640
7	**Total Net Supply**	**28,778**	**29,060**	**28,651**	**27,742**
8	1-in-2 Summer Demand	20,130	21,374	21,374	19,175
8a	**Reserve Margin (1-in-2 Demand)**	**43%**	**36%**	**34%**	**45%**
9	1-in-10 Summer Demand	21,464	22,790	22,743	20,446
9a	**Reserve Margin (1-in-10 Demand)**	**34%**	**28%**	**26%**	**36%**

Source: Energy Commission staff.

Table A-2: Reserve Margins SP 26, 2012 Summer Outlook (MW)

Resource Adequacy Planning Conventions		June	July	August	September
1	Existing Generation	23,263	25,177	24,773	24,678
2	Expected Retirements	0	-44	0	0
3	Expected Additions	99	60	70	23
4	Net Imports	10,100	10,100	10,100	10,100
5	**Total Net Generation**	**33,462**	**35,293**	**34,943**	**34,801**
6	Demand Response / Interruptible / Curtailable Programs	1,935	2,133	2,109	2,087
7	**Total Net Supply**	**35,397**	**37,426**	**37,051**	**36,888**
8	1-in-2 Summer Demand	23,561	25,724	27,593	25,377
8a	**Reserve Margin (1-in-2 Demand)**	**50%**	**45%**	**34%**	**45%**
9	1-in-10 Summer Demand	25,402	27,735	29,750	27,361
9a	**Reserve Margin (1-in-10 Demand)**	**39%**	**35%**	**25%**	**35%**

Source: Energy Commission staff.

This year as in past years the Energy Commission's *Summer Outlook* and the California ISO *Summer Assessment* report some of the same information; therefore, it is likely comparisons of the results are made. The *Summer Outlook* is in essential agreement with the *Summer Assessment*; that is, California, and specifically the California ISO BAA, both show robust levels of planning reserves.

The two reports do have differences in focus, scope, and method. Whereas the *Summer Outlook* examines and projects reserve margins at statewide level, the *Summer Assessment's* focus is the California ISO BAA only. In addition, the *Summer Outlook* is a planning projection, but the *Summer Assessment* is an operational projection. Both consider generation resource additions and retirements since last year, as well as resource additions and retirements expected through September 2012.

The difference in emphasis on planning versus operations leads to differences in the treatment of hydroelectric generation capacity and potential outages and, hence, the reported metrics. The *Summer Assessment* reduces ("derates") hydro capacity, and in some metrics, includes an outage factor. Both the PRM and operating reserves reported in the *Summer Assessment* are based on hydroelectric generation capacity based on historical deliveries. This derates capacity of hydroelectric facilities by about 1,000 MW. The estimate is based on average capacity provided during peak hours during a year with similar rainfall. The *Summer Assessment* also adjusts total generation for estimated forced outages for some metrics. On the other hand, the *Summer Outlook* does not derate hydro capacity because the capacity available at peak varies little despite rainfall variations. The energy available from California hydroelectric resources does vary from year to year, based on rainfall. Therefore, average energy deliveries are less, but available capacities are not. The *Summer Outlook* also does not adjust for potential outages. This is consistent with the calculation of a reserve margin for planning purposes, as contrasted with an operational reserve margin. Energy Commission staff's intent is to produce a metric consistent with a long-term PRM where a 15 – 17 percent PRM is considered adequate to support a 1-in-2 year outage reliability standard.

Nevertheless, the two reports compare very well in their conclusions that PRMs under both "usual" weather conditions and "very hot" conditions are ample. The differences in reserve margins directly result from differing treatment of hydroelectric generation capacity and the inclusion of an outage factor. This results from the *Summer Assessment* being operationally focused rather than planning-focused. For instance, under usual weather conditions the *Summer Outlook's* reserve margins during August are 34 percent for the California ISO's BAA and its two subareas, SP 26 and NP 26. The comparable values in the *Summer Assessment's* are 22 percent for SP 26, 24 percent for NP 26, and 23 percent for the entire BAA. But when California ISO's values are adjusted by removing the operationally driven hydro derating, the results differ by less than 1 percent. (Required reserve margins apply solely to the "usual" 1-in-2 weather conditions. The acceptable range is from 15 to 17 percent.)

For "very hot" 1-in-10 conditions, the *Summer Outlook's* margins are 25 percent for SP 26, 26 percent for NP 26, and for the overall California ISO area, 25 percent. The respective values in the *Summer Assessment* are 7 percent, 12 percent, and 12 percent; however, when California ISO's values are adjusted by removing the operationally driven hydro derating and outage factor, the results differ by about 3 percent.

In addition to the methodological differences resulting from the aims of the reports, the specific values that the Energy Commission reports do not exactly match those reported by the California ISO. The factors that lead to these differences are:

- **Different Forecasts:** The California ISO uses its internal demand forecast, while the Energy Commission uses the updated February 2012 Demand Forecast.
- **Demand Response:** The California ISO uses a weighted average of demand response values for July, August, and September to derive an estimate for the demand response available during a 1-in-2 summer peak, since the summer peak though most likely to occur in August could occur in another month. The Energy Commission uses the August demand response for statewide and SP 26 and the July value for NP 26 because these values more closely represent the availability of demand response during the annual 1-in-2 peak. The reason for this approach is that a portion of the demand response is available because the temperature-driven annual peak and averaging over the summer would bias downward the estimate of these resources.
- **Differences in Reported Capacities:** It is likely that there are some minimal differences in reported capacities used by the Energy Commission and California ISO.
- **Factors to Estimate Net Qualifying Capacity (NQC) of New Intermittent Resources**: For new intermittent resources other than wind and solar, the California ISO may have

used different factors, for example, fuel cells. These resources represent only a tiny fraction of total generation.

- **Status of Expected Additions:** The Energy Commission used publicly available data about expected additions and their timing, but the California ISO may have access to additional information, including confidential market data about the progress of individual projects. The California ISO can maintain confidentiality by aggregating the data of individual expected additions and retirements and reporting the total values for groups of resources. The inability to match public data to aggregated values prevents complete consistency, but the differences are small.
- **Imports:** The California ISO uses 10,000 MW and the Energy Commission uses 10,350 MW for imports.

The areas outside California are diverse, are not contiguous, and have little in common. The four smaller balancing authorities aggregated here are reported, so the substatewide tables are complete. The reserve margins for California outside the California ISO BAA, the 1-in-2 reserve margins for August, are at the high end of the 15 to 17 percent range that is considered to provide adequate reliability.

Table A-3: Outside the California ISO BAA, 2012 Summer Outlook (MW)

Resource Adequacy Planning Conventions		June	July	August	September
1	Existing Generation	11,643	11,643	11,643	11,643
2	Expected Retirements	0	0	0	0
3	Expected Additions	0	0	0	0
4	Net Imports	2,768	2,768	2,768	2,768
5	**Total Net Generation**	14,411	14,411	14,411	14,411
6	Demand Response / Interruptible / Curtailable Programs	313	316	316	313
7	**Total Net Supply**	14,724	14,727	14,727	14,724
8	1-in-2 Summer Demand	11,169	12,118	12,551	11,439
8a	**Reserve Margin (1-in-2 Demand)**	32%	22%	17%	29%
9	1-in-10 Summer Demand	12,173	13,209	13,657	12,469
9a	**Reserve Margin (1-in-10 Demand)**	21%	11%	8%	18%

Source: Energy Commission staff.

APPENDIX B: Generation Resources

Existing Generation

Existing generation includes generation facilities operational as of October 1, 2011, plus new generation expected to be on-line before June 1, 2012. Generation capacity in SP 26 includes about 1,080 MW of contracted capacity from units located in northern Baja California, Mexico, directly connected to and controlled by the California ISO.

Summer capacities used for existing generation within the California ISO area are taken from the most recent California ISO net qualifying capacity (NQC) listing.[16] For those intermittent resources whose NQC varies from month to month, the August value was used.

Generation Additions and Retirements

Table B-1 shows both the nameplate and dependable capacity additions for both the California ISO and non-California ISO areas and the statewide net capacities. The projected net additional nameplate capacity in the California ISO BAA is 1,299 MW, and the net additional dependable capacity is 688 MW. The net increase in SP 26 is about 249 MW nameplate capacity and 244 MW dependable capacity. The NP 26 subregion's net increase is 1,051 MW of nameplate capacity and 912 MW of dependable capacity.

Table B-1: California Net Capacity Additions (MW)

	Nameplate Capacity (MW)	Dependable Capacity (MW)
California ISO Additions	1,795	1,164
California ISO Retirements	496	496
California ISO Net Change	**1,299**	**668**
Non-California ISO Additions	440	331
Non-California ISO Retirements	-	-
Non-California ISO Net Change	**440**	**331**
State Net Change	**1,740**	**999**

Components may not sum to totals because of rounding.
Source: Energy Commission staff.

16 For resources within its area, the California ISO publishes a listing of qualifying capacities of resources for resource adequacy purposes annually on its website. This is available at: [http://www.caiso.com/Documents/NQCLocalAreaData_ComplianceYear2012.xls].

Table B-2: Additions and Retirements in the California ISO BAA (MW) September 2011 to August 2012

Generation Resources	Technology	Nameplate Capacity (MW)	Dependable Capacity (MW)	Actual or Estimated On-line Month & Year
Additions - SP 26				
Windstar 1, Aero Energy	Wind	120	20	Jan-12
Ridgetop I	Wind	6	1	Jan-12
Adelanto Solar Project	Solar PV	12	10	Feb-12
Mt. View Power Partners	Wind	49	8	Mar-12
Alta VI	Wind	150	25	Mar-12
TA - High Desert	Solar PV	20	17	Mar-12
Coram Brodie	Wind	102	17	Apr-12
Nickel 1 Solar	Solar PV	2	1	Apr-12
Newberry Springs Solar 1	Solar PV	4	3	Jun-12
Newberry Springs Solar 2	Solar PV	4	3	Jun-12
Flex Bernardino	Biogas	2	2	Jun-12
Olivenhain Lake Hodges 2	Hydro	20	20	Jun-12
Del Sur Solar	Solar PV	38	32	Jun-12
Flex Kern	Biogas	5	5	Jul-12
Escondido Energy Center (Repower)	Natural Gas - Simple Cycle	45	43	Jul-12
NRG Solar Borrego I	Solar PV	26	22	Jul-12
Pacific Wind LLC	Wind	140	23	Sep-12
Total Additions - SP 26		**744**	**252**	
Additions - NP 26				
Westside Solar Station	Solar PV	15	7	Sep-11
CSU SF Fuel Cell	Natural Gas - Fuel Cell	2	1	Sep-11
CSU East Bay	Natural Gas - Fuel Cell	2	1	Sep-11
Stroud Solar Station	Solar PV	20	9	Oct-11
Five Points Solar Station	Solar PV	15	7	Oct-11
Three Forks Water Project	Hydro	2	0	Oct-11
Shiloh III	Wind	60	16	Jan-12
SunPower High Plains	Solar PV	250	217	Apr-12
McHenry Solar Farm	Solar PV	25	22	Jun-12
Lodi Energy Center	Natural Gas - Combined Cycle	296	284	Jul-12
SPS Atwell Island	Solar PV	20	17	Aug-12
GWF Tracy	Natural Gas - Simple Cycle	145	139	Aug-12
Mariposa	Natural Gas - Combined Cycle	200	192	Aug-12
Total Additions - NP 26		**1,051**	**912**	
Total California ISO Additions (NP 26 Additions +SP 26 Additions)		**1,795**	**1,164**	
Retirements - SP 26				
Huntington Beach Unit 3[17]	Natural Gas - Steam Turbine	225	225	Mar-11
Huntington Beach Unit 4	Natural Gas - Steam Turbine	227	227	Mar-11
Escondido Energy Center (old unit)	Natural Gas - Simple Cycle	44	44	Jul-12
Total Retirements - SP 26		496	496	
Retirements - NP 26				
None				
Total Retirements - NP 26				
Total California ISO Retirements		**496**	**496**	
Net California ISO Additions (Total Additions less Total Retirements)		1,299	668	

Source: Energy Commission staff.

17 Huntington Beach 3 and 4 were returned to service in May 2012 to provide electric capacity unavailable due to the extended shutdown of the SONGS.

Table B-2 and **Table B-3:** provide additional detail regarding the additions and retirements. These are additions and retirements that were either not included in the *2011 Summer Outlook*, have occurred since October 1, 2011, or are believed to have a high probability of taking place before October 1, 2012.

Net Qualifying Capacity and Dependable Capacity

NQC is a capacity measure defined by the California Public Utilities Commission (CPUC) only for the IOUs for resource adequacy. The CPUC and the California ISO annually report NQCs for facilities within its BAA. For biomass, fossil fuel, and geothermal resources, the values correspond to dependable capacity. The average performances of solar and wind resources vary significantly by both the time of day and time of the year. For these resources the CPUC provides a method to calculate monthly values for these resources for use in resource adequacy. The values are based on the 30th percentile or the 70 percent exceedence of hourly generation during high load hours.[18] In addition, the method establishes a way to calculate an NQC for new resources without a performance history. For these resources, factors are established for each technology and month based on the ratio of calculated NQC to nameplate capacity for resources with established NQCs.

NQC does not formally apply to resources outside the California ISO. Therefore, this report uses the more generic term *dependable capacity*. For values within the California ISO and for which NQCs are established, those values are used. For non-California ISO BAA resources with reported dependable capacities from the *2011 Integrated Energy Policy Report (IEPR)* filings, those values were used. For renewable resources for which an initial NQC has not been established, or without a reported dependable capacity, the CPUC factors were used to calculate a value consistent with the NQC method. For natural gas-fueled generators, without a reported dependable capacity, a factor of 96 percent was used. These factors are reported in **Table B-3**. Nameplate capacity multiplied by these factors generated the estimate of dependable capacity for resources without an NQC or a reported dependable capacity.

18 California Public Utilities Commission, *Qualifying Capacity Methodology*, December 18, 2009, [http://www.cpuc.ca.gov/NR/rdonlyres/AC234508-FD4E-4B58-AA63-E0302BF64DD9/0/QualifyingCapacityRulesFinal.doc&sa=U&ei=DyiPT7nBGoKM6QHZs5j7Dg&ved=0CBwQFjAF&usg=AFQjCNFoX5-jW5hhUAAyQhiEru2SPG5JRQ].

Table B-3: Factors to Determine Dependable Capacity for Resources Without Otherwise Established Values: (Nameplate Capacity x Factor = Estimated Dependable Capacity)

Technology	All Months	June	July	August	September
Solar		90%	87%	84%	75%
Wind		33%	27%	17%	5%
Biogas	90%				
Biomass	90%				
Coal	96%				
Digester Gas	90%				
Geothermal	96%				
Natural Gas	96%				

Source: Energy Commission staff.

Table B-4 shows non–California ISO BAAs with nameplate capacity additions totaling 440 MW (331 MW dependable). No retirements have occurred or are expected.

Table B-4: Additions and Retirements, Non-California ISO BAAs (MW)

Generation Resources	Technology	Nameplate Capacity (MW)	Dependable Capacity (MW)	Actual or Estimated On-line Month & Year
Butte County (CA) LFG	Biomass	2	2	Dec-11
Imperial County (Niland) Solar	Solar PV	23	19	Jan-12
Buena Vista	Biomass	21	19	Feb-12
Kirkwood	Natural Gas - Internal Combustion	6	6	Mar-12
Ace Sacramento Solar	Solar PV	2	2	Mar-12
Almond II	Natural Gas - Simple Cycle	174	167	Apr-12
Solano Wind	Wind	128	35	Apr-12
El Centro Unit 3	Natural Gas - Combined Cycle	84	81	May-12
Total Additions - Non-California ISO		**440**	**321**	
Retirements - Non-California ISO				
None		0	0	

Source: Energy Commission staff.

Note : Non-California ISO are Turlock Irrigation District BAA, Imperial Irrigation District BAA, Los Angeles Department of Water and Power BAA, and Balancing Authority of Northern California.

Los Angeles Department of Water and Power reports the expectation that Adelano Solar PV project (20 MW nameplate, 18 MW dependable) will be on-line sometime during the summer of 2012. Because of the uncertainty of the on-line date, it was not included above.

APPENDIX C: Hydroelectric Generation Supplies

Hydroelectric Dependable Capacity

Under all but the most adverse water conditions, there are 10,928 MW of dependable generating capacity from hydroelectric resources to meet peak electricity demand in California every August. This conclusion is based on a physical systems assessment, historical performance, and utilities' resource supply plan filings to the Energy Commission. This is a conservative number based on an analysis of dry year conditions expected to occur, on average, once every five years and requires that a facility be able to deliver energy for four consecutive hours on three consecutive days. This 1–in–5 dry year criterion is used with historical performance data and the analytical results are built into the resource adequacy counting conventions for net qualifying capacity as used by a load-serving entity (LSE) in the California ISO BAA. This 1-in-5 dry year criterion is generally used by LSEs in other California BAAs for planning purposes.[19]

Table C-1 summarizes the amount of dependable capacity that staff expects will be available to serve loads in California BAAs this summer. This compilation does not assume all these resources will be made available by their owners to serve coincident peak system loads. Since hydropower is a "use limited" resource, LSEs are generally not required to release water at dispatchable hydro plants to serve loads of other LSEs. In general, however, LSEs can be expected to conserve these "use limited" energy resources so they can be called upon to generate on peak, when energy has the greatest economic value and when power has the greatest reliability value. Compared to other generating technologies, hydroelectric facilities have relatively few forced outages and derates for maintenance outages.

The capacity values presented here do not include those associated with hydroelectric energy provided during peak hours in the summer by generators in the Pacific Northwest in response to price signals in short-term and spot markets. The amount of such energy varies with hydro conditions and demand in the Pacific Northwest, and prices in both Northwest and California markets. While it cannot be credited against resource adequacy requirements, the amount of nonfirm energy available on peak can be substantial and, in

19 Dependable hydro capacity at peak does not significantly change between wet and dry water years even though the historical record shows that dry conditions can have a significant effect on available energy production. In California, hydroelectric generating capacity is not significantly diminished (or derated) when less water is available. Most of the capacity at utility hydroelectric powerhouses is located far below dams and river diversion points, making these resources relatively immune to seasonally fluctuating reservoir levels.

combination with those resources that are used to meet resource adequacy requirements, ensures reserve margins well above those needed to reliably serve load.

Table C-1: Dependable Capacity From Hydro Resources, Statewide, 2012 (MW)

Balancing Area	June	July	August	September
California ISO	7,844	7,759	7,533	7,239
LADWP	1,825	1,825	1,825	1,822
BANC	1,530	1,389	1,353	1,315
Turlock Irrigation District	152	152	152	152
Imperial Irrigation District	65	65	65	65
Total Capacity	**11,416**	**11,190**	**10,928**	**10,593**

Source: Energy Commission staff.

California ISO

Under 2012 water conditions, there are 9,080 MW of dependable generating capacity from hydroelectric resources to meet August peak loads in the California ISO BAA. As also indicated in **Table C-2**, more than 9,300 MW are available in June and July and more than 8,600 MW are available in September.

Table C-2: Dependable Capacity From Hydro Resources, California ISO, 2012 (MW)

Resources	June	July	August	September
Net Qualifying Capacity Hydro Resources Located in California ISO	7,844	7,759	7,533	7,239
Other Contributing Hydro Resources (Outside California ISO)				
Hoover	594	593	593	592
Central Valley Project	1,023	858	796	723
Hetch Hetchy	100	100	100	100
Total Capacity	9,561	9,310	9,022	8,654

Sources: Energy Commission staff; California ISO lists 2011 NQC values for hydro at http://www.caiso.com/1796/179688b22c970.html; where resources have month-specific NQC values, August values are used USBR 90 Percent Exceedence Values for Central Valley Project operations posted at http://www.usbr.gov/mp/cvo/data/PWRFeb90.pdf.

The aggregate NQC in August for the 331 hydroelectric facilities in the California ISO BAA is 7,533 MW. The totals in **Table C-2** do not include monthly NQC values for five pumping plants in the State Water Project because currently there is no agreement for these facilities to contribute dependable capacity through load curtailment.[20]

20 Banks, Dos Amigos, Pearblossom, Edmonston, and Oso. These pumps are located along the California Aqueduct within the California ISO.

Hydro capacity available to LSEs in the California ISO BAA also includes nearly 600 MW from Hoover Dam and more than 700 MW from Central Valley Project (CVP) hydro for Western Area Power Administration (WAPA) loads in Northern California. The allocation of capacity from these sources to individual LSEs in all of the BAAs in California is discussed below.

A share of the portfolio of hydroelectric resources controlled by the City and County of San Francisco (CCSF) is counted in the total that will be available to serve summer peak loads in the California ISO BAA. While the Hetch Hetchy power plants (402 MW nameplate, 410 MW dependable) are not obligated by regulatory requirements to serve loads in the California ISO BAA, at least 100 MW are continuously available in practice to serve CCSF municipal loads during summer months.[21] CCSF uses Hetch Hetchy to meet all of its energy needs and has an agreement with PG&E to "bank" up to 75 MW during hours when generation exceeds load.

Other California Balancing Authority Areas

Table C-3 presents the hydro capacity available to the other California BAAs: LADWP, BANC, TID, and IID. This totals 3,395 MW in August; the values for June and July are slightly higher; the September value is 41 MW lower.[22]

Dependable capacity values for hydro resource owned by publicly owned utilities reflect dry year assumptions and were taken from supply forms submitted to the Energy Commission in 2011 for the *Integrated Energy Policy Report* (*IEPR*).

21 In 2010, CCSF maximum hourly loads during the four summer months varied from 134 MW to 144 MW. Minimum loads in these months, always during off-peak hours, varied from 84 MW to 89 MW. Supply Form S-3 submitted by CCSF to to the Energy Commission, June 11, 2011, for the *2011 Integrated Energy Policy Report*.

22 The data available to Energy Commission staff for several hydro resources dedicated to loads in other California BAAs is limited to dependable capacity values at the time of noncoincident peak load. This occurs in July or August, depending on the LSE. As such, aggregate dependable hydro capacity in June (September) is likely to be slightly higher (lower) than indicated.

Table C-3: Dependable Capacity From Hydro Resources, Other California BAAs, 2012 (MW)

Hydro Resource	June	July	August	September
Hoover Capacity	488	487	487	486
LADWP's Utility-Owned Hydro	1,384	1,384	1,384	1,384
Tieton Hydro import (Burbank & Glendale)	16	16	16	16
LADWP BAA Total	**1,888**	**1,887**	**1,887**	**1,886**
CVP Capacity Available to BANC	789	674	622	554
SMUD Utility-Owned Hydro in BANC	649	649	649	649
SMUD's Contract Hydro Imports From California ISO	26	26	26	26
Modesto Irrigation District's Utility-Owned Hydro (share of Don Pedro)	62	62	62	62
Redding's Whiskeytown Facility	4	4	4	4
BANC BAA Total	**1,530**	**1,415**	**1,363**	**1,295**
Turlock Irrigation District's 133 MW Share of Don Pedro + 13 MW Local	147	147	147	147
Western Area Power Administration's CVP Base Resource to Turlock Irrigation District & Merced Irrigation District	5	5	5	5
Turlock Irrigation District BAA Total	**152**	**152**	**152**	**152g**
Imperial Irrigation District's Utility-Owned Canal Hydro	65	65	65	65
Imperial Irrigation District BAA Total	**65**	**65**	**65**	**65**
Total Capacity for Other California BAAs	**3,635**	**3,519**	**3,467**	**3,398**

Components may not sum to totals because of rounding.
Source: Energy Commission staff.

Hoover Dam Capacity

Hoover Dam's total nameplate capacity is 2,074 MW, of which 1,951 MW are allocated on a contingent (if available) basis to parties in California, Arizona, and Nevada.[23] Hydro conditions on the Colorado River in 2012 are forecasted to result in a reduction in available capacity of about 20 percent. **Table C-4** provides information regarding the allocation of Hoover capacity for rated capacities that are greater than or equal to 1,951 MW.

23 At the time of construction in 1935, 1,448 MW were allocated to parties, in 1993; parties that funded an expansion of the facility were allocated an additional 503 MW.

Table C-4: Hoover-Contingent-Capacity Allocations, Capacity Greater Than or Equal to 1,951 MW

California ISO BAA	MW	Allocation
Southern California Edison	278	14.2%
Metropolitan Water District	247	12.7%
Anaheim	40	2.1%
Riverside	30	1.5%
Vernon	22	1.1%
Pasadena	20	1.0%
Azusa	4	0.2%
Colton	3	0.2%
Banning	2	0.1%
California ISO Capacity	646	33.1%
LADWP BAA		
LADWP	491	25.2%
Burbank	20	1.0%
Glendale	20	1.0%
LDWP BAA Capacity	531	27.2%
Out-of State Entities	774	39.7%
Total Capacity	1,951	100.0%

Sources: California Energy Commission staff and U.S. Bureau of Reclamation at http://www.usbr.gov/lc/region/g4000/24mo.pdf.

The United States Bureau of Reclamation's (USBR) most recent rolling 24-month plan for the operation of Colorado River reservoirs forecasts Hoover's generator capacity will be 1,792 MW in July and August (159 MW less that the 1,951 MW contingent capacity) based on projected Lake Mead elevations.[24] **Table C-5** presents 2012 capacity allocations to serve loads in the California ISO and LADWP BAAs, according to the most recent USBR forecast.

Table C-5: Hoover Forecast Contingent-Capacity and Its Allocation to California BAAs Summer 2012 (MW)

	June	July	August	September
Total Capacity	**1,794**	**1,792**	**1,792**	**1,788**
California ISO Share	594	593	593	592
LADWP BAA Share	488	487	487	486

Sources: California Energy Commission staff and U.S. Bureau of Reclamation at http://www.usbr.gov/lc/region/g4000/24mo.pdf.

24 U.S. Bureau of Reclamation, *Operation Plan for Colorado River System Reservoirs, February 2012 24-Month Study*, http://www.usbr.gov/lc/region/g4000/24mo.pdf, accessed April 17, 2012.

Hoover capacity is forecast to be 1,802 MW in June, 1,800 MW in July and August, and 1,785 MW in September. The allocations to individual LSEs in the BAAs are reduced on a *pro rata* basis.

Central Valley Project Resources

The NQC totals for hydroelectric resources located in the California ISO BAA do not include "imports" delivered to the California ISO by WAPA and supported by their portfolio of CVP hydro plants at Lake Shasta, Trinity Reservoir, Folsom Lake, New Melones Reservoir, and elsewhere. The Sierra Nevada Region of WAPA posts a rolling 12-month forecast of monthly capacity and energy from the CVP resources; both median values and 90 percent exceedence values (1–in–10 dry year) are calculated. As of April 2012 and using this 1-in-10 dry year criteria, WAPA expects 796 MW of CVP capacity will be available during August 2012 to serve USBR project use and WAPA's load-serving obligations in the California ISO BAA.

Table C-6 presents USBR's 90 percent exceedence forecast of CVP capacity, of which 60 percent is allocated to California ISO and 40 percent to BANC loads. The forecast of CVP capacity for summer 2012 ranges from a high of 1,785 MW in June down to 1,300 MW in September. The USBR forecast includes 65 MW to 170 MW to serve "Project Use" pump loads in the Central Valley, all of which are in the California ISO. Another 23 MW to 28 MW is allocated to serve "First Preference" customers such as the Trinity Public Utilities District. Within the BANC, WAPA is the subbalancing area for all LSEs except BANC . In this role, WAPA estimates it will need 185 MW each summer month to provide ancillary services (regulation) and operating reserves for its subbalancing area. After regulation and reserve needs, "First Preference" customer demand and project use pump loads are met by CVP generation. The remaining capacity is available to WAPA to serve other wholesale and end-use loads in both the California ISO and BANC BAAs, of which about 60 percent are in the former. CVP capacity that WAPA can use to serve other wholesale and end-use loads is called the "Base Resource" by WAPA as shown in **Table C-6**.

Table C-6: Allocation of Central Valley Project Capacity (MW) to California ISO and BANC BAA Loads, Summer 2012

	June	July	August	September
Forecast CVP Capacity	1,785	1,560	1,445	1,300
CVP Project Use	65	125	140	170
First Preference Customers	24	28	27	23
Sub-BA Regulation & Reserves	185	185	185	185
Net CVP for WAPA	1,511	1,222	1,093	922
60% of WAPA's Base Resource	907	733	656	553
California ISO Loads Met by CVP (60% Share + Project Use)	1,023	858	796	723
BANC Loads Met by CVP (40% Share + Reg & Reserves)	789	674	622	554

Sources: Energy Commission staff and USBR 90 Percent Exceedence Values for Central Valley Project operations, posted at http://www.wapa.gov/sn/marketing/forecasts.asp, accessed April 17, 2012.

Within BANC, CVP capacity is an important, highly reliable resource for meeting peak loads. As indicated in the early *2011 IEPR* resource plans, 416 MW for SMUD, 104 MW for Redding, 10 MW for Shasta Lake, and 21 MW for Trinity Public Utilities District are available for meeting peak loads.

APPENDIX D: Imports

Net Imports (Net Interchange)

The net import assumption represents a conservative estimate of potential electricity imports into each region and is based on the ability of the remainder of the western United States' electricity system to provide surplus generation to California during peak demand periods. The interconnected and interdependent wholesale western power market provides reliability benefits as well as broad opportunities for cost savings due to the diverse mix of surplus electricity resources and different load patterns in each part of the western system.

Electricity imported from other western states, British Columbia, Alberta, and Northern Baja California involves both long-term and short-term and spot market transactions. A share of imported electricity is either generated at plants that are partially owned by California utilities or is purchased under long-term contract. The amount of imports associated with these sources does not vary substantially from year to year. The remaining electricity imports are generally acquired through short-term transactions in the western United States' wholesale power market. These acquisitions represent almost half of the total annual imports of electricity. California utilities and generators purchase electricity in short-term markets to reduce costs, such as those associated with operating more expensive generation facilities within California.

Short-term imports may vary seasonally and depend substantially on hydro-generation conditions in both California and the Pacific Northwest. They also vary day-by-day, depending on market prices and operating constraints. Energy Commission staff has determined that there is sufficient surplus capacity in neighboring regions to meet the net interchange estimates detailed below. **Figure D-1** provides a summary of the Bonneville Power Administration forecast of surplus capacity in the Northwest under various water conditions. Even under severe drought conditions there is enough surplus capacity in the region to meet the interchange assumption included in the *2012 Summer Outlook*.

The staff determined the amount of surplus resources in the Southwest by conducting internal modeling simulations and reviewing the most-recently adopted WECC *2011 Power Supply Assessment.* [25]

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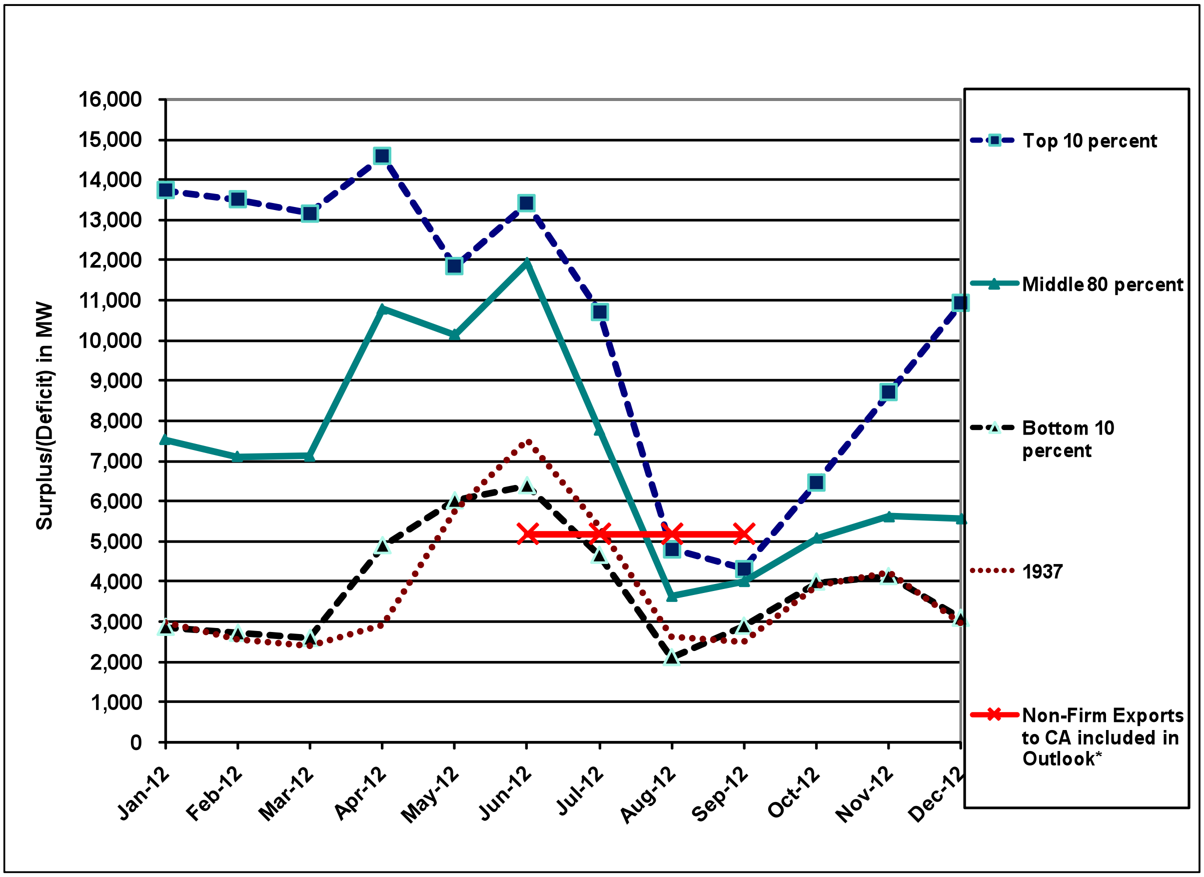
25 Western Electricity Coordinating Council, *2011 Power Supply Assessment*, November 17, 2011, [http://www.wecc.biz/Planning/ResourceAdequacy/PSA/Documents/2011%20Power%20Supply%20Assessment.pdf].

Figure D-1: 2012 Forecast of Northwest Regional Surplus/Deficit by Water Year



Sources: Energy Commission staff and *Bonneville Power Administration 2011 Pacific Northwest Loads and Resources Study* ("White Book").

Net Import Details by Region

Table D-1, Table D-2, Table D-3, and **Table D-4** provide details on the individual components of net interchange for each of four regions. Some imports are identified as capable of carrying their own reserves since transmission is the factor that limits capacity exchange, and there is sufficient surplus to replace a generation outage from the exporting region.

The LADWP Control Area interchange values provided in **Table D-1** and **Table D-2** include power that is *transported* through the LADWP BAA and resold to other municipal utilities served by the California ISO. Inclusion of this "wheeling" is the primary difference between import values used in the *Summer Outlook* and the California ISO's *Summer Assessment*. **Table D-3** reflects an export level on Path 26 of 1,500 MW under NP 26 peak load conditions. **Table D-4** reflects imports of 3,000 MW on Path 26 under SP 26 peak load conditions. Note that values are not additive because different areas experience peak electricity demand at different times.

Table D-1: Statewide Net Interchange (MW)

Northwest Imports Over the California-Oregon Intertie (COI)[26]	4,000
Southwest Imports	4,100
Pacific DC Intertie (California ISO Share)	2,000
LADWP and IID Balancing Authority Areas	3,018
Total	**13,118**

Source: Energy Commission staff.

Table D-2: California ISO Net Interchange (MW)

California ISO Share of NW Imports (COI)	2,300
WAPA Central Valley Imports	950
Southwest Imports	4,100
Pacific DC Intertie (California ISO)	2,000
Net LADWP Balancing Authority Area Interchange	1,000
Total	**10,350**

Source: Energy Commission staff.

Table D-3: NP 26 Net Interchange (MW)

California ISO Share of NW Imports	2,300
WAPA Central Valley Imports	950
Path 26 Exports	(1,500)
Total	**1,750**

Source: Energy Commission staff.

Table D-4: SP 26 Net Interchange (MW)

Path 26	3,000
California ISO Share of Pacific DC Intertie	2,000
Net SW Imports	4,100
Net LADWP Balancing Authority Area Interchange	1,000
Total	**10,100**

Source: Energy Commission staff.

26 Imports assumed to carry reserves as transmission line capacity is the limiting factor.

APPENDIX E: Interruptible and Demand Response Resources

While in the past many interruptible programs could be used only in emergencies when operating reserves approached minimally acceptable levels, in recent years these programs have increased in flexibility. **Table E-1** details the expected impacts from utility demand response and interruptible programs, and other demand resources contracted by utilities.

The estimated impacts of programs administered by the three large IOUs were developed to support implementation of the 2012 resource adequacy requirements for CPUC jurisdictional LSEs. Energy Commission and CPUC staff reviewed and revised the projected impacts to ensure that impacts are calculated consistently with the load impact estimation protocols developed in the CPUC Demand Response proceeding, and that projected enrollments are reasonable. An additional 110 MW of demand response from pumping load in SP 26 is included in **Table E-1** with Southern California Edison's interruptible loads. Other Demand Response categories include demand response reported by publicly owned utilities on their *2011 IEPR* supply forms. The "Rest of State Resources" category includes demand resources reported by LSEs in BAAs other than that of the California ISO. A detailed explanation of the program categories identified in **Table E-1** follows.

Interruptible Load Programs

Interruptible resources are composed primarily of two general types of programs: interruptible rates and direct control. In interruptible rate programs the customer receives discounted energy and demand charges for load subject to curtailment during system events. Because customers are subject to non-compliance penalties if demand is above the contracted firm service level during events, the compliance rate in recent years has been 95 percent or better.

Direct control programs are those in which the utility can control the operation of customer's equipment. For example, customers receive a bill credit if they allow the utility to temporarily turn-off or "cycle" their central air conditioner compressor during periods of peak demand. They can be dispatched for emergency purposes but can also be dispatched in response to high wholesale energy prices or expected peak demand conditions.

Table E-1: 2012 Demand Response and Interruptible Load Resources

	Expected MW			
	June	**July**	**August**	**September**
PG&E				
Interruptible Rates	224	230	227	226
Direct Control	54	108	78	65
Total Interruptible	278	338	305	290
Critical Peak Pricing	33	43	40	47
Demand Bidding & Other DR	98	100	101	100
Demand Response Aggregators	200	200	200	200
Total Demand Response	332	344	342	347
Other NP26 Demand Response	2	2	2	2
SCE				
Interruptible Rates	661	648	648	652
Direct Control	551	661	626	638
SCE Contract w/MWD	110	111	112	113
Total Interruptible	1,323	1,419	1,385	1,402
Critical Peak Pricing	74	77	76	72
Peak Day Rebate	231	286	295	265
Demand Bidding & Other DR	34	35	36	36
Demand Response Aggregators	110	114	116	115
Total Demand Response	449	512	524	488
Other SP26 Demand Response	48	48	48	48
SDG&E				
Interruptible Rates	11	12	11	12
Direct Control	7	13	16	18
Total Interruptible	18	25	27	30
Critical Peak Pricing	13	16	13	13
Peak Day Rebate	49	75	74	67
Demand Bidding	35	39	41	42
Demand Response Aggregators	-	-	-	-
Total Demand Response	97	130	127	122
Total CAISO	2,547	2,818	2,760	2,729
Rest of State Resources	313	316	316	313
Total Statewide	2,860	3,134	3,075	3,042

Source: CPUC and Energy Commission staff.

Demand Response Programs

Demand response programs employ a variety of incentive structures to motivate peak demand reduction and do not have penalties for noncompliance. Critical peak pricing rates offer discounts (energy, demand or both, depending on the particular design) for consumption during non-critical hours but charge a premium for energy consumed on a limited number of days when system conditions are forecast to be critical, typically due to high expected demand or supply shortfalls.

In demand bidding programs, participants are paid an incentive for load reductions during curtailment events that are "bid" in to the utility in advance. There is no penalty for not bidding or not fulfilling the bid obligation. These programs have a much lower performance rate (in terms of MW reduced per subscribed MW) than interruptible programs; the estimated impacts reflect this.

Demand response aggregators are contractors who develop their own demand response programs and provide load reductions to the investor owned utility. When the utility calls an event, the aggregators are responsible for dropping electrical load on an aggregated portfolio basis equal to their contracted amount.

The peak day rebate category represents new programs that pay residential customers a monthly bill credit if they reduce their energy usage during afternoons on days when the utility has declared a need for demand response based on specified conditions. The need for demand reductions is declared a day in advance and can be triggered for a number of reasons, including forecasted high temperatures, high loads, high wholesale electric prices, or a system emergency or alert.

APPENDIX F: 1-in-2 and 1-in-10 Peak Demand

The demand forecast in this outlook is the mid-case economic scenario from the most recent Energy Commission staff demand forecast. The mid-case forecast uses economic assumptions from Moody's Analytics October 2011 baseline economic projections. The mid-case BAA forecast tables can be found at: http://www.energy.ca.gov/2012_energypolicy/documents/2012-02-23_workshop/Mid_Case_LSE_and_Balancing_Authority_Forecast.xls. Further documentation of forecast assumptions and methods is included in the associated report *Revised California Energy Demand Forecast 2012-2022*, CEC-200-2012-001-SD-V2, February 2012. Loads and temperatures were evaluated for summer 2011 to derive estimates of 2011 weather-normalized demand (demand at 1-in-2 temperatures) and to estimate temperature response at above-average temperatures.

Table F-1 shows the weather-normalized 2011 demand and 2012 forecast for each of the BAAs in the state.

Table F-1: Peak Demand Forecasts for California Balancing Authority Areas (MW)

Balancing Authority Area	2011 Actual Peak Normalized to 1-in-2 Temperatures	Staff Forecast for BAA Coincident with Statewide Peak**	
		1-in-2	1-in-10
Turlock Irrigation District	**562**	**562**	**601**
Balancing Authority of Northern California*	**4,405**	**4,405**	**4,812**
Los Angeles Dept. of Water and Power	**6,596**	**6,588**	**7,170**
Imperial Irrigation District	**992**	**996**	**1,075**
California ISO	**46,645**	**47,792**	**51,279**
Total Statewide Coincident Peak**	**58,899**	**60,343**	**64,936**

*Formerly SMUD.

**The noncoincident peak of each BAA or CAISO subarea is multiplied 0.976 to adjust for coincidence.

Source: Energy Commission staff.