COMMITTEE FINAL REPORT

REVISED SHORT-TERM PEAK DEMAND FORECAST (2011-2012)

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CALIFORNIA ENERGY COMMISSION

ELECTRICITY AND NATURAL GAS COMMITTEE

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DISCLAIMER

This report was prepared by the California Energy Commission Electricity and Natural Gas Committee as part of *2011 Integrated Energy Policy Report* proceedings – Docket # 11-IEP-1C. The report will be considered for adoption by the full Energy Commission at its Business Meeting on March 9, 2011. The views and recommendations contained in this document are not official policy of the Energy Commission until the report is adopted.

ABSTRACT

This report presents revised short-term peak demand forecasts for the California Independent System Operator control area. The forecasts are designed to be used by the California Independent System Operator in its upcoming analysis of local area capacity requirements. Staff concluded that peak electricity demand is likely to be significantly lower (3-5 percent) for 2011 and 2012 than in the adopted *2009 Integrated Energy Policy Report* forecast for all three investor-owned utility transmission access charge areas within the California Independent System Operator control area. Staff, therefore, recommends a reduced short-term forecast for the Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric transmission access charge areas.

Keywords: Forecast, peak demand, weather adjustment, transmission access charge, load-serving entity, regression analysis

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CHAPTER 1: Introduction, Summary, and Study Approach

Introduction and Summary

The electricity demand forecasts adopted by the California Energy Commission are key inputs into analysis necessary to determine resource adequacy requirements in the California Independent System Operator (California ISO) control area. The forecasts presented in this report are designed to be used by the California ISO in its analysis of local area generation capacity requirements. The local capacity requirements (LCR) study determines the minimum amount of capacity resources that must be available to the California ISO within each area identified as having local reliability problems. This determines the generation capacity required to address these problems, and that capacity is allocated to load-serving entities (LSEs) as part of their year-ahead local resource adequacy requirement.

The most recent demand forecast was prepared for the *2009 Integrated Energy Policy Report (2009 IEPR)*.[1] Since that work was completed, economic conditions have worsened in California, relative to the short-term assumptions underlying load forecasts for 2009 and 2010, resulting in lower than predicted load growth for these years. A new, preliminary forecast for the *2011 IEPR* will be complete in May 2011. The California ISO LCR study, however, requires an updated demand forecast before then. Staff, therefore, evaluated the *2009 IEPR* forecast against actual 2009 and 2010 loads and reviewed recent economic/demographic projections to assess whether the May preliminary forecast is likely to be significantly different from the previous forecast in the short-term (2011 and 2012).

Staff concluded that for all three investor-owned utility (IOU) transmission access charge (TAC) areas[2], the peak electricity demand forecast for 2011 and 2012 is likely to be significantly lower than the current, adopted *2009 IEPR* forecast. Staff recommends a lowered short-term forecast for the Pacific Gas and Electric (PG&E), San Diego Gas & Electric (SDG&E), and Southern California Edison (SCE) TAC areas. The forecast recommended by this report for *1-in-10* (extreme) weather[3] is shown in **Table 1**, along with similar projections from the *2009 IEPR* forecast. Results for individual load pockets and LSEs within the IOU TAC areas are provided in Chapter 2. This revised forecast is intended

1 *California Energy Demand 2010-2020 Adopted Forecast*, California Energy Commission, December 2009. Available at http://www.energy.ca.gov/2009publications/CEC-200-2009-012/index.html.

2 The TAC areas include the IOUs and, for Pacific Gas and Electric and Southern California Edison, publicly owned utilities utilizing the IOU's transmission system.

3 Peak forecasts assuming *1-in-10* temperature conditions are of the most interest to the California ISO for planning purposes.

for near-term purposes only and does not imply any changes to the adopted longer-term forecast.

The estimated weather-normalized 2010 peak demand for the SCE TAC area as well as the 2011 and 2012 peak forecasts have been revised upward in this Committee report in comparison to the staff draft report for two reasons. First, staff discovered that the 2009 and 2010 data for one of the SCE TAC area weather stations (Burbank) was not consistent with the weather series used in developing the historical trend. Data was collected for the correct Burbank weather station and the regression for 2010 weather response was re-estimated for the SCE TAC area. Second, in response to public comments from SCE, staff decided to use 1960-2010 as the historical period to estimate average daily temperatures instead of 1950-2010. Staff determined that using a 50-year history provided more robust results. This change is discussed further later in this chapter. Each of these revisions had approximately equal impact on the increase in the 2011 and 2012 SCE peak estimates. This Committee report also provides an adjustment to the peak demand results designed to address California Department of Water Resources (DWR) water pumping operational concerns.

The rest of this chapter presents the staff approach to peak analysis. Chapter 2 provides results and caveats. Appendix A contains a discussion of peak demand coincidence analysis, and Appendix B gives the regression results driving the analysis.

Table 1: Comparison of Revised 1-in-10 and *2009 IEPR* Peak Demand Forecasts (Megawatts), 2011 and 2012

TAC Area	Year	Revised Forecast	2009 IEPR Forecast	Difference (Percent)
PG&E	2011	22,716	23,594	-878 (-3.7%)
	2012	23,033	23,959	-926 (-3.9%)
SCE	2011	25,107	25,878	-771 (-3.0%)
	2012	25,517	26,266	-749 (-2.9%)
SDG&E	2011	4,801	5,036	-235 (-4.7%)
	2012	4,882	5,124	-242 (-4.7%)

Source: California Energy Commission, 2011.

Study Approach

The two most significant factors in determining short-term peak demand forecasts are the level of current, weather-adjusted loads and near-term projections of the economic and demographic forecast drivers. To assess the reasonableness of using the *2009 IEPR* load forecast for the 2012 LCR study, staff examined hourly demand data through summer 2010 and the October 2010 economic projections by Economy.com for each of the three IOU TAC areas.

Weather-Adjusted Demand Assessment

Because summer peak demands are highly sensitive to temperature, any evaluation of peak demand trends must account for temperature effects. For this analysis, staff used hourly load data from the California ISO for the TAC areas and daily temperatures in 2010 to estimate the relationship between the summer weekday afternoon (1:00 p.m.-6:00 p.m.)[4] peak load and temperatures. Summer is defined as the period from June 15 to September 15. Since this analysis is intended to compare new estimates of weather-adjusted peak with the *2009 IEPR* long-term demand forecast, demand response impacts were added back into the actual peak loads.[5] The temperature variable for each TAC area is a weighted average of temperatures from a set of weather stations representative of the climate in that utility region. The weights are based on the estimated number of residential air conditioning units in each utility climate zone.

Staff used two weather variables: maximum and minimum daily temperatures. The maximum temperature, as applied in the analysis, was a weighted daily maximum, referred to as *max631*, consisting of 60 percent of the current day's maximum temperature, 30 percent of the maximum the day before, and 10 percent of the maximum two days previous. Weighting in this manner accounted for heat buildup over a three-day period. The minimum temperature was included to capture the effects of nighttime cooling (or lack of) and, combined with the maximum, serves as a proxy measure for daily humidity through the difference between the two temperatures. Daily afternoon maximum loads entered the regressions in absolute or logged form, depending on goodness of fit. Staff also tested for statistically significant differences, in terms of regression slope, among temperature increments.

The coefficients from the regressions were applied to historical temperature data for 1950-2010 for PG&E, 1960-2010 for SCE and 1979-2010 for SDG&E, resulting in an estimate of peak for each weather-year. The median of the annual peak estimates serves as a *1-in-2*, or average, weather adjustment for 2010. Extreme, or *1-in-10*, weather peaks were estimated by applying the adjustments used in the *2009 IEPR* forecast to the new *1-in-2* weather-adjusted peaks. These adjustments are based on historical relationships calculated between peak demand in extreme weather years and in average weather years assuming a normal distribution.[6]

Staff's typical practice in choosing a historical period to determine average temperatures is to use the maximum number of years for which daily temperatures are available for the

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4 Staff used 1 p.m. – 7 p.m. for PG&E, which often peaks later than the Southern California areas.

5 Maximum hourly demand response impacts in the summer of 2010 ranged from 80 MW for SDG&E to 325 MW for SCE. As of this draft, PG&E had not provided hourly demand response estimates for the summer of 2010.

6 The *1-in-10* multipliers were applied to *1-in-2* results as follows: 1.073 for PG&E, 1.088 for SCE and 1.10 for SDG&E. The multipliers are typically recalculated in each *IEPR* cycle.

required weather stations. For PG&E and SCE, this currently means 1950-2010. However, the 1950s were an unusually cool period in Southern California, with average temperatures increasing toward the end of the decade. This resulted in median peak estimates for SCE that varied considerably depending on the starting year used for weather history before 1960. After 1960, median peaks were not nearly as sensitive to the starting year—a starting year of 1965 or 1970 yielded almost identical results to 1960. Therefore, staff felt that the period 1960-2010 would provide more robust SCE results. Sensitivity to starting year was much lower for PG&E from 1950-2010. Full weather data for SDG&E is not available before 1979.[7]

Economic and Demographic Assumptions

In Energy Commission electricity demand forecasting models, one of the most fundamental drivers of the forecast is population growth. Staff uses the population forecast to project growth in the number of households and additions to commercial floor space in sectors such as schools, hospitals, and retail. The Department of Finance (DOF) population projections used by Energy Commission staff do not attempt to capture the short-term fluctuations in population associated with business cycles, so this driver is relatively stable over time and from forecast to forecast. DOF has not revised its demographic projections since the *2009 IEPR* forecast was prepared.

The near-term economic projections, however, are more pessimistic than those developed in 2009, reflecting a more severe economic downturn than had been anticipated. Economic forecast drivers, including personal income, employment, and industrial output, contribute to growth in the commercial and industrial sector demand forecasts and, to a lesser extent, to growth in the residential sector. Staff uses economic projections prepared by Economy.com and Global Insight to develop these economic forecast drivers. The *2009 IEPR* demand forecast base case relied on Economy.com's June 2009 "most likely" projections, while an "optimistic" case developed by Global Insight was used in the alternative economic scenarios for the 2009 forecast.

Figure 1 and **Figure 2** compare economic projections used in the *2009 IEPR* base forecast with the October 2010 Economy.com[8] "most likely" forecast of employment and state personal income, respectively.[9] The figures clearly indicate a more severe recession in 2009

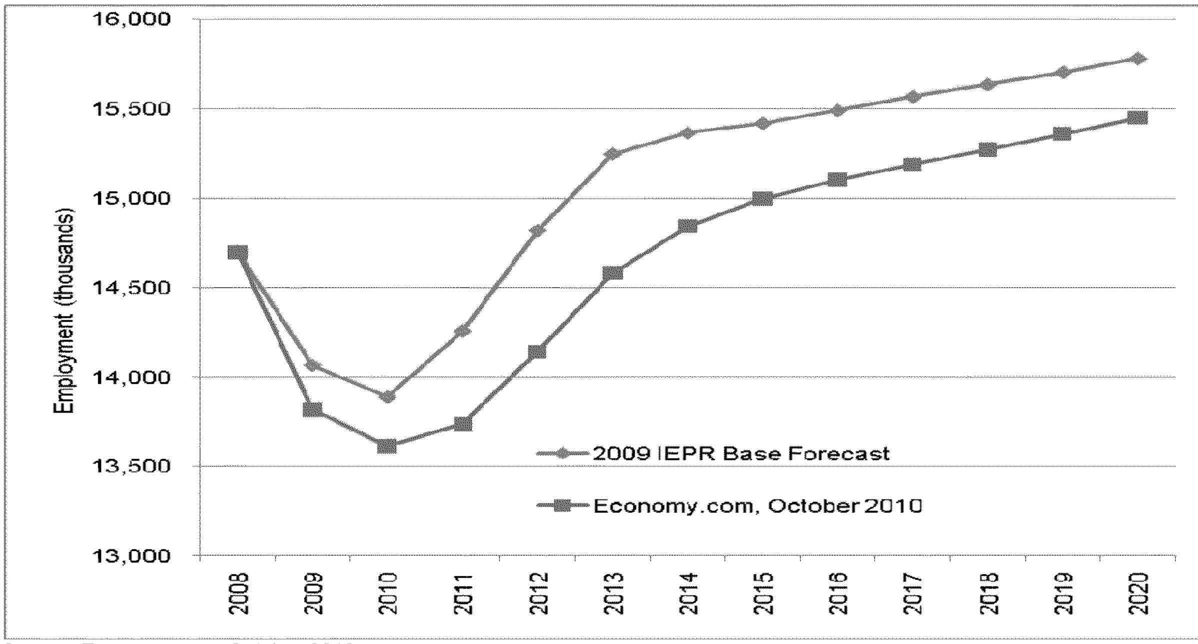
7 Daily weather data is not continuously available for El Cajon, one of the weather stations used for the SDG&E area, before 1979.

8 Since the *2009 IEPR* base forecast (as well as previous forecasts) relied on Economy.com projections, this analysis uses Economy.com as the reference economic forecast. Global Insight also projects significantly lower short-term economic growth compared to 2009 predictions.

9 Employment and personal income represent the two most important economic drivers for the *IEPR* forecasts. For some sectors, gross state product is used rather than personal income, but the two are highly correlated.

than was assumed in the *2009 IEPR* forecast and, in the case of employment, lower projected growth in the short-term (2010-2012). Economy.com (as well as Global Insight) updates its forecast monthly, so final economic projections used by staff in the *2011 IEPR* forecast will likely differ somewhat from this most recent forecast.

Figure 1: Comparison of Total State Employment Projections, *2009 IEPR* Base Forecast and Economy.com, October 2010



Source: Economy.com, October 2010.

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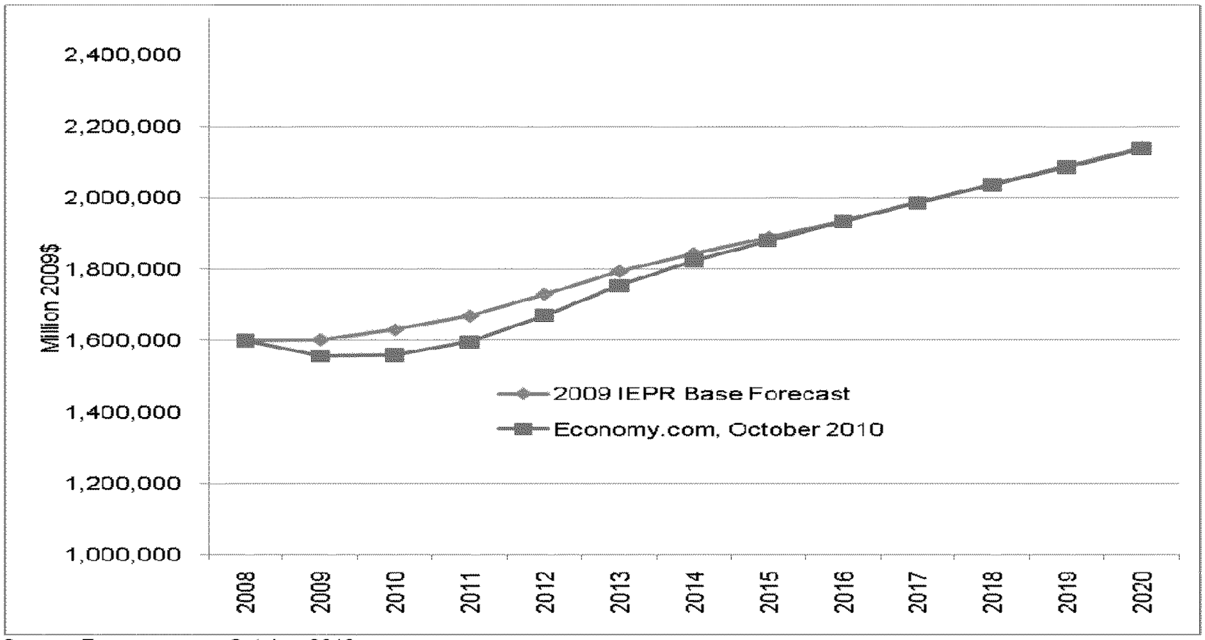
Figure 2: Comparison Total State Personal Income Projections (2009$),
***2009 IEPR* Base Forecast and Economy.com, October 2010**



Source: Economy.com, October 2010.

Staff develops *IEPR* demand forecasts at the planning area level by aggregating county projections from Economy.com. Economic growth forecasts for the IOU planning areas serve as forecasts for the TAC areas.[10] To develop a peak forecast starting from the estimated weather-adjusted peaks for 2010, staff employed a peak demand econometric model estimated for the *2009 IEPR* forecast.[11] Rerunning the full end-use models with updated economic data was not feasible in the time frame available for this analysis. The peak econometric model provides output at the planning area level and includes per capita personal income and the unemployment rate as economic indicators. Staff compared forecast peak demand from this model for 2011 and 2012 using *2009 IEPR* economic assumptions with a forecast using October 2010 Economy.com projections and applied the percentage differences to *2009 IEPR* peak demand forecast growth.[12] Econometric model

10 IOU planning and TAC areas do not match exactly for PG&E and SCE but are close enough so that planning area economic growth rates are an excellent indicator for TAC area growth. In the case of SDG&E, the TAC area is identical to the planning area.

11 *California Energy Demand 2010-2020 Adopted Forecast, Appendix*, pp. A-4 – A-7. Regression results for this model are shown in Appendix B.

12 For example, if peak demand in the econometric model increased by 3 percent for a planning area from 2010 to 2011 using *2009 IEPR* economic assumptions and 2 percent using October 2010 projections, the peak demand growth rate for 2010-2011 would be the *2009 IEPR* growth rate times 2/3.

results were indexed to *2009 IEPR* growth rates since, unlike the *IEPR* forecast, the model does not explicitly incorporate efficiency or self-generation impacts, which are expected to grow significantly (and therefore reduce peak demand) in the 2010-2012 period. **Table 2** compares per-capita income and the unemployment rate assumed in the *2009 IEPR* forecast with the October 2010 Economy.com projections for the three IOU planning areas for 2011 and 2012.

Table 2: Comparison of *2009 IEPR* and October 2010 Economy.com Employment Growth Projections, 2010-2012

Planning Area	Year	Per-Capita Income (2007$), 2009 IEPR Forecast	Per-Capita Income (2007$), Economy.com, October 2010	Unemployment Rate, 2009 IEPR Forecast	Unemployment Rate, Economy.com, October 2010
PG&E	2010	43,805	42,460	13.72%	13.01%
	2011	44,241	42,882	12.33%	13.02%
	2012	45,215	44,274	9.69%	11.38%
SCE	2010	35,832	35,789	13.32%	12.55%
	2011	36,161	36,173	11.99%	12.46%
	2012	36,970	37,400	9.42%	10.89%
SDG&E	2010	43,350	41,865	10.99%	10.68%
	2011	43,900	42,386	10.05%	10.65%
	2012	44,797	43,874	8.20%	9.62%

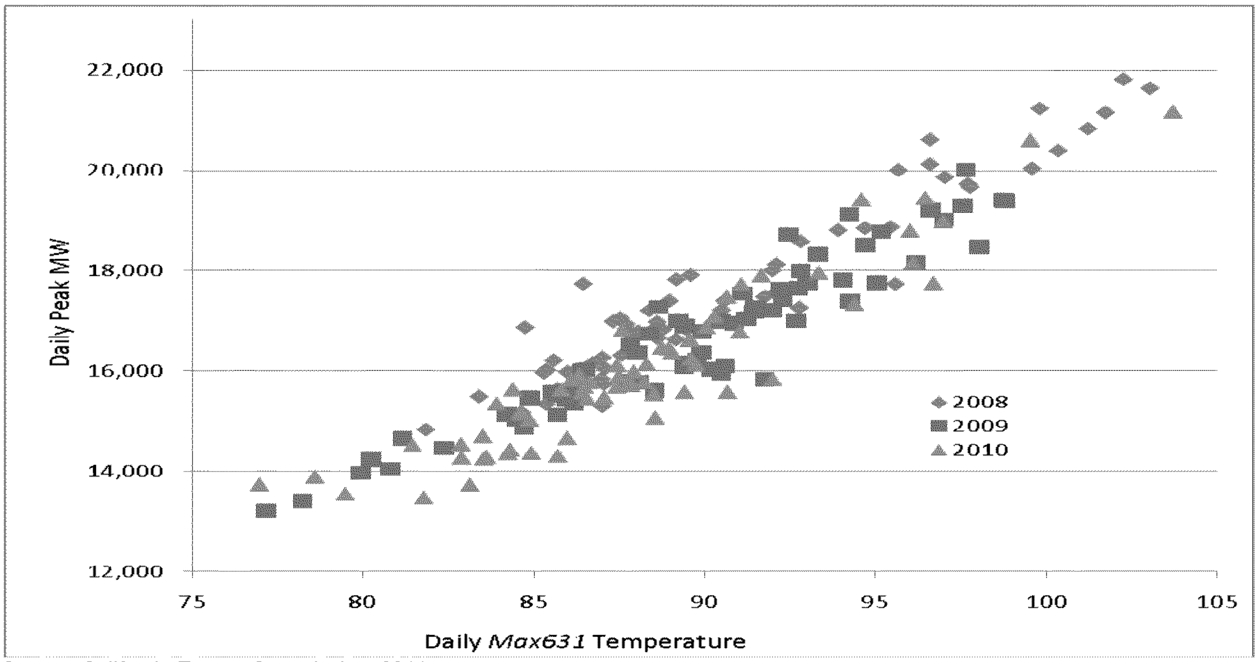
Source: Economy.com, 2009 and 2010.

The increased severity of the recession is most clearly seen in reduced projected personal income for 2010. As discussed in the next chapter, these indicators yield significantly reduced percentage growth in peak demand from 2010 to 2011 compared to the *2009 IEPR* forecast. Peak growth picks up from 2011 to 2012, although remaining slightly below *2009 IEPR* rates for all three planning areas.

CHAPTER 2: Results and Caveats

Figure 3, Figure 4, and **Figure 5** provide a glimpse of the data driving the 2010 weather-adjusted peak results presented in this chapter for PG&E, SCE, and SDG&E, respectively. Clearly, daily afternoon peak demand has fallen on average in 2009 and 2010 as a function of *max631* temperature compared to 2008. The figures show no apparent growth in peak demand from 2009 to 2010; indeed, demand appears to have dropped for SDG&E.

Figure 3: Summer Weekday Afternoon Peak (MW) Versus Daily Max631 Temperature PG&E 2008-2010



Source: California Energy Commission, 2011.

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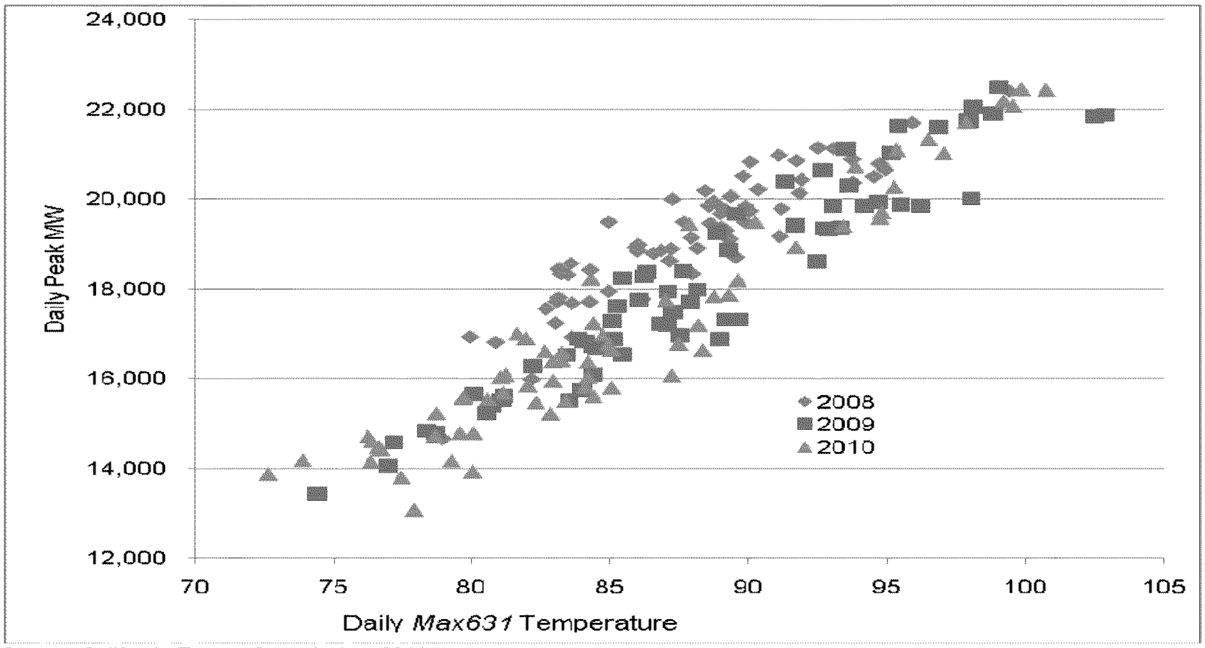
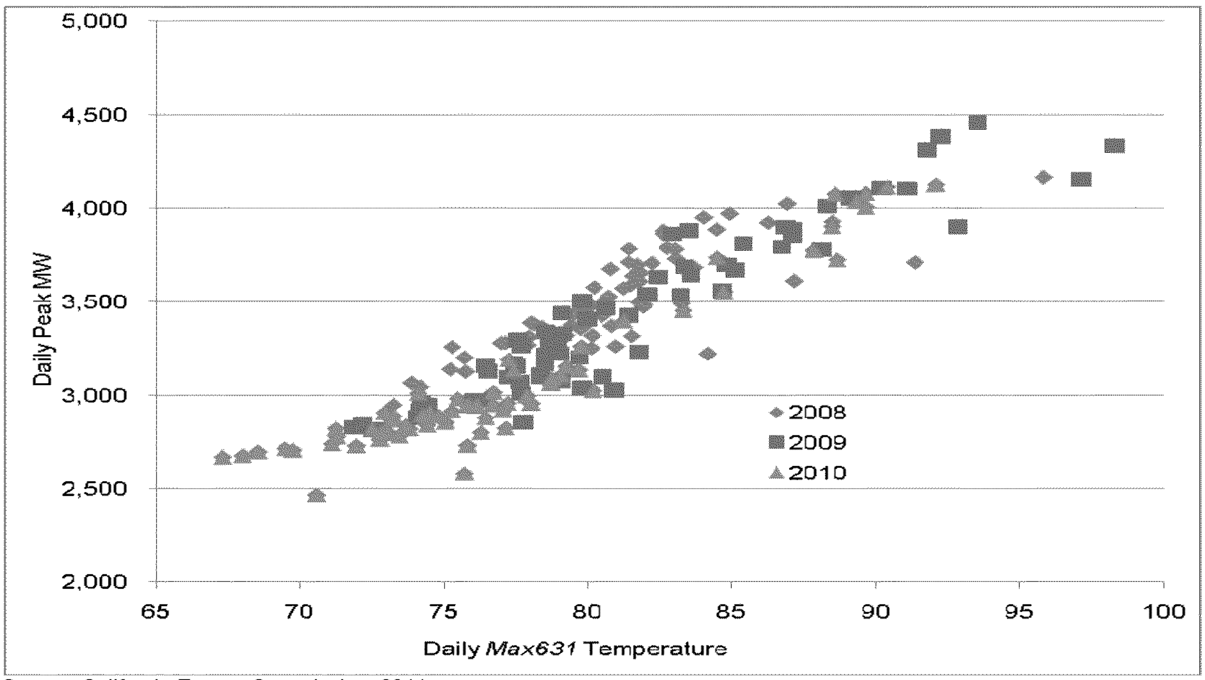
Figure 4: Summer Weekday Afternoon Peak (MW) Versus Daily Max631 Temperature SCE 2008-2010



Source: California Energy Commission, 2011.

Figure 5 Summer Weekday Afternoon Peak (MW) Versus Daily Max631 Temperature SDG&E 2008-2010



Source: California Energy Commission, 2011.

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Weather-Adjusted 2010 Peak Estimates

Table 3 shows the estimated revised 2010 weather-adjusted *1-in-2* and *1-in-10* peaks for each TAC area that resulted from the regression analysis and compares these results to the *2009 IEPR* forecast. In addition to TAC areas, hourly load data was available for the Greater Bay and non-Bay Area portions of PG&E; peak demand (coincident) results are also shown for these two load pockets. Additionally, the table includes coincident totals for the California ISO, calculated by adding the TAC area estimates and multiplying by a coincidence factor.[13]

Table 3: Revised and *2009 IEPR* Weather-Adjusted Peak Demand (MW) by TAC/Load Pocket, 2010

TAC Area/Load Pocket	Revised 1-in- 2 Peak Demand	2009 IEPR 1-in-2 Peak Demand	1-in-2 Difference	Revised 1-in-10 Peak Demand	2009 IEPR 1-in-10 Peak Demand	1-in-10 Difference
PG&E	20,753	21,694	-941	22,268	23,278	-1,010
PG&E Bay Area	8,531	8,675	-144	8,884	9,034	-150
PG&E non-Bay	12,222	13,019	-797	13,384	14,244	-860
SCE	22,720	23,479	-759	24,719	25,545	-826
SDG&E	4,324	4,516	-192	4,756	4,967	-211
California ISO Total Coincident	46,650	48,496	-1,846	50,501	52,499	-1,998

Source: California Energy Commission, 2011.

2011 and 2012 Peak Forecast

For this analysis, staff revised the projected *2009 IEPR* peak growth rates for the IOU planning areas by comparing the output from a peak econometric model with *2009 IEPR* and October 2010 Economy.com economic indicators. **Table 4** shows the results of this adjustment for 2011 and 2012, along with peak growth rates from the *2009 IEPR* and the two econometric model runs. As discussed in Chapter 1, the growth rates from the econometric model runs are higher than for the *2009 IEPR* forecast since the econometric model does not incorporate incremental efficiency and self-generation impacts from 2009 onward.

13 A region's coincident peak is the actual peak for the region while the non-coincident peak is the sum of actual peaks for subregions, which may occur at different times. The coincidence factor is 0.976, an estimate based on staff's review of historical differences between coincident and non-coincident peaks in the California ISO control area. See Appendix A for a discussion of coincidence factors.

Table 4: Adjusted *2009 IEPR* Peak Demand Growth Rates for 2011 and 2012 by Planning Area

Planning Area	Year	2009 IEPR Peak Demand Growth Rate	Econometric Model Growth Rates, 2009 IEPR Economic Data	Econometric Model Growth Rates, October 2010 Economic Data	Adjusted 2009 IEPR Peak Growth Rates
PG&E	2011	1.41%	2.45%	1.53%	0.88%
	2012	1.61%	3.66%	3.31%	1.45%
SCE	2011	1.33%	2.24%	1.48%	0.88%
	2012	1.53%	3.47%	3.12%	1.38%
SDG&E	2011	1.37%	2.00%	1.39%	0.95%
	2012	1.75%	2.80%	2.69%	1.69%

Source: California Energy Commission, 2011.

These growth rates, applied to the 2010 estimates shown in **Table 3**, yield the *1-in-2* and *1 in 10* peak projections, with two additional adjustments. First, water pumping energy use in the SCE and PG&E TAC areas is expected to increase due to a change in regulations.[14] Second, operational constraints on the Banks and South Bay water pumping plants in Northern California may require these facilities to operate at full capacity during peak hours.[15] Therefore, staff increased the *1-in-2* and *1-in-10* forecasts for the California Department of Water Resources in the Bay Area by the difference between estimated peak loads derived from observed data (after incorporating the increase discussed above) and the capacity of the Banks and South Bay plants.[16] **Table 5** shows the results for the TAC areas and major load pockets and compares these projections to *2009 IEPR* forecast totals.

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14 Restrictions on water pumping to California were lifted as of July 2010, based on a federal court decision: http://www.endangeredspecieslawandpolicy.com/uploads/file/09cv407%20Smelt%20(PI%20FOFCOL%20FINAL).pdf The load data for PG&E and SCE show an immediate increase in pumping contribution to peak demand in July 2010. Staff estimated the increase to be 140 MW for PG&E and 157 MW for SCE. These estimated increases were added to the 2011 and 2012 peak forecasts for these two areas.

15 Beginning in July 2007, a series of rulings have been issued that affect the operations of the State Water Project as it relates to exports from the Delta. These rulings specifically limit the ability of DWR to operate the Banks and South Bay pumping plants. The rulings are intended to protect endangered species and over the last few years, the operational criteria have evolved, with the rulings now addressing several fish species. As a result, DWR has fewer windows of time to export water from the Delta and the ability to move stored water through the Delta has shifted from spring into the summer months, when energy demands are the highest. As a result, DWR needs the ability to pump at Banks and South Bay Plants up to full capacity at any time when these constraints are not in effect, including hours of peak electricity demand.

16 This adjustment increased the DWR Bay Area (and therefore the PG&E Bay Area and PG&E total TAC) *1-in-2* and *1-in-10* peak forecasts by 98 MW for 2011 and 2012.

Table 5: Revised and *2009 IEPR* Weather-Adjusted Peak Demand (MW) Forecast by TAC/Load Pocket, 2011 and 2012

TAC Area/Load Pocket	Year	Revised 1-in-2 Peak Demand	2009 IEPR 1-in-2 Peak Demand	1-in-2 Difference	Revised 1-in-10 Peak Demand	2009 IEPR 1-in-10 Peak Demand	1-in-10 Difference
PG&E	2011	21,174	21,988	-814	22,716	23,594	-878
	2012	21,478	22,329	-851	23,033	23,959	-926
PG&E Bay Area	2011	8,870	8,768	102	9,226	9,131	95
	2012	8,995	8,880	115	9,355	9,247	108
PG&E non-Bay	2011	12,304	13,220	-916	13,490	14,463	-973
	2012	12,483	13,449	-966	13,678	14,711	-1,033
SCE	2011	23,077	23,785	-708	25,107	25,878	-771
	2012	23,453	24,142	-689	25,517	26,266	-749
SDG&E	2011	4,365	4,578	-213	4,801	5,036	-235
	2012	4,438	4,658	-220	4,882	5,124	-242
California ISO Total Coincident	2011	47,449	49,143	-1,694	51,361	53,200	-1,839
	2012	48,184	49,902	-1,718	52,150	54,021	-1,871

Source: California Energy Commission, 2011.

Finally, staff broke out individual load-serving entities (in addition to DWR) and load pockets for 2011 and 2012 using the same percentage distributions as in the *2009 IEPR* forecasts, adjusting the LSE entries so relevant sums matched totals for the TAC areas and the two PG&E load pockets. **Table 6** and **Table 7** show the results. North of Path 15 (NP 15), Zone Path 26 (ZP 26), and South of Path 15 (SP 15) are congestion zones as defined by the California ISO.[17] North of Path 26 (NP 26) is the sum of NP 15 and ZP 26 and is the same as the PG&E TAC area. DWR and Metropolitan Water District pumping loads are held constant for 2011 and 2012 across temperature scenarios. Water pumping loads tend not to be sensitive to temperature and economic conditions as is the case for other LSEs—staff therefore assumes no changes in forecast load unless new capacity is added.

17 The full network model map for the California ISO is available at http://www.caiso.com/2827/2827798d2ea50.xls

Table 6: Peak Demand Forecast (MW) by LSE/Load Pocket, Northern California

LSE/Load Pocket	1-in-2 Peak Forecast		1-in-10 Peak Forecast	
	2011	2012	2011	2012
PG&E Service Area - Greater Bay Area	7,730	7,842	8,050	8,166
Silicon Valley Power	488	495	508	515
NCPA - Greater Bay Area	274	278	285	289
Other NP 15 LSEs - Greater Bay Area	5	6	6	6
City/County of San Francisco	109	110	113	115
CA Department of Water Resources – North*	264	264	264	264
Greater Bay Area Subtotal	8,870	8,995	9,226	9,355
PG&E Service Area - Non Bay	9,200	9,337	10,110	10,254
NCPA - Non Bay	203	206	223	226
WAPA	173	176	190	193
Other NP 15 LSEs - Non Bay	146	148	160	163
Total NP 15	18,592	18,862	19,909	20,191
PG&E Service Area, ZP 26	2,267	2,301	2,492	2,527
CA Department of Water Resources, ZP 26	315	315	315	315
Total ZP 26	2,582	2,616	2,807	2,842
Total Non-Bay Area	12,304	12,483	13,490	13,678
Total NP 26 (PG&E TAC)	21,174	21,478	22,716	23,033

*Includes adjustment to address DWR operational concerns regarding the Banks and South Bay water pumping plants. This adjustment increases the DWR-North peak forecast (all entries in this row) by 98 MW.

Source: California Energy Commission, 2011.

Table 7: Peak Demand Forecast (MW) by LSE/Load Pocket, Southern California

LSE/Load Pocket	1-in 2-Peak Forecast		1-in-10 Peak Forecast	
	2011	2012	2011	2012
SCE Service Area - LA Basin	16,080	16,350	17,538	17,833
Anaheim	547	557	597	607
Riverside	580	590	633	644
Vernon	186	189	203	206
Metropolitan Water District	27	27	27	27
Other SP 15 LSEs - LA Basin	260	265	284	289
Pasadena	294	299	321	326
LA Basin Subtotal	17,975	18,276	19,603	19,931
SCE Service Area - Big Creek Ventura	3,897	3,962	4,250	4,322
CA Department of Water Resources-South	406	406	406	406
Big Creek/Ventura Subtotal	4,303	4,368	4,656	4,728
SCE Service Area - Out of Basin	533	542	582	591
Metropolitan Water District	259	259	259	259
Other SP 15 LSEs - Out of Basin	7	7	8	8
Total SCE TAC Area	23,077	23,453	25,107	25,517
SDG&E Service Area	4,365	4,438	4,801	4,882
Total SP 15	27,442	27,891	29,908	30,399

Source: California Energy Commission, 2011.

Caveats

The October 2010 Economy.com economic projections used in this analysis reflect recent information about the likely evolution of this recession, but forecast errors tend to be higher at times of turning points in the economy. Slackness in demand growth during times of recession can quickly be offset when the economy recovers.[18] Therefore, while electricity demand has been flat or declining in 2009 and 2010 as economic conditions deteriorated, a more significant "rebound" is certainly possible for 2011 and 2012 than is assumed in this analysis.

As discussed above, the forecast for 2011 and 2012 relies on an expectation that utility efficiency program and self-generation (particularly photovoltaic system) impacts will increase significantly in these two years, as assumed in the *2009 IEPR* forecast. Without these impacts, and using unadjusted output from the peak econometric model, the *1-in-2* peak forecast for PG&E and SCE would increase by around 500 MW by 2012. Projected 2012 SDG&E peak demand would increase by approximately 50 MW.

In the incremental uncommitted efficiency analysis[19] provided to the CPUC in early 2010 for long-term procurement purposes, staff estimated efficiency peak impacts additional to those estimated in the *2009 IEPR* forecast consistent with the requirement that IOUs make up 50 percent of savings that decay as efficiency measures wear out. The additional impacts are shown in Table 12 of the incremental uncommitted report. These impacts are not included in the results presented in this report—both Energy Commission and CPUC staff acknowledge that decay rates are highly uncertain and require further study. The additional efficiency as estimated would reduce the 2012 peak demand estimates by 117 MW for PG&E, 56 MW for SCE, and 4 MW for SDG&E.

As discussed previously, the forecast results depend to some degree on the historical period used to generate a distribution for peak demand. To account for climate change, a case can be made to use a period beginning more recently. For example, PG&E and SCE typically use a 30-year period for similar analyses. Using a 30-year time frame for this analysis would increase estimated 2010 weather-adjusted demand for SCE by around 90 MW and for PG&E by about 15 MW.

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18 Historically, in years immediately following a recession, annual growth in electricity usage has varied from less than 1 percent per year in the early 1990s to 7 percent in 1984.

19 *Incremental Impacts of Energy Policy Initiatives Relative to the 2009 Integrated Energy Policy Report Adopted Demand Forecast*, California Energy Commission, May 2010. Available at: http://www.energy.ca.gov/2010publications/CEC-200-2010-001/index.html

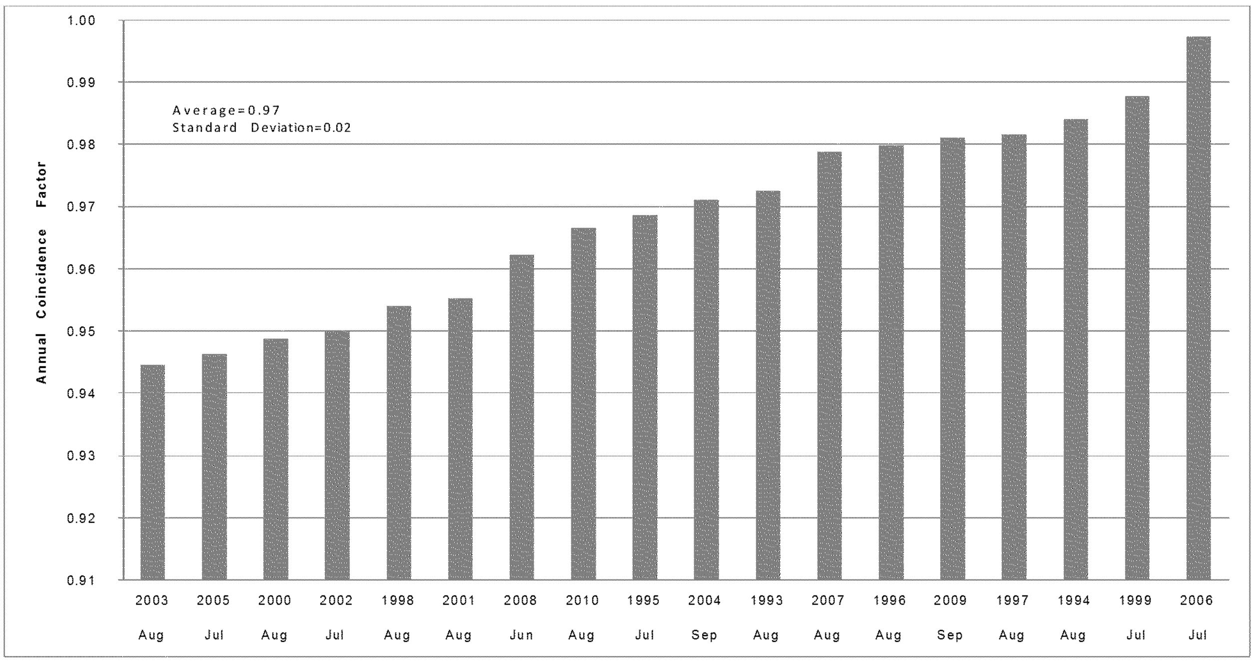
Glossary

2009 IEPR	*2009 Integrated Energy Policy Report*
California ISO	California Independent System Operator
DOF	Department of Finance
DWR	Department of Water Resources
IOU	Investor-Owned Utility
LCR	Local Area Capacity Requirement
LSE	Load-Serving Entity
MW	Megawatt
NP 15	North of Path 15
PG&E	Pacific Gas and Electric
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SP 15	South of Path 15
TAC	Transmission Access Charge
ZP 26	Zone Path 26

APPENDIX A: California ISO Balancing Authority Area Coincidence

The peak demand for each TAC area in the California ISO is the non-coincident annual peak for that area. The peak demand forecast for the California ISO is the sum of the TAC areas (PG&E or NP26, SCE, and SDG&E), adjusted for the expected coincidence of the area peaks. Because each area may experience its peak demand on a different day or hour, the California ISO annual peak will be less than the sum of the individual area peak demands. The annual coincidence factor used in the forecast tables in this report and in the *2009 IEPR* forecast is 0.976, meaning the peak is assumed to be 2.4 percent less than the sum of the non-coincident peaks. This factor was estimated from the historic coincidence patterns between SDG&E, PG&E, and SCE utility areas. **Figure A-1** shows the historical variation in coincidence using Federal Energy Regulatory Commission Form 714 hourly loads for 2003 and California ISO hourly loads for 2004 to 2010.

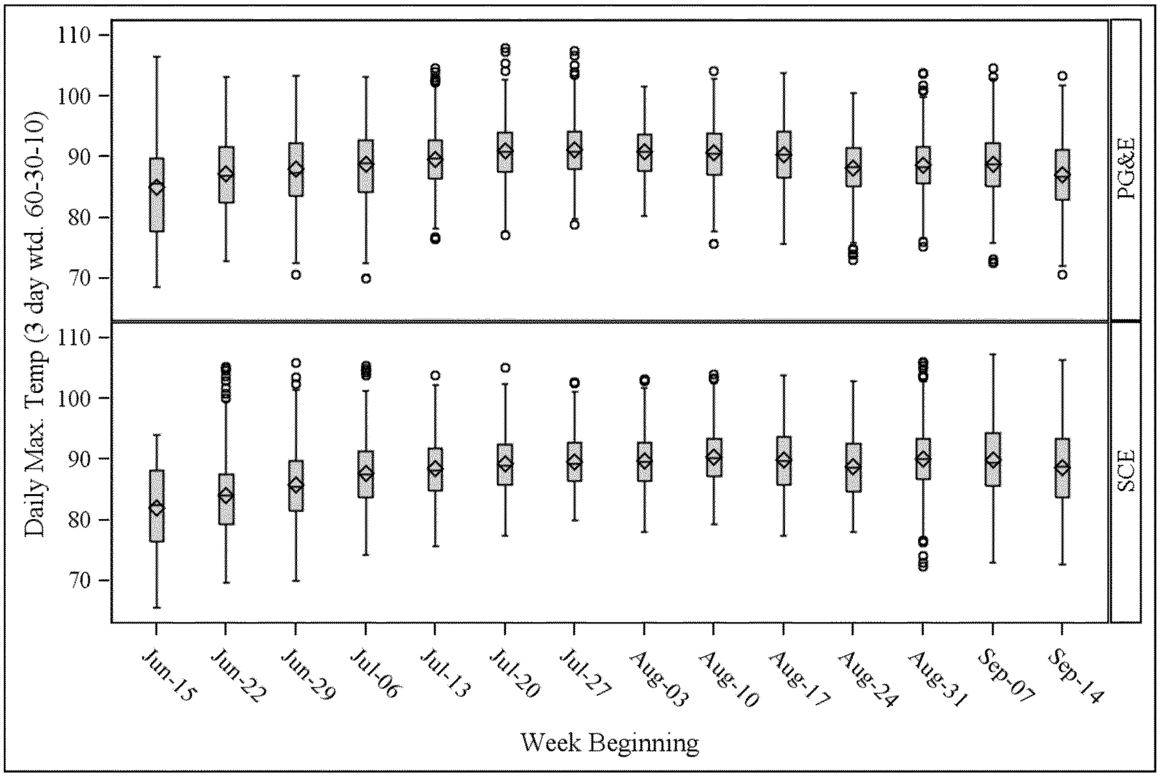
Figure A-1: Historical Coincidence of Annual Peak Loads in the California ISO



Source: California Energy Commission, 2010.

The different weather patterns between Northern and Southern California contribute greatly to this diversity. **Figure A-2** shows the average, 95th confidence interval and outliers of summer weekly temperatures over the last 60 years. Northern California is mostly likely to experience extreme temperatures in late July, when high temperature events in the SCE area are much less common. SCE's hottest days most frequently occur in late August and early September when PG&E experiences declining average temperatures along with some occasional high temperatures. This late summer pattern means the California ISO annual peak is most likely to occur in late summer. Two-thirds of the annual peaks in the last 17 years have occurred in August or September.

Figure A-2: Maximum Weekly Temperatures in Northern and Southern California (1950-2010)



Source: California Energy Commission, 2010.

Given this diversity, what is the expected coincident peak in each area at the time of the California ISO system peak? **Table A-1** shows each area's coincidence factor at the time of the system peak since 2001, where a coincidence factor of 1.0 means the TAC area had its annual peak at the time of the California ISO annual peak. The median coincidence factor for SCE is the highest of the three areas at 0.987, with a factor of 1.0 in five out of the last nine years. This indicates that most of the expected diversity at the time of the system peak is the result of lower loads in NP26, where the median coincidence factor is 0.961.

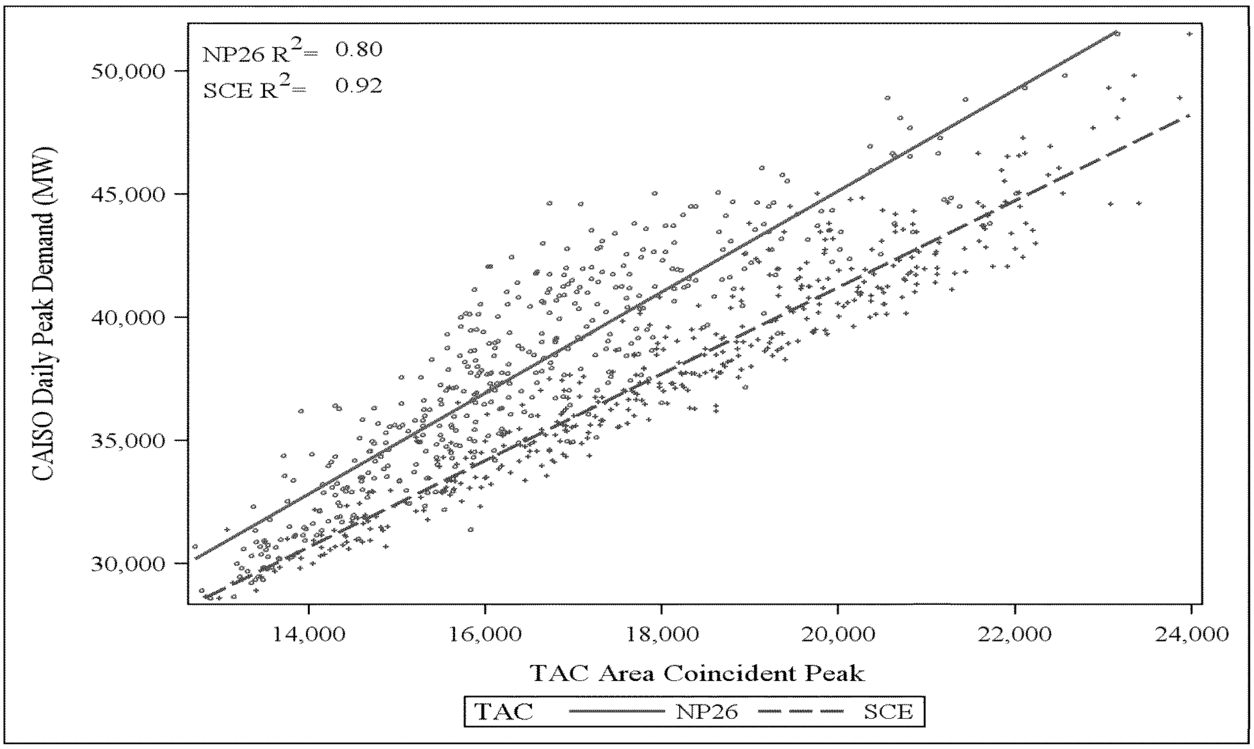
Table A-1: TAC Area Coincidence Factor at Time of California ISO Annual Peak Demand

Year	NP26	SCE	SDG&E
2001	0.922	1.000	0.915
2002	0.971	0.975	0.738
2003	0.966	0.922	0.836
2004	0.985	0.968	0.924
2005	0.954	0.951	0.883
2006	0.999	1.000	0.978
2007	0.956	1.000	0.977
2008	0.925	1.000	0.958
2009	0.956	1.000	1.000
2010	0.999	0.957	0.868
Average	0.963	0.977	0.908
Median	0.961	0.987	0.920

Source: California Energy Commission, 2010.

Figure A-3 illustrates the relatively stronger correlation between SCE loads and the California ISO peak, compared to NP 26 loads. This figure shows California ISO summer weekday daily peaks and SCE and NP 26 area coincident peaks since 2006. While SCE loads rise linearly with the California ISO peak, NP 26 loads show a correlation of about 10 percent less; the California ISO peak is most strongly driven by SCE area loads, and therefore the SCE peak is more coincident.

Figure A-3: California ISO Summer Daily Peaks and TAC Area Coincident Peaks (2006-2010)



Source: California Energy Commission, 2010.

APPENDIX B: Regression Results

Table B-1: Regression Results for Total PG&E TAC

Variable	Estimated Coefficient	Standard Error	t-statistic
Max631	0.01947	0.00141	13.84
Minimum Temperature	-0.00070	0.00201	-0.35
Dummy Constant: Weekend	-0.08128	0.00637	-12.76
Constant	8.00168	0.08396	95.30
Adjusted for autocorrelation: rho = 0.609, Durbin-Watson statistic = 1.565 R- Squared = 0.908 Dependent variable = natural log of daily afternoon peak, June 15 - September 15, 2010			

Source: California Energy Commission, 2010.

Table B-2: Regression Results for PG&E Greater Bay Area

Variable	Estimated Coefficient	Standard Error	t-statistic
Max631	0.0134	0.0009	15.36
Minimum Temperature	0.0046	0.0017	2.70
Dummy Constant: Weekend	-0.1226	0.0064	-19.25
Constant	7.4706	0.0853	87.63
Adjusted for autocorrelation: rho = 0.581, Durbin-Watson statistic = 1.750 R- Squared = 0.904 Dependent variable = natural log of daily afternoon peak, June 15 - September 15, 2010			

Source: California Energy Commission, 2010.

Table B-3: Regression Results for PG&E Non-Bay Area, Includes Pumping

Variable	Estimated Coefficient	Standard Error	t-statistic
Max631	0.0197	0.0018	10.80
Minimum Temperature	-0.0008	0.0022	-0.35
Dummy Constant: Weekend	-0.0624	0.0085	-7.33
Constant	7.3659	0.1023	71.98
Adjusted for autocorrelation: rho = 0.595, Durbin-Watson statistic = 1.482 R- Squared = 0.874 Dependent variable = natural log of daily afternoon peak, June 15 - September 15, 2010			

Source: California Energy Commission, 2010.

Table B-4: Regression Results for PG&E Non-Bay Area, Excludes Pumping

Variable	Estimated Coefficient	Standard Error	t-statistic
Max631	0.0204	0.0018	11.18
Minimum Temperature	0.0003	0.0022	0.14
Dummy Constant: Weekend	-0.0646	0.0087	-7.41
Constant	7.1869	0.1001	71.78
Adjusted for autocorrelation: rho = 0.542, Durbin-Watson statistic = 1.570 R- Squared = 0.896 Dependent variable = natural log of daily afternoon peak, June 15 - September 15, 2010			

Source: California Energy Commission, 2010.

Table B-5: Regression Results for SCE

Variable	Estimated Coefficient	Standard Error	t-statistic
Max631	276.43	15.24	18.13
Minimum Temperature	151.64	27.04	5.61
Dummy Constant: Weekend	-2017	100.60	-20.05
Constant	-15789	1273	-12.41
Adjusted for autocorrelation: rho = 0.513, Durbin-Watson statistic = 1.846 R- Squared = 0.937 Dependent variable = daily afternoon peak, June 15 - September 15, 2010			

Source: California Energy Commission, 2011.

Table B-6: Regression Results for SDG&E

Variable	Estimated Coefficient	Standard Error	t-statistic
Max631<=75 degrees	32.88	6.74	4.88
75<Max631<=80	40.06	7.50	5.34
80<Max631<=85	88.00	9.20	9.56
Max631>85	73.02	9.27	7.88
Minimum Temperature	12.65	3.93	3.22
Dummy Constant: Weekend	-374.45	17.33	-21.61
Constant	-321.54	581.32	-0.55
Adjusted for autocorrelation: rho = 0.402, Durbin-Watson statistic = 2.054 R- Squared = 0.958 Dependent variable = daily afternoon peak, June 15 - September 15, 2010			

Source: California Energy Commission, 2011.

Table B-7: Peak Demand Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Natural Log (max631)	0.4710	0.0795	5.93
Per capita income (07$)	0.0070	0.0012	5.92
Unemployment rate	-0.0064	0.0014	-4.51
Avg. residential electricity rate (07$)	-0.0033	0.0017	-1.94
Avg. commercial electricity rate (07$)	-0.0026	0.0013	-1.97
Dummy: 2001	-0.0960	0.0177	-5.42
Dummy: 2002	-0.0625	0.0176	-3.55
Constant: Burbank/Glendale	-0.1113	0.0093	-11.99
Constant: IID	0.3591	0.0186	19.29
Constant: LADWP	-0.3426	0.0146	-23.51
Constant: PASD	-0.0594	0.0252	-2.36
Constant: PG&E	-0.2552	0.0137	-18.65
Constant: SCE	-0.2852	0.0132	-21.66
Constant: SDG&E	-0.5291	0.0272	-19.42
Overall constant	-1.5683	0.3693	-4.25
Adjusted for autocorrelation and cross-sectional correlation Wald chi squared = 4,463 Dependent variable = natural log of annual peak per capita, 1980-2008			

Source: California Energy Commission, 2009.