California Energy Commission

STAFF REPORT

SUMMER 2011 ELECTRICITY SUPPLY AND DEMAND OUTLOOK

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ABSTRACT

The *Summer 2011 Electricity Supply and Demand Outlook* is the California Energy Commission staff's assessment of the ability of the electricity system to provide sufficient energy to meet peak electricity demand in California in the summer of 2011.

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 2011 Electricity Supply and Demand Outlook* (*2011 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 2011. 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 given forecasted demand and available supplies.

Two primary factors support this assessment. First, there has been an overall increase in generation capacity available to meet expected summer demand levels since last year. Second, the economic recession slowed load growth in 2009 and 2010, and the forecasted growth for 2011 is lower than in the previous forecast. These two factors result in planning reserve margins that are higher than the expected levels during 2009 and 2010.[1] The higher planning reserve margins lead to a lower probability that emergency conditions will occur this summer.

Reserve Margins

Statewide electricity reserve margins are shown in **Table 1**. Statewide values for August correspond with the timeframe used by the California ISO in its *Summer Loads and Resources Operations Preparedness Assessment* (*Summer Assessment*) for its planning reserve margin estimates.

1 Supply adequacy has traditionally assumed at least a 15 to 17 percent "buffer" of electricity supplies above expected peak demand. This surplus is referred to as a *planning reserve margin*. It ensures that there will be sufficient supplies to meet demand for "all but one day in ten years," given the possibility of higher than expected peak demand and/or the unavailability of a large number of power plants due to maintenance needs. Planning reserve margins are typically estimated using average, or 1-in-2-year peak demand conditions.

Table 1: Statewide 2011 Summer Outlook (MW)

	Resource Adequacy Planning Conventions	June	July	August	September
1	Existing Generation	61,359	61,450	61,314	60,979
2	Expected Retirements	0	0	0	0
3	Expected Additions	89	27	48	65
4	Net Imports	13,118	13,118	13,118	13,118
5	Total Net Generation	74,566	74,393	74,135	73,943
6	Demand Response / Interruptible / Curtailable Programs	2,811	3,054	2,946	2,982
7	Total Net Supply	77,377	77,446	77,081	76,925
8	1-in-2 Summer Demand	53,123	57,343	59,571	54,220
8a	**Reserve Margin (1-in-2 Demand)**	**46%**	**35%**	**29%**	**42%**
9	1-in-10 Summer Demand	57,579	62,163	64,527	58,800
9a	**Reserve Margin (1-in-10 Demand)**	**34%**	**25%**	**19%**	**31%**

Note: All capacities are dependable, not nameplate. Existing generation values for July, August and September incorporate expected additions from previous months.
Source: Energy Commission staff.

Estimated planning reserve margins for this summer are greater than those in the *2010 Summer Outlook* for average (1-in-2 year) and above average (1-in-10 year) peak weather conditions.[2] 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.

Supply

Energy Commission staff expects California will have added 2,004 megawatts (MW) of generation capacity in the one-year period before October 1, 2011. This quantity is based on nameplate ratings and is expected to yield 1,337 MW of dependable capacity. Retirements of 846 MW are expected, resulting in a net addition of 491 MW of dependable capacity, 348 MW of which will be in the California Independent System Operator's (California ISO) Balancing Authority Area (BAA) and 143 MW in other areas.

Two significant retirements have taken place. First, the remaining three generation units at the South Bay power plant in San Diego retired on December 31, 2010. These units totaled 311 MW (dependable capacity). Second, the California ISO no longer requires the Potrero power plant in San Francisco under a Reliability–Must Run contract. The station's four units, totaling 362 MW, are retired as of February 28, 2011. Both South Bay and Potrero featured large natural gas-fired units that used once-through-cooling technology for power plant cooling. Of the non–California ISO BAAs, only the Sacramento Municipal Utility District (SMUD) will have added new generation between October 1, 2010 and

2 *Summer 2010 Electricity Supply and Demand Outlook* (*2010 Summer Outlook*) *Table 1: California 2010 Summer Outlook (MW)*, p. 3. [http://www.energy.ca.gov/2010publications/CEC-200-2010-003/CEC-200-2010-003.PDF]

October 1, 2011. None of the other non–California ISO areas have, or are expected to have, retired or replaced generation during this time period.

An important component of California's supply is hydroelectric generation. 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 2011.

Demand response and interruptible programs are considered as supply resources in the *2011 Summer Outlook*. An increase of about 300 MW in expected load impacts from demand response and interruptible programs contribute to higher planning reserve margins compared to 2010. The majority of this increase is from programs that directly control air conditioning load.

Demand

The statewide peak demand forecast for summer 2011 is about 1,200 MW, or two percent lower than the *2010 Summer Outlook* forecast for summer 2010, reflecting the continued effects of the recession. Economic conditions in California have worsened relative to the assumptions underlying the previous load forecast, resulting in lower–than–predicted load in 2010, and lower forecasted growth in 2011.

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, staff used the analysis of peak demand response to temperature prepared for the most recent Energy Commission demand forecast.[3] 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 historic 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.

3 California Energy Commission, *Revised Short-Term (2011-2012) Peak Demand Forecast*, CEC-200-2011-011-CMF, March 2011.

Findings

During the past decade, the Energy Commission's *Summer Outlook* and California ISO's *Summer Assessment* have provided decision-makers and the public with projections of electricity supply adequacy during the critical period from June through September.[4]

The *2011 Summer Outlook* encompasses all of the state's major Balancing Authority Areas (BAA). 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: Sacramento Municipal Utility District (SMUD), Imperial Irrigation District (IID), Turlock Irrigation District (TID), and Los Angeles Department of Water and Power (LADWP).[5] The appendices provide detailed BAA-level information about generation additions, retirements, imports, hydroelectric resources, demand, and demand response and interruptible programs.

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 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.

During the past five years, resource adequacy requirements imposed by the California ISO on load-serving entities (LSE) 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.

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4 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.

5 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 approximately 180 MW.

2011 Summer Supply and Demand Outlook

Table 2 compares the supply of electricity with expected demand during the period June 1 through September 30, 2011.[6] 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 planning reserve margins.

Table 2: Statewide 2011 Summer Outlook (MW)

Resource Adequacy Planning Conventions		June	July	August	September
1	Existing Generation	61,359	61,450	61,314	60,979
2	Expected Retirements	0	0	0	0
3	Expected Additions	89	27	48	65
4	Net Imports	13,118	13,118	13,118	13,118
5	Total Net Generation	74,566	74,393	74,135	73,943
6	Demand Response / Interruptible / Curtailable Programs	2,811	3,054	2,946	2,982
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8a	**Reserve Margin (1-in-2 Demand)**	**46%**	**35%**	**29%**	**42%**
9	1-in-10 Summer Demand	57,579	62,163	64,527	58,800
9a	**Reserve Margin (1-in-10 Demand)**	**34%**	**25%**	**19%**	**31%**

Note: All capacities are dependable, not nameplate. Changes in the Existing Generation value reflect both variation in the monthly capacity values of resources existing prior to June 2011 and expected additions during the summer months.
Source: Energy Commission staff.

Supply

Supply consists of in-state generation, including demand response and interruptible programs, and electricity imports. **Table 3** summarizes the estimated net capacity additions included in the *2011 Summer Outlook*. These figures are based on additions and retirements that were either not included in the *2010 Summer Outlook*, have occurred since October 1, 2010, or are believed to have a high probability of taking place before October 1, 2011.

New generation totals 2,004 MW nameplate (1,337 MW dependable). Retirements totaling 846 MW are expected to take place during this period, for a net addition of 1,158 MW of nameplate capacity and 491 MW of dependable capacity. See Appendix A for a detailed presentation of additions and retirements.

6 For the purposes of the *2011 Summer Outlook*, Energy Commission staff considers demand reduction, interruptible and curtailable programs as supplies. Other documents, studies and programs may consider these programs differently.

Table 3: Summary of Net Additions, Statewide

	Nameplate Capacity (MW)	Dependable Capacity (MW)
California ISO	985	348
Non-California ISO	173	143
Net	**1,158**	**491**

Source: Energy Commission staff.

Hydro conditions in California are above average this year; the full capacity of the hydroelectric system is expected to be available. Appendix B provides Energy Commission staff's analysis of this year's hydroelectric generation 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 Imports are discussed in Appendix C.

Demand response and interruptible programs are considered as supply in the *2011 Summer Outlook.* An increase of about 300 MW in expected load impacts from demand response and interruptible programs contributes to the higher planning reserve margin compared to 2010. The majority of this increase is from programs which directly control air conditioning load. Appendix D provides more detail about these programs.

Demand

The peak demand forecast for summer 2011 is about two percent (1,200 MW) lower than the *Summer 2009 Electricity Supply and Demand Outlook* forecast for summer 2010, reflecting the continued effects of the recession. Economic conditions in California have worsened relative to the assumptions underlying the previous load forecast, resulting in lower–than–predicted load in 2010, and lower forecasted growth in 2011. The forecasts for the California ISO BAA and sub-areas are documented in *2011-2012 Peak Demand Forecast.* The forecasts for the non–California ISO areas are presented in Appendix E.

The greatest uncertainty in the 2011 peak demand forecast is weather-related; air conditioning loads increase rapidly as temperatures rise. To characterize the range of possible demands under varying temperatures, staff used the analysis of peak demand response to temperature prepared for *2011-2012 Peak Demand Forecast*.[7] 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 historic distribution of annual

7 California Energy Commission, *Revised Short-Term (2011-2012) Peak Demand Forecast*, CEC-200-2011-011-CMF, March 2011.

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.

Planning Reserve Margins

For the entire summer of 2011, the planning reserve margins for all regions under 1-in-2 weather conditions are expected to be higher than the target of 15 percent, with the lowest being 29 percent during August. Under 1-in-10 weather conditions, the lowest planning reserve margin is 19 percent, also in August. These reserve margins indicate there should be more-than-sufficient resources to cover a broad range of system contingencies, such as unplanned facility outages or increased demand due to hotter-than-expected weather conditions.

The net imports assumption represents a conservative estimate of the available electricity imports into each region, based on the Western U.S. 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 C for a more detailed presentation of imports.

Glossary

Acronym or Term	Definition
AFC	Application for Certification
BAA	Balancing Authority Area
Energy Commission	California Energy Commission
California ISO	California Independent System Operator
CPUC	California Public Utilities Commission
ESP	Energy Service Provider
IEPR	Integrated Energy Policy Report
IOU	Investor–Owned Utility
LADWP	Los Angeles Department of Water & Power
MW	Megawatt
NQC	Net Qualifying Capacity
NP 26	North of Path 26
PG&E	Pacific Gas and Electric
QF	Qualifying Facility
SP 26	South of Path 26
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SMUD	Sacramento Municipal Utility District
WALC	Western Area Lower Colorado
WECC	Western Electricity Coordinating Council

APPENDIX A: Generation Resources

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 analytical activity became particularly important following the 2000–2001 energy crisis.

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 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.

A specified *planning* reserve margin target is the level necessary to cover a particular range of possible system fluctuations 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 translates into a 15 to 17 percent planning 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.

A planning reserve margin of 15 to 17 percent ensures that an adequate operating reserve margin can be maintained by the balancing authority. An *operating* reserve margin is the generation capacity available to the balancing authority in real time in excess of that needed to meet the forecasted daily peak load. In order for the balancing authority 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 seven to nine percent or more is required, depending upon the composition of the generation resources on line, 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. The North American Electric Reliability Corporation[8] (NERC) establishes Minimum Operating Reserve Criteria (MORC) that are necessary to maintain system reliability. The Western Electricity Coordinating Council is the regional body that evaluates the MORC levels for the balancing authorities in the Western United States.

8 Known formerly as the North American Electric Reliability Council.

Existing Generation

Existing generation includes generation facilities operational as of October 1, 2010, plus new generation expected to be online prior to June 1, 2011. Merchant thermal generation capacity in SP 26 includes 1,080 MW of contracted capacity from units located in northern Baja California, Mexico.

Summer capacities used for existing generation within the California ISO area are taken from the most recent California ISO Net Qualifying Capacity (NQC) listing. For those resources whose NQC varies from month to month, the August value was used.

Generation Additions and Retirements

Table A-1 shows both the nameplate and dependable capacity additions for both the California ISO and non-California ISO areas, and the statewide net capacities.

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

	Nameplate Capacity (MW)	Dependable Capacity (MW)
California ISO	985	348
Non-California ISO	173	143
Net	**1,158**	**491**

Source: Energy Commission staff.

The projected net additional nameplate capacity in the California ISO BAA is 985 MW and the net additional dependable capacity 348 MW. The SP 26 sub region's share is about 280 MW nameplate, but because many capacity additions are wind resources the net dependable capacity is reduced by 36 MW. The NP 26 sub region's additional net is about 705 MW of nameplate capacity and 384 MW of dependable.

Table A-2 and **Table A-3** provide additional detail regarding the additions and retirements presented in **Table A-2**. These are additions and retirements that were either not included in the *2010 Summer Outlook*, have occurred since October 1, 2010, or are believed to have a high probability of taking place before October 1, 2011.

The capacities of generation additions and retirements are determined in the following manner:

- The dependable capacities of new generation for which a NQC has not been established are set at 91.9 percent of nameplate for solar, 21.3 percent for wind.[9]

9 Staff reduces new generation nameplate capacities for solar and wind resources for which Net Qualifying Capacities have not been established by using factors contained in the California ISO's

- The dependable capacity for new natural gas-fired plants is set at 94 percent of nameplate capacity.[10]
- The dependable capacities of retired units are net qualifying capacities from the most recent California ISO listing that contained the NQC.

NQC Local Area Data for Compliance Year 2011 - Final 07-Dec-2010. [Spreadsheet tab labeled *"2011 TAC Area Wind Factors"* at http://www.caiso.com/1796/179688b22c970.html accessed February 2, 2011.] California ISO staff uses slightly different factors based on whether the location is in the northern or southern sub region. These factors change from time to time and are not publicly available.

10 Thermal unit capacity is de-rated to reflect summer operating conditions and can range from 90 to 96 percent of nameplate capacity based on the type of unit considered and its geographic location. Energy Commission staff uses a factor of 94 percent for these resources.

Table A-2: Additions and Retirements in the California ISO BAA (MW)

Generation Resouces	Technology	Nameplate Capacity (MW)	Dependable Capacity (MW)	Month/Year
Additions - SP 26				
El Cajon Energy Center	NG SC	49	46	Jun 2010
Calabasas Gas-to-Energy Facility	Landfill Gas	14	13	Sep 2010
Rialto RT Solar	Solar PV	2	2	Nov 2010
Chiquita Canyon Landfill Generating Facility	Landfill Gas	6	6	Nov 2010
CPC West - Alta Wind I	Wind	150	32	Dec 2010
CPC West - Alta Wind II	Wind	150	32	Dec 2010
Riverside Energy Resource Center Units 3 & 4	NG SC	95	89	Dec 2010
Sand Canyon Tehachapi	Wind	40	9	Jun 2011
TA High Desert	Solar PV	20	18	Jul 2011
Alta Mesa	Wind	40	9	Jul 2011
Ridgetop II	Wind	5	1	Aug 2011
Clear Vista Ranch	Solar PV	20	18	Sep 2011
Total Additions - SP 26		591	275	
Additions - NP 26				
Santa Cruz Energy LLC	Landfill Gas	2	2	Feb 2010
Big Creek Water Works (Re-Power)	Hydro	5	5	Jun 2010
Blue Lake Power	Biomass	11	10	Sep 2010
Santa Maria II LFG Power Plant	Landfill Gas	2	1	Sep 2010
Sunset Reservoir - North Basin	Solar PV	5	4	Oct 2010
Humboldt Bay Generating Station	NG Recip	163	153	Oct 2010
Hatchet Ridge Wind Farm	Wind	101	22	Nov 2010
Colusa Generating Station	NG CC	660	620	Dec 2010
FPL Montezuma Wind	Wind	37	8	Jan 2011
SCE Porterville (NP 26)	Solar PV	7	6	Feb 2011
Eurus Sand Drag	Solar PV	19	17	May 2011
Eurus Sun City	Biogas	20	19	May 2011
Eurus Avenal Park	Biomass	9	8	Jun 2011
Shiloh III	Wind	200	43	Jun 2011
Total Additions - NP 26		1,240	919	
Net California Additions		1,831	1,194	
Retirements - SP 26				
South Bay Gas Turbine 1	NG GT	-15	-15	Jan 2011
South Bay Unit 1	NG ST	-150	-150	Jan 2012
South Bay Unit 2	NG ST	-146	-146	Jan 2013
Total Retirements - SP 26		-311	-311	
Retirements - NP 26				
Humboldt Bay Power Plant Unit 1	NG ST	-53	-53	Oct 2010
Humboldt Bay Power Plant Unit 2	NG ST	-52	-52	Oct 2010
Humboldt Bay Mobile Units	NG Recip	-30	-30	Oct 2010
Cogen National	Coal ST	-38	-38	Dec 2010
Potrero Unit 3	NG ST	-206	-206	Feb 2011
Potrero Unit 4	NG GT	-52	-52	Feb 2011
Potrero Unit 5	NG GT	-52	-52	Feb 2011
Potrero Unit 6	NG GT	-52	-52	Feb 2011
Total Retirements - NP 26		-535	-535	
Net California ISO Retirements		-846	-846	
California ISO Net		**985**	**348**	

Source: Energy Commission staff.

Table A-3 shows non–California ISO BAAs with nameplate capacity additions totaling 173 MW (143 MW dependable). No retirements have occurred or are expected.

Table A-3: Additions and Retirements, Non–California ISO BAAs (MW)

Generation Resouces	Technology	Nameplate Capacity (MW)	Dependable Capacity (MW)	Month/Year
Non-California ISO: Additions				
SMUD - Aerojet Addition	Solar PV	2	2	Jun 2010
Redding Unit 6 Conversion	NG CC	44	41	Dec 2010
SMUD - Solano	Wind	27	6	Jun 2011
Canyon Power Plant Unit 4	NG SC	50	47	Aug 2011
Canyon Power Plant Unit 3	NG SC	50	47	Sep 2011
Non-California ISO: Net Additions		**173**	**143**	
Non-California ISO: Retirements				
None		0	0	
Non-California ISO Net		**173**	**143**	

Source: Energy Commission staff.

Numerous changes to the state's electricity generation fleet have occurred since September 30, 2010, including additions, replacements, and retirements. In addition, some resources that became operational during Summer 2010 were not included in the *2010 Summer Outlook*. They are included this year. Other new generation resources are listed that have been delayed from original expected commercial operations. Finally, some generation resource additions were suspended during various approval processes.

New Resources Not Included in the 2010 Summer Outlook

SP 26

- El Cajon Energy Center became operational in June 2010. Operations have been confirmed using *Quarterly Fuel and Energy Report* information submitted by the operator (49.2 MW nameplate, 46.2 MW dependable).
- Calabasas Gas-to-Energy Facility became operational in September 2010. Operations have been confirmed using *Quarterly Fuel and Energy Report* information submitted by the operator (13.8 MW nameplate, 13.0 MW dependable). [11]

11 Ibid.

NP 26

- Santa Cruz Energy LLC's landfill gas plant in Santa Cruz became operational in February 2010 (2.0 MW nameplate, 1.9 MW dependable). Operations have been confirmed using Energy Commission Quarterly Fuel and Energy Report information submitted by the operator.
- Big Creek Water Works is a hydroelectric power plant near Hyampom in Trinity County. A repowering project added capacity in June 2010 (5.0 MW nameplate, 4.7 MW dependable).[12]
- Blue Lake biomass plant in Humboldt County attained commercial operational status in September 2010. As noted in the *2010 Summer Outlook*, this plant was not included last year because the expected commercial operations date during June 2010 could not be confirmed[13] (11.0 MW nameplate, 10.3 MW dependable). Operations have been confirmed using Energy Commission Quarterly Fuel and Energy Report information submitted by the operator.
- Santa Maria II Landfill Gas in Santa Barbara County power plant attained commercial operational status in September 2010 (1.5 MW nameplate, 1.4 MW dependable). Operations have been confirmed using Energy Commission Quarterly Fuel and Energy Report information submitted by the operator.

Non–California ISO Areas

- A 2.2 MW addition to an existing Aerojet solar photovoltaic plant in the SMUD BAA in Rancho Cordova attained operational status in June 2010 (2.4 MW nameplate, 2.2 MW dependable).[14]

Resources Either Added Since September 30, 2010 or Expected Prior to June 1, 2011

Fourteen resources have either been added since September 30, 2010, or are expected to be added prior to June 1, 2011. Five are in SP 26, eight in NP 26 and one is in the SMUD BAA.

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12 California Public Utilities Commission Status of RPS Projects spreadsheet. [http://www.cpuc.ca.gov/PUC/energy/Renewables/, accessed February 28, 2011.]

13 Pryor, Marc, Lynn Marshall, Christopher McLean, Jim Woodward. 2010. *Summer 2010 Electricity Supply and Demand Outlook*. California Energy Commission, Electricity Supply Analysis Division. CEC-200-2010-003-SD, p. A-8

14 News release. [http://www.globalsolartechnology.com/solar/index.php?option=com_content&view=article&id=5606:aerojet-solar-power-and-smud-switches-on-6-mw-solar-installation-at-aerojeta146s-sacramento-site&catid=1:news&Itemid=27] accessed February 25, 2011.]

SP 26

- Rialto RT Solar, a rooftop solar PV project located in San Diego County achieved commercial operations in November (2.0 MW nameplate, 1.8 MW dependable).[15]
- Chiquita Canyon landfill project, a landfill gas project near Lancaster, Los Angeles County, achieved commercial operations in November (6.0 MW nameplate, 5.6 MW dependable). Operations have been confirmed using Energy Commission Quarterly Fuel and Energy Report information submitted by the operator.
- CPC West – Alta Wind I became operational in December (150.0 MW nameplate, 32.0 MW dependable).[16]
- CPC West – Alta Wind II (not Alta Wind I) became operational in December (150.0 MW nameplate, 32.0 MW dependable).[17]
- Riverside Energy Resource Center Units 3 and 4 is an expansion of an existing plant. The natural gas-fired simple-cycle generation expansion is located near Riverside in Riverside County and came on line in December (95.0 MW nameplate, 89.3 MW dependable).[18,19]

NP 26

- Sunset Reservoir North Basin in San Francisco started operating in October (4.5 MW nameplate, 4.1 MW dependable).[20]
- Humboldt Bay Generating Project achieved operational status in October, replacing the older once-through-cooled Units 1 and 2. It is located in Eureka, Humboldt County and is comprised of natural gas-fired Wartsila 18V50DF 16.3 MW reciprocating engine-generator sets (163.0 MW nameplate, 153.2 MW dependable).[21]

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15 Energy Business Review webpage article. [http://solar.energy-business-review.com/news/southern-california-edison-begins-operation-of-rialto-solar-plant_191110 accessed January 25, 2011.]

16 Various press releases.

17 Various press releases.

18 City of Riverside, Public Utilities, Application for a Small Power Plant Exemption, March 2008. [http://www.energy.ca.gov/sitingcases/riverside_expansion/documents/applicant/afc/2008-03-19_SPPE_APPLICATION.PDF accessed January 31, 2011.]

19 Energy Commission Compliance Project Manager Dale Rundquist. Various conversations with Marc Pryor, Electricity Analysis Office.

20 Energy Commission staff conversation with California ISO staff, February 2011.

21 Energy Commission Compliance Project Manager Chris Davis. Various conversations with Marc Pryor, Electricity Analysis Office.

- Hatchet Ridge is a wind project in Shasta County that came on-line in October (101.2 MW nameplate, 21.6 MW dependable).[22]
- Colusa Generating Station, a natural gas-fired combined cycle plant came on line in December. The location is about 14 miles northwest of Williams in Colusa County (660.0 MW nameplate, 620.4 MW dependable).[23]
- FPL Montezuma Wind attained operational status in January. The wind power operation is located in Solano County (36.8 MW nameplate, 7.8 MW dependable).[24]
- Southern California Edison (SCE) added SCE Porterville in Tulare County in February (6.7 MW nameplate, 6.2 MW dependable).[25]
- Eurus Sand Drag, a solar PV project near Avenal, Kings County, is expected to begin operations in May (19.0 MW nameplate, 17.5 MW dependable).[26]
- Eurus Sun City, a biogas project near Avenal, Kings County, also is expected to begin operations in May (20.0 MW nameplate, 18.8 MW dependable).[27]

Non–California ISO Areas

- The City of Redding's conversion of Redding Power Plant's Unit 6 into a combined cycle configuration became operational in December; this plant is in the SMUD BAA (44.0 MW nameplate, 41.4 MW dependable).[28]

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22 Various press releases.

23 Energy Commission Compliance Project Manager Chris Davis. Various conversations with Marc Pryor, Electricity Analysis Office.

24 Various press releases.

25 Various press releases.

26 California Public Utilities Commission Status of RPS Projects spreadsheet. [http://www.cpuc.ca.gov/PUC/energy/Renewables/, accessed February 28, 2011.]

27 Various press releases.

28 Various press releases.

Resources Expected to be Added June 1, 2011 through September 30, 2011

Ten new generating projects are expected to become operational during the summer. This additional capacity, coming on-line after the beginning of the summer peak demand period, is not included in the California ISO's *Summer Assessment.*

SP 26

- Sand Canyon Tehachapi is wind project near Blythe, Riverside County, and is expected in June (40.0 MW nameplate, 8.5 MW dependable).[29]
- The TA High Desert is a solar PV project near Lancaster, Los Angeles County, which is expected to come on line during July (20.0 MW nameplate, 18.4 MW dependable).[30]
- Alta Mesa Phase IV is a wind project near Palm Springs, San Bernardino County, which is expected during July (40.0 MW nameplate, 8.4 MW dependable).[31]
- Ridgetop II, a wind project in Kern County, is expected in August[32] (5.0 MW nameplate, 1.1 MW dependable).[33]
- Clear Vista Ranch,a solar PV project located near Tehachapi, Kern County, is expected to commence operations in September (20.0 MW nameplate, 18.9 MW dependable).[34]

NP 26

- Eurus Avenal Park, a biomass project near Avenal, Kings County, is expected to begin operations in June (9.0 MW nameplate, 8.5 MW dependable)[35]
- The Shiloh III wind project in Solano County is expected to be operational in June. (200 MW nameplate, 42.6 MW dependable).[36]

Non–California ISO Areas

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29 Renewable Energy World article. [http://www.renewableenergyworld.com/rea/news/article/2009/12/first-solar-nrg-energy-open-21-mw-blythe-project, accessed February 17, 2010.]

30 Ventura Regional Sanitation District. [http://www.vrsd.com/news.htm, accessed 2/16/10.]

31 Various press releases.

32 California Public Utilities Commission Status of RPS Projects spreadsheet. [http://www.cpuc.ca.gov/PUC/energy/Renewables/, accessed February 28, 2011.]

33 California Public Utilities Commission Status of RPS Projects spreadsheet. [http://www.cpuc.ca.gov/PUC/energy/Renewables/, accessed February 28, 2011.]

34. Source: Energy Commission, compliance project manager.

35 California Public Utilities Commission Status of RPS Projects spreadsheet. [http://www.cpuc.ca.gov/PUC/energy/Renewables/, accessed February 28, 2011.]

36 Ibid.

- SMUD's Solano wind project is expected to add 27.3 MW of nameplate capacity in June (27 MW nameplate, 6 MW dependable).[37]
- The Canyon Power Plant is expected to add 50 MW of nameplate capacity in both August and September (100 MW nameplate, 94 MW dependable). Unit 4 would be operational first, with Unit 3 following. Units 2 and 1 are expected in October and November, respectively.[38]

Retirements Effected or Expected by End of the Summer of 2011

SP 26

- The remaining three South Bay power plant units in Chula Vista, San Diego County, were retired on December 31, 2010: the once through-cooled Units 1 and 2 (149.6 MW and 146 MW, respectively) and the 15 MW combustion turbine. Retirement is now completed.

NP 26

- The old Humboldt Generating Station's remaining units, totaling 153 MW, were replaced by new generation in October 2010.

  The Potrero power plant's remaining four generation units in San Francisco ceased reliability must-run operations on February 28, 2011: the 206 MW once through-cooled Unit 3 and three 52-MW gas turbines, Units 4 through 6. The Trans Bay cable achieved operational status in late Fall 2010, thus allowing this long-awaited closure.

Non–California ISO Areas

There were no retirements in these areas.

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37 Various press releases.

38 Telephone conversation between M. Pryor, Energy Commission staff, and Mr. Elden Krause of the City of Anaheim.

APPENDIX B: Hydroelectric Generation Supplies

Hydroelectric Dependable Capacity

Under all but the most adverse water conditions, there are 12,654 MW of dependable generating capacity from hydroelectric resources to meet peak electricity demand in California in 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 in 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 built into the resource adequacy counting conventions used by LSEs in the California ISO BAA and is generally used by LSEs in other California BAAs for planning purposes.[39]

Table B-1 summarizes the amount of dependable capacity that staff expects will be available to serve loads in California BAAs this summer. Note 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 addition, there will be a few forced outages and derates for maintenance outages, although the outage factors for hydro resources are less than for their thermal counterparts. In general, however, LSEs can be expected to conserve these "use limited" energy resources so they can be called to generate on peak, when energy has the greatest economic value and when power has the greatest reliability value.

The capacity values presented here do not include that 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 energy available on peak can be substantial and, in combination with those resources that are used to meet resource adequacy requirements, currently ensures reserve margins well in excess of those needed to reliably serve load.

39 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 impact on available energy production. In California, hydroelectric generating capacity is not significantly diminished (or de–rated) 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.

Table B-1: Dependable Capacity from Hydro Resources, Statewide, 2011 (MW)

BAA	June	July	August	September
California ISO	9,566	9,537	9,301	8,808
LADWP	1,860	1,858	1,860	1,857
SMUD	1,355	1,369	1,301	1,255
Turlock Irrigation District	165	165	165	165
Imperial Irrigation District	65	65	65	65
Total Capacity	**13,011**	**12,994**	**12,692**	**12,155**

Source: Energy Commission staff.

California ISO BAA

Under 2011 water conditions, there are 9,301 MW of dependable generating capacity from hydroelectric resources to meet August peak loads in the California ISO BAA. As also indicated in **Table B-2**, more than 9,500 MW are available in June and July, and more than 8,800 MW are available in September.

Table B-2: Dependable Capacity from Hydro Resources, California ISO BAA, 2011 (MW)

	June	July	August	September
Net Qualifying Capacity	8,686	8451	8,636	8203
Less Pumping Loads	-732	-645	-956	-873
	7954	7806	7,680	7330
Hoover	517	515	517	513
Central Valley Project	995	1116	1,004	865
City & County of San Francisco	100	100	100	100
Total Capacity	9,566	9,537	9,301	8,808

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 Exceedance Values for Central Valley Project operations posted at http://www.usbr.gov/mp/cvo/data/PWRFeb90.pdf

The aggregate NQC in August for the 195 hydro units in the California ISO BAA is 8,636 MW. However, these monthly NQC values include five pumping plants in the State Water Project[40]; in calculating dependable capacity, these pump loads should be excluded. Pump loads in August are 956 MW, for a net capacity for the units in aggregate of 7,680 MW. Values for the other months of the summer differ slightly.

Hydro capacity available to LSEs in the California ISO BAA also includes more than 500 MW from Hoover and more than 1,000 MW from Central Valley Project (CVP) hydro for

40 Banks, Dos Amigos, Pearblossom, Edmonston, and Oso

Western Area Power Administration (Western) 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, 375 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. [41]

Other California BAAs

Table B-3 presents the hydro capacity available to the other California BAAs: SMUD, LADWP, TID, and IID. This totals 3,353 MW in August; the values for June and July are slightly higher, the September value is lower.[42]

Table B-3: Dependable Capacity from Hydro Resources, Other California BAAs, 2011 (MW)

	June	July	August	September
Hoover Capacity	425	423	425	422
LADWP's Utility-Owned Hydro	1,421	1,421	1,421	1,421
LADWP's In-Basin Hydro Contracts	14	14	14	14
LADWP Total	**1,860**	**1,858**	**1,860**	**1,857**
Loads in SMUD BA Served by CVP	580	594	526	480
SMUD Utility-Owned Hydro in SMUD BA	684	684	684	684
SMUD's Contract Hydro Imports From CAISO	26	26	26	26
MID's Utility-Owned Hydro	62	62	62	62
Redding's Whiskeytown facility	3	3	3	3
SMUD Total	**1,255**	**1,269**	**1,201**	**1,155**
TID's Utility-Owned Hydro	145	145	145	145
2011 CCSF to TID	20	20	20	20
Turlock Irrigation District total	**165**	**165**	**165**	**165**
IID's Utility-Owned Canal Hydro	65	65	65	65
Imperial Irrigation District total	**65**	**65**	**65**	**65**
Total Capacity for California Non-ISO BAAs	**3,445**	**3,457**	**3,391**	**3,342**

Source: Energy Commission staff.

41 In 2008, maximum hourly retail loads during the summer at the San Francisco Airport, served by CCSF, ranged from 92 MW in July to 100 MW in September. Supply Form S-3 submitted by CCSF to to the Energy Commission, April 6, 2009, for the 2009 Integrated Energy Policy Report.

42 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 non-coincident 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,

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 2009 for the Integrated Energy Policy Report (IEPR).

Hoover Dam Capacity

Hoover Dam's total nameplate capacity is 2,074 MW, of which 1,951 is allocated on a contingent (if available) basis to parties in California, Arizona, and Nevada.[43] 2011 hydro conditions on the Colorado River are forecasted to result in a reduction in available capacity of approximately 20 percent.

Table B-4 provides information regarding the allocation of Hoover capacity for rated capacities that are greater than or equal to 1,951 MW.

Table B-4: Hoover Contingent Capacity Allocations, Capacity Greater than or Equal to 1,951 MW (MW)

California ISO BAA		
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%
LADWP 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 U.S. Bureau of Reclamation's (USBR) most recent rolling 24-month plan for the operation of Colorado River reservoirs forecasts a reduction in Hoover's generator capacity

43 1,448 MW is allocated to participants in the 1935 construction of the facility; an additional 503 MW is allocated to parties that funded an expansion of the facility in 1993

for the summer of 2011 based on projected Lake Mead elevations. [44] **Table B-5** presents the 2011 capacity allocations for the California ISO and LADWP BAAs as estimated by USBR.

Table B-5: Hoover Contingent Capacity and its Allocation to California BAAs Summer 2011 (MW)

	June	July	August	September
Total Capacity	1,561	1,555	1,562	1,549
California ISO share	517	515	517	513
LADWP share	425	423	425	422

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

Hoover capacity is forecast to be 1,561 MW in June, declining to 1,549 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 Western and supported by their portfolio of CVP hydro plants at Lake Shasta, Trinity Reservoir, Folsom Lake, New Melones, and elsewhere. The Mid-Pacific Region of the USBR posts a rolling 12-month forecast of monthly capacity and energy from the CVP resources; both median values and 90 percent exceedance values (1–in–10 dry year) are calculated.

Table B-6 presents USBR's 90 percent exceedance forecast of CVP capacity, which is then allocated to California ISO and SMUD loads. Forecast CVP capacity for summer 2011 ranges from 1,710 MW in July to 1,345 MW in September. The USBR forecast includes capacity to serve "Project Use" pump loads in the Central Valley, all of which are in California ISO. After project use pump loads are met by CVP generation, the remaining capacity is available to Western to serve other loads in both the California ISO and SMUD BAAs, of which about 60 percent are in the former.

Table B-6: Allocation of Central Valley Project Capacity to California ISO, SMUD loads, Summer 2011 (MW)

	June	July	August	September

44 U.S. Bureau of Reclamation, *Operation Plan for Colorado River System Reservoirs, February 2011 24-Month Study*, http://www.usbr.gov/lc/region/g4000/24mo.pdf, accessed February 23, 2011.

Forecast CVP Capacity	1,575	1,710	1,530	1,345
CVP Project Use	125	225	215	145
Net CVP for Western	1,450	1,485	1,315	1,200
60% of Western's Loads	870	891	789	720
California ISO Loads Met by CVP (60% Share + Project Use)	995	1,116	1,004	865
SMUD Loads Met by CVP (40% Share)	580	594	526	480

Sources: Energy Commission staff, and USBR 90 Percent Exceedance Values for Central Valley Project operations, February 23, 2011, posted at http://www.usbr.gov/mp/cvo/data/PWRFeb90.pdf

APPENDIX C: Imports

Net Imports (Net Interchange)

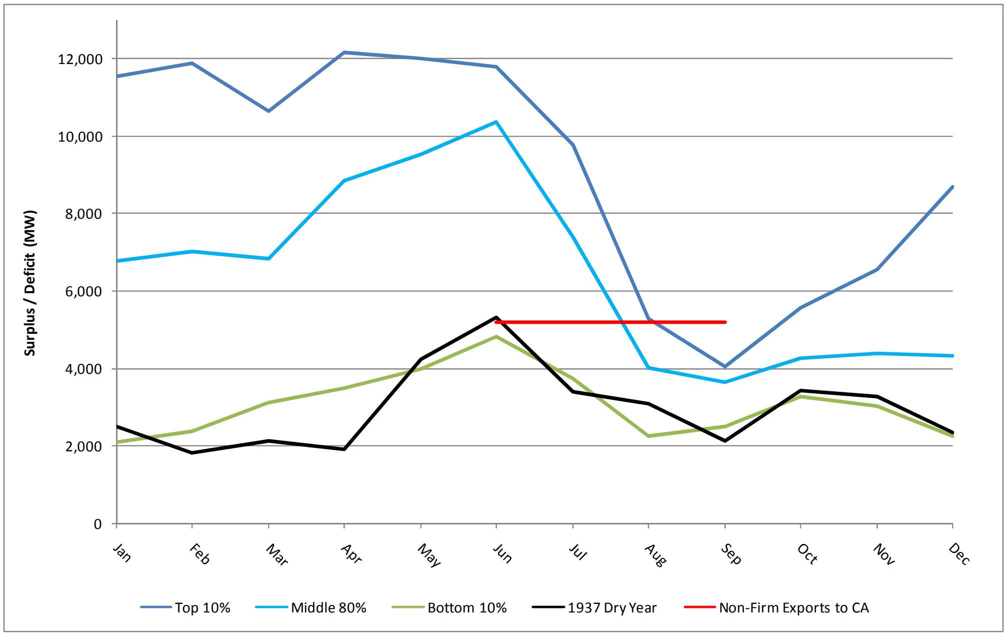
The net import assumption represents a conservative estimate of potential electricity imports into each region and is based on the ability of the remainder of the Western U.S.'s electricity system to provide surplus generation to California during peak demand periods. The interconnected and interdependent 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 and 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 U.S. 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 C-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 *2011 Summer Outlook*.

The staff determined the amount of surplus resources in the Southwest by conducting internal modeling simulations and reviewing the most-recently adopted Western Electricity Coordinating Council's *2009 Power Supply Assessment* (October 1, 2009).

Figure C-1: 2011 Forecast of Northwest Regional Surplus/Deficit by Water Year



Sources: Energy Commission staff, and *Bonneville Power Administration 2010 Pacific Northwest Loads and Resources Study* ("White Book"), pp. 144-147.

Net Import Details by Region

Table C-1, **Table C-2**, **Table C-3** and **Table C-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 Los Angeles Department of Water and Power) Control Area interchange values provided in **Table C-1**and **Table C-2** include power that is wheeled through the LADWP Balancing Authority Area 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 C-3** reflects an export level on Path 26 of 1,500 MW under NP 26 peak load conditions. **Table C-4** reflects imports of 3,000 MW on Path 26 under SP-26 peak load conditions.

Table C-1: Statewide Net Interchange (MW)

Northwest Imports over the California-Oregon Intertie (COI)[45]	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 C-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 C-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 C-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.

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

APPENDIX D: Interruptible and Demand Response Resources

There are several mitigation measures available to balancing authorities when operating reserves fall below minimally acceptable levels. **Table D-1** details the expected impacts from utility demand response and interruptible programs, and other demand resources contracted for by utilities.

The estimated impacts of programs administered by the three large IOUs were developed to support implementation of 2011 resource adequacy requirements for CPUC-jurisdictional LSEs. CPUC and Energy Commission 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 D-1** among SCE's interruptible loads. The NP 26 and SP 26 Other Demand Response categories include demand response reported by publicly owned utilities in the California ISO BAA on their *2009 Integrated Energy Policy Report (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 D-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 IOU to temporarily turn-off or "cycle" their central air conditioner compressor during periods of peak demand.

Table D-1: 2011 Demand Response and Interruptible Load Resources

	Expected MW			
	June	July	August	September
PG&E				
Interruptible Rates	208	220	229	225
Direct Control	84	170	119	116
Total Interruptible	292	390	348	341
Critical Peak Pricing	136	165	150	152
Demand Bidding & Other DR	105	107	105	106
Demand Response Aggregators	169	169	169	169
Total Demand Response	410	441	424	427
Other NP26 Demand Response	2	2	2	2
SCE				
Interruptible Rates	643	660	658	670
Direct Control	628	758	704	735
SCE Contract w/MWD	110	110	110	110
Total Interruptible	1,381	1,418	1,362	1,404
Critical Peak Pricing	60	60	61	61
Demand Bidding & Other DR	24	25	25	25
Demand Response Aggregators	137	147	150	151
Total Demand Response	221	232	236	238
Other SP26 Demand Response	48	48	48	48
SDG&E				
Interruptible Rates	7	7	7	7
Direct Control	6	21	26	31
Total Interruptible	13	28	33	38
Critical Peak Pricing	21	25	25	25
Demand Bidding	91	128	126	121
Demand Response Aggregators	19	26	27	27
Total Demand Response	131	178	177	172
Total CAISO	2,498	2,738	2,631	2,669
Rest of State Resources	313	316	316	313
Total Statewide	2,811	3,054	2,946	2,982

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 IOU. When the IOU calls an event, the aggregators are responsible for dropping electrical load on an aggregated portfolio basis equal to their contracted amount.

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

The peak demand forecast for the California ISO BAA is the current adopted Energy Commission demand forecast. Documentation of forecast assumptions and methods is included in that report. Staff used a similar method to update forecasts for the other BAAs in California.

The California ISO used econometric methods similar to those used by Energy Commission staff to project growth in peak demand for 2011. The difference is that the econometric results derived by staff were benchmarked to the 2009 IEPR forecast. In other words, the method used accounted for increasing levels of utility program savings and self-generation incorporated in the 2009 IEPR forecast.

Loads and temperatures were evaluated for summer 2009 and 2010 to derive a current estimate of weather-normalized demand and temperature response. **Table E-1** shows the forecast for each of the other BAAs in the state.

Table E-1: Peak Demand Forecast for Other California Balancing Authority Areas (MW)

Balancing Authority	2011 1-in-2	2011 1-in-10
SMUD	4,469	4,885
LADWP	6,265	6,798
Imperial Irrigation District	985	1,062
Turlock Irrigation District	648	692
Total Adjusted for Coincidence	**12,070**	**13,437**

Source: Energy Commission staff.