California Clean Energy Future Metrics

Reserve Margin (Data Reference)

The California energy agencies periodically evaluate short-term market developments and a range of potential system variations to determine if there are any significant risks of potential electricity supply shortfalls during the upcoming peak demand season. This analytical activity became particularly important following the 2000-2001 energy crisis experiences.

The electricity supply assessment for the summer peak demand season includes evaluating existing electricity generation capacity reserves that serve as a buffer for unplanned fluctuations (sudden increases in demand or power plant emergency outages), and analyzing the probabilities that a system emergency may occur[1]. A reserve margin is a measure of the amount of electricity imports and in-state generation capacity available over average peak demand conditions. Reserve margins are measured at two levels: planning (month-ahead to 10 years) and operating (real-time).

The real-time minimum operating reserve margin target is established by the Western Electricity Coordination Council and implemented by balancing authority area operators, such as the California Independent System Operator (CAISO).[2] Dropping below an operating reserve margin target triggers additional purchases of power, and calls for demand response and voluntary interruptible programs to reduce load. The CAISO will initiate warning stages at a 7 percent (Stage 1) and 5 percent (Stage 2) operating reserve. Stage 3 is called when operating reserves fall to a level between 3 and 1.5 percent, depending on the specific operating conditions. The CAISO may initiate rotating outages (involuntary load curtailment) during a Stage 3 event to insure that the system remains stable and avoid the possibility of uncontrolled outages that can cascade throughout the west.

A planning reserve margin target is a long-term measurement intended to assure sufficient electricity supplies can meet real-time operating reserve requirements and avoid the possibility that a loss of load (Stage 3 outages) would occur no more frequently that one-day-in-ten-years. Rare conditions will occur, such as the 2006 summer temperatures that caused a simultaneous spike in electricity demand throughout California and the West. Even though this 1-in-30 year event topped out above the range of uncertainties established for the planning reserve margin target, sufficient electricity imports and generation supplies avoided any customer curtailments. The purpose of a planning and operating

[1] System emergencies do not include distribution outages or possibilities of natural catastrophes.

[2] Operating reserve margin is the amount of imports and actual spinning generation above current demand and represents real-time operations that fluctuate minute by minute. This does not include the generation that is not scheduled to operate, shut down for planned maintenance, unexpected failure outages, or unable to be delivered due to transmission problems. Actual demand levels may also be higher than expected when generation was scheduled to operate the day before and result in a shortfall in operating power plant supply.

reserve margin target is to balance the risks of outages and overall costs to maintaining a redundant system.

The one-day-in-ten-year outage reliability criteria translates into a 15 to 17 percent planning reserve target, which has been the California reliability standard for years. The California Public Utilities Commission (CPUC) uses this target for determining the amount of electricity supplies that the investor-owned utilities must procure to meet customer demand.[3] This reliability target may slightly differ from the planning reserve margin used by POUs and other utilities throughout the west.

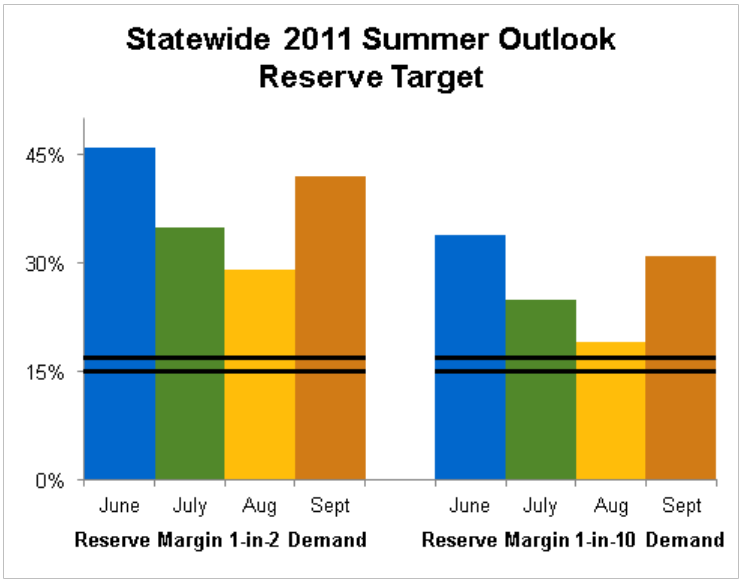
Calculating the planning reserve margin is done early each year to determine if sufficient generation will be available to meet summer peak demand and established reliability targets. Resource capability is calculated as a sum of generation available at time of peak demand, anticipated imports during peak load conditions, and expected load reductions from demand response and interruptible programs. For generation that participates in the CPUC resource adequacy (RA) program a qualifying capacity (QC) is determined for RA purposes. QC is calculated based on the CPUC methodology for determining the maximum capacity eligible for the RA requirement counting process based on a generating facility's historical capacity during peak periods. The ISO adjusts the QC based on available transmission to determine the Net Qualifying Capacity or NQC.

The planning reserve margin is calculated using the forecast 1-in-2 peak demand based on 1-in-2 weather and economic conditions. The 1-in-2 peak demand means there is a 50% probability that the demand will be higher than the 1-in-2 forecast amount and a 50% probability that it will be lower. The reserve margin is calculated by subtracting the forecast peak demand from the total available supply and dividing the result by the forecast 1-in-2 peak demand. Figure 1 shows that the generation reserves to serve the summer peak demand (August) was almost double the planning reserve reliability target. Figure 1 also shows that the reserve margin using a 1-in-10 peak demand forecast also exceeds that planning reserve target. 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.[4]

[3] For more information, see http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/.

[4] There is no reliability reserve targets that apply a 1-in-10 demand projection, so even if the 1-in-10 reserve margin estimate falls below the 15% the electricity system is still considered to be adequate.

Figure 1: Statewide 2011 Summer Outlook Reserve Target



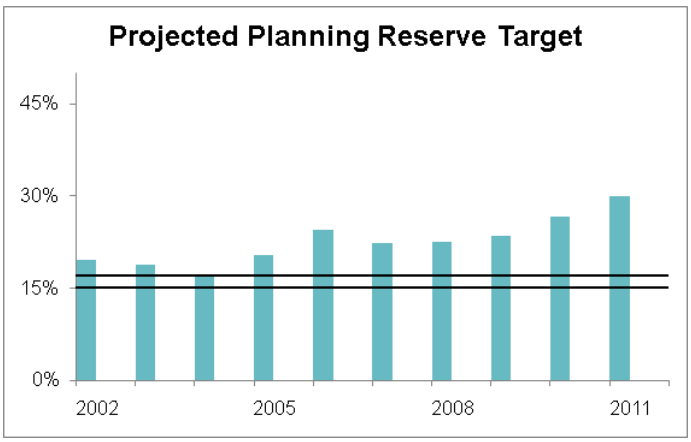
The planning reserve margin values in Table 2 are drawn from the Summer Outlook produced by the Energy Commission since 2002. This table shows the statewide peak generation capability, demand response and interruptible programs, expected imports, and 1-in-2 peak demand as well as the calculated planning reserve margin for the peak electricity demand for 2009, 2010, and 2011. The values in Table 2 are planning numbers and were all generated in the months prior to the summer in question. As a result, the demand values do not match actual demand for each summer. New generation facilities have been added since the 2000-01 energy crisis, bringing the planning reserve margins above the reliability targets for the decade.

Table 2: Reserve Margin for California 2002-2011

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
On-peak Generation (MW)	53,897	54,676	55,680	54,902	57,377	58,553	59,224	60,329	61,100	61,362
Demand response and Interruptible Programs	2,044	1,845	1,885	1,840	2,040	2,127	2,486	2,599	2,784	2,946
Expected Imports (MW) (Note 1)	5,374	5,374	5,374	12,921	13,118	13,118	13,118	13,118	13,118	13,118
Total Net Supply (MW)	61,315	61,895	62,939	69,663	72,535	73,798	74,828	76,046	77,002	77,426
1-in-2 Peak Demand (MW)	51,277	52,073	53,896	57,913	58,228	60,344	61,094	61,623	60,797	59,571
Projected Planning Reserve Margin	**20%**	**19%**	**17%**	**20%**	**25%**	**22%**	**22%**	**23%**	**27%**	**30%**

General Note: Calculation methodologies changed over the period. This is an attempt to reconcile the differences to create reasonable comparisons. Therefore, reserve margins shown may not match those in the source documents.
Note 1: Pre-2005 imports only include out of state generation owned or under contract by California utilities. 2005 and later reflects the value the system is capable of importing during a limited number of peak summer hours. During the heat storm of 2006, imports exceeded these values for several hours at peak.

Figure 2: Projected Planning Reserve Target



The peak demand forecast used for the 2011 outlook is a limited update to the 2009 IEPR forecast, primarily to account for worse-than-projected economic conditions. As such, it includes the same demand-side adjustments as that forecast: 2011 incremental effects of about 525 MW from committed utility efficiency programs, and 71 MW of customer-side distributed generation. No demand response program adjustments were made on the demand side; 2976 MW of demand response programs are treated as supply-side resources.

The data for Figure 1 and Table 2 come from the following sources:

2011 values from Page 2, Table 1 of:

Pryor, Marc, Lynn Marshall, Christopher McLean, Jim Woodward. 2011. Summer 2011 Electricity Supply and Demand Outlook. California Energy Commission, Electricity Supply Analysis Division. CEC-200-2011-004.

2010 values from Page 3, Table 1 of:

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.

2009 values from page 2, Table 1 of:

Pryor, Marc, Denny Brown, Christopher McLean. Lynn Marshal. 2009. Summer 2009 Electricity Supply and Demand Outlook. California Energy Commission. CEC-200-2009-007.

For daily demand forecast, actual demand, and available resources in the California Independent System Operator balancing authority area see http://caiso.com/outlook/SystemStatus.html.