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FINAL STAFF FORECAST OF 2008 PEAK DEMAND

STAFF REPORT

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Abstract

This document describes staff's final forecast of 2008 peak demand for the major utilities, control areas, and load serving entities (LSEs) in California. The final 2008 peak demand forecasts for the respective territories of the state's three investor-owned utilities (IOUs)—Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E)—will serve as a reference case for the California Public Utilities Commission's (CPUC) 2008 resource adequacy process. To develop the 2008 peak demand forecast, staff first estimated the relationship between temperature and daily summer afternoon peak demand for each service or planning area. This estimated equation was then applied to the historic average of annual maximum temperatures to develop an estimate of weather-normalized demand for 2006. Weather normalization estimates what loads would have been assuming average — or 1-in-2 — weather conditions. Finally, the 2006—2008 growth rate from the September 2005 demand forecast was used to produce a revised annual peak forecast for 2008. The PG&E service area forecast is increased by 1.9 percent, and the forecast for the PG&E transmission planning area (which includes the PG&E service area loads and loads of publicly owned utilities on the PG&E transmission system) is 3.0 percent higher. The SMUD forecast is 3.7 percent higher. In the SCE area, load growth was slower than projected and the forecast is revised down 1.6 percent. The SDG&E forecast is 1.2 percent higher.

Keywords

Electricity demand, demand forecast, weather normalization, annual peak demand

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INTRODUCTION AND BACKGROUND

This document describes staff's draft forecast of 2008 peak demand for the major utilities, control areas, and load serving entities (LSEs) in California. The methods and accuracy of the methodology used to develop the year-ahead forecast are also discussed. This forecast was presented at an Integrated Energy Policy Report (IEPR) Committee workshop on May 24, 2007. In response to discussion at the workshop, staff has made minor changes to the SCE forecast, described in the "SCE Planning Area" section.

The final 2008 peak demand forecasts for the respective territories of the state's three investor-owned utilities (IOUs)—Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E)—will serve as a reference case for the California Public Utilities Commission's (CPUC) 2008 resource adequacy process. The CPUC determined in its resource adequacy proceeding that the Energy Commission's demand forecast, as the "state's official load forecast," should serve as the reference case in the resource adequacy load forecast review and adjustment process implemented by Energy Commission staff.[1] The final forecast of 2008 for CPUC-jurisdictional LSEs will be applied to hourly forecast load shapes to develop a monthly peak forecast for each service area. If the sum of the year-ahead forecasts submitted by load serving entities (LSEs) is more than one percent different from the Energy Commission forecast, Energy Commission staff adjust the LSE forecasts to within one percent, as directed by the CPUC. These adjusted forecasts must be used in the LSE's year-ahead compliance filing with the CPUC, in which they demonstrate that they have contracted in advance for resources sufficient to cover 90 percent of their forecasted peak demand. The Energy Commission forecast may also be used by the California Independent System Operator (California ISO) for the allocation of import capabilities, in grid planning studies, and in other applications.

The Energy Commission's most recent forecast of peak demand was adopted in June 2006.[2] That forecast, the June 2006 Update, is the basis for the 2007 resource adequacy forecasts under which LSEs now operate, and combines an analysis of loads and temperatures in summer 2005 with growth rates from the most recent adopted 10-year Energy Commission forecast,[3] which was prepared for the *2005 IEPR* and adopted in September 2005. The September 2005 forecast was based on historic energy consumption and peak demand through 2004. For the 2008 peak demand forecast, staff has updated its analysis based on loads and temperatures experienced in the summer of 2006.

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[1] Rulemaking 04-04-003, Decision 05-10-042, October 27, 2005, [http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/50731.htm].

[2] California Energy Commission, *Staff Forecast of 2007 Peak Demand*. June 2006. Publication no. CEC-400-2006-008-SF.

[3] California Energy Commission. *California Energy Demand 2006–2016, Staff Energy Demand Forecast, Revised September 2005*. Staff final report. Publication no. CEC-400-2005-034-SF-ED2.

SUMMARY OF RESULTS

To develop the 2008 peak demand forecast, staff first estimated the relationship between temperature and daily summer afternoon peak demand for each service or planning area. This estimated equation was then applied to the historic average of annual maximum temperatures to develop an estimate of weather-normalized demand for 2006. Weather normalization estimates what loads would have been assuming average — or 1-in-2 — weather conditions. Finally, the 2006-2008 growth rate from the September 2005 demand forecast was used to produce a revised annual peak forecast for 2008.

Many applications of the Energy Commission forecast require that forecasts be disaggregated to individual LSEs. Resource adequacy applications also require the segregation of CPUC-jurisdictional loads from non-jurisdictional loads. Staff used hourly loads for individual LSEs within the planning areas or zones to disaggregate the forecast. Weather-normalized loads were also estimated for sub-areas of the California ISO for comparison with the sum of LSE-specific results.

Table 1 shows the results of this analysis. In Northern California, weather-normalized loads overall were somewhat higher than forecast. The PG&E service area forecast is increased by 1.9 percent, reflecting a higher assessment of 2005 weather-adjusted loads. The forecast for the PG&E transmission planning area (which includes the PG&E service area loads and loads of publicly owned utilities on the PG&E transmission system) is 3.0 percent higher; the load of the publicly-owned utilities in the PG&E area grew faster than projected. The SMUD forecast is 3.7 percent higher because of both faster than projected load growth and an updated assessment of weather-normalized load. In the SCE area, load growth was slower than projected and the forecast is revised down 1.6 percent. The SDG&E forecast is 1.2 percent higher; load growth was slightly slower than projected, but staff has changed the weather stations used for analysis of SDG&E loads. Because of the offsetting changes in the north and south, the California ISO forecast is unchanged. Overall the forecast for the state is 1.2 percent higher.

Tables 10 and 11 present more detailed results. The remainder of this document describes the methodology and data used for each utility area forecast.

Table 1: Revised versus June 2006 Peak Demand Forecast Megawatts (MW)

		June 2006 Update Forecast for 2006	2006 Weather-Normalized	Staff Forecast 2008	% Change from June 2006 Update (2006)
	PG&E Service Area	19,162	19,523	20,057	1.9%
	PG&E Area CAISO LSEs	1,233	1,206	1,239	-2.2%
	Dept of Water Resources - North	409	409	409	0.0%
Total North of Path 15		**20,804**	**21,137**	**21,705**	1.6%
Turlock Irrigation District Control Area		482	570	587	18.1%
	Sacramento Municipal Utility District	2,995	3,106	3,252	3.7%
	Other SMUD/WAPA LSEs	1,349	1,594	1,633	18.1%
Total SMUD Control Area		**4,345**	**4,700**	**4,885**	8.2%
Total PG&E Planning Area (excl. DWR &SMUD)		**22,227**	**22,892**	**23,516**	3.0%
	SCE Planning Area	22,791	22,434	23,109	-1.6%
	Pasadena Water and Power	296	310	310	4.5%
	San Diego Gas & Electric	4,384	4,438	4,586	1.2%
	Dept of Water Resources - South	506	506	506	0.0%
Total South of Path 15		**27,977**	**27,670**	**28,493**	-1.1%
Sum of Noncoincident Peaks in CAISO Control Area		**48,781**	**48,807**	**50,198**	0.1%
CAISO Coincident Peak		**47,613**	**47,639**	**48,996**	0.1%
	LADWP	5,779	5,958	5,999	3.1%
	Burbank	288	292	292	1.2%
	Glendale	304	302	302	-0.6%
Total LADWP Control Area		**6,371**	**6,552**	**6,593**	2.8%
Imperial Irrigation District		869	958	985	10.2%
Sum of Noncoincident Peaks		**60,849**	61,604	63,266	1.2%
Statewide Coincident Peak Demand		**59,392**	60,129	61,751	1.2%

GENERAL WEATHER NORMALIZATION METHODOLOGY

Staff used Federal Energy Regulatory Commission (FERC) Form 714 hourly load data and utility planning area daily temperatures to estimate the relationship between summer weekday afternoon (1 p.m.– 6 p.m.) peaks and temperatures. Summer is defined as the period from June 15 to September 15 for this analysis. The reported peak impacts of demand response and interruptible programs were added to the recorded load. The temperature variable for each utility is the weighted average of temperatures from a set of weather stations representative of the climate in that particular utility's region (Table 2).

Because residential air conditioning is the primary driver of day-to-day changes in peak demand, weather station weights are based on the estimated number of residential air conditioning units in each of the utility forecast zones assumed in the Energy Commission's residential demand forecast model. In 2006, staff modified the weights of PG&E's weather stations in order to more accurately reflect the distribution of air conditioners. Since the May 2006 version of this staff report, staff has updated the saturations for the SCE area, shown in Table 2.

Table 2: Planning Area Weather Weighting Factors

PG&E	**Ukiah**	**Sacramento**	**Fresno**	**San Jose**	**San Francisco**
	0.067	0.169	0.413	0.282	0.069
SCE	**Fresno**	**Long Beach**	**Burbank**	**Riverside**	
May Report	0.062	0.324	0.243	0.371	
Revised	0.058	0.376	0.213	0.354	
SDG&E	**Lindbergh Field**	**Miramar**	**El Cajon**		
	0.333	0.333	0.333		
LADWP	**Long Beach**	**Burbank**			
	0.42	0.581			

Two separate weather variables were calculated for this analysis. The first is a weighted average of maximum temperatures for three days (*max631*). This weighting consists of 60 percent of the current day's maximum temperature, 30 percent of the previous day's maximum temperature, and 10 percent of the second previous day's maximum temperature. This lag is used to account for heat build up over a three-day period. The "1-in-2," or normal peak temperature, is derived from <u>annual</u> maximum temperature, for the years 1950-2006, for both PG&E and SCE. The time period for the SDG&E planning area was limited to 1979–2006 because daily weather data was not continuously available for El Cajon before 1979.

The daily temperature spread, or diurnal variation (*divar*), is the second temperature variable. This variable is the daily maximum temperature less the daily minimum temperature. It serves as a proxy measure of daily humidity. The assumption is that the lower the daily temperature spread for a given temperature, the higher the daily humidity—for example, a day with a maximum temperature of 95 degrees Fahrenheit (F) and a minimum of 75 degrees F is likely to be more humid than a day with a maximum temperature of 95 degrees F and a minimum temperature of 65 degrees F. This proxy is used because there is little available historic information on humidity for long time periods for most weather stations, while daily maximum and minimum temperatures are readily available. The daily diurnal variation is not lagged since its purpose is to provide a measurement of the actual daily humidity, which in turn affects the physical need for air conditioning compressors to take water vapor out of the air.

The daily afternoon peak demand is regressed against *max631, divar*, and a variable identifying weekends and holidays. To derive the demand under 1-in-2 temperatures, the estimated coefficients are applied to the historic daily temperatures to calculate predicted annual maximum peak demands. The predicted annual peaks represent the distribution of possible peak demands under the weather conditions that have been observed since 1950. The median of the predicted annual peaks is the weather-normalized, “1-in-2,” peak demand.

PG&E PLANNING AREA RESULTS

The PG&E transmission planning area includes the PG&E service area and an additional 3,000 MW of load served by other LSEs. For Silicon Valley Power (SVP), the Northern California Power Agency (NCPA), Turlock Irrigation District (TID), Modesto Irrigation District (MID), and the cities of Redding and Roseville, staff used 2006 hourly load data to estimate a weather-adjusted peak. For smaller utilities where hourly load data is not available, staff estimated the peak from annual energy consumption and compared that peak estimate with reported or forecasted peaks from other data sources including supply forms filed as part of the *2007 IEPR*.

After compiling peaks for individual LSEs and adjusting for coincidence, staff compared the aggregate of the California ISO LSE peaks with weather-normalized peaks for California ISO loads north of path 15 (NP 15). The aggregate coincident weather-normalized peaks are within 0.25 percent of the weather-normalized 2006 NP 15 peak.

PG&E Service Area Results

Estimates of weather-normalized peak demand can vary significantly depending upon data and methods used. In comparing forecasts for the June 2006 Update, Energy Commission and PG&E staffs differed significantly in their respective estimates of weather-normalized peak demand. Weather stations used by PG&E resulted in a lower MW-per-degree response to increasing temperatures than did the weather stations used by Energy Commission staff. Below-average maximum temperatures in 2005 contributed to uncertainty over the most accurate estimate of weather-normalized 2005 service area peak. The weather-normalization method assumes that the temperature/load relationship estimated from the below-average temperatures experienced in the summer of 2005 is equally valid at 1-in-2 temperatures. Because of the lack of consensus on this issue, the final June 2006 Update forecast used the midpoint of the Energy Commission and PG&E estimates as the base value.

Above-average temperatures in 2006 allow us to better evaluate the predictive ability of the weather data used in the staff forecast. Figure 1 presents June 2006 estimates using 2005 daily peaks comparing two different weather analyses discussed for the June 2006 Update. It also contains the 2006 projected peak value, using actual July 2006 temperatures. The actual peak of 21,356 MW is 0.3 percent above the estimated peak using the staff's standard four weather stations, but is 5.3 percent above estimated peak using the alternative model using 2 stations weighted equally. Based on these results, staff concludes that its original weather normalization methodology provides a more accurate estimate of the actual peak and will use it in this forecast update.

Figure 2 presents the temperature and loads for both the 2005 and 2006 summer weekday periods (June 15 through September 15). Also shown are the estimated peaks at the 1-in-2 temperature for each year, and the June 2006 Update forecast. It is interesting to note differences in the overall temperature ranges of the two respective summer periods.

Figure 1: PG&E Peak Estimation Method Comparison

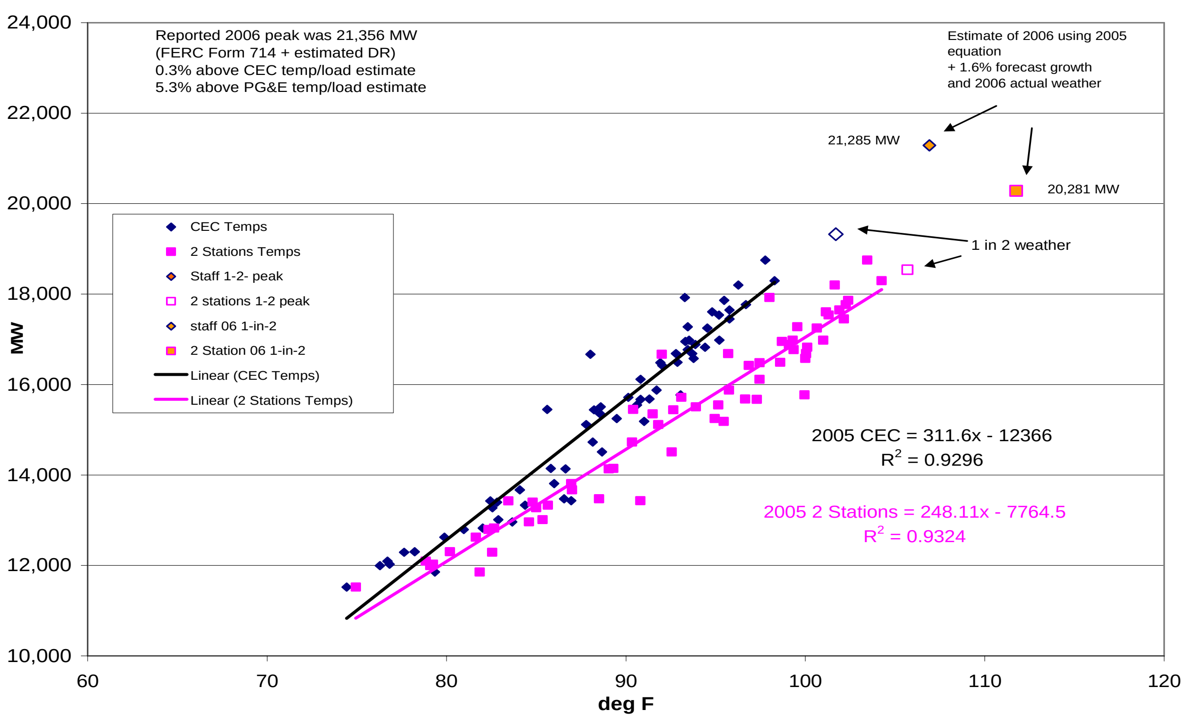


Figure 2: PG&E Summer Weekday Temperature versus Peak

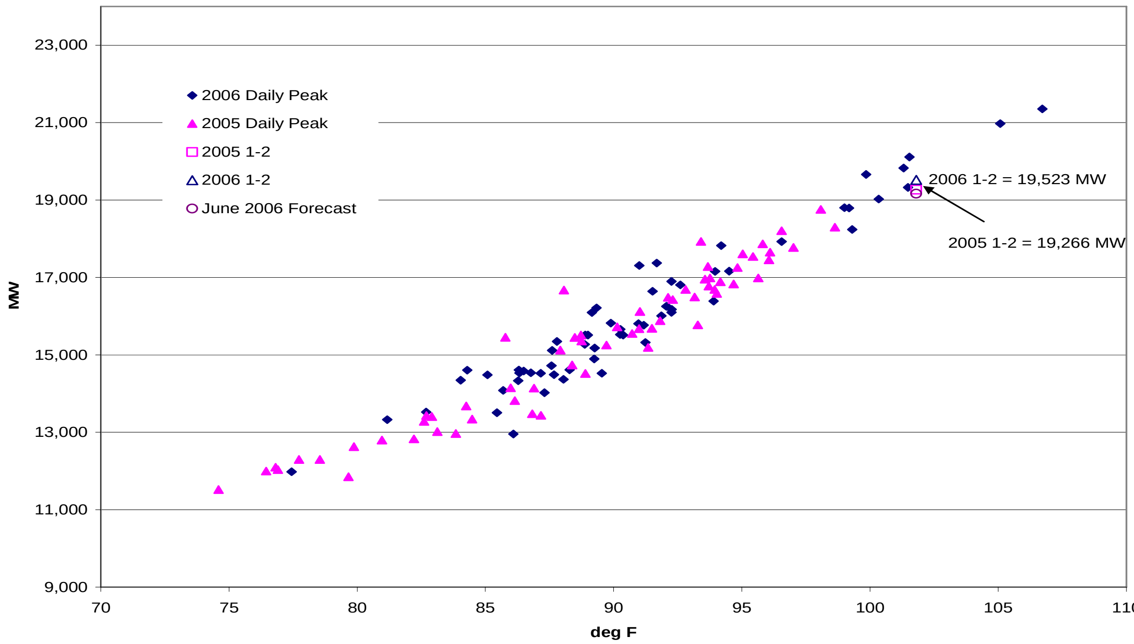


Table 3 shows staff's estimated coefficients and the resulting forecast. The revised weather-adjusted estimate for 2006 is 1.9 percent higher than the averaged 2006 estimate on which the June 2006 Update forecast for 2007 was based. The proposed forecast for 2008 of 20,057 MW is slightly higher (by 89 MW) than PG&E's forecast, submitted in January 2007 as part of the Energy Commission's 2007 IEPR proceeding.

Table 3: PG&E Service Area Forecast

Estimated Temperature-Load Statistics for 2006	*Coefficients*	*Standard Error*	*t Statistic*
Intercept	-13,896.33	770.65	-18.03
Weekend/Holiday	-1,561.90	104.58	-14.93
PG&E631Max	328.28	8.45	38.83
Adjusted R Square	0.95		

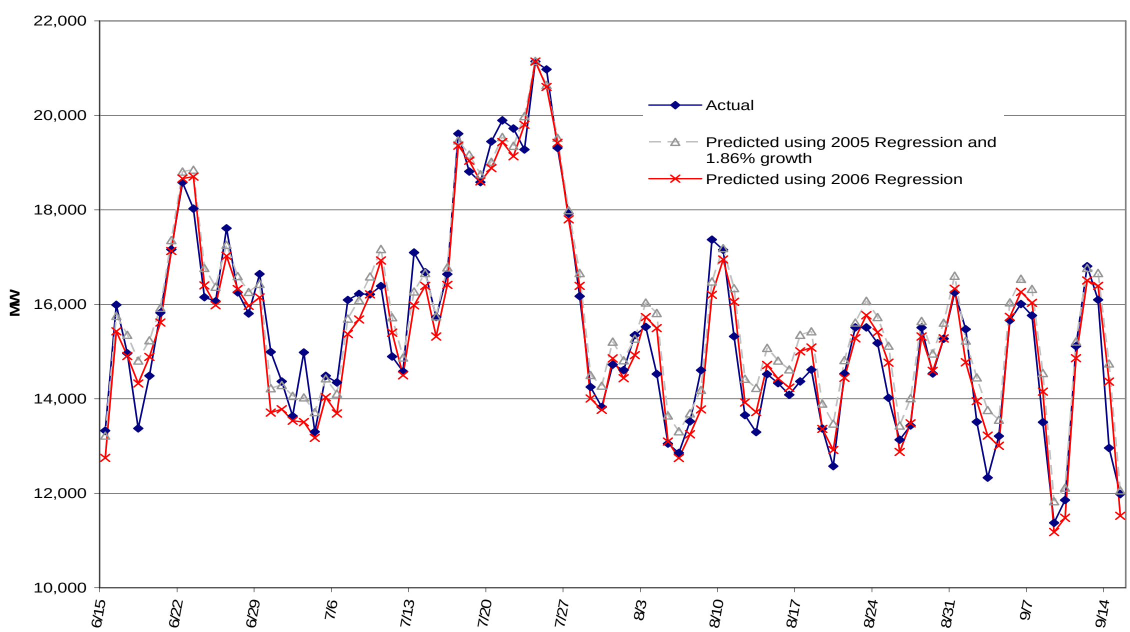
Staff PG&E Service Area Forecast						
Weather Scenario	**Weather Normalized 2006**	**2007**	**2008**	**% Increase above 1-in-2**	**PG&E's *2007 IEPR* Forecast of 2008**	**% Difference Staff/LSE Forecast**
1-in-2	19,523	19,807	20,057		19,968	0.99%
1-in-5	20,048	20,340	20,597	2.69%		
1-in-10	20,245	20,540	20,799	3.70%		
1-in-20	21,065	21,373	21,643	7.90%		

Table 3 also shows the staff forecast under extreme temperature conditions. Because the extreme temperatures of 2006 are included in the weather history, which used to generate the probability of high-load events, the weather scenario multipliers have increased slightly.

Forecast Accuracy

Figure 3 presents a comparison of actual summer 2006 daily peaks with estimated daily peaks derived from both the 2006 estimation equation and the 2005 estimation equation grown at the 2005–2006 adopted forecast growth rate. The staff weather model using the 2005 estimates has a mean absolute percentage error of 3.2% percent over the summer of 2006. The error of the 2006 model is 2.4 percent. Based upon these results, staff recommends the staff weather station weightings (shown in Table 2) be used to develop a year-ahead summer 2008 peak forecast.

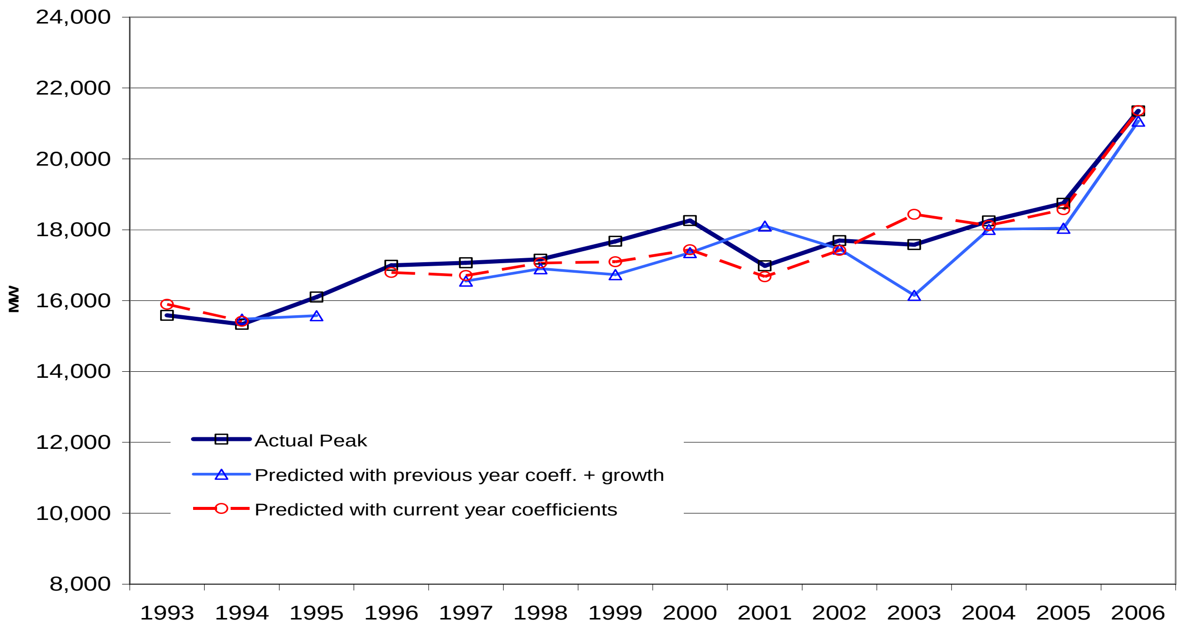
Figure 3: 2006 PG&E Service Area Predicted versus Actual Peaks



To further evaluate the accuracy of the method used to develop year-ahead peak forecasts, staff compared the weather-normalized peak (which would have been predicted with past years' weather data and forecasts) with actual loads that occurred at that temperature. Staff estimated the weather coefficients for the PG&E service area for the years for which hourly loads are available—1993 through 2006. For each of those years, a year-ahead temperature load model was constructed by combining the coefficients estimated from the previous year's load and temperature data with annual growth from the most recent adopted forecast. For example, the year-ahead model for 1994 combines coefficients estimated from 1993 daily peaks and temperatures with the 1993–1994 growth rate (2.2 percent) from the 1992

Electricity Report demand forecast. This model was then applied to the actual temperatures occurring for each summer day in 1994. From these predicted daily peaks, the annual maximum peak (given the daily weather that actually occurred) is extracted. Figure 4 compares these hypothetical year-ahead forecasts with actual peak demands.

Figure 4: PG&E Actual versus Predicted Annual Peaks 1993–2006



The predictions of peak using current-year coefficients have an absolute average error of 1.9 percent. Using the previous years' coefficients with a forecasted growth rate increases the average error to 3.5 percent. The largest error in year-ahead forecasts is in 2003, when the economic driver used predicted a decline of the Northern California economy that did not occur. Similarly, the method under-forecasts during the technology boom of1999 to 2000.

PG&E Area Publicly Owned Utilities (POUs)

Table 4 shows staff's revised forecast for the major POUs in Northern California, the previous Energy Commission forecast, and, for those who submitted demand forecasts in the *2007 IEPR* proceeding, the POU's own forecast. The Energy Commission's POU forecasts were not updated as part of the June 2006 Update; the comparison shown is therefore to the *2005 IEPR* forecast. That forecast disaggregated the PG&E area total based upon shares of 2003 actual, not weather-adjusted, loads.

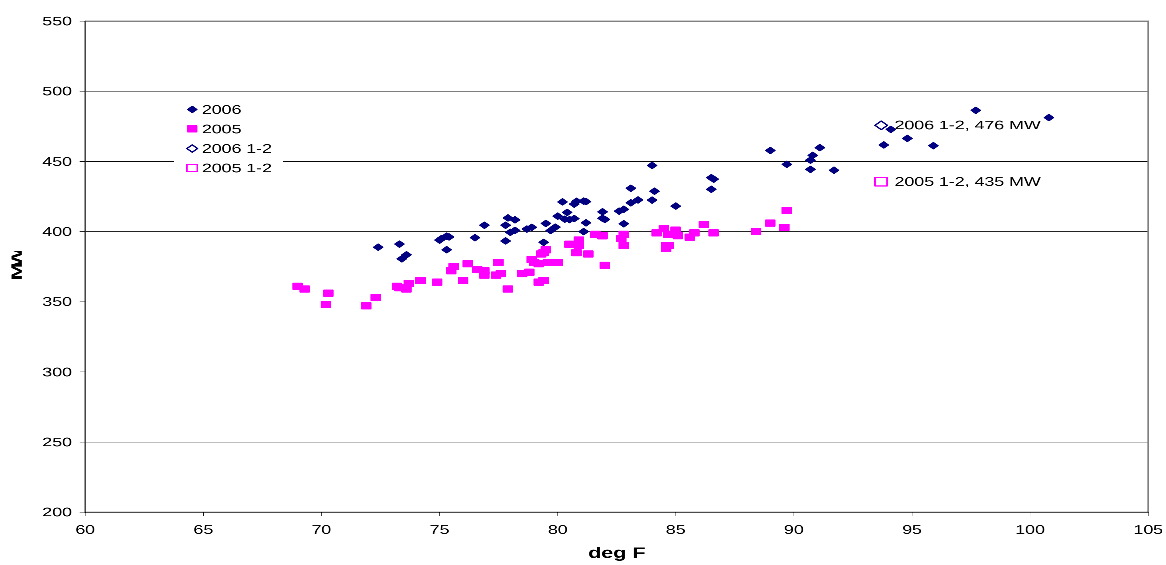
Using 2006 weather-adjusted loads significantly increases the estimated peaks of most LSEs. In all cases, staff's revised forecast is within 3 percent of the forecast submitted by the POU. In the remainder of this section, temperature-load relationships for 2005–2006 are shown for the three largest POUs: SVP, MID, and TID.

Table 4: 2008 Peak Forecasts for Northern California POUs

LSE	2005 IEPR Forecast of 2006	Weather-Normalized 2006 Peak		% Change from June 2006 Update	Staff Forecast of 2008	LSE'S *2007 IEPR* Forecast of 2008	% Difference Staff/ LSE Forecast
		Co-incident	Non-coincident				
SVP	380	469	473	23.2%	486	485	0.3%
NCPA LSEs	510	480	485	-5.8%	498		
Other CAISO LSEs	343	257	262	-25.1%	269		
TID	404	493	498	22.0%	513	517	-0.7%
Merced Irrigation District	78	77	77	-1.9%	79		
Central Valley Project	244	251	251	2.7%	251		
MID	525	662	669	26.2%	689	711	-3.0%
Redding	203	244	246	19.9%	253	257	-1.5%
Roseville	299	331	332	10.5%	342	339	0.9%

Figure 5 shows loads and temperatures for Silicon Valley Power (SVP). The results indicate 2005–2006 peak growth of 9 percent. SVP notes in its *2007 IEPR* demand forecast submittal that they experienced an increase in energy consumption of about 7 percent in fiscal year 2006 as commercial and industrial vacancy rates declined. The staff's weather-normalized peak produces a forecast of 486, nearly identical to SVP's forecast.

Figure 5: SVP 2005 – 2006 Summer Weekday Temperature versus Peak



Figures 5 and 6 show temperature-load trends for MID and TID. Both LSE's load grew 2 percent from 2005 to 2006, slightly faster than the Energy Commission forecast growth rate.

Figure 6: MID 2005 – 2006 Summer Weekday Temperature versus Peak

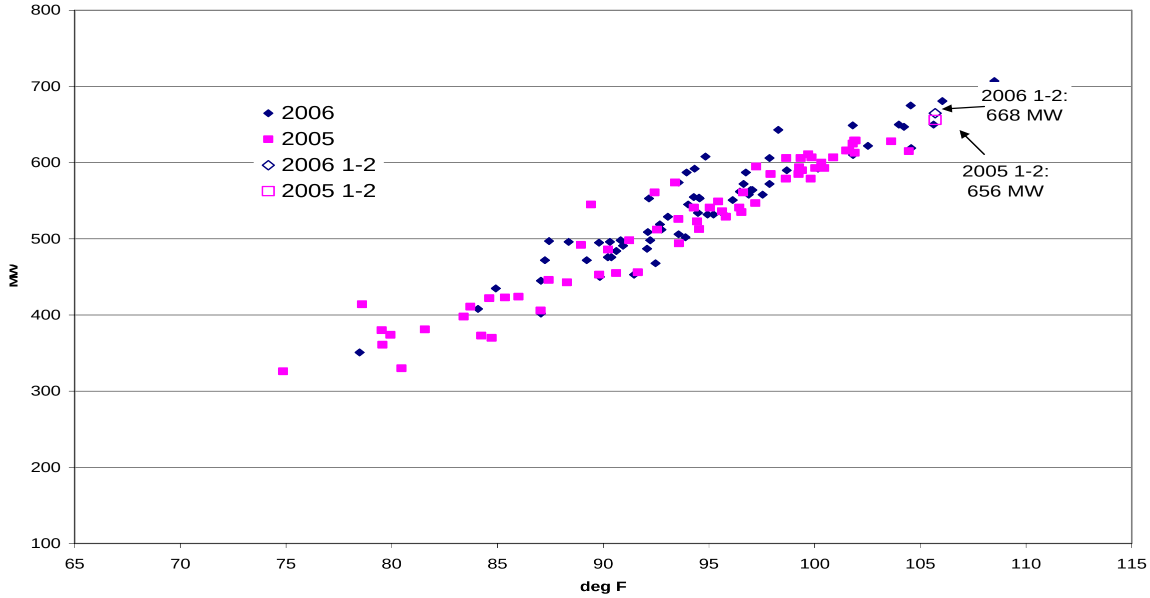
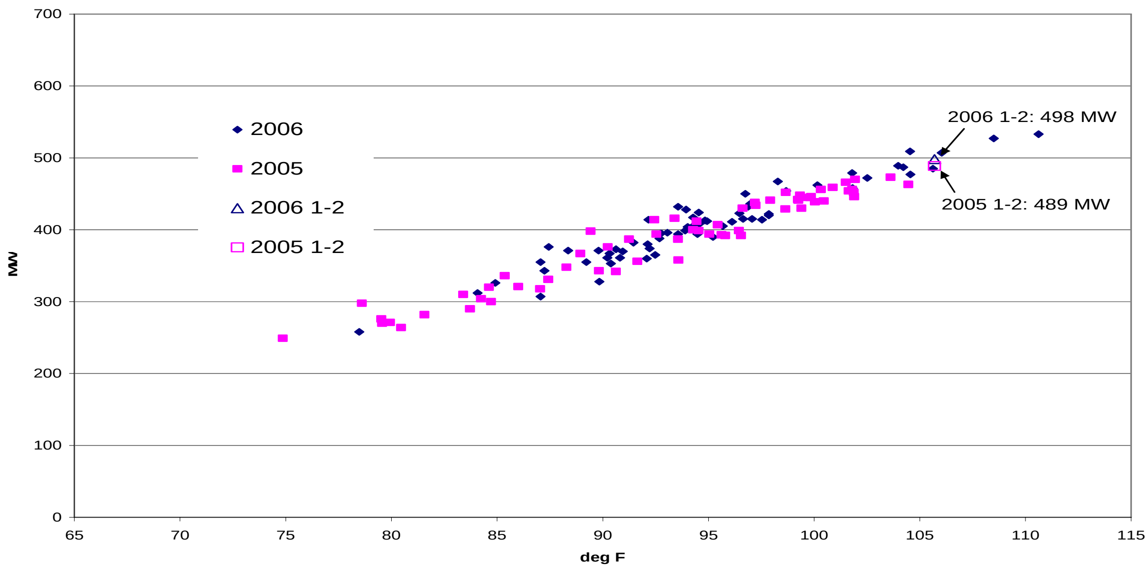


Figure 7: TID 2005 – 2006 Summer Weekday Temperature versus Peak

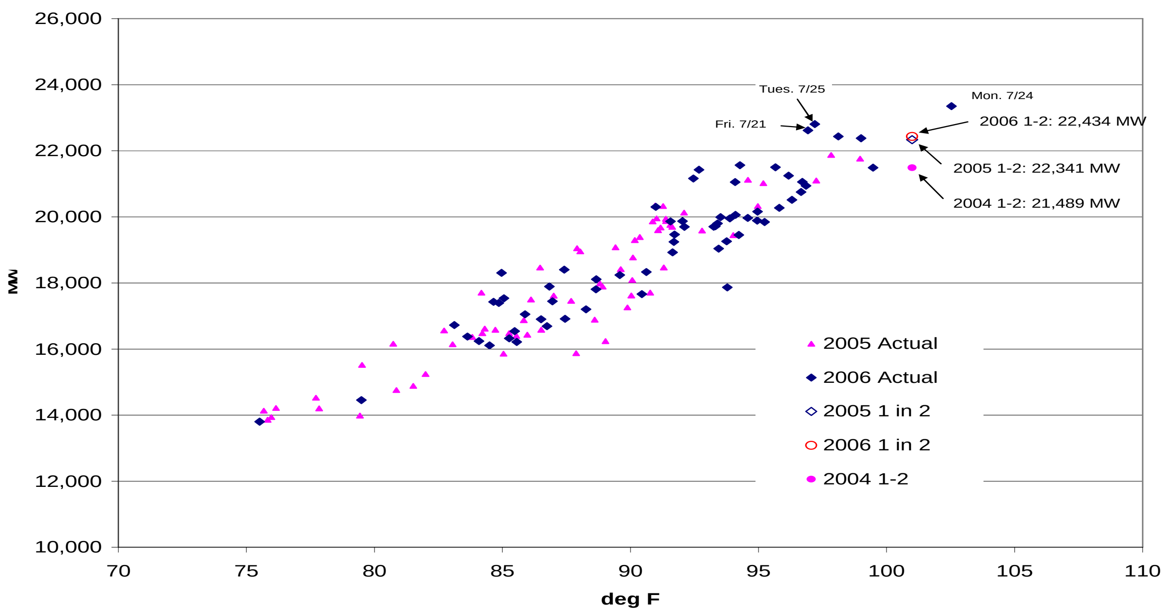


SCE PLANNING AREA RESULTS

Unusual weather conditions during the summer of 2005 prompted staff to introduce the use of daily diurnal variation in addition to temperature. Staff continues to use both lagged temperature and daily diurnal variation for the weather normalization procedure for the SCE planning area.

Figure 8 shows 2005 and 2006 summer weekday temperatures and peaks. Also shown are the weather-normalized 1-in-2 peak estimates for each year. On average, 2006 summer weekday service area temperatures were somewhat higher than in 2005. Other than the difference in the peak week temperatures, the most notable difference is the group of 2005 temperatures on the low end of the range. The difference in weather-normalized 1-in-2 peak estimates for both years, however, is less than 0.5 percent, indicating essentially no growth in peak demand after adjusting for temperature. By comparison, weather-adjusted demand from 2004 to 2005 grew by 4.6 percent—nearly 1,000 MW. This slowing growth may reflect the effects of both weakening economic conditions and increasing rates in the SCE service area.

Figure 8: SCE 2005 – 2006 Summer Weekday Temperature-Peak Comparison



Based on discussion at the workshop, staff considered several changes to the SCE area forecast. Staff changed the original weather station weights to account for 2006 air conditioning saturations as projected in our forthcoming long term forecast. This resulted in a new 1-in-2 2006 peak value of 22,448 MW, an increase of 31 MW. The regression estimation equation was also corrected for serial correlation. Applying this correction reduced the 22,448 MW value to 22,434 MW (a reduction of 14 MW).

SCE also suggested using separate variables for Saturday, Sundays and holidays in order to capture the difference in load for each of those day-types. This correction is more suited for day-to-day forecasting. The purpose of the staff forecast is to forecast summer peak which is assumed to happen on a weekday. Making separate variables for weekend day-types will have minimal outcome on the forecasted summer peak.

SCE also suggested that correlation between temperature and diurnal spread variables would result in a biased temperature coefficient. While correlation between these two variables will increase the standard error of the estimate, it should not bias the estimate itself. Since the staff forecast is not using the standard error of the estimate itself, it is not clear that this criticism is valid.

Table 5 shows the estimated coefficients used to calculate the weather-normalized peak and the resulting revised forecast. The estimated 1-in-2 2006 peak of 22,434 MW is 1.6 percent lower than the June 2006 Update projection. As a result, staff proposes to lower the SCE area forecast. Table 5 also shows the staff forecast under extreme temperature conditions. Because the extreme temperatures of 2006 are included in the weather history used to predict load under increasing temperatures, the weather scenario multipliers have increased slightly.

Following the May 24 workshop, SCE provided staff with a new peak demand forecast, developed for its forthcoming rate case, that is 300 MW lower than in the 2007 CPUC Long Term Procurement Plan forecast which was discussed at the workshop. The reduction is due to lower growth in the number of customers in 2007 than previously forecast. Staff's forecast of 23,109 MW is 950 MW lower than SCE revised forecast. The difference between the staff and SCE forecasts reflects differences between both their starting points and their projected annual growth rates. Staff's forecasted growth rate is 1.5 percent annually, compared with SCE's projected growth rate of 2.5 percent. While the staff growth rate is based on the previous ten-year forecast, the economic and demographic projections being used for the forthcoming *2007 IEPR* forecast have similar growth rates.

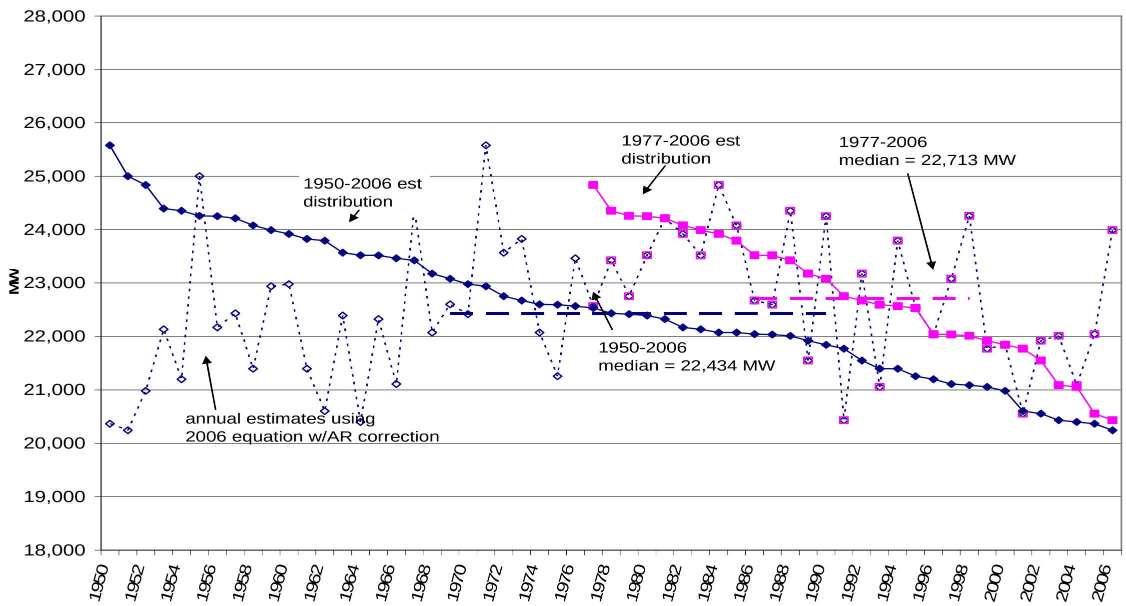
Table 5: SCE Planning Area Forecast

Estimated Temperature-Load Statistics for 2006			
Variable	*Coefficients*	*Standard Error*	*t Statistic*
Intercept	-15591.00	1201.28	-12.98
Weekend/Holiday	-2332.85	144.72	-16.12
631Max	403.58	15.57	25.92
Divar	-71.71	16.18	-4.43
Adjusted R Square	0.92		

Staff SCE Planning Area Forecast					**SCE's *2007 IEPR* Forecast**		**% Difference Staff/LSE Forecast 2008**
	Weather Normal-ized 2006	2007	2008	% Increase above 1-in-2	2007	2008	
1-in-2	22,434	22,784	23,109		23,517	24,062	-3.96%
1–in-5	23,951	24,324	24,671	6.76%			
1–in-10	24,410	24,791	25,144	8.81%			
1-in-20	24,870	25,258	25,618	10.86%			

A partial explanation of the difference in estimated 2006 loads is in the historic time period used for weather-normalization. SCE's documentation indicates that they use the last 30 years of weather history to weather-normalize peak. Staff uses the period 1950-2006 for weather normalization. Limiting the staff weather-normalization period to 1977-2006 increases the weather-normalized peak by 300 MW to 22,713 MW. Figure 9 demonstrates the difference in estimation using each time frame.

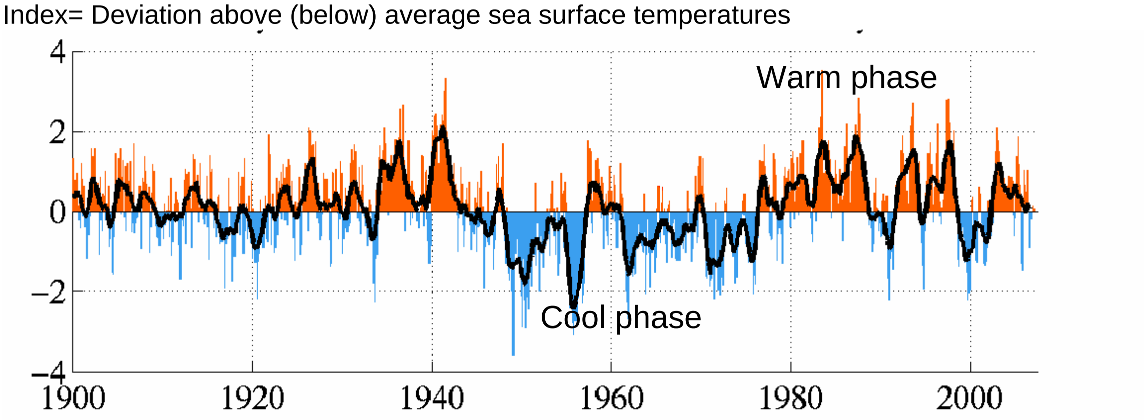
Figure 9: Weather-Normalized 2006 SCE Peak under Alternative Time Frames



It appears that southern California annual peaks and their associated time profile may be strongly affected by the phase of the Pacific Decadal Oscillation (PDO), a 20-to-30 year climate cycle that affects Pacific sea surface temperatures. West coast temperature anomalies are significantly positively related to the PDO trend.[4] Figure 10 shows the historical trend of the PDO from 1900. From 1950 to 1977 the PDO was in a cool phase of below-average sea surface temperatures. In 1997 a shift occurred to a warm phase. It is believed that the PDO shifted back to cool phase in 1998, but a 2002 shift back to warm phase makes it difficult to determine yet whether this was a true shift to a cold phase. The trigger of PDO phase shifts is not well understood and climatologists do not yet have the ability to predict them. Because a longer time period captures temperatures during both phases, staff believes it is more appropriate in determining a 1-in-2 temperature value than a shorter period.

Figure 10: Monthly Values for the PDO Index: 1900 – February 2007

Index= Deviation above (below) average sea surface temperatures



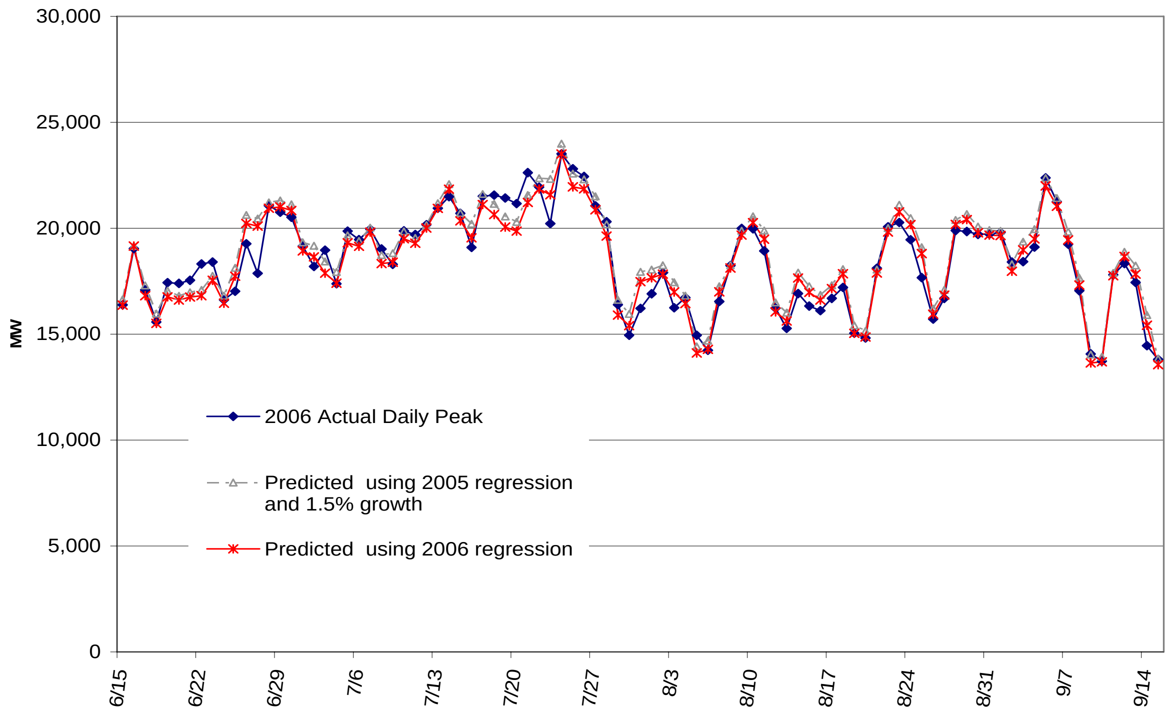
Source: Joint Institute for the Study of the Atmosphere and the Ocean, http://jisao.washington.edu/pdo/PDO.latest

[4] LaDochy, S., J. Brown, M. Selke, and W. Patzert, 2004: Can U. S. West Coast climate be forecast? Proc. AMS, Symp. On Forecasting the Weather and Climate of the Atmosphere and Ocean, Seattle, WA Jan 11-14. Available at: http://ams.confex.com/ams/pdfpapers/71130.pdf

Accuracy of Forecast

Figure 11 presents a comparison of the actual summer daily peaks with estimated daily peaks derived using both the 2006 estimation equation and the 2005 estimation equation grown at the 2005–2006 adopted forecast growth rate. The mean absolute percentage error estimated using 2006 weather and loads is 2.5 percent, with a standard deviation of 2.1 percent. The average error of the year-ahead method, using coefficients estimated from 2005 loads and temperatures, is slightly higher at 2.8 percent with a standard deviation of 2.4 percent.

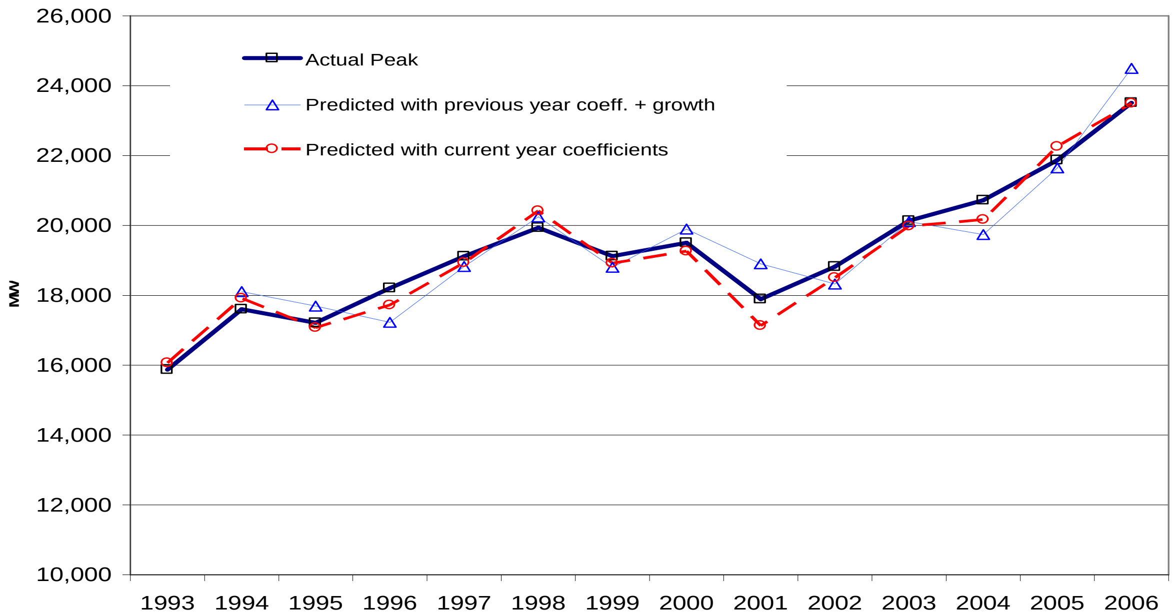
Figure 11: SCE 2006 Actual versus Predicted Daily Peaks



To evaluate the accuracy of the method used to develop the SCE year-ahead peak forecasts, staff compared the weather statistics which would have been estimated with past years' weather data with actual loads at that temperature. Staff estimated the weather coefficients for the SCE planning area for years for which daily maximum peaks are available, 1993 through 2006. From this data, the annual maximum peak (given the daily weather that actually occurred) is extracted. Figure 12 shows hypothetical year-ahead forecasts and actual annual peak demands.

The predictions of peak using current-year coefficients have an absolute average error of 1.8 percent. Using the previous years' coefficients with a forecasted growth rate increases the average error to 2.7 percent. The largest error is in 2001, when many electric customers voluntarily curtailed demand in response to the energy crisis.

Figure 12: SCE Actual versus Predicted Annual Peaks 1993–2006



SCE-Area LSE Forecasts

In addition to loads of SCE distribution-service customers, SCE's FERC Form 714 hourly loads include the loads of customers in Anaheim, Azusa, Banning, Colton, Riverside, Vernon, and other smaller LSEs. To weather-normalize load of SCE distribution customers, staff applied the same methodology used for the planning area to 2006 hourly loads submitted by SCE for use in the Resource Adequacy load forecast adjustment process.

For other utilities in the SCE area, staff used historic loads for individual LSEs from both FERC Form 714 and California ISO hourly settlement data to estimate weather-adjusted peaks for individual LSEs. The 1-in-2 temperature values used to estimate the LSE weather-adjusted peaks are the average of those variables on days where the SCE area-wide annual maximum temperatures were average. For smaller LSEs for which no hourly load data is available, the peak is estimated from annual energy consumption. Finally, the sum of the individual LSE loads was calibrated with the SCE planning area total.

Table 6 shows staff's proposed forecast for the larger LSEs compared to the previous Energy Commission forecast. The forecast for the SCE service area was developed using the same methodology as the SCE planning area, but using service area hourly loads provided by SCE. Forecasts for the POUs, which were not revised as part of the June 2006 update, have increased while the SCE service area forecast is lowered to be more consistent with current weather-normalized loads.

The September 2005 disaggregate forecast tables relied upon actual load data only through 2003.

Table 6: 2008 Peak Forecast for SCE Area LSEs

LSE	June Update/ Sept. 2005 Forecast of 2006	Weather-Normalized 2006 Peak		% Change in Forecast	Staff Forecast of 2008	LSE Fore-cast of 2008	% Difference Staff/LSE Forecast
		Coincident	Non-coincident				
SCE Service Area	21,368	20,710	20,710	-3.1%	21,333		
City of Anaheim	473	580	588	22.5%	606	577	5.0%
City of Riverside	399	563	566	40.9%	583	573	1.8%
City of Vernon	164	175	200	6.8%	206		
Metropolitan Water Department	197	200	225	1.7%	232		
Total Other LSEs	190	205	208	8.3%	214		

Temperature-load relationships for the two largest POUs, Anaheim and Riverside, are shown below. In Riverside, year-over-year growth was flat, similar to the SCE planning area as a whole. In Anaheim, the weather-adjusted peak grew at 1.5 percent.

Figure 13: Riverside Summer Weekday Peak versus Temperatures

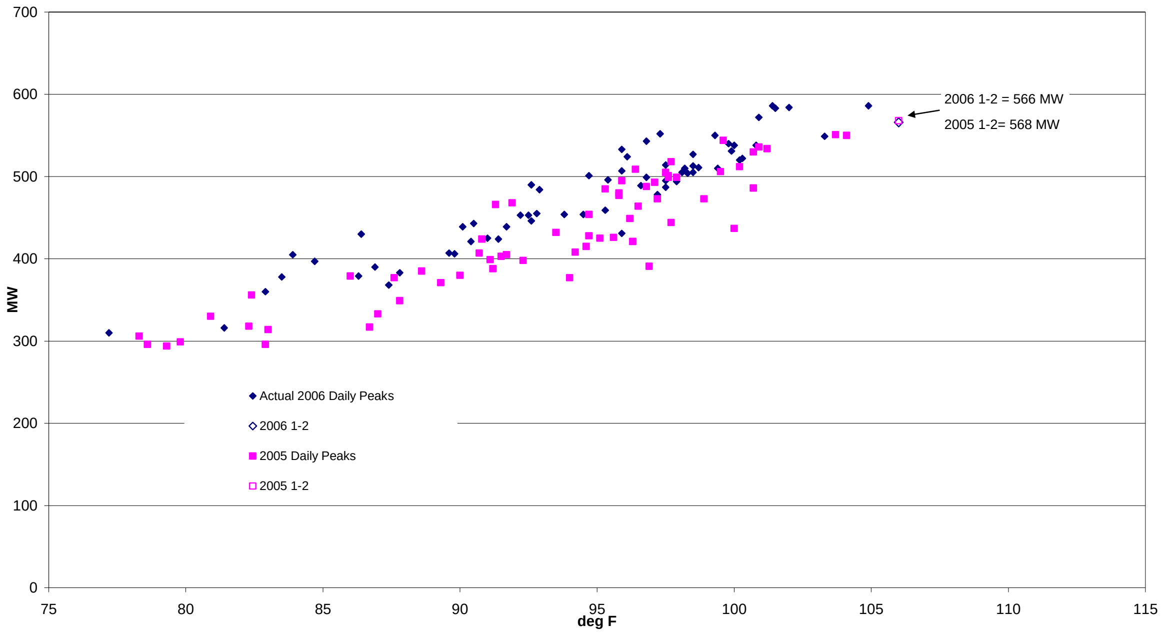
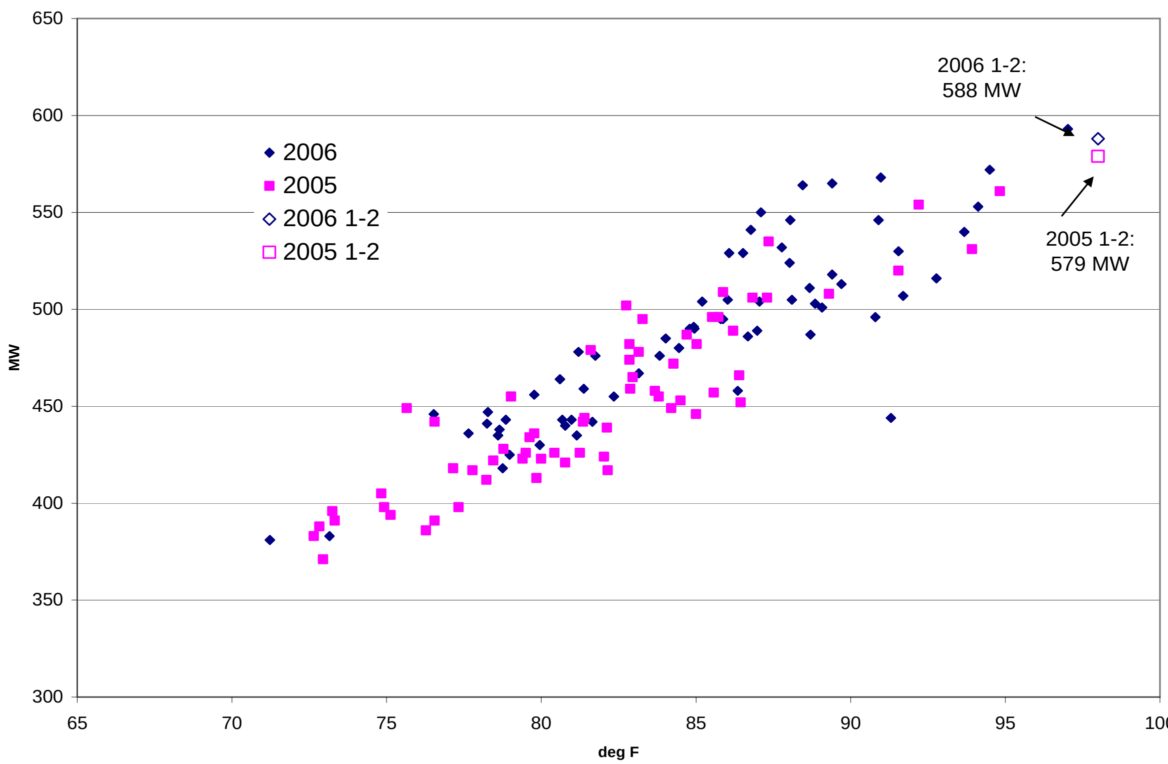


Figure 14: Anaheim Summer Weekday Peak versus Temperatures

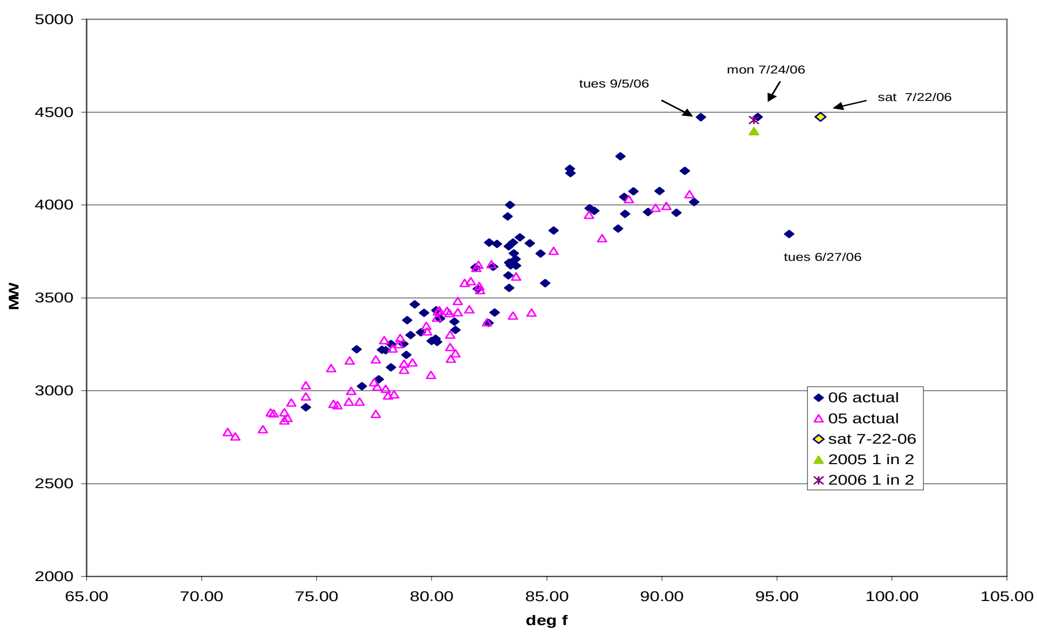


SDG&E PLANNING AREA RESULTS

The SDG&E planning area analysis used both lagged maximum temperature and daily diurnal variation. Staff also used a combination of Lindbergh Field, Miramar Marine Corp Air Station, and El Cajon weather stations to represent the SDG&E planning area. Because staff has no reliable weather information for El Cajon before 1979, the time period for historic analysis was limited to 1979–2006. Weather variables were calculated as the average of the three stations.

The diverse weather patterns during the summer of 2006 proved challenging when attempting to create a weather-normalized peak value. Summer 2006 produced three days in the SDG&E planning area with peaks within two MW of the annual peak, as shown in Figure 15. As in the previous utility areas, 2006 temperatures were generally warmer than in 2005.

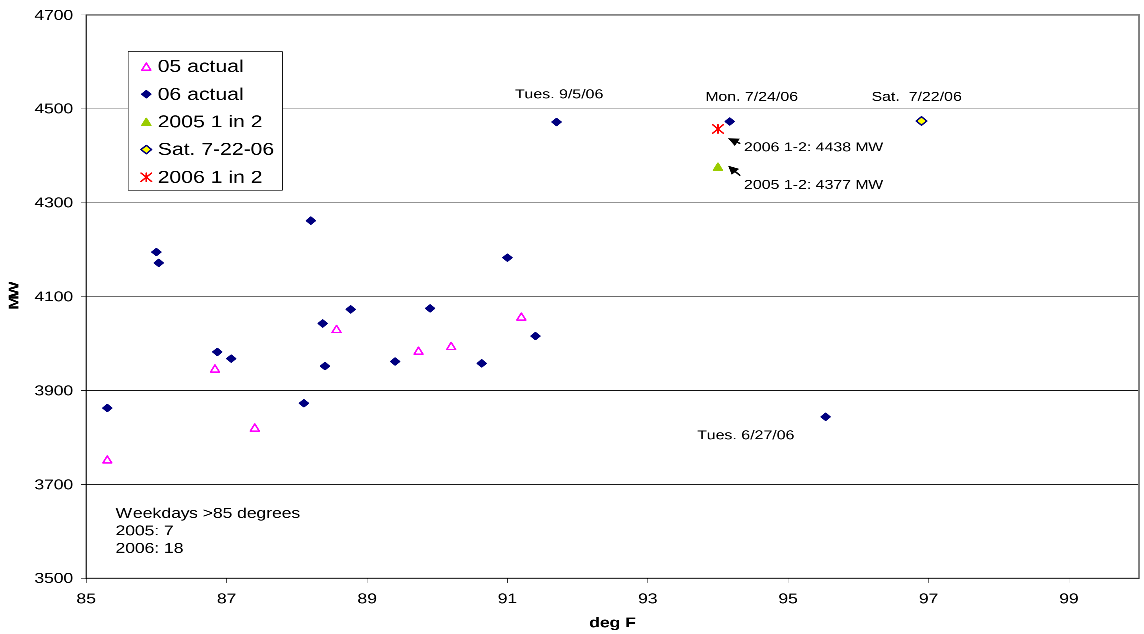
Figure 15: SDG&E 2005–2006 Summer Weekday Temperature Peak Comparison



Two of these days occurred during the mid-July California heat storm, with the third occurring on September 5 (the day after Labor Day). Figure 16 provides a more detailed look at the higher temperature and load periods of the past two summers. During the July heat storm, the hottest day in the SDG&E planning area occurred on Saturday, July 22. This event produced the annual peak for SDG&E, which would have been higher had it occurred on a weekday. Temperatures for the SDG&E region had returned to near 1-in-2 levels by Monday, July 24, when the California ISO reached its statewide peak. Temperatures were slightly below annual 1-in-2 peak levels on the September peak day, but added loads from return-to-normal business after the summer vacation period could have caused an increase in the daily peak. Demand observed on the second hottest summer day, June 27 adds to the SDG&E 2006 weather puzzle. Temperatures on this day were at the 1-in-2 level, but the associated loads were well below what would be expected, possibly because it was the first hot day of the summer. The fact that in 2005 there were only seven summer days with temperatures above 85 degrees, while 2006 had 18 such days may impact the difference in temperature response between in the two years .

Weather normalized peaks calculated with the method used in the June 2006 Update forecast indicate a 2005–2006 peak growth of 1.4 percent for the SDG&E planning area.

Figure 16: SDG&E 2005–2006 Summer Temperature-Peak Comparison for Temperatures above 85 degrees



The estimated 1-in-2 peak of 4,438 MW is 1.23 percent higher than the June 2006 Update projection for 2006. As a result, staff proposes to raise the SDG&E area forecast. Table 7 shows the estimated coefficients used to calculate the weather-normalized peak and the resulting revised forecast. The staff forecast is less than1 percent greater than SDG&E's own forecast.

Table 7: SDG&E Planning Area Forecast

Estimated Temperature-Load Statistics for 2006			
	Coefficients	*Standard Error*	*t Statistic*
Intercept	-3160.95	346.86	-9.11
Weekend/Holiday	-457.42	34.85	-13.13
SDGE631Max	83.78	4.74	17.66
Divar	-10.72	4.58	-2.34
Adjusted R Square	0.87		

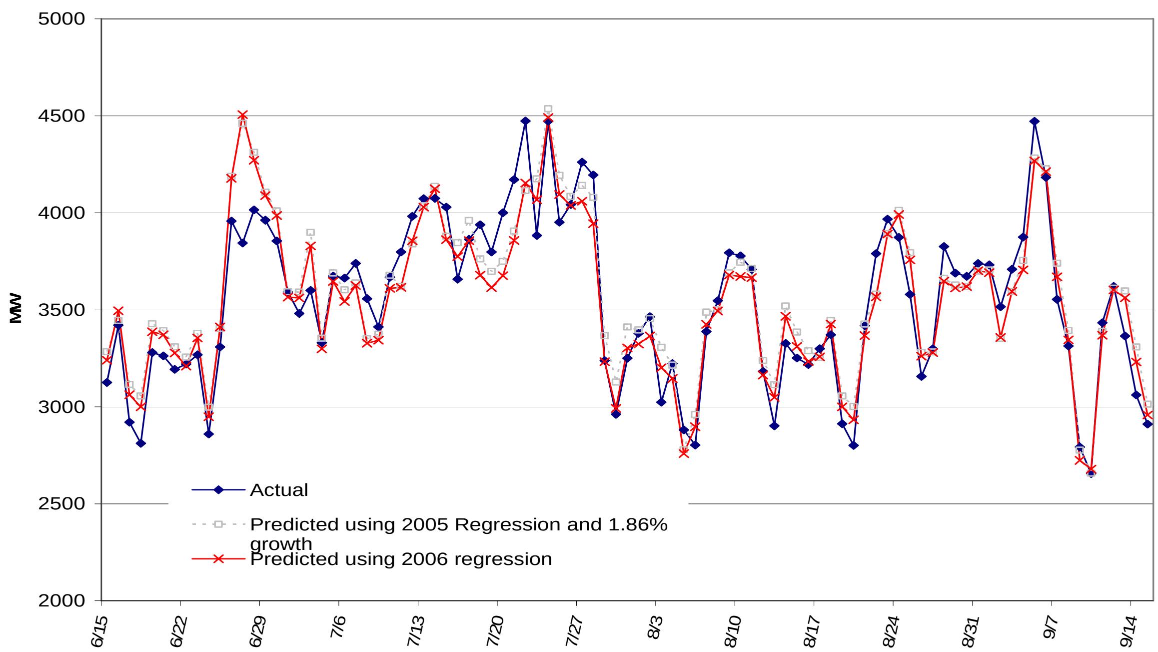
Staff SDG&E Planning Area Forecast					**SDG&E 2007 IEPR Forecast**		**% Difference Staff/LSE Forecast 2008**
	Weather Normal-ized 2006	2007	2008	% Increase above 1-in-2	2007	2008	
1-in-2	4,438	4,504	4,586		4,471	4,546	0.82%
1-in-5	4,742	4,813	4,901	6.8%			
1-in-10	4,830	4,902	4,992	8.8%			
1-in-20	5,100	5,176	5,271	14.9%			

The difference between the staff and SDG&E forecasts largely reflects differences between the assumed 2006 weather-normalized starting point. Both forecasts projected 2006–2008 annual growth rates of approximately 1.7 percent annually.

Accuracy of Forecast

Figure 17 presents a comparison of actual summer daily peaks with estimated daily peaks derived using both the 2006 estimation equation and the 2005 estimation equation, grown at the 2005–2006 adopted forecast growth rate. Both the overestimation of the first warm summer period and the underestimation of the last warm summer period can be seen. Using 2006 weather and loads, the mean absolute percentage error is 3.2 percent with a standard deviation of 2.5 percent. The average absolute error of the year-ahead method, using coefficients estimated from 2005 loads and temperatures and the adopted forecast growth rate, is slightly higher at 3.6 percent, with a standard deviation of 2.7 percent.

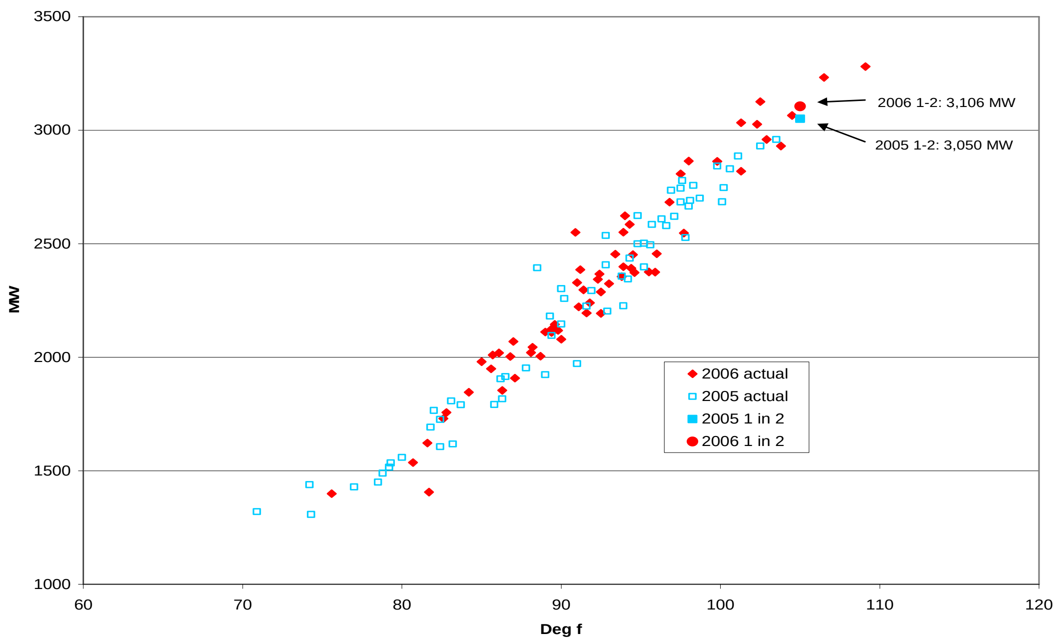
Figure 17: SDG&E 2006 Actual versus Predicted Daily Peaks



SMUD PLANNING AREA RESULTS

For the Sacramento Municipal Utility District (SMUD) planning area staff used the three-day lagged weighted average of daily maximum temperature as the primary explanatory variable. Figure 18 presents 2005 and 2006 summer weekday temperature and peaks. Also shown are each year's weather normalized 1-in-2 peak estimates. On average, 2006 summer weekday service area temperatures were somewhat higher than in 2005. Other than the difference in the higher 2006 peak week temperatures, the most notable difference is the group of temperatures on the low end of the range that were seen in 2005.

Figure 18: SMUD 2005 – 2006 Summer Weekday Temperature-Peak Comparison



The estimated 2006 1-in-2 peak is 3,105 MW, 3.7% percent higher than the 2006 forecast in the June 2006 update. Table 8 shows the estimated coefficients used to calculate the weather-normalized peak and the resulting revised forecast. The proposed staff peak forecast for 2008 is 130 MW higher than the forecast submitted by SMUD as part of the *2007 IEPR* proceeding.

The distinction between the staff and SMUD forecasts reflects differences between the projected annual growth rates. Staff's forecast grows at 2.4% percent annually, compared to SMUD's growth rate of 2% percent. There may also be small differences in the assumed weather normalized starting point.

Table 8: SMUD Planning Area Forecast

Estimated Temperature-load Statistics for 2006			
	Coefficients	*Standard Error*	*t Statistic*
Intercept	-3,326.41	151.24	-21.99
Weekend/Holiday	-140.57	23.29	-6.03
SMUD631Max	61.26	1.63	37.52
Adjusted R Square	0.94		

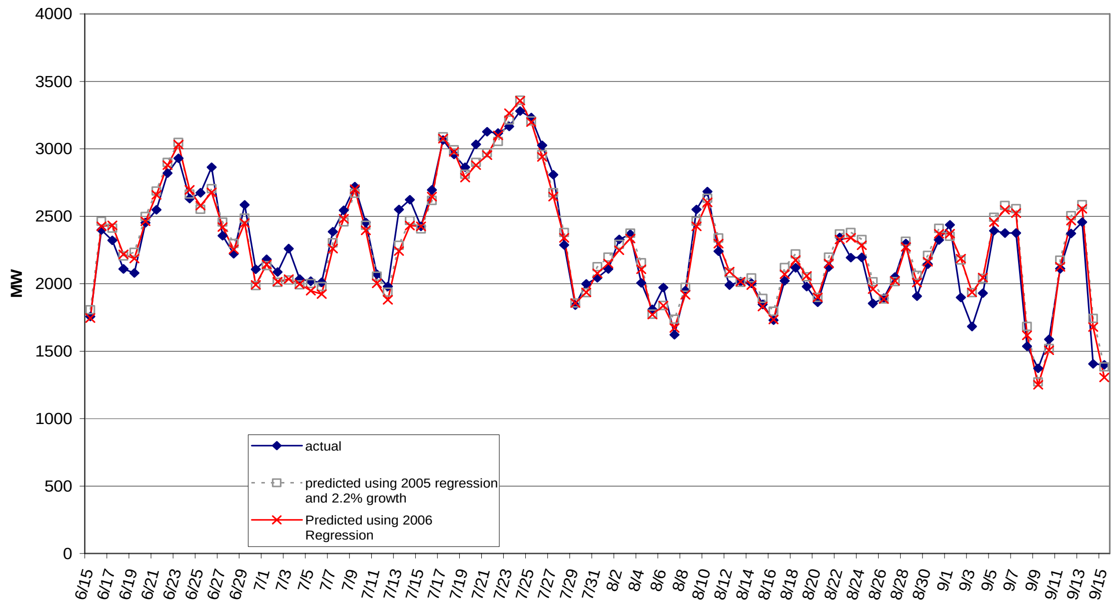
Staff SMUD Planning Area Forecast (MW)					**SMUD's *2007 IEPR* Forecast**		**% Difference Staff/LSE Forecast 2008**
	Weather Normal-ized 2006	2007	2008	% Increase above 1-in-2	2007	2008	
1-in-2	3,106	3,175	3,252		3,060	3,122	4.16%
1-in-5	3,289	3,363	3,444	5.89%	3,159	3,223	6.88%
1-in-10	3,412	3,488	3,573	9.85%	3,254	3,320	7.62%
1-in-20	3,473	3,551	3,637	11.82%	3,324	3,391	7.25%

For the high temperature cases, the difference between the staff and SMUD forecasts is larger. The staff forecast increases by 9.85 percent under 1-in-10 temperatures, compared to SMUD’s increase of 7.6 percent.

Accuracy of Forecast

Figure 19 presents a comparison of the actual summer daily peaks with estimated daily peaks derived using both the 2006 estimation equation and the 2005 estimation equation grown at the 2005–-2006 adopted forecast growth rate. The mean absolute percentage error estimated using 2006 weather and loads is 3.8 percent with a standard deviation of 3.3 percent. The average error of the year-ahead method, using coefficients estimated from 2005 loads and temperatures, is slightly higher at 4.2 percent with a standard deviation of 3.5 percent.

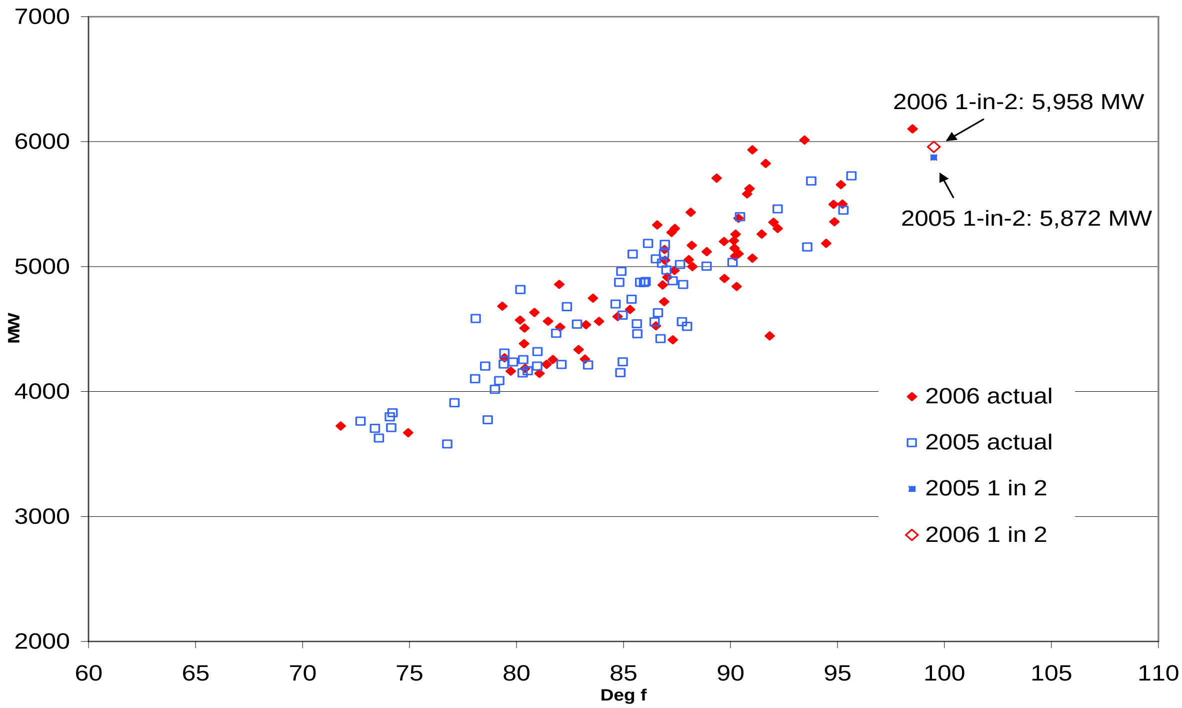
Figure 19: SMUD 2006 Actual versus Predicted Daily Peaks



LADWP PLANNING AREA RESULTS

For the Los Angeles Department of Water and Power (LADWP) planning area, staff used both the three-day lagged weighted average of daily maximum temperature and daily diurnal variation as explanatory variables. Figure 20 presents 2005 and 2006 summer weekday temperature and peaks. Also shown are each year's weather normalized 1-in-2 peak estimates. On average, 2006 summer weekday service area temperatures were somewhat higher than in 2005.

Figure 20: LADWP 2005 – 2006 Summer Weekday Temperature-Peak Comparison



The estimated 2006 1-in-2 peak is 5,958 MW, 3.1% higher than the 2006 forecast in the June 2006 update. As a result staff proposes raising the LADWP service area forecast.

Table 9 shows the estimated coefficients used to calculate the weather-normalized peak and the resulting revised forecast. The proposed staff peak forecast for 2008 is 381 MW (6.78%) higher than the forecast submitted by LADWP as part of the *2007 IEPR* proceeding. The difference between the staff and LADWP forecasts reflects differences between the assumed 2006 weather-normalized starting point. LADWP uses a different set of weather stations that indicate 2006 was a more extreme weather year than indicated with the staff weather stations.

Table 9: LADWP Planning Area Forecast

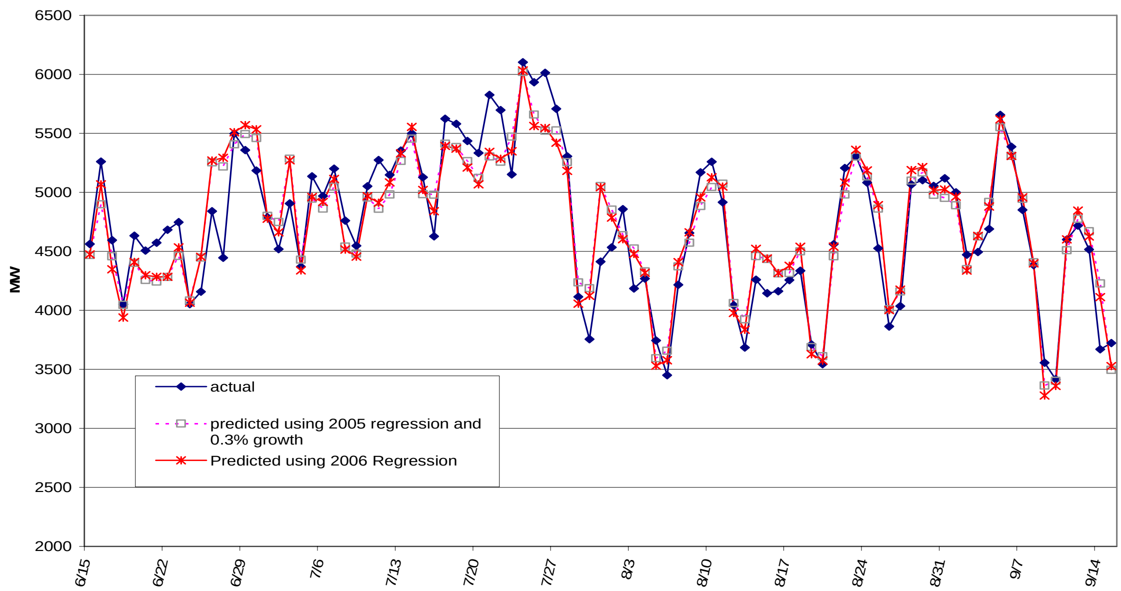
Estimated Temperature-load Statistics for 2006			
	Coefficients	*Standard Error*	*t Statistic*
Intercept	-3,455.98	452.09	-7.64
Weekend/Holiday	-778.52	54.41	-14.31
LADWP631Max	103.42	6.20	16.68
LA divar	-26.48	6.36	-4.17
Adjusted R Square	0.85		

Staff LADWP Planning Area Forecast (MW)					**LADWP's *2007 IEPR* Forecast**		**% Difference Staff/LSE Forecast 2008**
	Weather Normalized 2006	2007	2008	% Increase above 1-in-2	2007	2008	
1-in-2	5,958	5,977	5,999		5,557	5,618	6.78%
1-in-5	6,344	6,364	6,388	6.48%	5,945	6,010	6.29%
1-in-10	6,514	6,535	6,560	9.34%	6,065	6,132	6.98%
1-in-20	6,653	6,674	6,699	11.67%	6,169	6,237	7.41%

Accuracy of Forecast

Figure 21 presents a comparison of the actual summer daily peaks with estimated daily peaks derived using both the 2006 estimation equation and the 2005 estimation equation grown at the 2005–2006 adopted forecast growth rate. The mean absolute percentage error estimated using 2006 weather and loads is 3.95 percent with a standard deviation of 3.2 percent. The average error of the year-ahead method, using coefficients estimated from 2005 loads and temperatures, is slightly higher at 4.16 percent with a standard deviation of 3.28 percent.

Figure 21: LADWP 2006 Actual versus Predicted Daily Peaks



Statewide Forecast Tables

Table 10: 1-in-2 Coincident Peak Demand by LSE

Area/LSE	2006 Weather-Normalized	2007	2008	Average Annual Growth 2006-2008
PG&E Service Area	19,523	19,807	20,057	1.4%
Silicon Valley Power	469	476	482	1.4%
Total NCPA	480	487	493	1.4%
Total Other LSEs in CAISO	257	261	264	1.4%
Dept of Water Resources - North	409	409	409	0.0%
Total North of Path 15	**21,137**	**21,440**	**21,705**	1.3%
	1,206	1,223	1,239	
Turlock Irrigation District Control Area	570	579	587	1.5%
Sacramento Municipal Utilities District	3,106	3,175	3,252	2.3%
Merced Irrigation District	77	78	79	1.4%
Central Valley Project	251	251	251	0.0%
Modesto Irrigation District	662	673	682	1.5%
City of Redding	244	247	251	1.4%
City of Roseville	331	336	340	1.4%
Shasta Dam Area Public Utility District	30	30	31	1.4%
Total SMUD Control Area	**4,700**	**4,789**	**4,885**	2.0%
Total PG&E Planning Area (excl. DWR &SMUD)	**22,322**	**22,645**	**22,929**	1.4%
SCE Service Area	20,710	21,033	21,333	1.5%
City of Anaheim	580	589	597	1.5%
City of Riverside	563	572	580	1.5%
City of Vernon	175	178	181	1.5%
Metropolitan Water Department	200	203	206	1.5%
City of Azusa	63	64	65	1.5%
City of Colton	87	89	90	1.5%
Other Small LSEs	55	56	57	1.5%
Pasadena Water and Power	310	310	310	0.0%
San Diego Gas & Electric	4,438	4,504	4,586	1.7%
Dept of Water Resources - South	506	506	506	0.0%
Total South of Path 15	**25,964**	**26,353**	**26,735**	1.5%
Sum of Noncoincident Peaks in CAISO Control Area	**47,101**	**47,792**	**48,440**	1.4%
CAISO Coincident Peak	**45,970**	**46,645**	**47,277**	1.4%
LADWP	5,958	5,977	5,999	0.3%
Burbank	292	292	292	0.0%
Glendale	302	302	302	0.0%
Total LADWP Control Area	**6,552**	**6,571**	**6,593**	0.3%
Imperial Irrigation District	958	972	985	1.4%
Sum of Noncoincident Peaks	**59,880**	**60,703**	**61,490**	1.3%
Statewide Coincident Peak Demand	**58,443**	**59,246**	**60,014**	1.3%

Table 11: 1-in-10 Peak Demand by Area

Area/LSE		2007	2008
	PG&E Service Area	20,540	20,799
	PG&E Area CAISO LSEs	1,268	1,284
	Dept of Water Resources - North	409	409
Total North of Path 15		**22,218**	**22,493**
		1.036	1.036
Turlock Irrigation District Control Area		600	609
	Sacramento Municipal Utilities District	3,488	3,573
	Other SMUD/WAPA LSEs	1,774	1,795
Total SMUD Control Area		**5,261**	**5,367**
Total PG&E Planning Area (excl. DWR &SMUD)		**24,182**	**24,487**
	SCE Planning Area	24,580	24,930
	Pasadena Water and Power	334	334
	San Diego Gas & Electric	4,902	4,992
	Dept of Water Resources - South	506	506
Total South of Path 15		**30,322**	**30,761**
Sum of Noncoincident Peaks in CAISO Control Area		**52,539**	**53,254**
CAISO Coincident Peak		**51,278**	**51,976**
	LADWP	6,535	6,559
	Burbank	319	319
	Glendale	331	331
Total LADWP Control Area		**7,184**	**7,209**
Imperial Irrigation District		972	985
Sum of Noncoincident Peaks		**66,557**	**67,424**
Statewide Coincident Peak Demand		**64,960**	**65,806**