STATE OF CALIFORNIA — THE RESOURCES AGENCY ARNOLD SCHWARZENEGGER, Governor

CALIFORNIA ENERGY COMMISSION
1516 Ninth Street
Sacramento, California 95814

Main website: www.energy.ca.gov

Notice of Electricity Committee Workshop on Summer 2008 Supply and Demand Outlook

The California Energy Commission's (Energy Commission) Electricity Committee (the Committee) will conduct a workshop to obtain comments on assumptions, methodologies and results in the staff 2008 Supply and Demand Outlook. Commissioner Jeffrey D. Byron is the Presiding Member, and Commissioner John L. Geesman is the Associate Member of the Committee. Other Commissioners may attend and participate in the workshop. The workshop will be held:

WEDNESDAY, JANUARY 16, 2008
1:00 p.m.
CALIFORNIA ENERGY COMMISSION
1516 Ninth Street
First Floor, Hearing Room A
Sacramento, California
(Wheelchair Accessible)

Audio from this meeting will be broadcast over the Internet.
For details, please go to:
www.energy.ca.gov/webcast

To participate in the meeting by phone,
please call (888) 495-9739 by 1:00 p.m.
Passcode: SUMMER Call Leader: DENNY BROWN

Purpose

The Committee requests comments on the Summer 2008 Electricity Supply and Demand Outlook (Summer Outlook). Preliminary results and a staff paper summarizing changes in the Summer Outlook since 2007 will be presented at the workshop. To provide a useful, relevant, and comprehensive assessment, the Committee seeks the participation of the state's major utilities, system operators, hydro-electric system operators, generators and other interested parties in this process. The Committee is also requesting input from stakeholders on the impact of possible dry hydro conditions on the ability of the electricity system to meet peak load conditions. Finally, the Committee would like to hear comments from utilities on how Demand Response and Interruptible Load programs are utilized during periods of high demand or unusual resource limitations.

Background

The Summer 2008 Electricity Supply and Demand Outlook is the Energy Commission staffs current assessment of the overall capability of the physical electricity system to provide power to meet electricity demand in four regions - California Statewide, California Independent System Operator (CA ISO) Control Area, CA ISO North of Path 26 (NP 26), and CA ISO South of Path 26 (SP 26).

Staff is including a probabilistic assessment to enhance the deterministic tables we have historically provided. This probabilistic assessment evaluates the complete range of possible demand scenarios, generation and transmission forced outage occurrences, and the possibility of three adverse conditions occurring simultaneously.

Stakeholder input to the staff hydro assumptions is strongly encouraged and welcomed. The staff hydro assumptions are based on the premise that dependable hydro capacity during peak periods does not significantly change between a wet and a dry water year, even though the historic record shows that dry conditions can have a significant impact on available energy production. The estimate of dependable hydro capacity that the staff uses is based on low water year conditions and would only be revised slightly upward in an extremely wet year to account for additional run-of-river capacity that could be produced in June and early July by additional runoff.

Workshop Participation and Comments

The Committee requests the participation of interested parties in this workshop and encourages interested parties to present their views either orally at the workshop or through written comments. The Committee will take general comment from the public immediately following the workshop presentations.

Parties should provide comments regarding the preliminary Summer Outlook, both orally at the workshop and in writing. Proposals or other written comments to be considered after the workshop must be submitted by 5:00 p.m. on January 18,2008. For written comments on the Summer Outlook, include the docket ***No. 08-SDO-1*** and indicate ***2008 - Supply Demand Outlook*** in the subject line or first paragraph of your comments. Please send your comments in writing to:

California Energy Commission
Dockets Office, MS-4
Re: Docket No. ***No. 08-SDO-1***
1516 Ninth Street
Sacramento, CA 95814-5512

The Energy Commission encourages comments by e-mail. Please include your name or organization in the name of the file. Those submitting comments by electronic mail should provide them in either Microsoft Word format or as a Portable Document File (PDF) to [docket@energy.state.ca.us].

AGENDA

Electricity Committee Workshop on the Summer 2008 Supply and Demand Outlook

(Docket No. 08-SDO-I)

WEDNESDAY, JANUARY 16, 2008 – 1:00 p.m.
California Energy Commission
1516 9th Street, Hearing Room A
Sacramento, California 95814

Phone Line for Call-in
(888) 495-9739 by 1:00 p.m.
Passcode: SUMMER
Call Leader: DENNY BROWN

1. Opening Comments
   Commissioner Jeffrey D. Byron
   Commissioner John L. Geesman

2. Summer 2008 Electricity Supply and Demand Outlook
   Denny Brown, Electricity Analysis Office
   Stakeholder Comments:
      Robin Smutny-Jones, California Independent System Operator

3. Peak Demand Overview
   Lynn Marshall, Demand Analysis Office

4. Demand Response and Interruptible Load Programs
   David Hungerford, Demand Analysis Office
   Stakeholder Comments:
      Robin Smutny-Jones, California Independent System Operator
      Utility Representatives

5. Dependable Hydro Capacity
   Jim Woodward, Electricity Analysis Office
   Stakeholder Comments:
      Hydro-generation System Operators

6. Public Comments

Participants may also provide an original and 10 copies at the beginning of the workshop. All written materials relating to this workshop will be filed with the Dockets Unit and become part of the public record in this proceeding.

Public Participation

The Energy Commission's Public Adviser's Office provides the public assistance in participating in Energy Commission activities. If you want information on how to participate in this forum, please contact the Public Adviser's Office at: (916) 654-4489 or toll free at (800) 822-6228, by FAX at (916) 654-4493, or by e-mail at [pao@energy.state.ca.us]. If you have a disability and require assistance to participate, please contact Lou Quiroz at (916) 654-5146 at least five days in advance.

Please direct all news media to Claudia Chandler, Assistant Executive Director, at (916) 654-4989, or by e-mail at [mediaoffice@energy.state.ca.us]. For technical questions regarding the Summer 2008 Electricity Supply and Demand Outlook, please contact Denny Brown at (916) 654-4829, or by e-mail at [dbrown@energy.state.ca.us].

Date: January 2, 2008

Jeff Byron
JEFFREY D. BYRON
Commissioner and Presiding Member
Electricity Committee

JOHN L. GEESMAN
Commissioner and Associate Member
Electricity Committee

Note: California Energy Commission's formal name is State Energy Resources Conservation and Development Commission.

Summer 2008 Electricity Supply and Demand Outlook Workshop

January 16,2008

Workshop Topics

- Summer 2008 Supply and Demand Outlook
- Peak Demand Overview
- Demand Response and Interruptible Load Programs
- Impact of Hydro Conditions on Capacity

Purpose of 2008 Supply and Demand Outlook Workshop

- Get stakeholder comments prior to presenting the Governor and Legislature
- Request input on impact of dry hydro conditions on capacity
- Hear comments on how Demand Response and Interruptible Load Programs are utilized

Summer 2008 Electricity Supply and Demand Outlook

January 16, 2008

Denny Brown

Electricity Generation Systems Specialist II

Electricity Analysis Office

Overview

- Changes from 2007 Report
- Planning Reserve Margins
- Cumulative Probability Distribution
- Detailed Assumption Data

Changes from 2007 Outlook

- Basic methodology is the same
- Updated values to reflect 2008 data
- Relocated Calpine Sutter from SMUD Control Area to CA ISO
- Reduced WAPA CVP Imports by 250 MW to reflect CVP capacity used to meet internal load

Summer 2008 Electricity Outlooks

- Forecast planning reserve margins
  - Statewide, California ISO, NP26 and SP26

- Probabilistic analysis
  - California ISO, NP26 and SP26
  - Statewide assessment not conducted

2008 California Electricity Supply and Demand Outlook

(Megawatts)

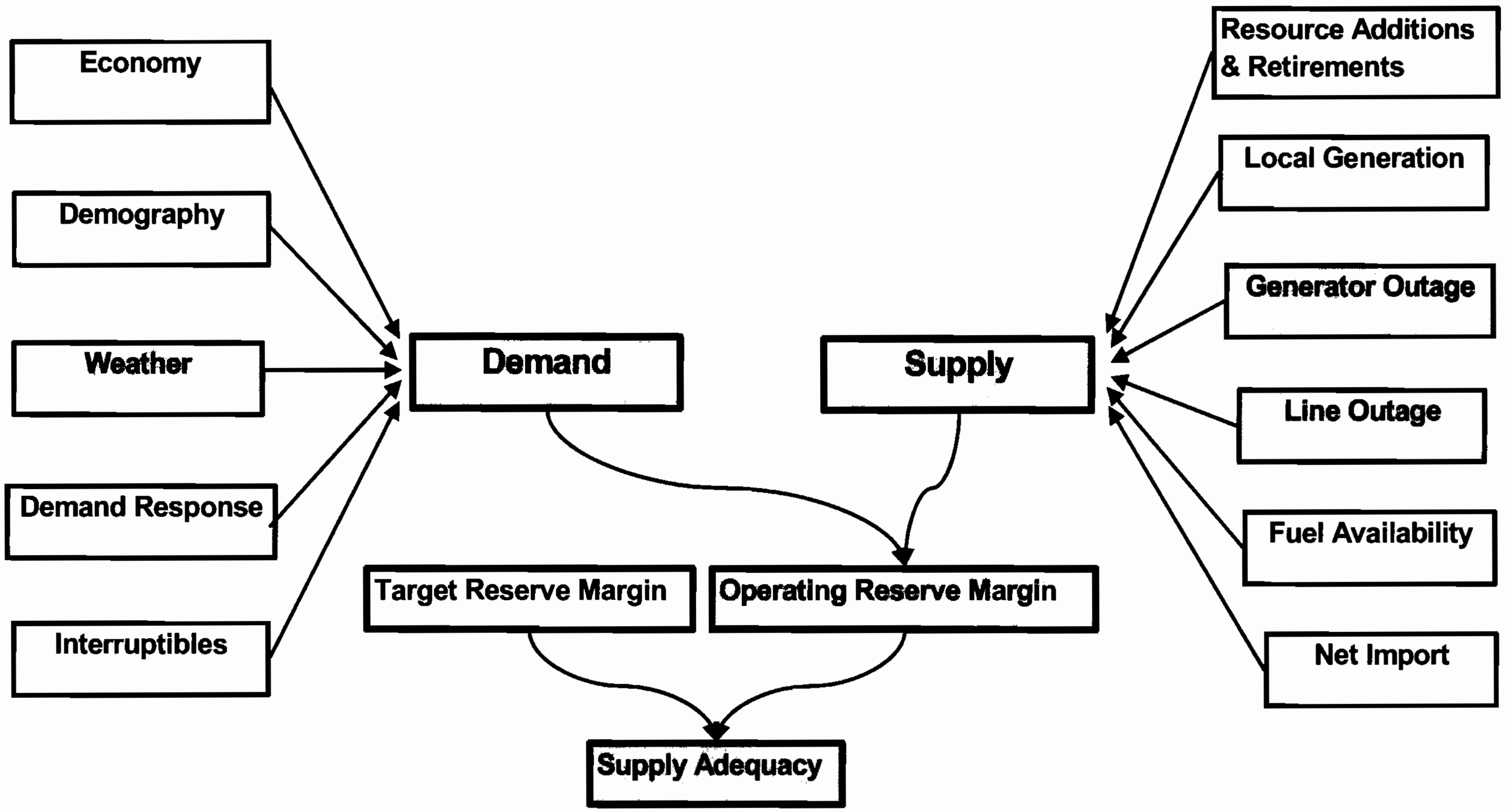
(Staff Draft)

Resource Adequacy Planning Conventions	NP 26	SP 26	CA ISO	Statewide
1 Existing Generation	25,039	22,277	47,316	58,553
2 Retirements (Known)	0	0	0	0
3 High Probability CA Additions	0	935	935	1,013
4 Net Interchange *	250	10,100	10,350	13,118
5 Total Net Generation (MW)	25,289	33,312	58,601	72,684
6 1-in-2 Summer Temperature Demand (Average)	21,671	28,604	49,071	61,439
7 Demand Response (DR)	458	186	644	644
8 Interruptible/Curtailable Programs	427	1,105	1,532	1,732
9 **Planning Reserve**	**20.8%**	**21.0%**	**23.9%**	**22.2%**

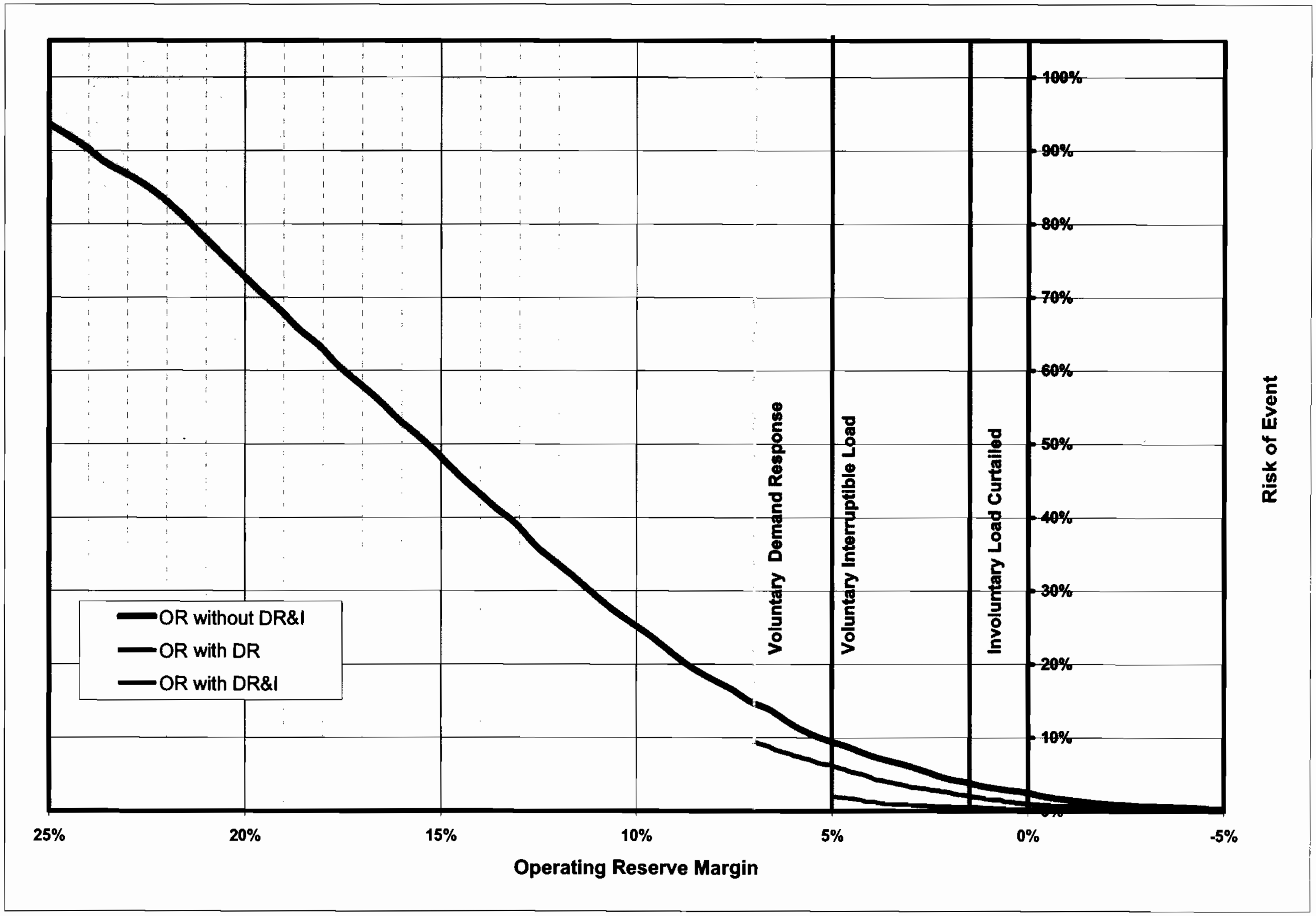
Probability of Peak Day Event	NP 26	SP 26	CA ISO
Probability of Involuntary Firm Load Curtailments (Stage 3)	0.7%	1.6%	0.6%

* Outlook assumes 3,000 MW flowing North to South on Path 26 at time of peak. This flow could flow South to North, if needed. As SP 26 improves planning reserve margins above NP 26, this assumption should be reduced to a level necessary to balance the planning reserve margins in both regions.

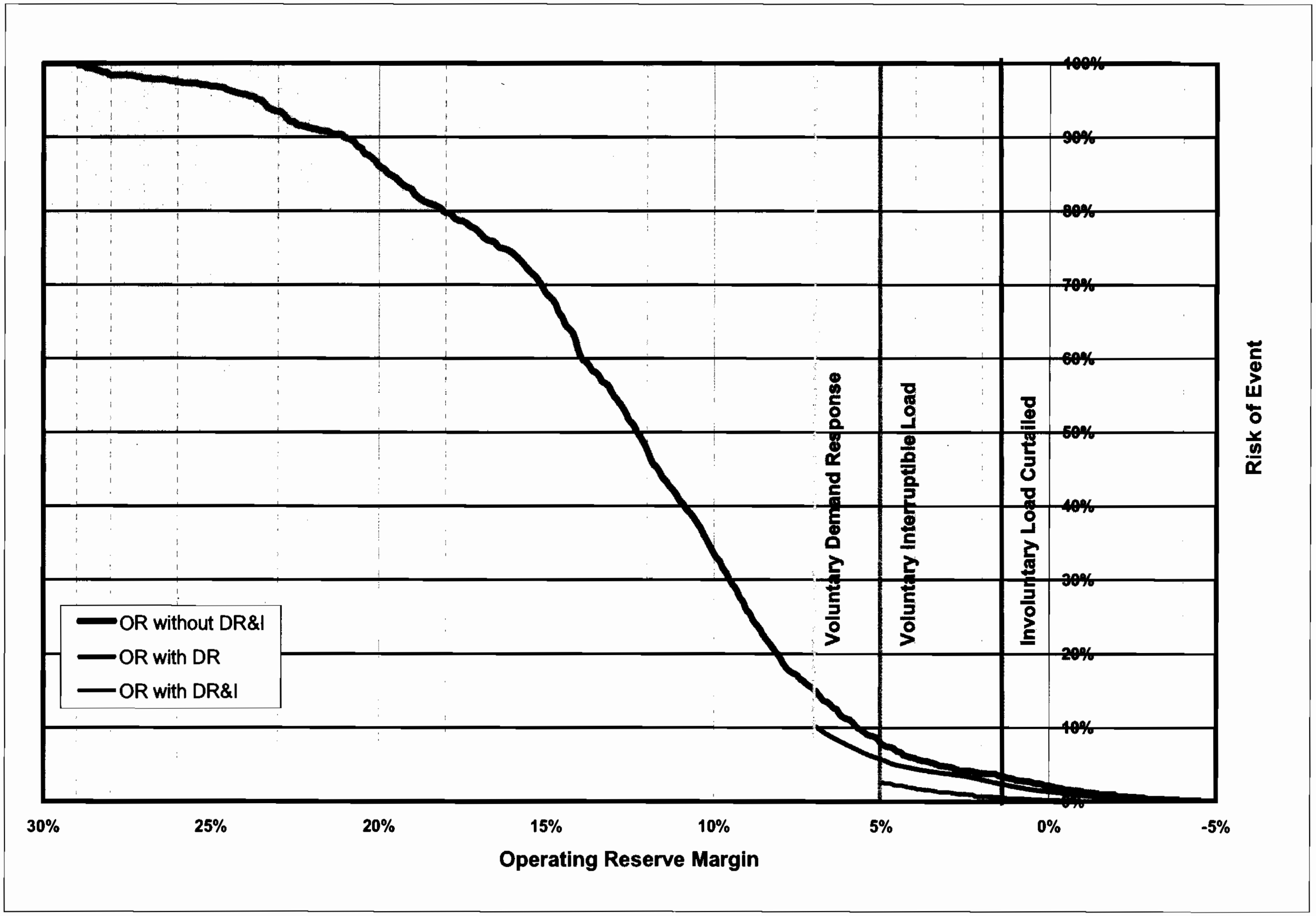
Major Factors Affecting Supply Adequacy



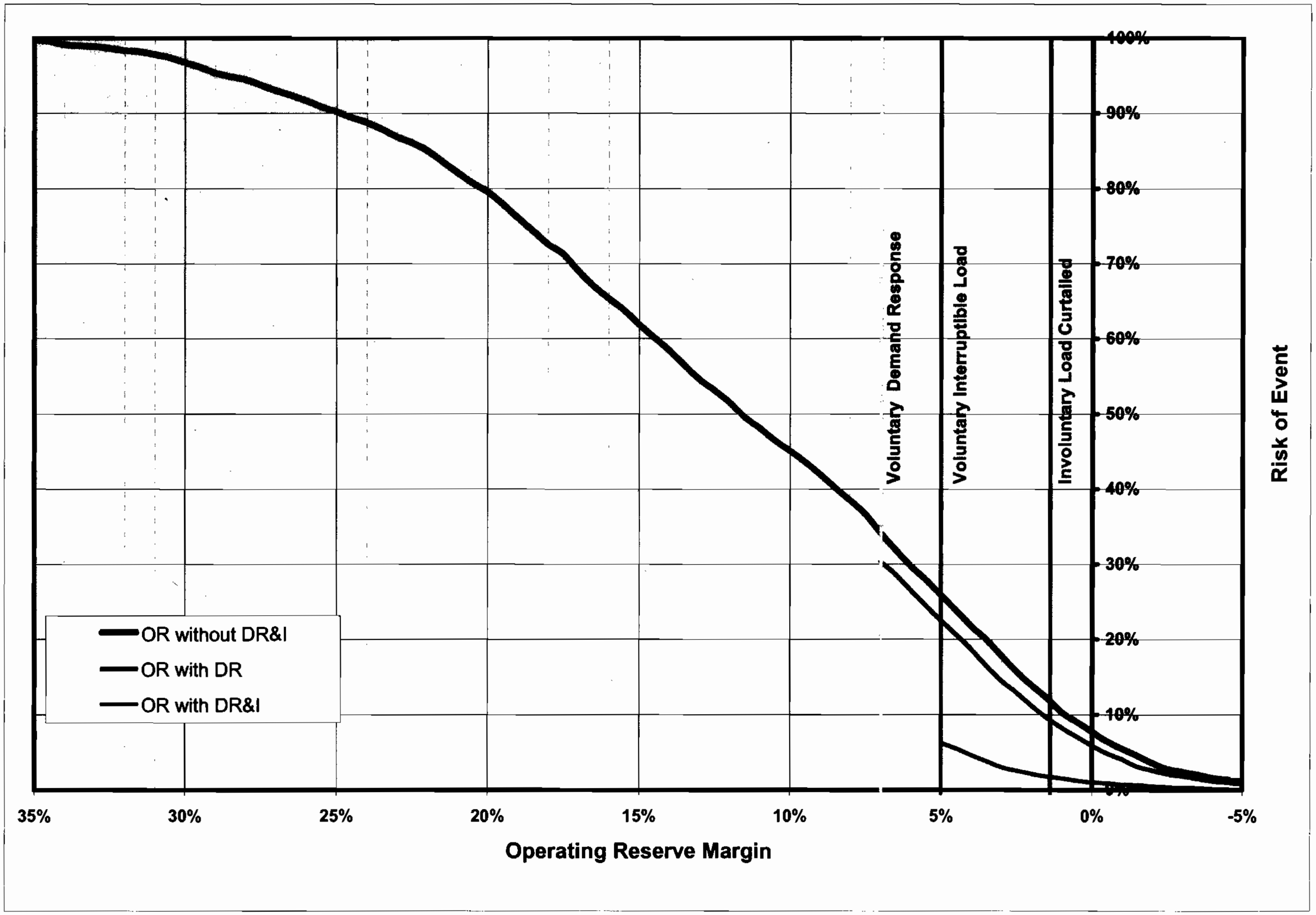
Risk of Event
California ISO – Summer 2008



Risk of Event
NP 26 – Summer 2008



Risk of Event
SP26 – Summer 2008



Existing Generation

	SP26	NP26	TOTAL
CA ISO Control Area			
Merchant Thermal & QF	17,049	16,525	33,574
Municipal Thermal	751	182	933
IOU Retained Thermal	3,430	2,393	5,823
Derated Hydro	1,047	5,939	6,986
TOTAL CA ISO	**22,277**	**25,039**	**47,316**
Non-CA ISO	6,523	4,714	11,237
STATEWIDE TOTAL			**58,553**

- As of August 1, 2007
- Non-CA ISO includes thermal and hydro

2008 Additions

CA ISO Control Area					
SP26			**NP26**		
Additions			**Additions**		
Name	**MW**	**Expected**	**Name**	**MW**	**Expected**
SCE Oxnard	44	Jun-08			
J Power Pala	82	Jun-08			
Wellhead Margarita	44	Jul-08			
Inland Empire	765	Jun-08			
	935				

Non-CA ISO Control Areas					
LADWP & IID Control Areas			**SMUD & TID Control Areas**		
Additions			**Additions**		
Name	**MW**	**Expected**	**Name**	**MW**	**Expected**
Niland Peaker	**78**	Jun-08			

Net Interchange

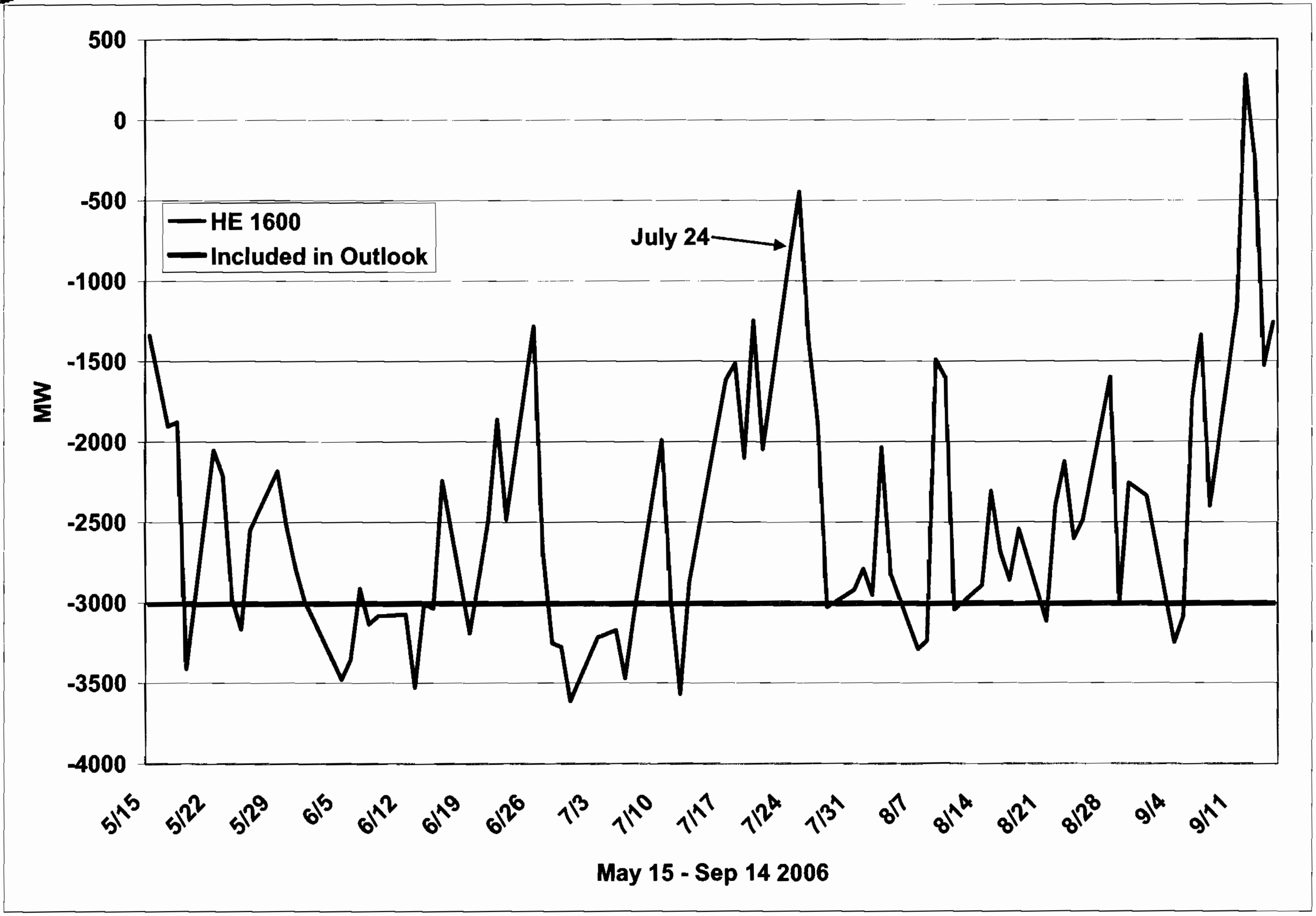
Statewide	
Northwest Imports	4,000
Southwest Imports	4,100
Pacific DC Intertie (California ISO)	2,000
LADWP and IID Control Areas	3,018
Total	**13,118**

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

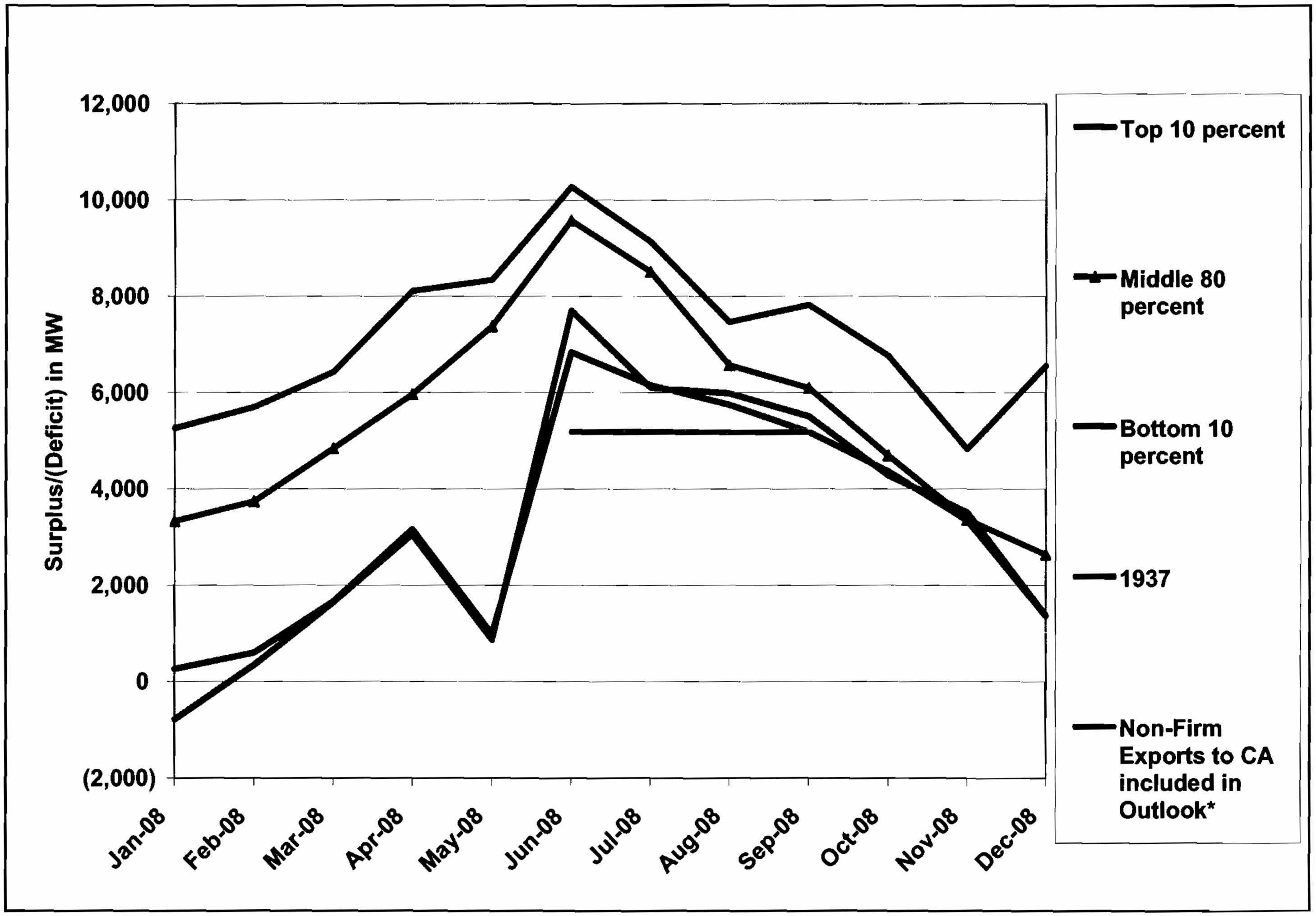
NP26	
California ISO Share of NW Imports	2,300
WAPA Central Valley Imports	950
Path 26 Exports	(3,000)
Total	**250**

SP26	
Path 26	3,000
Southwest Imports	4,100
Pacific DC Intertie (California ISO)	2,000
Net LADWP Control Area (Wheeled)	1,000
Total	**10,100**

Summer 2006 Path 26 Net Flows



BPA Forecast Regional 2008 Surplus/(Deficit) by Water Year



Source: 2006 Pacific Northwest Loads and Resource Study Technical Appendix Vol 2, Section 10 & 12

Demand Response and Interruptible Load Programs

Demand Response Programs		**Expected**	
	SCE	**SDG&E**	**PG&E**
CPP Programs	3	15.0	48.0
DBP	34	6	55
CBP	75	23	27
CAL-DRP/Spec Contracts	10		308
CI 20/20 or BEC		20	20
Demand Response Sub-Total	**122**	**64**	**458**
Interrruptible Load Programs			
I-6 or E-19/E-20			
AL TOU CP			
BIP	476	5	288
ACCP	562	25	96
OBMC/RBRP	3		13
AP-I/Emergency CCP/NF	21	3	30
Clean Gen/Peak Gen		10	
Special Contracts			
Interruptible Sub-Total	**1062**	**43**	**427**
Total	**1184**	**107**	**885**

Summer 2008 Electricity Supply and Demand Outlook:

Demand Forecast and Preliminary Summer 2007 Temperature-Load Assessment

January 16, 2008

Lynn Marshall

Demand Analysis Office

Introduction

- The forecast used for this supply demand outlook is the *California Energy Demand 2008 - 2018: Staff Revised Forecast*, publication # CEC-200-2007-015-SF2.(Nov. 2007)
- That forecast incorporates analysis of 2006 load and temperatures from *Staff Forecast of 2008 Peak Demand*, publication # CEC-200-2007-006-SF. (June 2007)
- Today we present a preliminary assessment of 2007 loads and temperatures in the CAISO Control Area.
- Staff will prepare a similar analysis for individual LSEs and other control areas as more detailed load data becomes available.

Comparison of Forecasted, Actual and Weather-Adjusted Peak Demand

(MW)

		2007 Forecast	2007 Actual	2007 Weather-Adjusted (preliminary)	2008 Forecast
Total NP15		21,406	21,300	21,314	21,671
	SCE Transmission Area	23,638	23,832	23,321	24,035
	San Diego Gas & Electric	4,506	4,601		4,568
Total SP 15		28,144	28,433		28,604
CAISO Noncoinc. peak			49,733		
CAISO Coincident Demand		48,363	48,615	48,911	49,071
Turlock Irrigation District Control Area		554	604		563
SMUD Control Area		4,665	4,673*		4,727
LADWP Control Area		6,285	6,738		6,317
Imperial Irrigation District Control Area		1,032	995*		1,063
Statewide Noncoincident Demand		62,085	62,743		62,946
Statewide Coincident Demand		60,599	NA		61,439

*Preliminary data - not yet confirmed.

2007 Loads and Temperatures

CAISO Results

- 2007 daily peaks were consistent with what staff's estimates temperature-load response would predict, given observed temperatures and forecasted growth.
- Weather adjusted 2006/2007 CAISO growth in peak demand was 1.5%. Forecasted growth was 1.42%, or 730 MW.
- Summer 2007 hot spells centered around holiday periods (July 4th and Labor Day); the remainder of the summer was relatively mild.
- 2007 CAISO peak was driven by hot temperatures in southern California.

NP15 Results

- Estimated 2007 peak is within ½ percent of forecast. Estimated 2006/2007 weather-adjusted load growth is 1.3 percent (240 MW), the same as the forecast growth rate.
- These loads include PG&E, northern California POUs and other LSEs, and DWR north.
- DWR North load curtailments are reported by PG&E.

SCE Area Loads

- The estimate of weather adjusted 2007 peak is 300 MW below our forecast for 2007, but this reflects lower DWR loads than projected. The staff forecast assumes average hydro condtions.
- Adjusting for actual pumping load, the weather-adjusted peak is with ½ percent of the staff forecast.

Weather Normalization Methodology

- Staff uses hourly load data, reported curtailed load summer afternoon weekday peak and temperature to estimated peak demand as a function of temperature:

Predicted MW =

a +b*(Lagged Daily Max. Temp.) +c*(Temp. Spread)

- Load data are CAISO EMS hourly loads for NP15, SCE transmission area, and SDG&E area.
- Temperature data is from National Weather Service (NWS) sites for PG&E and SCE.
- Demand response and interruptible impacts from IOU monthly reports.

STATE OF CALIFORNIA ENERGY COMMISSION

Weather Variable Definitions

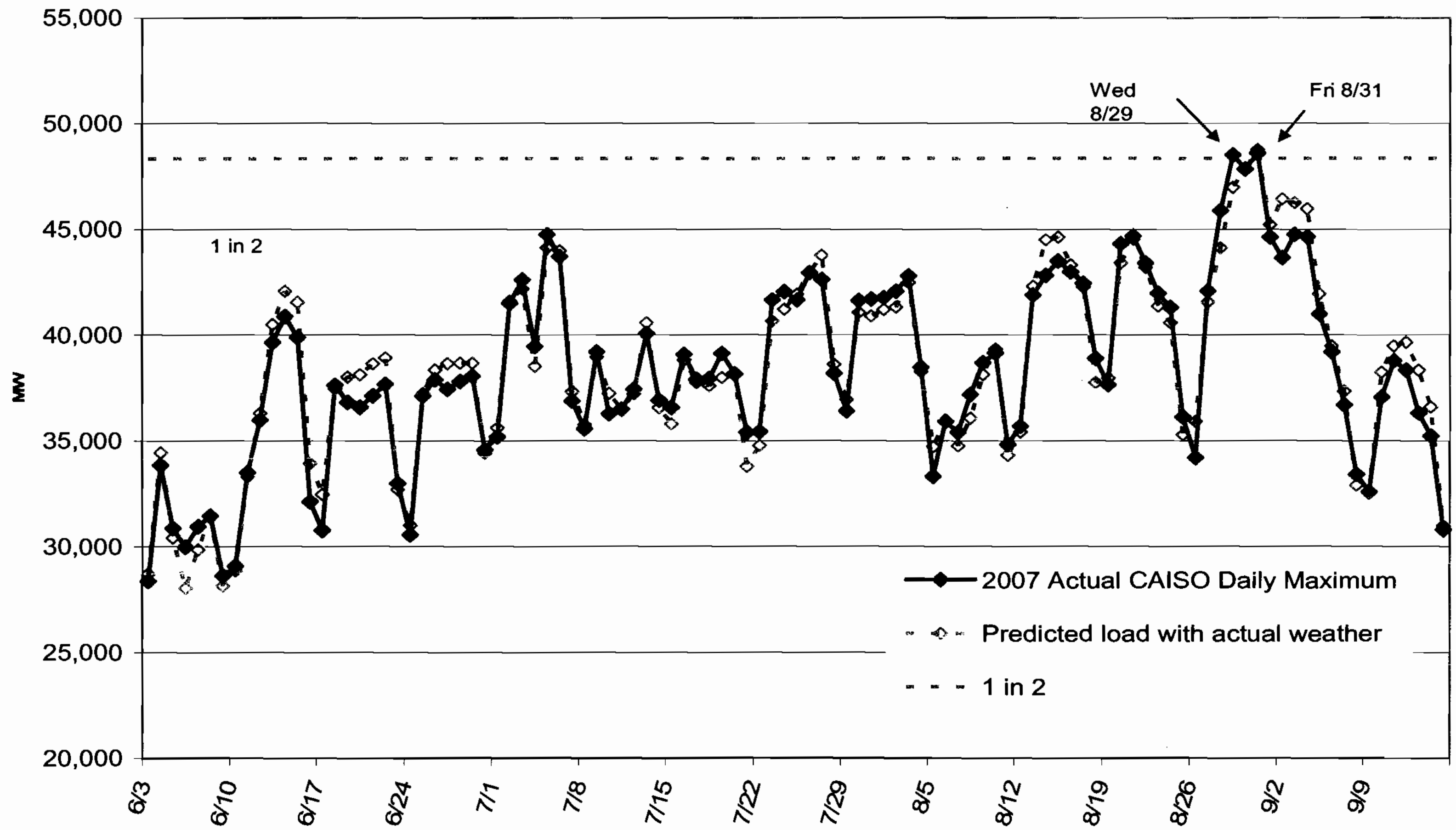
- 3-day weighted maximum temperature (Max631)
  - Used to account for heat build-up
  - Max631 = .6*(max current day) +.3*(max day-1) + .1*(max day-2)

Utility	Station/Weight				
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	
	0.062	0.324	0.243	0.371	
SDG&E	Lindbergh Field	Mirimar	El Cajon		
	0.333	0.333	0.333		
LADWP	Long Beach	Burbank			
	0.42	0.581			

Weather Variable Definitions

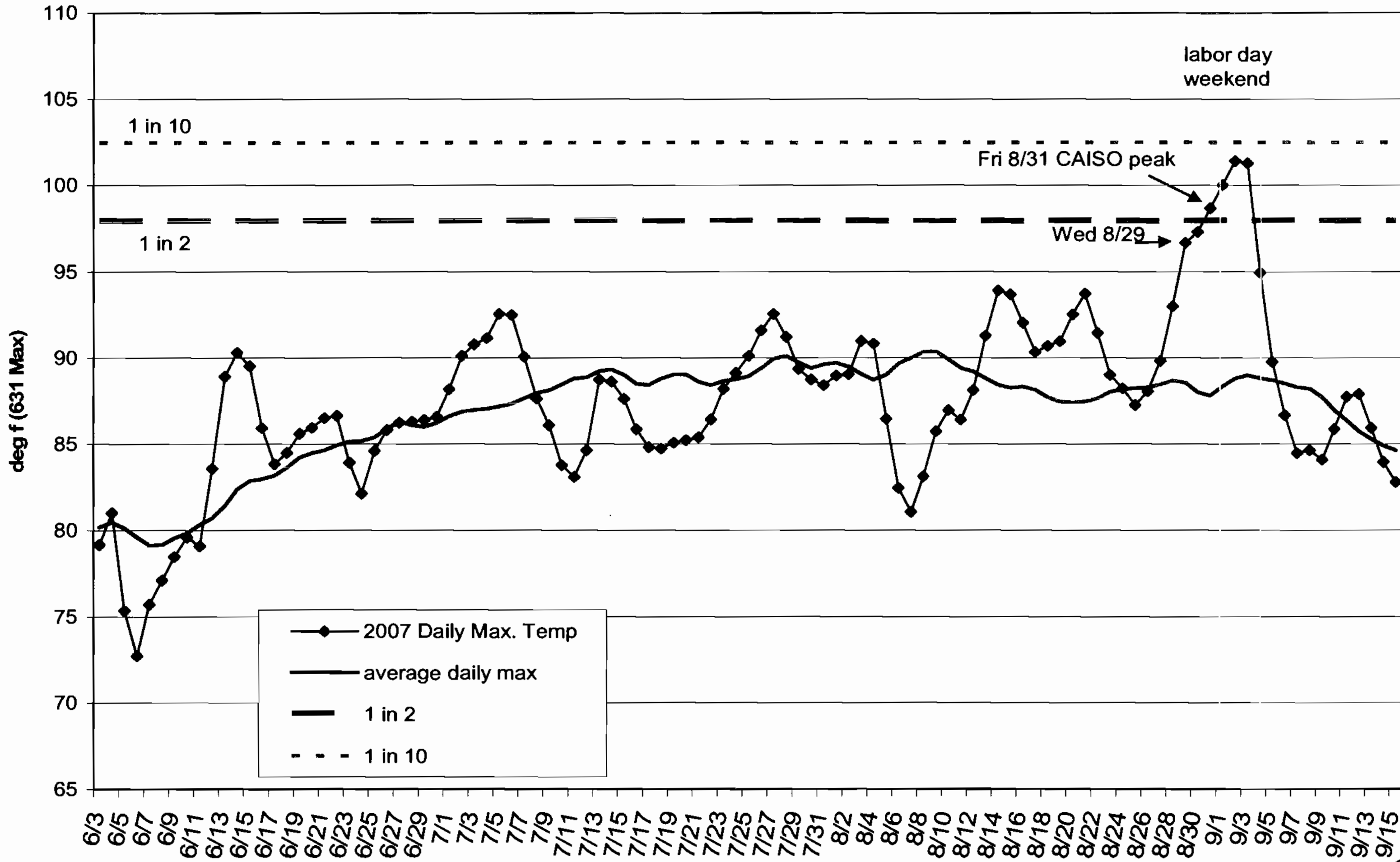
- Daily temperature spread or diurnal variation (Divar)
  - Used as a proxy for humidity
  - For a given maximum temperature the lower the temperature spread the higher the humidity
  - Divar = daily maximum temperature – daily minimum temperature
  - Divar is not lagged because it is meant to capture the actual operating characteristics of a/c units (energy used to remove water from air).

2007 CAISO Area Daily Peaks: Actual and Predicted



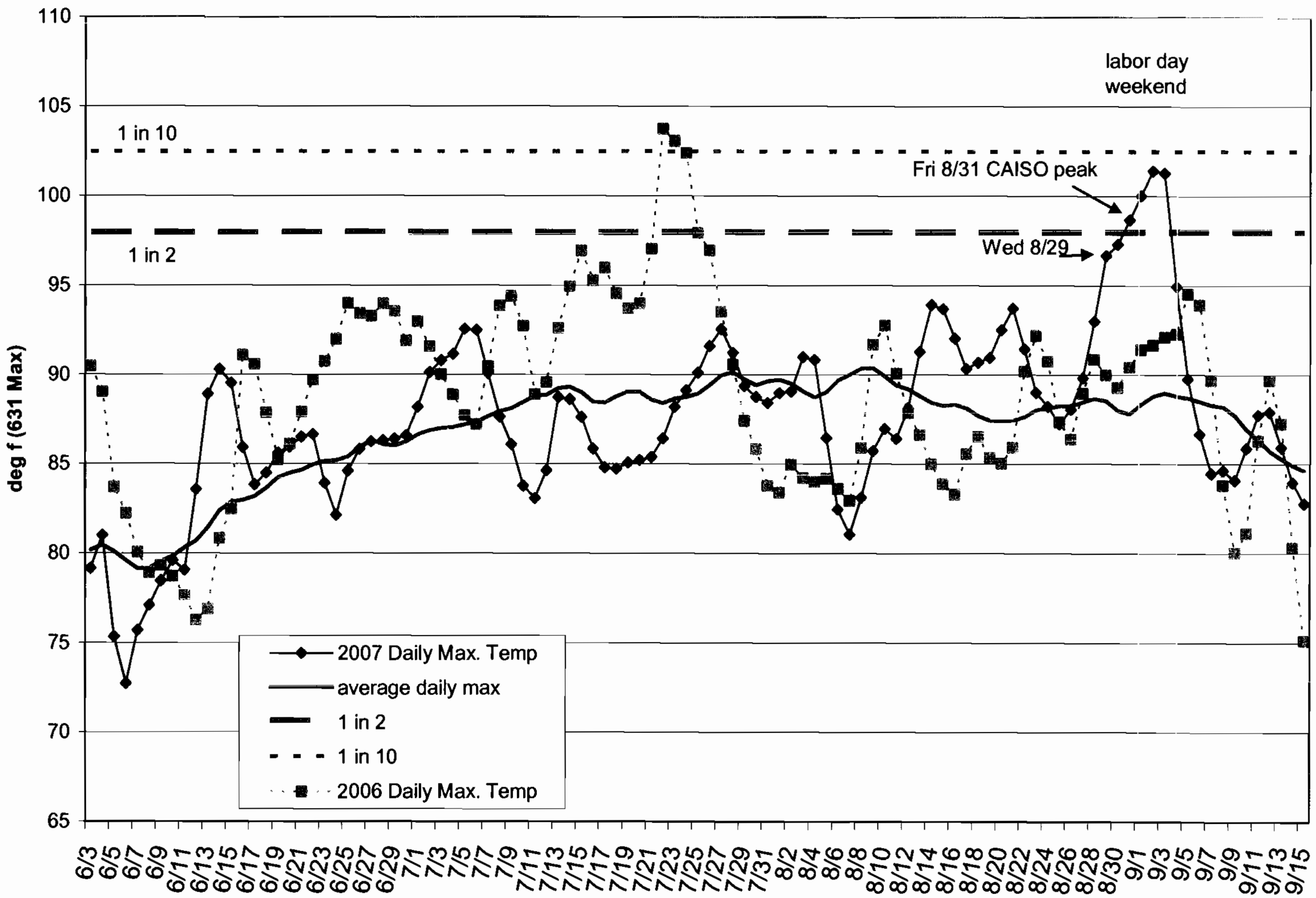
Summer 2007 Daily Temperatures in the CAISO

(Composite Lagged Daily Maximum)

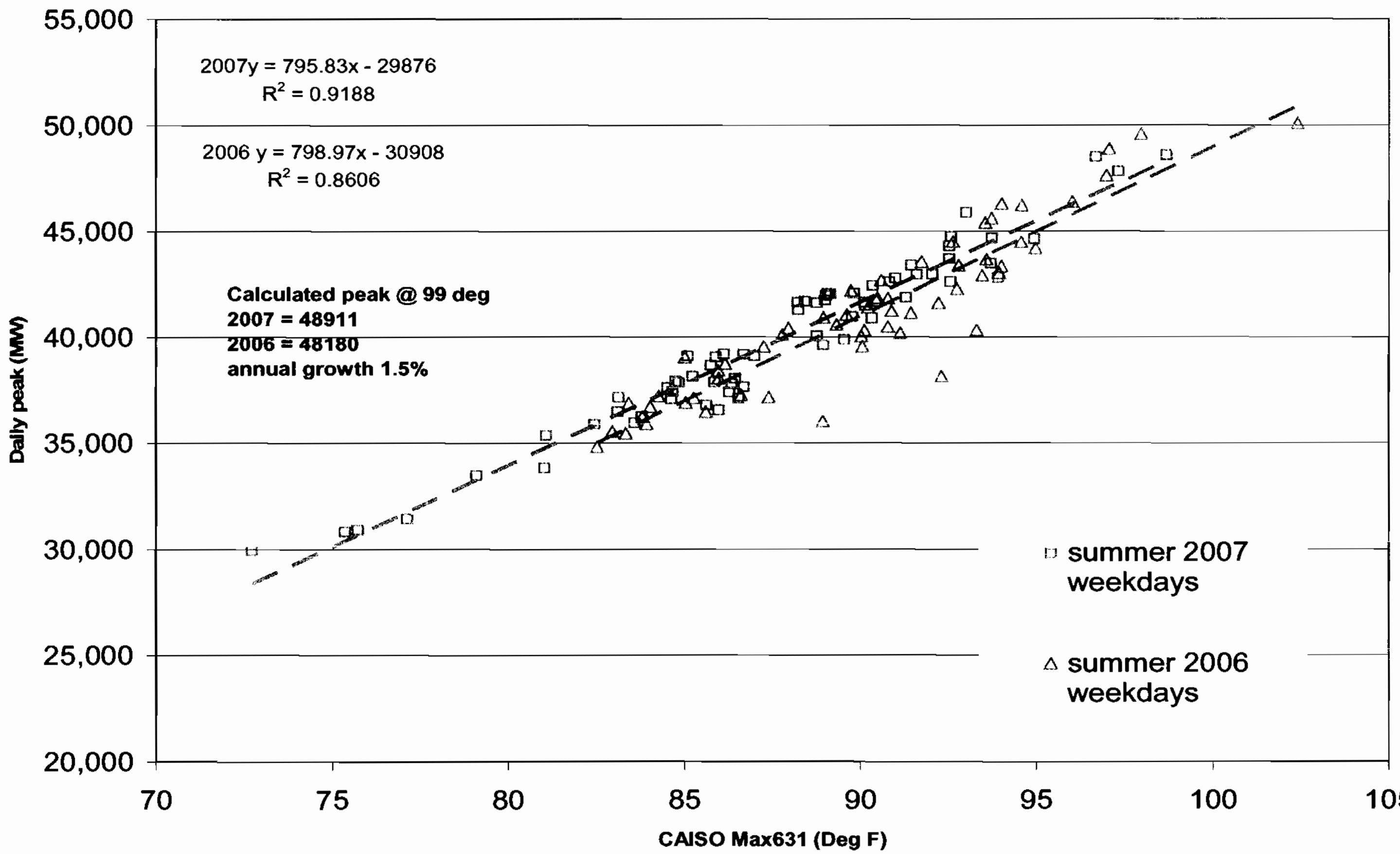


Daily CAISO peak temperatures were below 1 in 2 levels until the end of summer.

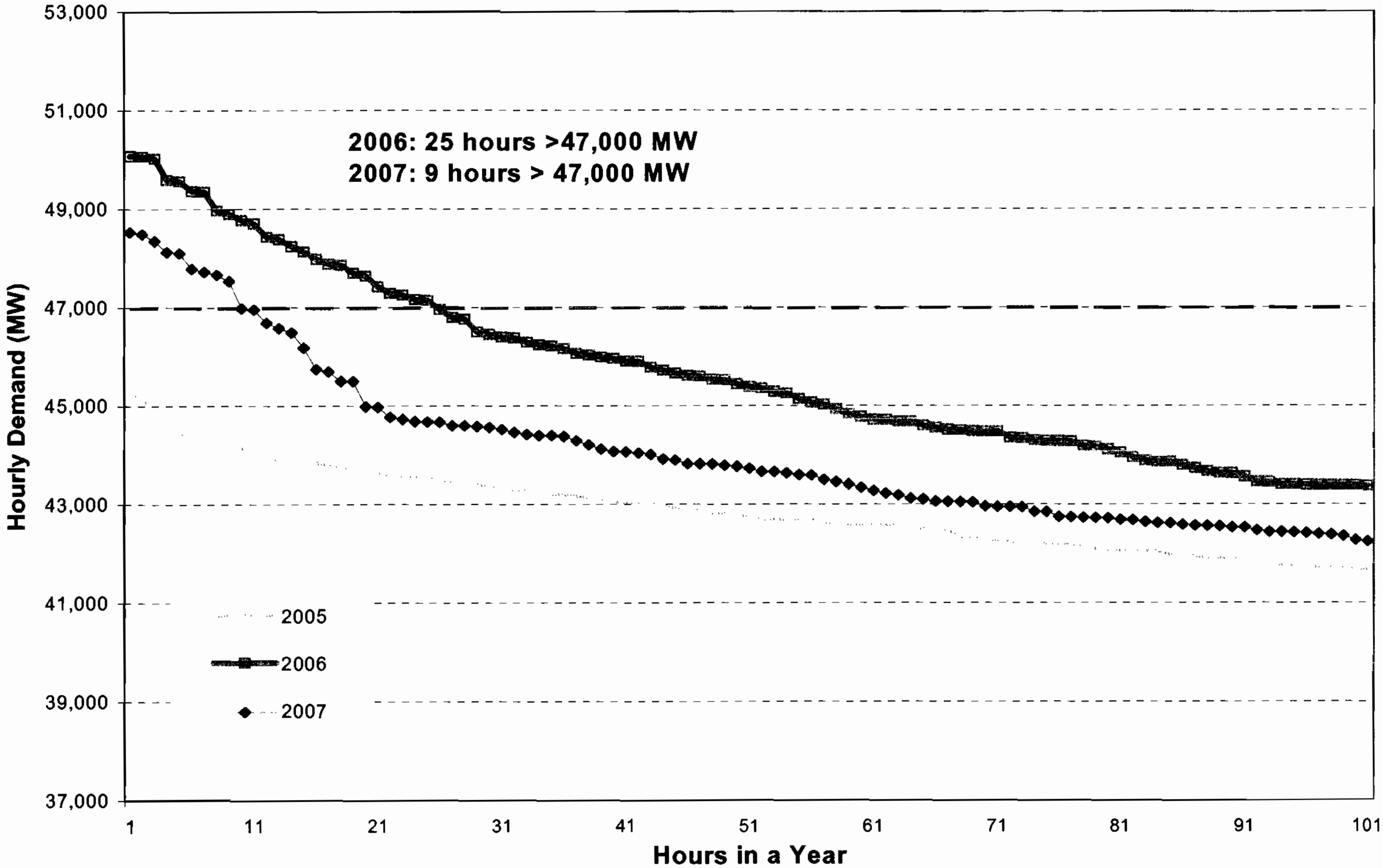
CAISO 2006-2007 Temperature Comparison



CAISO 2006-2007 Summer Weekday Temperature and Afternoon Peak Comparison

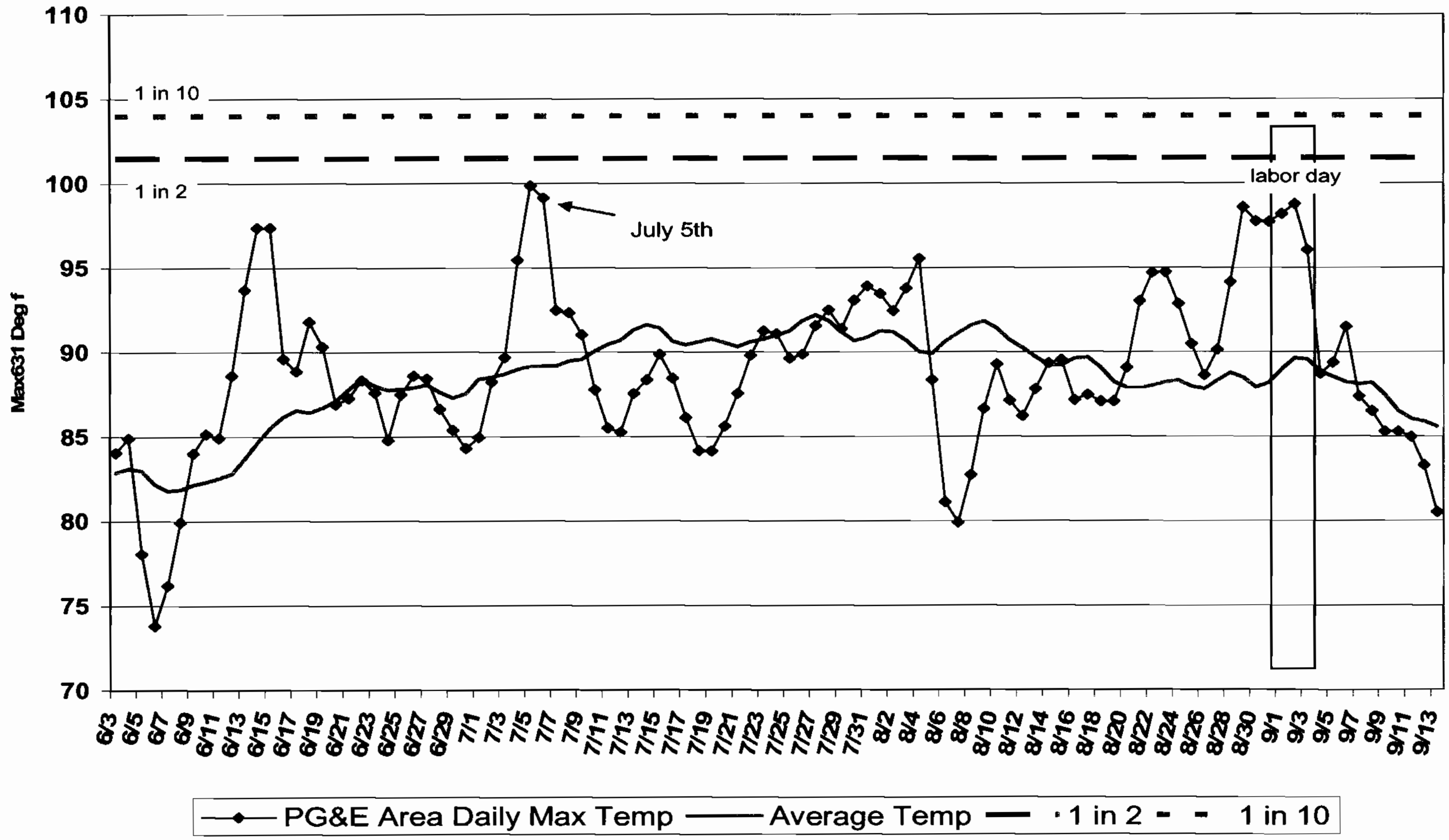


2005-2007 CAISO Hourly Demand -Highest 100 Hours



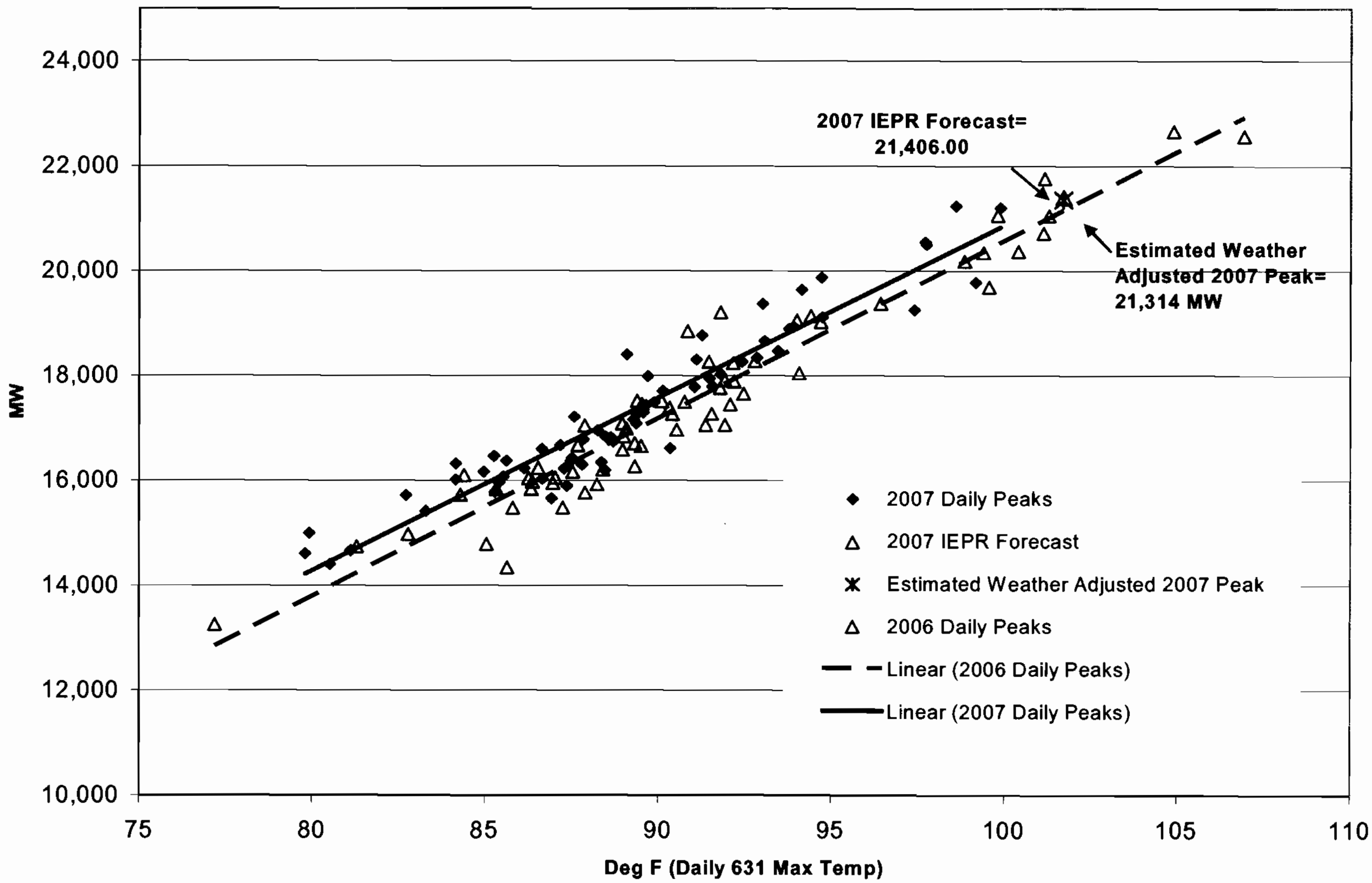
Source: CAISO/ FERC Form 714

PG&E Area 2007 Daily Temperatures



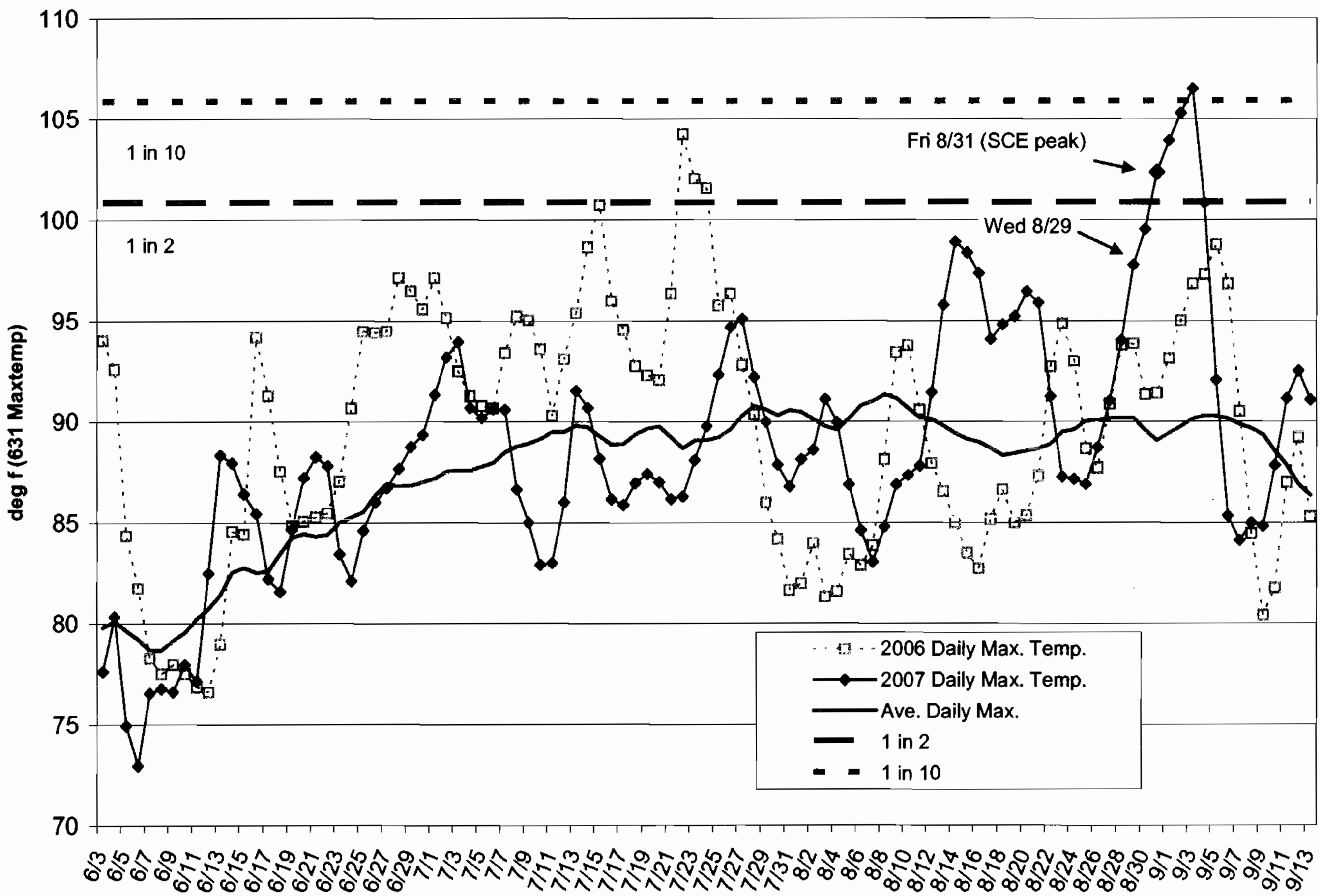
PG&E summer peak temperatures occurred July 5th and 6th.
These temperatures were below 1 in 2 level.

NP 15 2006-2007 Daily Peaks & Temperatures



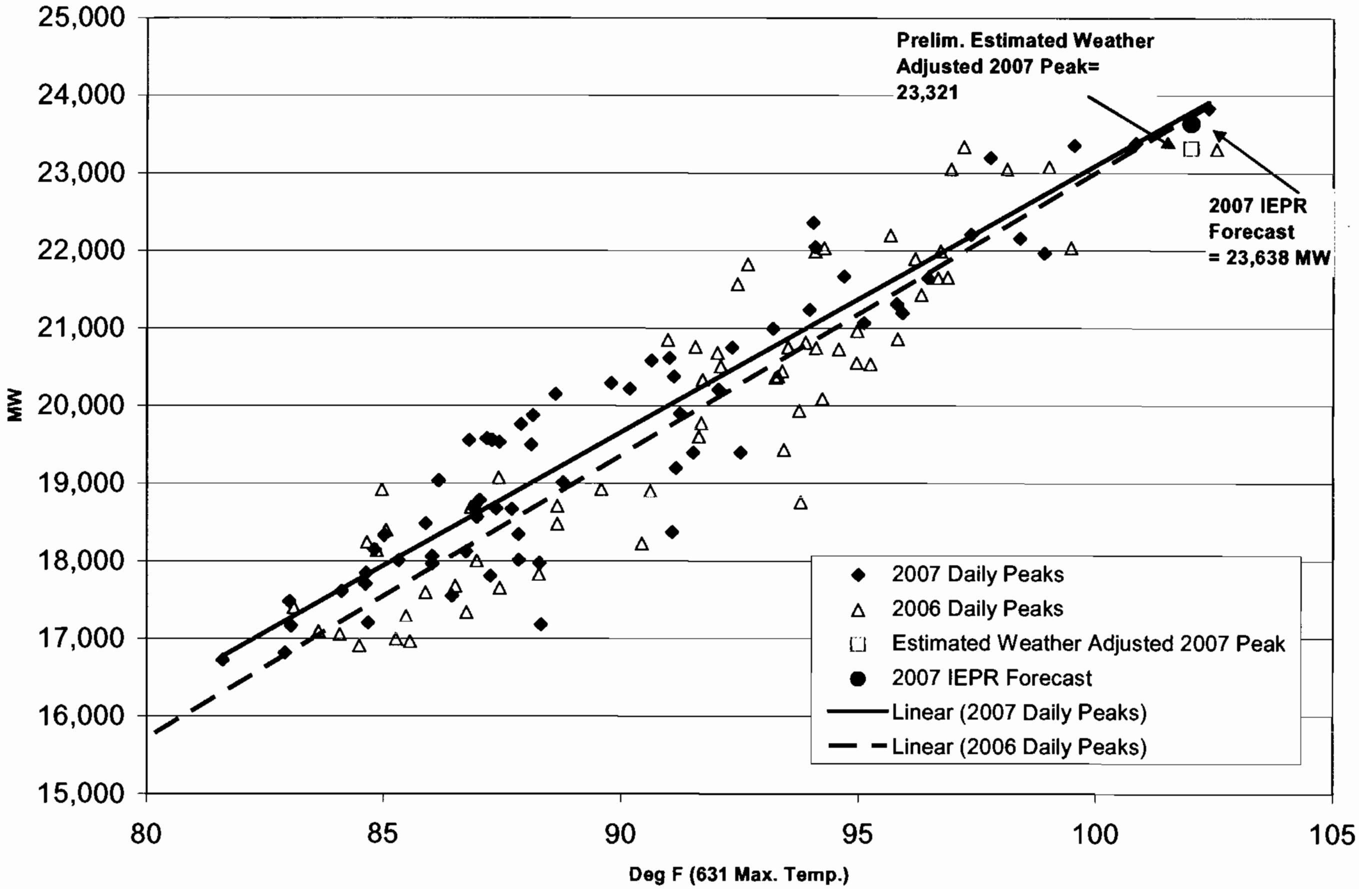
Weather-adjusted 2007 NP15 peak is within ½ percent of forecast. Estimated 2006/2007 load growth is 1.3 percent (240 MW), the same as the forecast growth rate.

SCE Area 2006-2007 Daily Peaks & Temperatures



SCE peak temperature occurred on Labor Day.
Day of SCE peak 8/31 was above 1 in 2 temperature

SCE Transmission Area 2007 Daily Peaks and Temperatures



Weather adjusted SCE peak is 300 MW lower than forecast, reflecting lower pumping loads than assumed.

Summer 2008 Demand Response

January 16, 2008

David Hungerford

Demand Response Staff Lead

Demand Analysis Office

Demand Response Overview

- DR Impact expectations
  - Categories and triggers
  - Enrollment growth
  - New programs and program adjustments
  - De-rating program enrollment
- Load Management Standards

DR Impact Expectations

Demand Response Resources (Peak Estimates for August 2008)

IOU	DR Program Description	Projected Enrollment 2008 in MW	Derate Based on Expected 2008 Performance	2008 DR Allocated for RA w/ Revised Enrolled MW
PGE	AC Cycling/SmartAC 2008	192	0.50	96
	Base Interruptible Program, Non-Firm	335	0.95	318
	Capacity Bidding Program	30	0.90	27
	Critical Peak Pricing	107	0.45	48
	Demand Bidding Program	596	0.09	54
	Other - DWR & DR RFP Contracts, BEC, OBMC	383	0.89	341
	Total PG&E	**1643**		**884**
SCE	AC Cycling/Summer Discount	562	1.00	562
	Base Interruptible Program	501	0.95	476
	Capacity Bidding Program	23	0.90	21
	Critical Peak Pricing	3	1.00	3
	Demand Bidding Program	227	0.15	34
	Other - Ag & Pumping Interruptible, DRP, OBMC	148	0.59	88
	Total SCE	**1464**		**1184**
SDGE	AC Cycling/Summer Saver	42	0.59	25
	Base Interruptible Program	5	0.97	5
	Capacity Bidding Program	25	0.90	23
	Critical Peak Pricing - Voluntary and Emergency	31	0.58	18
	Demand Bidding Program	25	0.24	6
	Other - Clean Gen, C&I 20/20	89	0.35	31
	SDG&E Total	**217**		**107**
				2175

Load Management Standards

- Order Instituting Investigation/Order Instituting Rulemaking approved 1/2/08
- Docket number 08-DR-01
- Purposes:
  - (1) assess which rates, tariffs, equipment, software, protocols, and other measures would be most effective in achieving demand response, and
  - (2) adopt regulations and take other appropriate actions to achieve a responsive electricity market.

Dependable Hydro Capacity Summer 2008 Electricity Supply and Demand Outlook Workshop

January 16, 2008

Jim Woodward
Electricity Systems Generation Specialist I
Electricity Analysis Office

Hydro Capacity Ratings Are Based on Summer Reliability Needs or Performance

- "A hydro resource must be able to operate during 4 super-peak hours for 3 consecutive days for capacity in that month to count." – *CEC supply form instructions January 2007*
- QF hydro Qualifying Capacity "will be determined based on historic performance during the Standard Offer 1 peak hours of noon to 6:00 p.m., using a three-year rolling average." – *MRTU tariff 40.13.3*

Hydro Capacity in CAISO

LSEs in the CAISO Balancing Authority Area (BAA)	30+ MW	< 30 MW	All 1-in-2 Utility-owned	Dry Year Derate	QF Hydro 1-in-2	Con-tracts 1-in-2	Total
PG&E	4,370	246	4,616	conf.	61	0	
DWR - SWP (on peak)	1,565	32	1,597	530			
SCE	996	92	1,088	0	17	23	
CCSF - Hetch Hetchy	297		297			0	
Silicon Valley Power	227	24	251	75		0	
NCPA	128	2	130				
12 other LSEs with hydro	103	15	96		1	22	
CAISO area totals	7,686	411	8,075	605	79	45	7,594

Dependable Hydro Capacity in CAISO is Based on the Dry Year

- "Qualifying Capacity … will be determined based on net dependable capacity defined by NERC GADS minus variable head de-rate based on average dry year reservoir level."
- "Average dry year reflects a one-in-five dry hydro scenario (for example, using the 4th driest year from the last 20 years on record." – *MRTU tariff 40.13.3*

CAISO retains some discretion over LSE-owned & controlled hydro

- SCs shall provide "a proposed annual use plan for each Use-Limited Resource"
- CAISO can discuss proposed annual use plans "and suggest potential revisions to meet reliability needs of the system."
- "Hydroelectric Generating Units and Pumping Load will be able to update use plans intra-monthly as necessary to reflect hydrological and meteorological conditions." – *MRTU tariff 40.6.4.2*
- Gen units & Pumping Load will not be subject to Residual Unit Commitment process – *tariff 40.6.4.3.2*

Hydro Capacity in SMUD / Western

LSEs in the SMUD Balancing Authority Area (BAA)	30+ MW	< 30 MW	All 1-in-2 Utility-owned	Dry Year Derate	QF Hydro 1-in-2	Con-tracts 1-in-2	Total
SMUD	649	35	684	0		438	
Roseville	82	0	82	3		0	
Modesto ID	62	0	62	7		0	
Redding	0	2	2	0		99	
Shasta Lake	0	0	0			11	
Western: end-use loads	137		137			0	
SMUD BAA totals	930	37	967	10	0	548	1,505

Hydro Capacity in LADWP

LSEs in the LADWP Balancing Authority Area	30+ MW	> 30 MW	All 1-in-2 Utility-owned	Dry Year Derate	QF Hydro 1-in-2	Con-tracts 1-in-2	Total
LADWP	1,720	211	1,931			0	
Burbank	20	0	20	0		0	
Glendale	20	0	20	0		0	
LADWP BAA totals	1,760	211	1,971	0	0	0	1,971

Dependable Hydro Capacity Statewide in August 2008

"Statewide" Summary of 5 Balancing Authority Areas	30+ MW	< 30 MW	All 1-in-2 Utility-owned	Dry Year Derate	QF Hydro 1-in-2	Contracts 1-in-2	Total
CAISO	7,686	411	8,075	605	79	45	7,594
SMUD - Western	930	37	967	10	0	548	1,505
LADWP	1,760	211	1,971	0	0	0	1,971
Imperial ID	33	32	65	0	0	0	65
Turlock ID	134	12	146	11	0	27	162
Statewide Totals	10,543	703	10,708	626	68	620	11,297

How Would a Severe Drought Affect Hydro Capacity?

Additional Derates for Hydro Capacity

From a 1-in-5 Dry Year to a **1-in-10 Critically Dry Year**

LSE	MW Derate
SCE	50
SVP	74
TID	11
Roseville	5
Total	**140 MW**

Data from 2005 *IEPR* LSE supply plan filings (*did not include DWR or Western*)

Hydro Capacity Does <u>not</u> Derate in Proportion to Annual or Monthly Snowpack or Runoff

- Most utility-owned hydro capacity uses high-head penstock infrastructure not subject to gross head derates caused by low reservoirs
- Most utility-managed reservoirs are kept full to meet daily, weekly, and annual peak loads
- Low elevation PHs at multipurpose reservoirs will derate in late summer and are transparent

CALIFORNIA
ENERGY
COMMISSION

SUMMER 2007 ELECTRICITY SUPPLY AND DEMAND OUTLOOK

DRAFT STAFF REPORT

May 2007
CEC-200-2007-005-SD

Arnold Schwarzenegger, *Governor*

CALIFORNIA ENERGY COMMISSION

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ABSTRACT

This report provides a summary of the California Energy Commission staff's current assessment of the capability of the physical electricity system to provide power to meet electricity demand in specific geographic areas within California. It also documents key assumptions and methodologies used to develop an assessment of physical resources and requests input from interested parties for future analytical work.

KEYWORDS

Supply and demand outlook, probability, operating reserve, loss of load, demand, forced outage, generation, net interchange, demand response, interruptible load, reserve margin

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INTRODUCTION AND SUMMARY

The *Summer 2007 Electricity Supply and Demand Outlook* provides a summary of the California Energy Commission (Energy Commission) staff's current assessment of the capability of the physical electricity system to provide power to meet electricity demand in specific geographic areas within California. The report does not include an evaluation of the condition of the electricity market, specific contractual details or the adequacy of any individual utility.

This outlook includes an examination of four regions - California Statewide, California Independent System Operator (California ISO) Control Area, California ISO North of Path 26 (NP26), and California ISO South of Path 26 (SP26). The California ISO Control Area is divided into Northern and Southern California because there are transmission constraints south of the transmission segment known as Path 26, which limit the transfer of electricity from north to south. Northern California includes the Pacific Gas and Electric (PG&E) service area, participating municipal utilities and Energy Service Providers (ESPs) in Northern California served by the California ISO. Southern California includes Southern California Edison (SCE), San Diego Gas and Electric (SDG&E), Southern California municipal utilities and ESPs that participate in the California ISO. The outlook is base on the *Staff Forecast of 2007 Demand* developed in June 2006 for forecasted loads in each region.

This analysis was prepared in coordination and consultation with the California Public Utilities Commission (CPUC), the California ISO, utilities and other stakeholders. An Integrated Energy Policy Report (IEPR) Committee workshop will be held on May 24, 2007 to receive stakeholder and public comments on the staff draft report. The staff is also seeking input on the proposed analysis for the *Summer 2008 and Five -Year Electricity Supply and Demand Outlook* scheduled to be published this fall.

Format and Methodology Changes from 2006 Report

This assessment includes several changes in format and methodology as a result of the staff's continuing effort to develop probabilistic assessments to enhance the tables we have historically completed. The deterministic tables only provide line-by-line analysis to the planning reserve calculation. The expected and adverse operating reserve margin scenarios have been removed from the 2007 outlook. The staff believe that a probabilistic approach more accurately represents the complete range of demand possibilities, as well as generation and transmission forced outage occurrences. These probabilities are calculated using historical data to assess the possibility of multiple adverse conditions occurring simultaneously.

The 2007 outlook introduces probabilistic studies for the entire California ISO Control Area and the NP26 portion of the California ISO Control Area, in addition to the SP26 region included in the 2006 outlook. The California Statewide outlook is only presented in a deterministic format because the statewide system is composed of multiple control areas and does not operate as a single entity.

Summary of Results

The 2007 Summer Outlook is summarized below in both the deterministic and probabilistic formats. Table 1 provides the planning reserve margins for each of the four regions. The planning reserve margin is calculated in a similar manner as in CPUC resource adequacy proceedings and is the margin by which the capacity from net generation, demand response and interruptible load programs exceeds the 1-in-2 demand forecast. The region with the lowest planning reserve margin for 2007 is the portion of the California ISO Control Area located South of Path 26, although the margin exceeds the 15-17 percent planning reserve criteria required by the CPUC. Appendix A provides detailed monthly tables and a line-by-line description of the supporting information and assumptions used in the planning reserve margin calculations.

Table 1: 2007 California Electricity Outlook
(Megawatts)

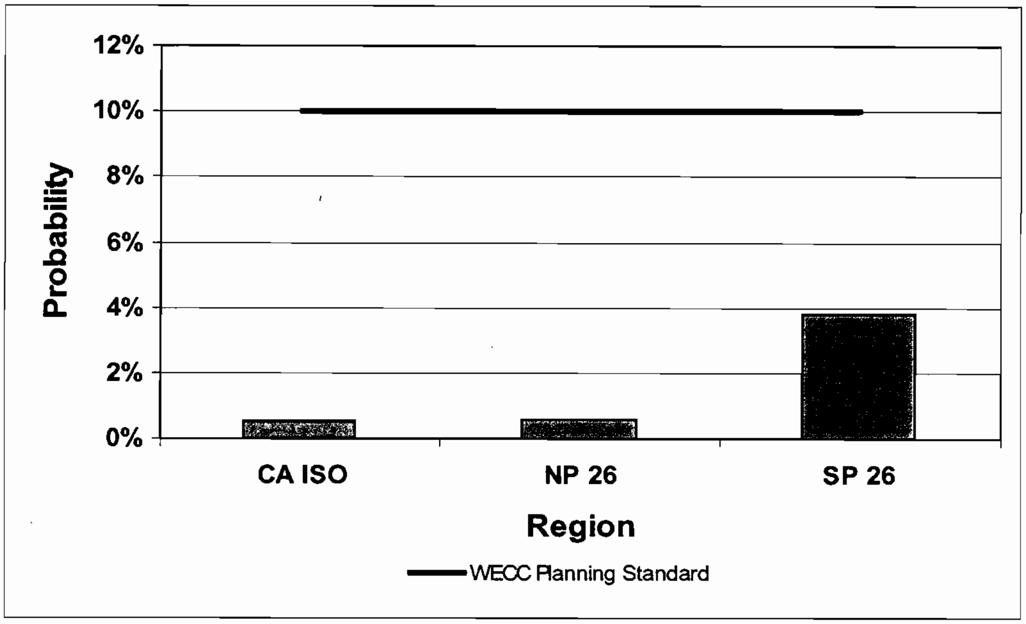
		NP 26	SP 26	CA ISO	Statewide
1	Existing Generation (Summer Derated)	24,417	21,848	46,265	57,897
2	Retirements (Known)	0	0	0	0
3	High Probability CA Additions (Summer Derated)	74	429	503	656
4	Net Interchange	500	10,100	10,600	13,118
5	Total Net Generation	24,991	32,377	57,368	71,671
6	1-in-2 Summer Temperature Demand (Average)	21,100	28,374	48,289	60,344
7	Demand Response	322	202	524	524
8	Interruptible/Curtailable Programs	316	1,087	1,403	1,603
9	Planning Reserve	21.5%	18.7%	22.8%	22.3%

Figure 1 displays the staff estimate of the probability of involuntary load curtailment in the California ISO Control Area and the two sub-regions on the peak day for the summer 2007 period. The SP26 region has the highest probability of involuntary load curtailment or rotating outages. The corresponding Loss of Load Probability (LOLP) for the region is 3.5 percent, which is significantly lower than the Western Electricity Coordinating Council (WECC) acceptable planning criteria of one loss of load event every 10 years, equivalent to a 10 percent LOLP. Staff estimates the California ISO Control Area and NP26 both have an LOLP of less than 1 percent for summer 2007.

Utilities that are not members of the California ISO Control Area appear to have adequate resources to meet expected electricity demand this summer. These public utilities include Los Angeles Department of Water and Power (LADWP), Burbank

Water and Power, Glendale Water and Power, and Imperial Irrigation District in Southern California and Sacramento Municipal Utility District (SMUD), Modesto Irrigation, Redding, Roseville Electric, and Turlock Irrigation in Northern California.

Figure 1: Loss of Load Probability



Next Steps

The analytic process for the *Summer 2008 and Five-Year Electricity Supply and Demand Outlook* is currently underway with plans to publish the results by this fall. The outlook will use the 2008 Peak Demand and long-run demand forecasts once they have been subject to public review as part of the 2007 IEPR proceedings.

The staff is requesting stakeholder input on topics that may be included in the report. A few topics for possible study have already been identified and include:

- Probabilistic assessment of wind variability.
- Develop randomization factors for additional demand variables to enable a probabilistic long-term assessment.
- Modeling the 3,000 Megawatt (MW) Path 26 interchange assumption correctly.
- Study planning reserve margins to determine the associated loss of load risk using 15 percent, 17 percent and 2008 projected planning reserve margins.
- Potential impacts of environmental issues, including greenhouse gas reduction and once-through cooling limitations.

Parties are asked to provide comments regarding the *Summer 2007 Electricity Supply and Demand Outlook* or proposed topics to include for future study, both orally at the May 24, 2007 workshop and in writing. Comments submitted before the workshop will be used to facilitate the discussion. For written comments, please include the docket number ***No. 06-IEP-1J*** and indicate ***2007 IEPR – Supply Demand Outlook*** in the subject line or first paragraph of your comments.

Regional Probabilistic Assessments

Background of Probabilistic Assessment

The staff is continuing with its development of a full probabilistic assessment to enhance the deterministic tables provided in previous reports. In the staff's deterministic tables presented in previous year's outlooks, reserve margins were estimated for two operating scenarios: expected (1-in-2) and adverse (1-in-10) conditions. However, in system planning, neither supply nor demand can be predicted with absolute accuracy or determined on a single point forecast. Future conditions that determine load, as well as availability of supply, can be better predicted within a range of uncertainty. Studies based just on the most likely set of conditions fall short of looking at the full range of possible demand and the fluctuation in supply capabilities. Likewise, studies based on adverse conditions are still limited in scope and may overestimate the exposed risk to these events.

As the summer 2006 showed, the peak load in the Northern California was significantly higher than projected in the 1-in-10 forecast and was not captured by the deterministic methodology. This experience demonstrated that the single- or two-point deterministic evaluations are not sufficient; therefore a wider range of factors and future conditions should be evaluated to exclude unexpected contingencies in the forecast of supply adequacy.

The observed performance of the electricity system over time and an extensive record of temperature conditions that are correlated to actual demand has allowed the Energy Commission staff to develop probability of occurrence measures for each of the major uncertainty factors. Incorporating the probability of occurrence to an electricity supply assessment provides a better representation of the fluctuations in the system and measures the risks of actually encountering an electricity emergency event based on historical data.

The Supply Adequacy Model (SAM) is a forecasting tool that assesses the balance of power supply and demand for a power system throughout the WECC regions. SAM was originally developed at the Energy Commission in 1998. For this analysis, the staff needed to modify SAM to analyze a specific region. This modified version of the SAM is referred to as SAM-A. The SAM-A was designed to be a relatively fast and simple analytical tool with the capability of incorporating uncertainty variables. The probabilistic approach for analyzing supply adequacy is an important feature of SAM-A, which differs from other deterministic models.

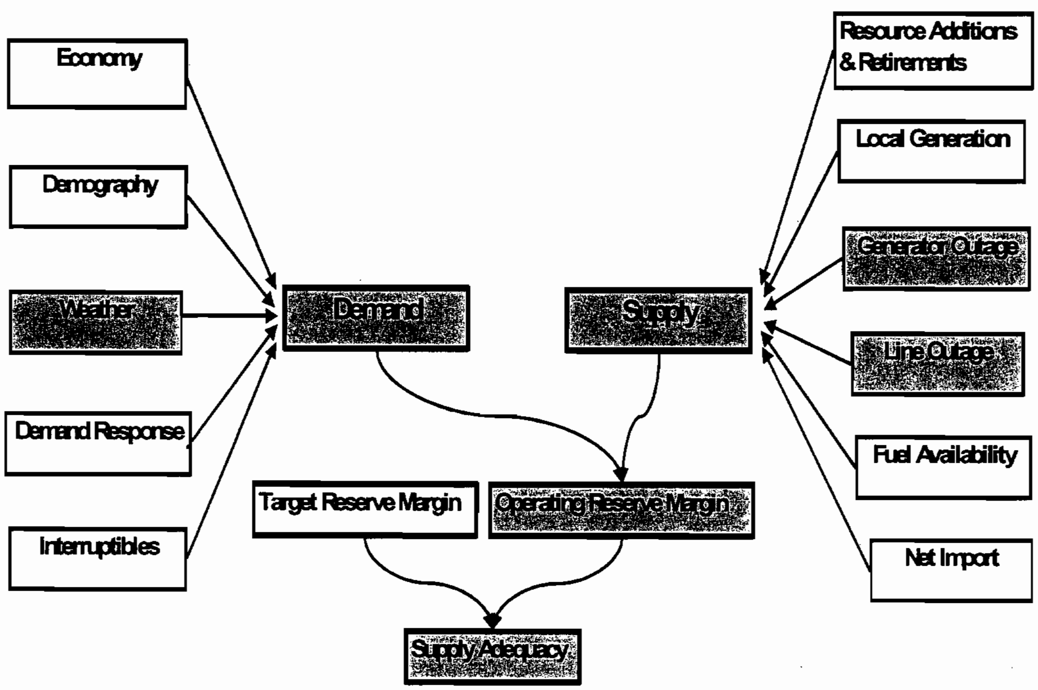
In the initial probabilistic study, the staff included the probabilities of high demand and generation forced outages in the Southern California (SP26) portion of the California ISO Control Area. The SP26 region was selected because it had the lowest planning reserve margin and presented the highest probability of not meeting operating reserve requirements. *The Summer 2006 Electricity Supply and Demand*

Outlook incorporated the probability of forced outages of transmission lines in the SP26 region. In this 2007 report, the staff added analysis of the entire California ISO Control Area and the NP26 sub-region using the same three probabilistic variables of demand, generation outages and transmission outages used in the 2006 report.

There are a number of variables to consider when assessing supply adequacy of a system. This probabilistic assessment evaluates the complete range of demand scenarios based on weather variation, as well as generation and transmission outage occurrences based on historical data. The staff developed multiple cases of different resource availability, transmission capabilities and demand-varying scenarios using the Monte Carlo method to determine physical supply adequacy. Figure 2 shows the major factors used to develop the 2007 outlook. The probabilistic methodology was applied to the factors in the highlighted boxes in the chart.

The staff is continuing to expand the probabilistic methodology and will continue to randomize the effects of additional factors when more information is made available from stakeholders. The following description is an explanation of how the probabilistic methodology was applied to analyze the SP26 region. The analytical process is the same for all three regions, but SP26 was selected for illustrative purpose because it has the highest risk of firm load curtailments.

Figure 2: Major Factors Affecting Supply Adequacy



Probability of Demand

The probability of demand calculations are based on the most recent adopted Energy Commission demand forecast[1] as updated for the Investor Owned Utility (IOU) portion in June 2006[2] .Complete documentation of assumptions and methodologies are included in the above reports.

Peak electricity demand does not always occur in the hottest day of the year. There is a strong correlation between peak electricity demand and a buildup of high temperatures over several days. To incorporate the effect this buildup of heat has on peak demand, the staff calculated a weighted average temperature (max 631). The weighting consists of 60 percent of the current day's maximum temperature, 30 percent of the previous day's maximum and 10 percent of the second previous day's maximum. The lag is used to account for heat build-up over a three day period.

The staff used the max 631 to develop a temperature response adjustment for varying degrees of hotter-than-average temperatures. The staff estimated the relationship between temperature and daily peaks using recorded 2004 hourly loads reported to FERC by SCE and SDG&E, and a three-day moving average of daily maximum temperatures weighted by the number of air conditioning units estimated to be in each region. The estimation included weekdays from June 15 through September 15, on which the weighted average maximum temperature was above 75 degrees in SCE, or 70 degrees in SDG&E service territories.

Figures 3 and 4 show the 2004 relationship between temperature and load and the estimated weather response function for SCE and SDG&E, respectively. By calculating the slope, the staff determined that a one degree increase in weighted average temperature equates to a 317 MW increase in peak demand for SCE and a 66.5 MW increase for SDG&E.

Figure 3: SCE Load vs. Temperature Relations

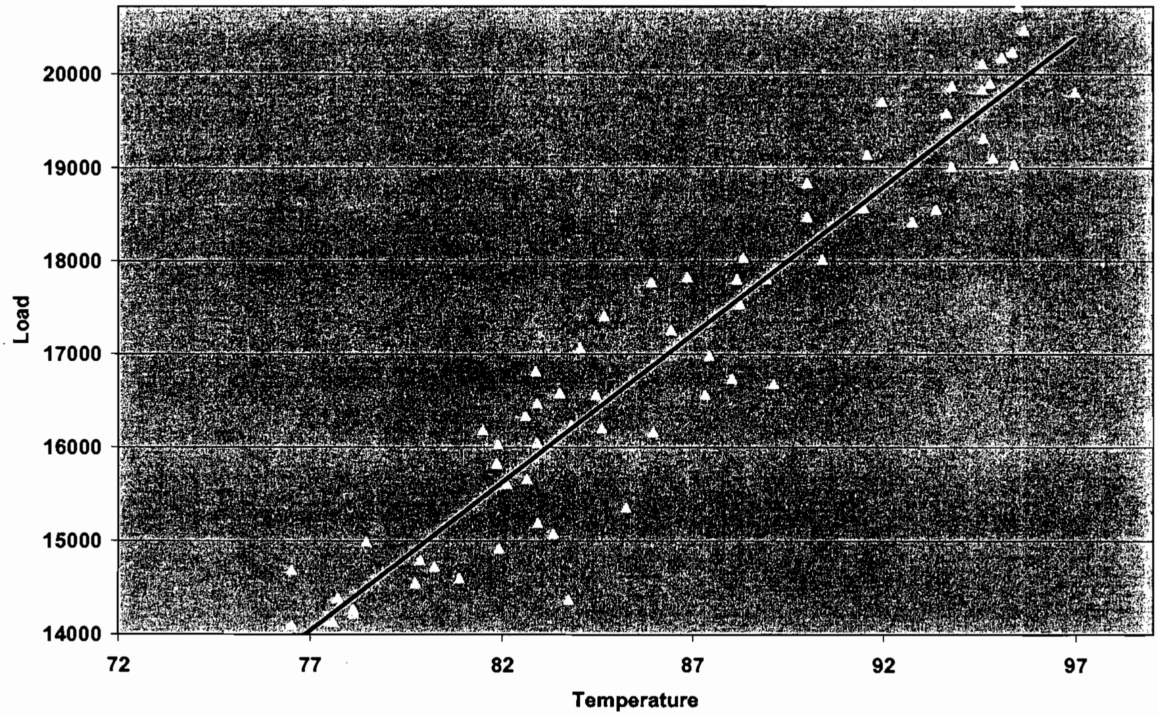
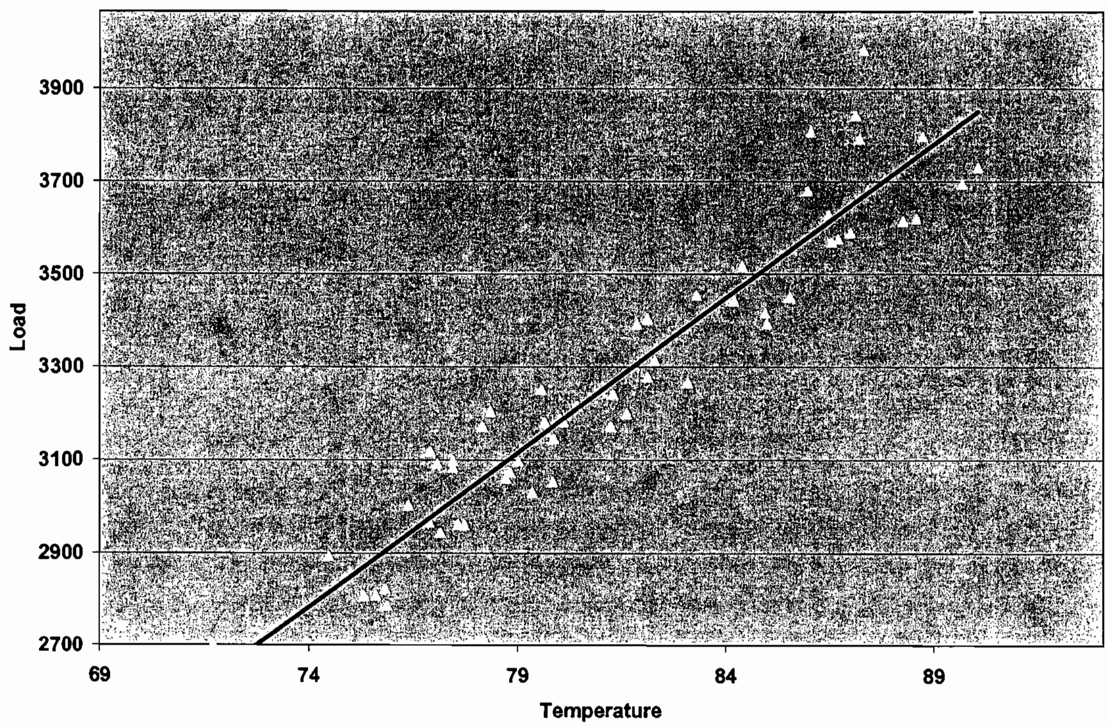


Figure 4: SDG&E Load vs. Temperature Relations



The staff then compared the weighted average temperature for the 54 years of historic weather data to calculate a distribution of summer 2007 peak demand possibilities. For example, if the weighted average temperature used in the demand forecast for SP26 is 98 degrees and the weighted average temperature in 1976 was 101, the resulting 2007 peak demand increase using 1976 temperature data would be 1,150 MW ((317+66.5) * (101-98)) for the SP26 region. Finally, the staff applied the change in demand for each recorded peak temperature over the 54 year period to develop a peak demand distribution. The resulting probabilistic graph for Southern California is presented in Figure 5. The chart characterizes the probability of aggregated load occurring for the whole Southern California region.

Figure 5: Probability of Demand
California ISO SP26 Summer 2007

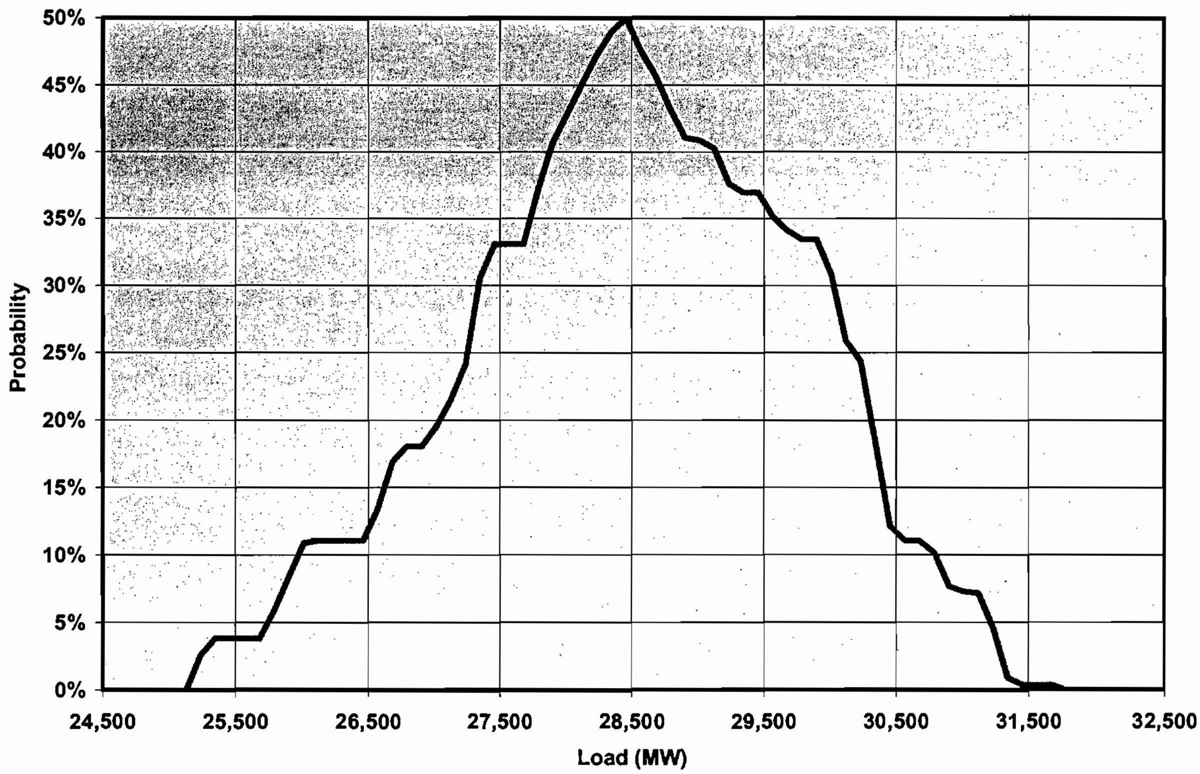


Figure 5 shows that the range of SP26 demand in 2007 could be as low as 25,125 MW or as high as 31,785 with a 'most likely' demand of 28,455 MW. While the forecast could equally be higher or lower than the mean, the risks associated with the higher options are more relevant for planning considerations.

Probability of Generation Forced Outages

Similar to the impact and range of possible demand, the magnitude of the total available resources can be expected to fall within a range of uncertainty due to the variation in forced outages. Energy Commission staff calculated potential 2007 outages using actual 2002 thru 2006 daily outage totals for the summer peak period provided by the California ISO. This set of data was statistically processed, and the results are presented in Figure 6.

Figure 6: Probability of Generation Forced Outages California ISO SP26 Summer 2007

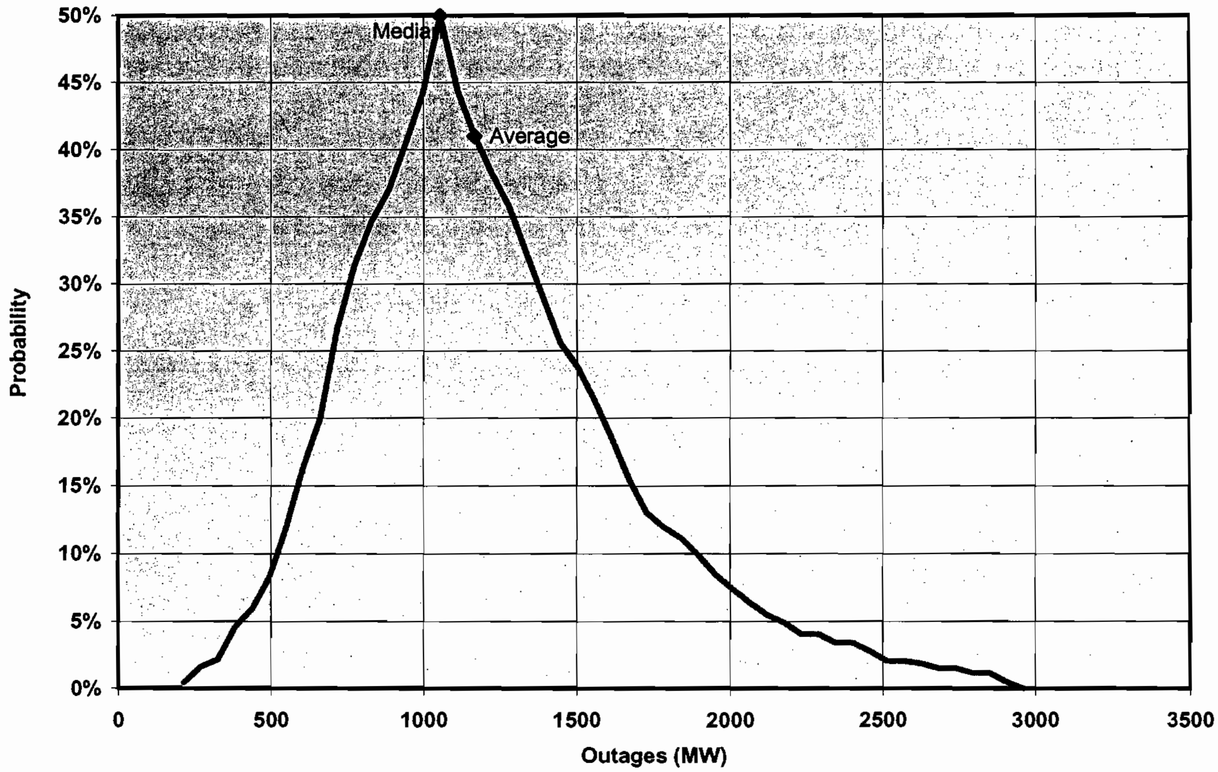


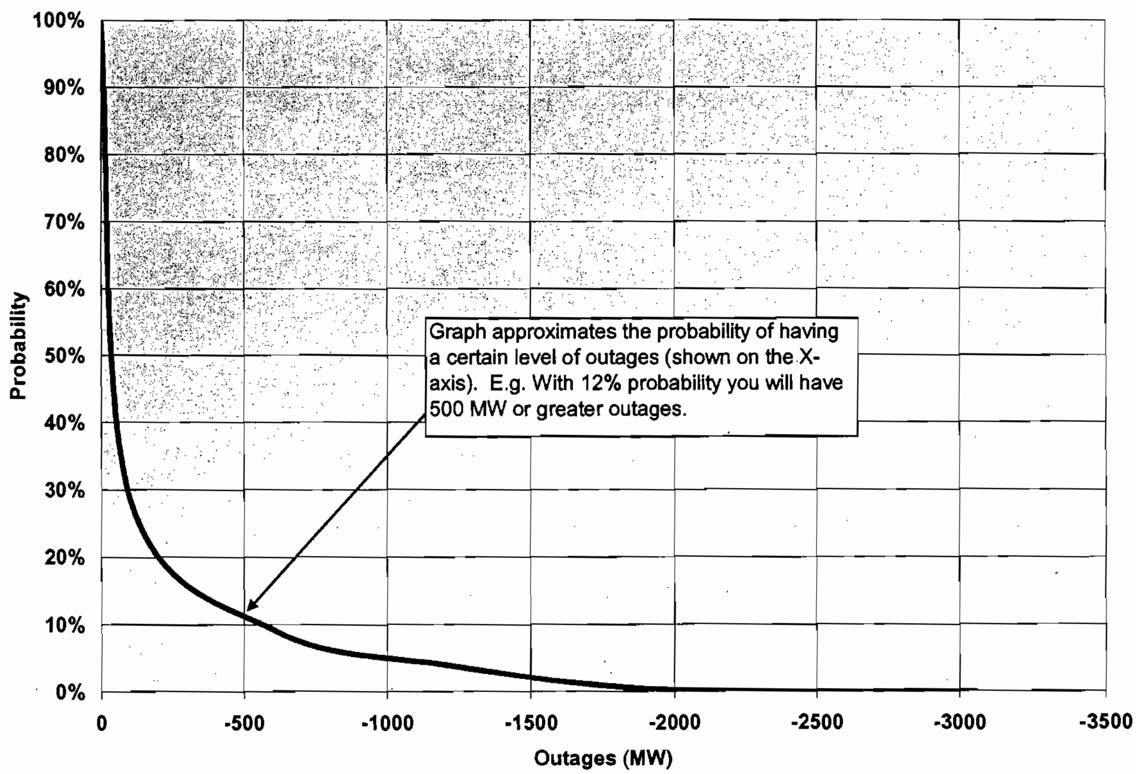
Figure 6 shows the range of SP26 forced outages in 2007 could be as low as 213 MW or as high as 2,960 MW, with a 'most likely' outage number of 1,054 MW. Again, the risks associated with the higher outages are the more relevant factors for resource planning considerations. The staff estimates a ten percent probability that forced outages will be as high as 1,894 MW, and a three percent probability that they will be as high as 2,400 MW.

Probability of Transmission Line Forced Outages

A major transmission line outage can also have significant impacts on the overall operation of the system. These outages often occur with little or no warning and, in the case of the Pacific DC Intertie (PDCI), can account for as much as a 2,000 MW reduction in resources available to meet load. On August 25, 2005, the PDCI unexpectedly dropped out of service just as Southern California was approaching its daily peak load. This outage, coupled with a 2,000 MW deviation in the day-ahead peak demand forecast, required the California ISO to issue a Transmission Emergency notice requesting utilities in SP26 reduce demand by curtailing 900 MW of firm load and 800 MW of voluntary interruptible load for about 35 minutes.

The staff included the effects of major transmission outages in the probabilistic analysis for this report. To calculate the overall impact of these failures on the SP26 region, the staff used data obtained by subpoena from the California ISO to compare hourly transfer capacities with the WECC rating for each transmission line. One limitation of using this methodology is that it may omit short duration outages that are not visible at the time the transfer capacity is reported. For example, a line that trips off at 5 minutes after the hour and is restored 50 minutes later would not be visible in the dataset. Figure 7 provides the range of transmission outages observed from May 15 thru September 15 for the years 2003 thru 2005.

Figure 7: Probability of Transmission Line Forced Outages California ISO SP26 Summer 2007



Probability of Maintaining Minimum Required Operating Reserves

Calculating generation and transmission availability and comparing the sum against a complete range of electricity demand results in a probabilistic assessment of resource adequacy. Using the Monte Carlo method, 5,000 cases of different resource and demand scenarios are developed for summer 2007. Each case is then reviewed to determine whether resources are sufficient to meet demand plus minimum operating reserves. The SAM-A model conducts the calculations in the following four major steps:

1. Using Monte Carlo draws, the model generates a deterministic case of input data in which each uncertainty factor takes a random value from its respective range of possible values.
2. Evaluation of the adequacy of supply is made for each deterministic case using spreadsheet tables.
3. The above steps are repeated for multiple cases to reasonably cover all possible combinations of the values of the uncertain factors.
4. The resulting set of cases is statistically processed to calculate:
    a. The probability that there is insufficient capacity to meet the peak demand and maintain a given reserve margin.
    b. The probability that there is sufficient capacity to meet the peak demand and maintain a given reserve margin.

Figures 8 thru 10 provide the probabilities of meeting minimum reserve margins for each of the three studied regions.

Figure 8: Operating Reserve - California ISO Summer 2007

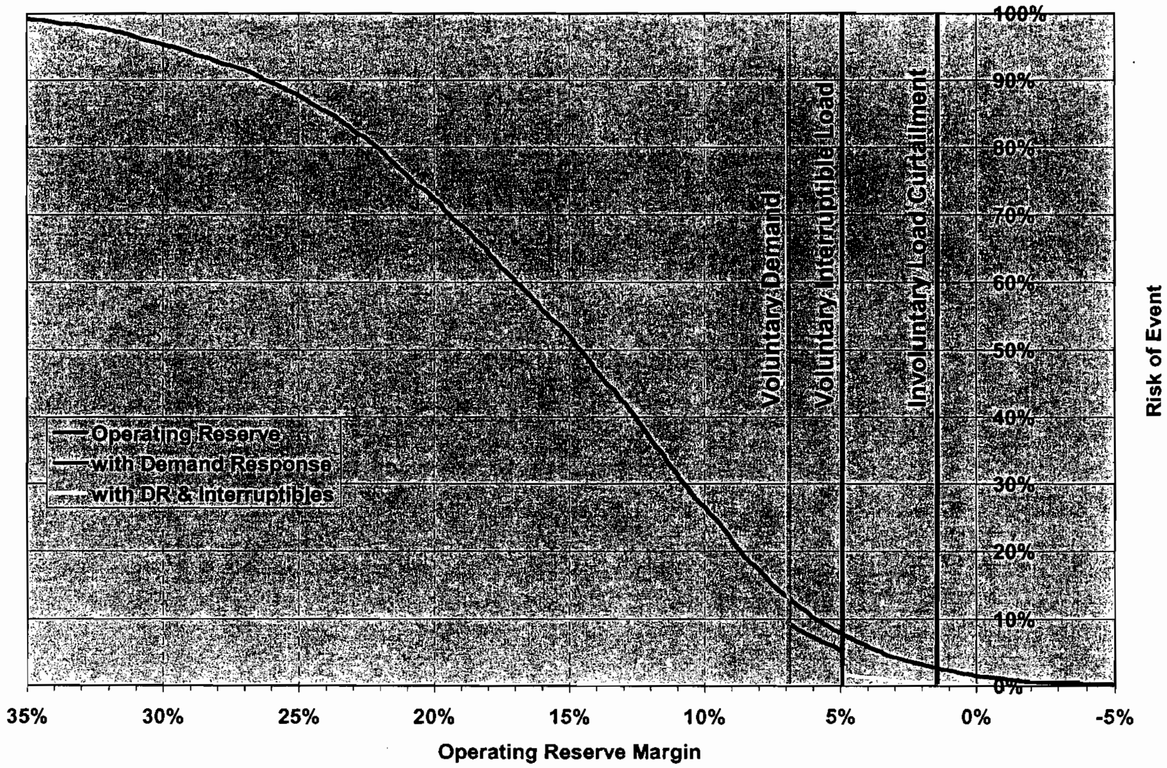


Figure 9: Operating Reserve - California ISO NP26 Summer 2007

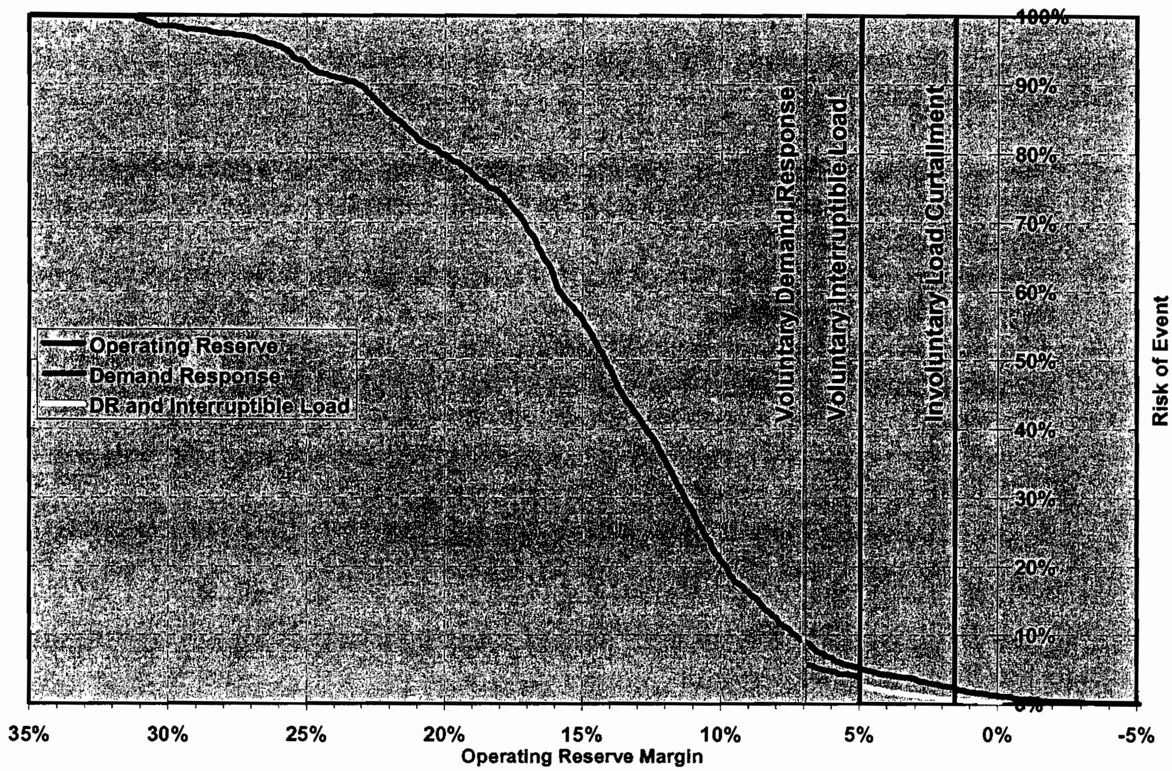


Figure 10: Operating Reserve - California ISO SP26 Summer 2007

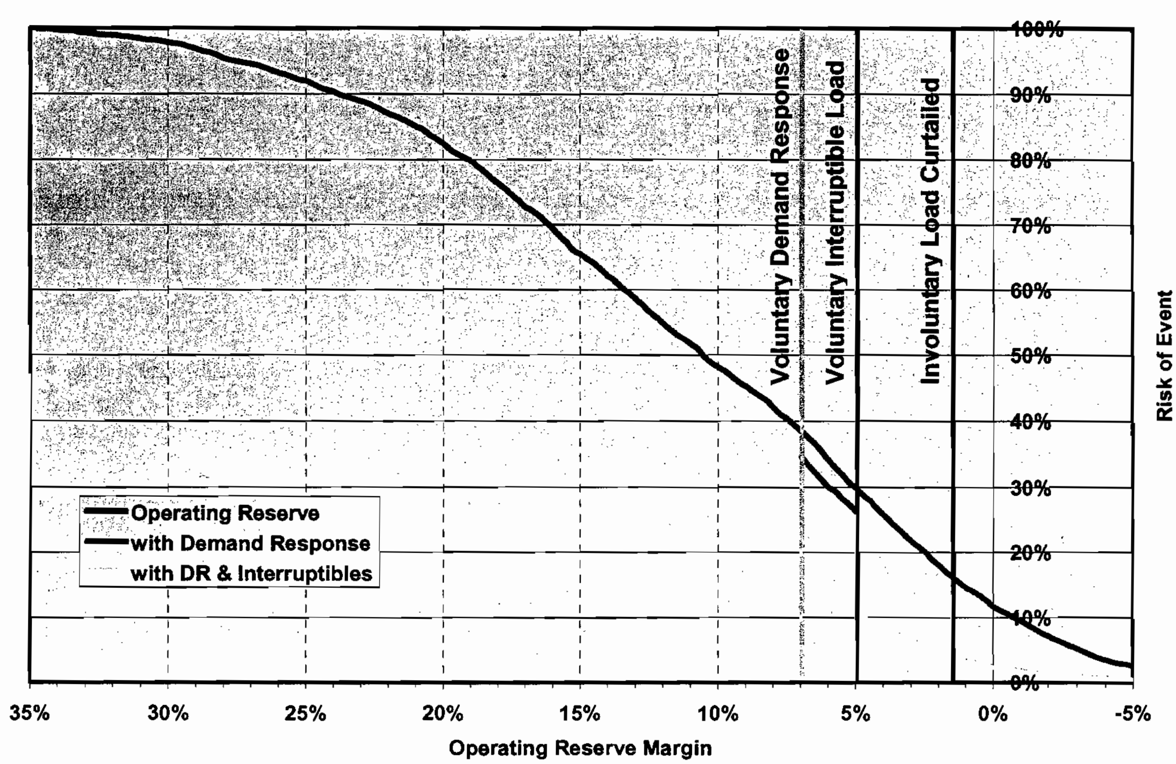
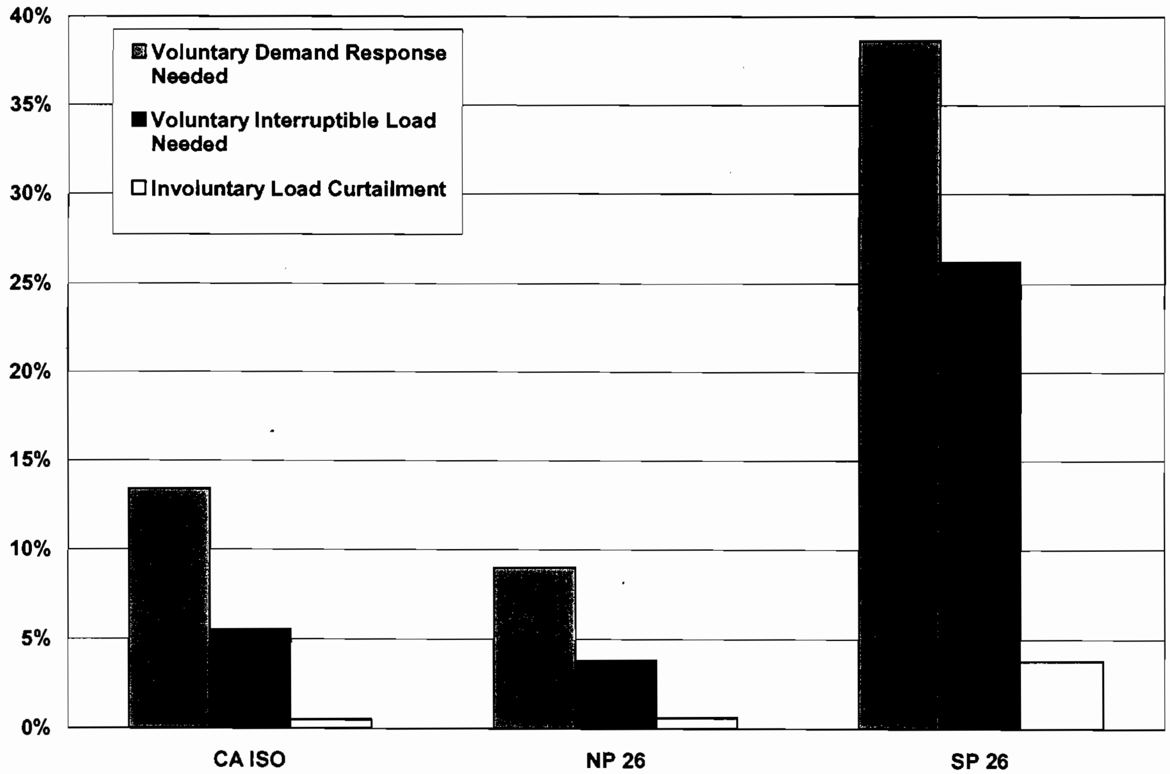


Figure 11 provides a snapshot of the critical points identified in Figures 8 thru 10 for each of the three regions on the peak day of summer 2007. The results can be also interpreted in terms of risk.

The staff estimates that there is a very low risk of involuntary load curtailments in the California ISO and NP26 regions. The risk is higher in the SP26 region, but still significantly lower than the WECC acceptable planning criteria of one event every 10 years, or a 10 percent probability.

The risk of utilizing voluntary demand response and interruptible load programs is much higher, particularly in SP26. This may be considered an acceptable level, however, since the customers enrolled in these programs receive preferential rates or other incentives to provide an extra level of mitigation during peak load conditions.

Figure 11: Risk of Event on the Summer 2007 Peak Day



APPENDIX 1: DETAILED ASSUMPTIONS USED TO CALCULATE PLANNING RESERVE MARGINS

Tables A-1 thru A-4 provide a detailed monthly outlook for each of the four regions to the planning reserve calculation.

Table A-1: 2007 Detailed Monthly Electricity Outlook – Statewide
(Megawatts)

Resource Adequacy Planning Conventions	June	July	August	September
1 Existing Generation	57,897	57,986	58,224	58,553
2 Retirements (Known)	0	0	0	0
3 High Probability CA Additions	89	238	329	0
4 Net Interchange	13,118	13,118	13,118	13,118
5 Total Net Generation	71,104	71,342	71,671	71,671
6 1-in-2 Summer Temperature Demand (Average)	57,125	59,726	60,344	59,419
7 Demand Response	524	524	524	524
8 Interruptible/Curtailable Programs	1,603	1,603	1,603	1,603
9 Planning Reserve	28.2%	23.0%	22.3%	24.2%

Table A-2: 2007 Detailed Monthly Electricity Outlook – California ISO Control Area
(Megawatts)

Resource Adequacy Planning Conventions	June	July	August	September
1 Existing Generation	46,265	46,354	46,592	46,768
2 Retirements (Known)	0	0	0	0
3 High Probability CA Additions	89	238	176	0
4 Net Interchange	10,600	10,600	10,600	10,600
5 Total Net Generation	56,954	57,192	57,368	57,368
6 1-in-2 Summer Temperature Demand (Average)	46,148	48,138	48,289	47,858
7 Demand Response	524	524	524	524
8 Interruptible/Curtailable Programs	1,403	1,403	1,403	1,403
9 Planning Reserve	27.6%	22.8%	22.8%	23.9%

Table A-3: 2007 Detailed Monthly Electricity Outlook – California ISO Northern Region (NP26)
(Megawatts)

Resource Adequacy Planning Conventions	June	July	August	September
1 Existing Generation	24,417	24,491	24,491	24,491
2 Retirements (Known)	0	0	0	0
3 High Probability CA Additions	74	0	0	0
4 Net Interchange	500	500	500	500
5 Total Net Generation	24,991	24,991	24,991	24,991
6 1-in-2 Summer Temperature Demand (Average)	20,653	21,098	20,815	20,052
7 Demand Response	322	322	322	322
8 Interruptible/Curtailable Programs	316	316	316	316
9 Planning Reserve	24.1%	21.5%	23.1%	27.8%

Table A-4: 2007 Detailed Monthly Electricity Outlook – California ISO Southern Region (SP26)
(Megawatts)

Resource Adequacy Planning Conventions	June	July	August	September
1 Existing Generation	21,848	21,863	22,101	22,277
2 Retirements (Known)	0	0	0	0
3 High Probability CA Additions	15	238	176	0
4 Net Interchange	10,100	10,100	10,100	10,100
5 Total Net Generation	31,963	32,201	32,377	32,377
6 1-in-2 Summer Temperature Demand (Average)	26,044	27,612	28,050	28,375
7 Demand Response	202	202	202	202
8 Interruptible/Curtailable Programs	1,087	1,087	1,087	1,087
9 Planning Reserve	27.7%	21.3%	20.0%	18.6%

Resources

Existing Generation

Existing generation accounts for thermal and hydro generation facilities operational as of August 1, 2006. Thermal generation consists of California ISO control area merchant and municipal thermal resources (including non-hydro renewable), Investor-Owned Utility (IOU) retained generation, and Qualifying Facilities (QFs). The merchant thermal generation in SP26 includes 1,080 MW of contracted capacity from units located in Baja California Norte. Thermal unit capacity is derated to reflect summer operating conditions. The summer derate capacity can range from 90 to 96 percent of nameplate capacity based on the type of unit and location. The Non-California ISO generation totals include both thermal and hydro capacity. Table A-5 provides a more detailed breakout of existing generation.

Table A-5: Derated Existing Generation

	SP26	NP26	TOTAL
CA ISO Control Area			
Merchant Thermal & QF	16,620	15,903	32,523
Municipal Thermal	751	182	933
IOU Retained Thermal	3,430	2,393	5,823
Derated Hydro	1,047	5,939	6,986
TOTAL CA ISO	**21,848**	**24,417**	**46,265**
Non-CA ISO	6,523	5,109	11,632
STATEWIDE TOTAL			**57,897**

Dependable hydro capacity at peak does not significantly change between a wet and a dry water year even though the historic record shows that dry conditions can have a significant impact on available energy production. The estimate of dependable hydro capacity that the staff uses is based on low water year conditions and would only be revised slightly upward in an extremely wet year to account for additional run-of-river capacity that could be produced in June and early July by additional runoff. The low precipitation conditions experienced this last winter are not expected to affect peak hydro capacity.

Additions and Retirements

Table A-6 provides a listing of the dependable capacity of all additions and retirements included in the 2007 outlook. The Long Beach repowering and four SCE peaking generation plants are included in the deterministic and probabilistic tables. However, if the summer peak occurs prior to August 1, or the construction of these plants is delayed, some or all of their capacity may not be available.

Table A-6: 2007 Additions and Retirements

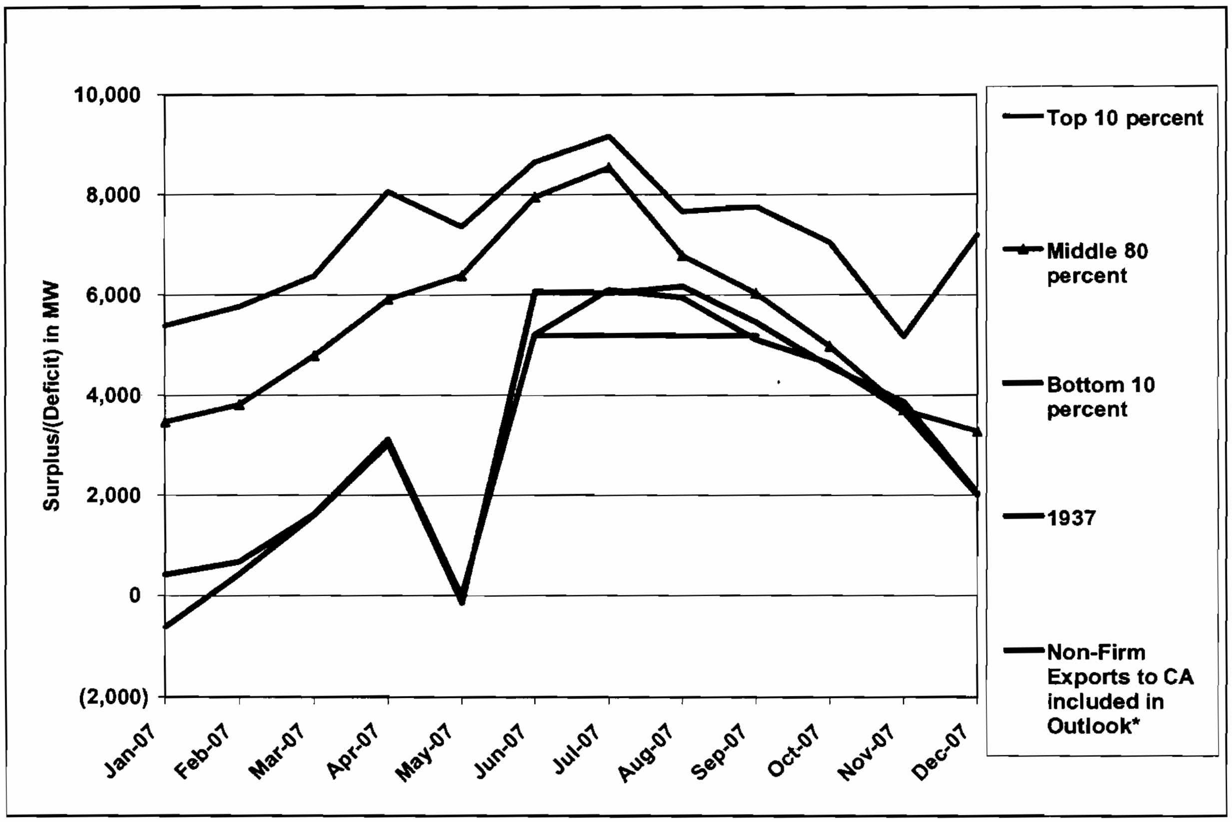
CA ISO Control Area					
SP26			**NP26**		
Additions			**Additions**		
Name	**MW**	**Expected**	**Name**	**MW**	**Expected**
MM Lopez Energy	6	Online	Midsun Generation	22	Online
Otay 3	4	Online	Lake Mendocino Hydro	3	May-07
Rancho Penasquitos	5	Online	Buena Vitsa Wind	3	May-07
Long Beach Repower	238	Jul-07	Fresno Cogen Expansion 2	23	May-07
SCE Regional Peakers	176	Aug-07	Bottle Rock Power	20	May-07
	429		Marina	3	May-07
				74	
Retirements (Known)			**Retirements (Known)**		
Non-CA ISO Control Areas					
LADWP & IID Control Areas			**SMUD & TID Control Areas**		
Additions			**Additions**		
Name	**MW**	**Expected**	**Name**	**MW**	**Expected**
			Roseville Energy Park	153	Aug-07
				153	

Net Interchange

Energy Commission staff determined that there is a sufficient quantity of surplus capacity in neighboring regions to meet the net interchange estimates detailed below. Figure A-1 provides a summary of the Bonneville Power Administration forecast of surplus capacity in the Northwest by various water conditions. Even in the driest year on record (1937), there is enough surplus capacity in the region to meet the interchange assumption included in the outlook.

The staff determined the amount of surplus resources in the Southwest by conducting internal modeling simulations and reviewing the *WECC Summary of Estimated Loads and Resources Report* issued in June 2006.

Figure A-1: 2007 Forecast of Northwest Regional Surplus/Deficit by Water Year



Based on 2006 BPA White Book 1-Hour Capacity in Megawatts

Tables A-7 thru A-10 detail the individual components of net interchange for each of the four regions. Some imports are identified as capable of carrying their own reserves since transmission is the factor that limits capacity exchange, and there is sufficient surplus to replace a generation outage from the exporting region.

Table A-7: Statewide Net Interchange

Northwest Imports (COI)[1]	4,000
Southwest Imports[1]	4,100
Pacific DC Intertie (California ISO)[1]	2,000
LADWP and IID Control Areas	3,018
Total	**13,118**

Table A-8: California ISO Net Interchange

California ISO Share of NW Imports (COI)[1]	2,300
WAPA Central Valley Imports	1,250
Southwest Imports[1]	4,100
Pacific DC Intertie (California ISO) [1]	2,000
Net LADWP Control Area Interchange	1,000
Total	**10,650**

Table A-9: NP26 Net Interchange

California ISO Share of NW Imports[1]	2,300
WAPA Central Valley Imports	1,250
Path 26 Exports	(3,000)
Total	**550**

The SP26 net interchange import numbers in Table A-10 include increases in the Southwest imports by 400 MW above 2005 observed levels to account for capacitor upgrades on the Palo Verde-to-Devers line. The LADWP Control Area interchange value includes wheeled power to other municipal utilities served by the California ISO.

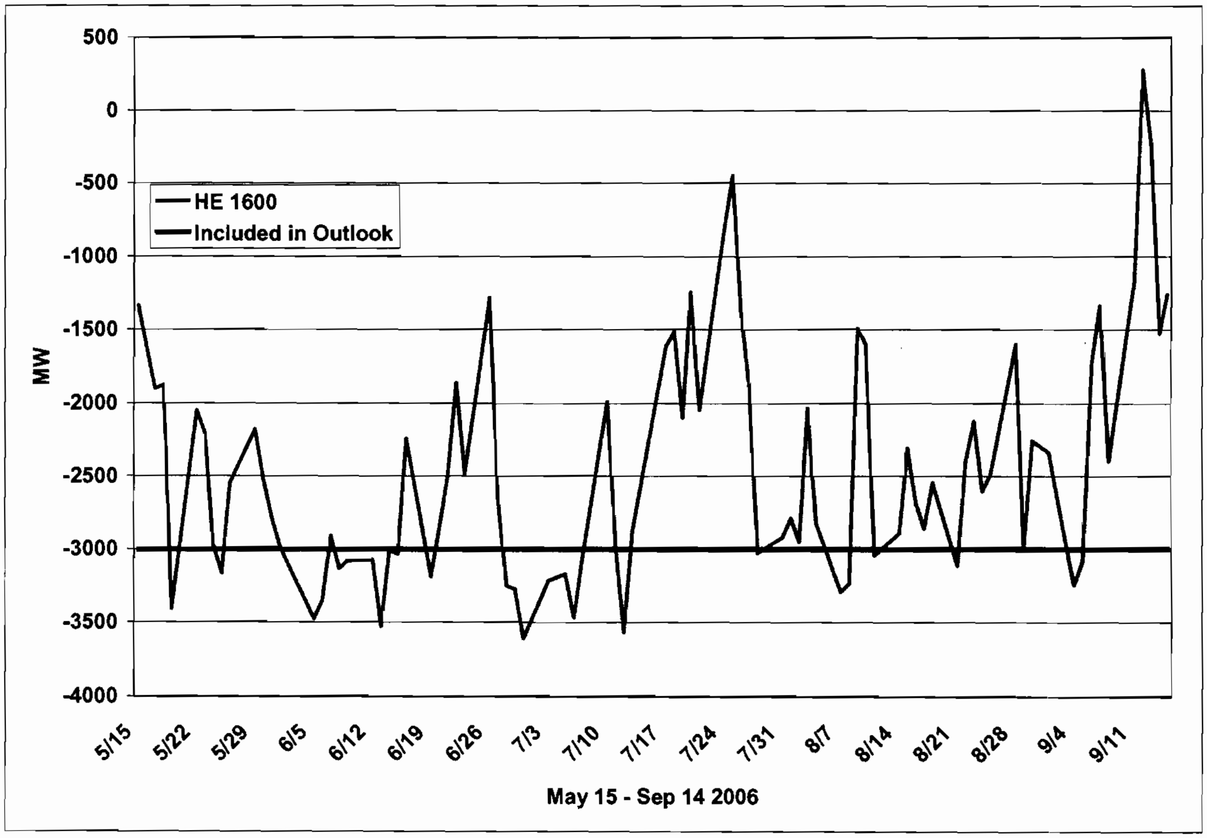
Table A-10: SP26 Net Interchange

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

[1] Imports assumed to carry reserves as transmission is the limiting factor.

Tables A-9 and A-10 include 3,000 MW of Path 26 North to South flows from NP26 to SP26. The export reflects the greater need of capacity in SP26 than NP26, but does not imply that it is contractually obligated to be delivered into SP26. This is a topic that the staff has identified for additional analysis to improve the modeling of this assumption. Figure A-2 provides the actual flows on Path 26 for the hour ending 1600 during summer 2006. Negative numbers indicate North to South flows and positive numbers are South to North. There is clearly a wide range of variation in the flows from one day to the next and, in the case of the heat storm period of July 24 and 25, the North to South flow was less than 1,000 MW during the unusual periods of extreme temperatures in Northern California.

Figure A-2: Path 26 Summer Flows HE 1600



Demand

1-in-2 Summer Temperature Demand (Average)

The demand forecast is the Statewide 1 in 2 Electric Peak Demand by Load Serving Entity (MW), Base Case in the most recent adopted Energy Commission demand forecast[1] as updated for the Investor Owned Utility portion in June 2006[2]. Complete documentation of assumptions and methodologies are included in the above reports.

Demand Response and Interruptible Programs

There are several mitigation measures available to the California ISO and individual utilities to respond to adverse conditions when operating reserves fall below minimum acceptable levels. Tables A-11 and A-12 detail the subscribed and expected IOU demand response and interruptible programs that are established at the CPUC and/or have been contracted by an IOU. Expected values are obtained by calculating the percentage of each subscribed program that was observed when previously called and applying that percentage to the currently subscribed amount. There is also an additional 110 MW of demand response from pumping load in SP26 that is not included in the PUC filings.

Because several of these programs are new or evolving, and participation may be significantly different than projections, the staff used the 2006 demand response estimate for the summer 2007 until actual data can be obtained on the performance of these programs. A detailed explanation of the demand response programs identified in Tables A-11 and A-12 follows:

Demand Response Programs

CPP. Critical Peak Pricing: CPP rates offer discounts (energy, demand or both, depending on the particular design) in non-critical hours but charge a premium for energy consumed on a limited number of days when system conditions are forecast to be critical, typically due to high expected demand or supply shortfalls.

DBP—Demand Bidding Program: Participants are paid an incentive for load reductions during curtailment events that are "bid" in to the utility a day in advance. There is no penalty for not bidding or not fulfilling the bid obligation.

CAL-DRP—California Demand Reserves Partnership: Program aggregators provide a contracted amount of load reduction during curtailment events by aggregating participant load reductions. Aggregators are paid a monthly capacity reservation charge for contracted load reduction amounts and an additional energy payment for consumption avoided during curtailment events.

C/I 20/20—20/20 for Commercial/Industrial customers (SDG&E only): A 20 percent bill credit given to customers who reduce on-peak consumption by an average of 20 percent or greater over all critical peak days.

BEC—Business Energy Coalition: A pilot program in the PG&E service territory operated in partnership with The Energy Coalition, participants are paid a per kW incentive to reduce load during curtailment events. The Energy Coalition works with participating customers to develop customized load reduction strategies.

Interruptible Load Programs

I-6— SCE Traditional non-firm rate: provides discounted energy and demand charges for load subject to curtailment during Stage 2 or 3 system emergencies. Per-kWh non-compliance penalties are applied to consumption above the contracted firm service level during events.

E-19/E-20—PG&E traditional non-firm rates: provide discounted energy and demand charges for load subject to curtailment during Stage 2 or 3 system emergencies. Per-kWh non-compliance penalties are applied to consumption above the contracted firm service level during events.

AL TOU CP—SDG&E critical peak rate: On-peak energy charges increase to $1.80/kWh during "critical peak" events, defined as Stage 2 or 3 system conditions.

BIP—Base Interruptible Program: Relatively new interruptible program that offers demand charge credits for load subject to interruption during system emergencies. Significant per kWh penalties apply for non-compliance.

ACCP—Air Conditioner Cycling Program (SCE only): Residential and small - to medium-sized commercial and industrial customers receive a bill incentive to allow SCE to remotely cycle their AC during system emergencies or high demand periods. The incentive varies based on the percent time the customer is willing to have his equipment cycled off.

OBMC—Optional Binding Mandatory Curtailment: Offers blackout avoidance during rotation outages for up to a 15 percent reduction in circuit load during events.

RBRP—Rolling Blackout Reduction Program (SDG&E only): Offers energy credits for load reductions—obtained through self-generation—during Stage 3 system conditions. Fifteen minute response is required.

AP-I—Agricultural and Pumping Interruptible (SCE only): Provides energy credits on consumption above the contracted firm service level in exchange for emergency reductions. Per kWh penalties apply for non-compliance.

"Emergency" CPP and DBP—these programs operate the same as the CPP and DBP programs except that notification to customers is made day-of instead of day ahead. Incentives reflect the higher value of the load reduction.

Smart Thermo—Smart Thermostat (SCE and SDG&E): Customers with communicating, programmable thermostats receive a bill incentive to allow the utilities to set their thermostats higher during periods of high demand or system emergencies.

Table A-11: IOU Subscribed Demand Response and Interruptible Programs

Demand Response Programs	Subscribed SCE	Subscribed SDG&E	Subscribed PG&E
CPP Programs	2	15	45
DBP	181	31	205
CAL-DRP	160	5	248
CI 20/20 or BEC		51	10
Demand Response Sub-Total	**343**	**102**	**508**
Interrruptible Load Programs			
I-6 or E-19/E-20	699		300
AL TOU CP		15	
BIP	101	8	27
ACCP	424	12	
OBMC/RBRP	10	65	14
AP-I/Emergency CCP/DBP-E/DBP-E	72	12	
Smart Thermo		2	
Interruptible Sub-Total	**1306**	**114**	**341**
Total	**1649**	**216**	**849**

Source: IOU filings under PUC R.00-10-002 and R.02-06-001.

Table A-12: IOU 2007 Expected Demand Response and Interruptible Programs

Demand Response Programs	Expected SCE	Expected SDG&E	Expected PG&E
CPP Programs	0.9	5.8	28.3
DBP	37.4	0.7	64.8
CAL-DRP	35.4	3.2	226.0
CI 20/20 or BEC		8.7	3.2
Demand Response Sub-Total	**74**	**18**	**322**
Interrruptible Load Programs			
I-6 or E-19/E-20	585.8		276.8
AL TOU CP		1.7	
BIP	60.8	0.2	25.8
ACCP	353.7	8.6	
OBMC/RBRP	10	25.2	13.5
AP-I/Emergency CCP/DBP-E/DBP-E	34	5.6	
Smart Thermo		1.4	
Interruptible Sub-Total	**1044**	**43**	**316**
Total	**1118**	**61**	**638**

Source: IOU filings under PUC R.00-10-002, R.02-06-001 and D.06-03-024.

Planning Reserve Margin

The planning reserve margin is calculated in a similar manner as in CPUC resource adequacy proceedings. The formula used to calculate the planning reserve margin is: ((Total Net Generation + Demand Response + Interruptible) / Demand)) – 1.

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[1] *California Energy Demand 2006-2016 - Staff Energy Demand Forecast, Revised September 2005 - Staff FINAL Report* (CED 2006). Publication # CEC-400-2005-034-SF-ED2. [http://www.energy.ca.gov/2005publications/CEC-400-2005-034/CEC-400-2005-034-SF-ED2.PDF]

[2] *Staff Forecast of 2007 Peak Demand, June 2006.* CEC-400-2006-008-SF [www.energy.ca.gov/2006publications/CEC-400-2006-008/CEC-400-2006-008-SF.PDF]

CALIFORNIA
ENERGY
COMMISSION

CALIFORNIA ENERGY DEMAND 2008-2018 STAFF REVISED FORECAST

(EXTRACTED FROM ORIGINAL DOCUMENT)

STAFF FINAL REPORT

NOVEMBER 2007
CEC-200-2007-015-SF2

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EXECUTIVE SUMMARY

Introduction

This California Energy Commission staff report presents forecasts of electricity and end-user natural gas consumption and peak electricity demand for the State of California and for utility planning areas and climate zones within the state for 2008–2018. The staff *California Energy Demand 2008–2018* revised forecast supports the analysis and recommendations in the *2007 Integrated Energy Policy Report,* including the electricity and natural gas system assessments and renewable energy progress analysis.

Statewide Forecast Results

Table ES-1 compares the staff revised electricity consumption forecast with the staff draft forecast published in June 2007 and the final forecast used in the *2005 Integrated Energy Policy Report.*[1] The revised forecast is slightly lower than the draft forecast in the beginning of the forecast period. Over the 10 year forecast period, it is projected to grow at a slightly higher rate (1.3 percent versus 1.2 percent) than the draft forecast. This results in the revised electricity forecast being about 0.3 percent higher than the draft electricity forecast by the end of the 10 years.

The revised peak forecast has the same starting point as the draft forecast and grows at a faster rate (1.4 percent versus 1.2 percent). This results in the revised peak forecast being about 1 percent (or 700 megawatts) higher than the draft peak forecast by the end of the forecast period. It is also about 3 percent higher than the September 2005 forecast, consistent with the increases seen in the 2006 and 2007 Energy Commission updates to the short-term peak demand forecast. The higher recorded peaks from those years represent the effect of higher saturations of residential air conditioning than was previously assumed. Peak demand is now projected to grow at an average of 1.4 percent annually. The peak demand growth rate is higher than electricity consumption growth because it is assumed the 2005 federal air conditioning standards have no impact on peak. While the 2005 standard's change to seasonal energy efficiency rating (SEER) of 13 is accounted for in the energy consumption projection, some analyses indicate uncertainty as to whether the move to a higher seasonal energy efficiency ratio actually reduces peak demand, therefore, no effects from the 2005 standards are included in the peak demand forecast.

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[1] The *California Energy Demand 2008–2018* revised forecast is referred to as the "revised 2008 forecast" or "revised forecast" throughout the report. The draft forecast published in June 2007 is referred to as the "draft 2008 forecast" or "draft forecast" throughout. The final forecast developed in support of the *2005 Integrated Energy Policy Report* and published in *California Energy Demand 2006–2016, Staff Energy Demand Forecast, Revised September 2005,* (publication no. CEC-400-2005-034-SF-ED2) is referred to as *CED 2006.*

Table ES-1: Comparison of *CED 2006* and Staff Draft and Revised Statewide Electricity Forecasts

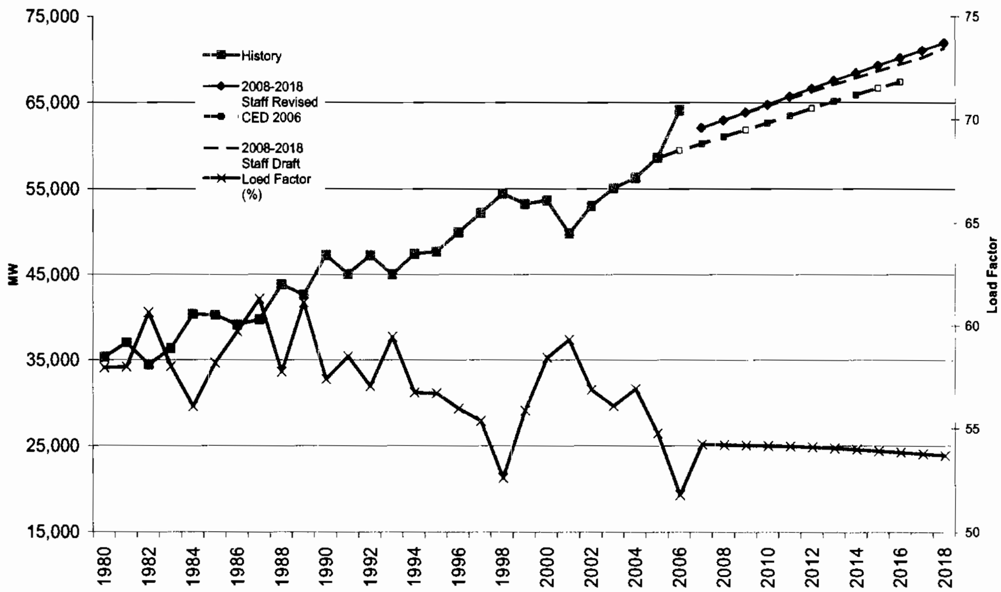
Consumption (GWH)					
	CED 2006 (Sept. 2005)	Staff Draft (July 2007)	Staff Revised (Oct. 2007)	Percent Difference Staff Draft/*CED 2006*	Percent Difference Staff Revised/Staff Draft
1990	229,375	229,868	229,868	0.22%	0.00%
2000	265,021	265,776	265,769	0.28%	0.00%
2005	276,012	272,491	272,449	-1.28%	-0.02%
2008	286,813	290,187	288,976	1.18%	-0.42%
2013	304,400	309,147	309,148	1.56%	0.00%
2016	313,397	319,331	320,178	1.89%	0.27%
Average Annual Growth Rates					
1990-2000	1.45%	1.46%	1.46%		
2000-2005	0.82%	0.50%	0.50%		
2005-2008	1.29%	2.12%	1.98%		
2008-2016	1.11%	1.20%	1.29%		
Peak (MW)					
	CED 2006 (Sept. 2005)	Staff Draft (July 2007)	Staff Revised (Oct. 2007)	Percent Difference Staff Draft/*CED 2006*	Percent Difference Staff Revised/Staff Draft
1990	47,431	47,209	47,285	-0.47%	0.16%
2000	54,028	53,661	53,669	-0.68%	0.01%
2005	58,546	58,602	58,646	0.10%	0.07%
2008	61,042	62,935	62,946	3.10%	0.02%
2013	65,144	67,067	67,524	2.95%	0.68%
2016	67,379	69,426	70,174	3.04%	1.08%
Average Annual Growth Rates					
1990-2000	1.31%	1.29%	1.27%		
2000-2005	1.62%	1.78%	1.79%		
2005-2008	1.40%	2.41%	2.39%		
2008-2016	1.24%	1.23%	1.37%		
Historic values are shaded					
GWH=gigawatt-hour					
MW = megawatt					

Source: California Energy Commission, 2007

The growth of peak demand is offset slightly by a higher self-generation load forecast; the revised forecast includes staff's estimates of effects from the California Solar Initiative program and other programs to promote market penetration of photovoltaics. **Figure ES-1** graphically represents the peak forecast.

Figure ES-1 also shows the load factor for the state as a whole, as well as the estimated 1-in-10 peak temperature scenario. The load factor represents the relationship between average energy demand and peak; a high load factor means the peak demand is not much higher than average hourly demand. The load factor varies with temperature: in extremely hot years (1998, 2006), actual peak demand shows a sharper increase than would be observed with average peak weather. The general decline in the load factor over the last 20 years represents a population shift to warmer areas and more homes and businesses with central air conditioning. The 1-in-10 temperature scenario estimate represents the projected peak given the 90th percentile of annual maximum temperatures. This is defined as a statewide weighted annual maximum temperature value, which theoretically would occur only 1 year out of every 10.

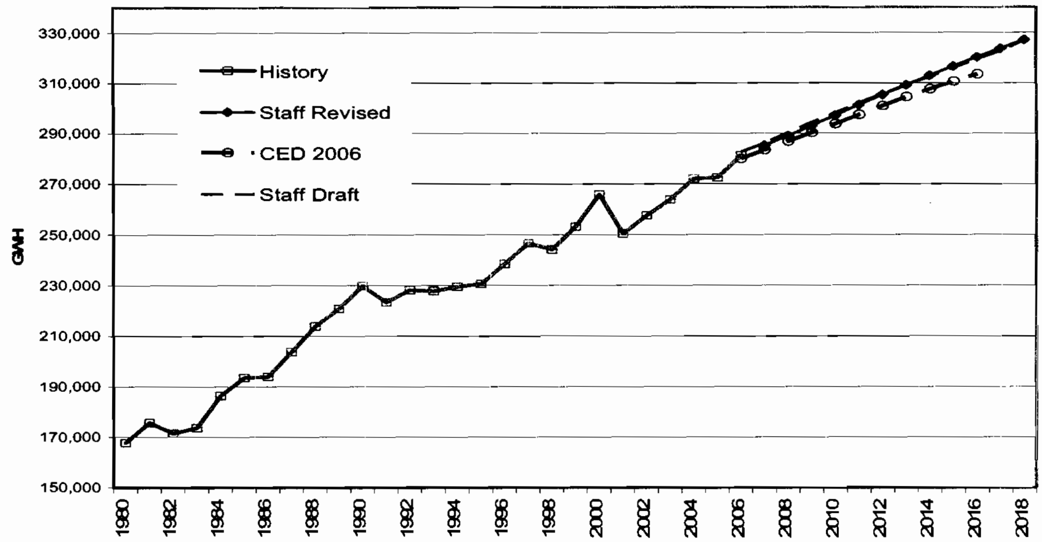
Figure ES-1: Statewide Non-Coincident Peak Demand



Source: California Energy Commission, 2007

The overall increase in the statewide electricity forecast compared to the *CED 2006* forecast reflects several factors. Higher-than-projected actual consumption in 2005 and 2006, adjusted for temperature, increased the starting point. Improvements to floor space estimation techniques led to increased floor space projections, which, accordingly, raise the forecast for commercial electricity consumption. Higher projections of personal income increase the forecasts of residential and commercial sector consumption. **Figure ES-2** shows the effect of these changes from the previous forecast.

Figure ES-2: Statewide Electricity Consumption



Source: California Energy Commission, 2007

Summary of Revised Utility Area Forecasts

While the revised forecasts are not significantly different at the statewide level, the revised Department of Finance population projections had a noticeable effect for some individual utility areas. The Sacramento Municipal Utility District (SMUD) area forecast was revised downward 9 percent as population previously expected to locate in Sacramento County is now expected to locate in the surrounding areas not served by SMUD. The Southern California Edison (SCE) energy forecast increased by 2.5 percent and the peak forecast by 3.5 percent. The larger increase of the peak forecast reflects the change in population distribution. Within the SCE area, peak demand is projected to grow 2.3 percent annually in the Riverside-San Bernardino area, but less than 1 percent annually in the coastal areas. A similar pattern is evident in the Pacific Gas & Electric Company (PG&E) planning area. The energy consumption forecast was revised downward 1 percent because population projections are lower overall, but the peak forecast increases slightly because of growth in hotter areas served by PG&E and increased saturation of air conditioners in cooler areas that are used only during peak periods. Peak demand in the Sacramento Valley and foothills area is projected to grow by 2.4 percent annually, while the consumption in the East Bay and Central Coast area forecast is projected to grow at 1.3 percent. Demand in the Central Valley (excluding the Sacramento area) is projected to grow at 1.6 percent. Forecast results by climate zone are reported in the chapters on the SCE and PG&E forecasts. Another fast-growing area is that by served the Imperial Irrigation District (IID), with peak demand projected to grow 2.7 percent annually.

The revised annual consumption and peak forecasts for each utility area are shown in tables ES-2 and ES-3. The peak demand forecast for the California

Department of Water Resources (DWR) represents their peak demand on summer afternoons, assuming average water conditions.

Table ES-2: Revised Electricity Consumption Forecast by Utility Planning Area

Planning Area Annual Consumption Forecast (GWH)					Annual Growth Rates		
	1990	2005	2008	2018	1990-2005	2005-2008	2008-2018
PG&E	86,803	101,460	107,929	122,336	1.0%	2.1%	1.3%
SMUD	8,358	10,523	11,174	12,851	1.5%	2.0%	1.4%
SCE	82,069	99,261	105,054	121,400	1.3%	1.9%	1.5%
LADWP	23,263	24,638	25,921	27,154	0.4%	1.7%	0.5%
SDG&E	14,926	19,910	21,304	24,567	1.9%	2.3%	1.4%
Burbank-Glendale	2,065	2,201	2,245	2,305	0.4%	0.7%	0.3%
Pasadena	898	1,193	1,253	1,301	1.9%	1.7%	0.4%
Imperial	1,921	3,232	3,413	4,441	3.5%	1.8%	2.7%
DWR	8,171	8,283	8,865	8,865	0.1%	2.3%	0.0%

Table ES-3: Revised Peak Demand Forecast by Utility Planning Area

Planning Area Peak Demand Forecast (MW)					Annual Growth Rates		
	1990	2005	2008	2018	1990-2005	2005-2008	2008-2018
PG&E	17,055	21,435	23,413	26,754	1.5%	3.0%	1.3%
SMUD	2,198	2,964	3,174	3,645	2.0%	2.3%	1.4%
SCE	17,635	21,956	23,272	27,112	1.5%	2.0%	1.5%
LADWP	5,326	5,725	5,717	5,966	0.5%	0.0%	0.4%
SDG&E	2,956	4,003	4,568	5,263	2.0%	4.5%	1.4%
Burbank-Glendale	540	590	600	609	0.6%	0.6%	0.1%
Pasadena	250	292	300	306	1.0%	0.9%	0.2%
Imperial	551	897	1,063	1,395	3.3%	5.8%	2.8%
DWR	772	783	838	838	0.1%	2.3%	0.0%

Source: California Energy Commission, 2007

Forecast of End-User Natural Gas Demand

The revised natural gas forecast, shown in Table ES-4, has a higher growth rate than the September 2005 forecast. However, revised historic consumption estimates makes the revised forecast about 4 percent lower than September 2005 at the beginning of the forecast period. The increased growth rate of the revised forecast relative to September 2005 is because of higher commercial floor space projections. In the revised forecast, the growth rate slows in later years because of rising natural gas prices which reduce commercial and industrial demand. This forecast includes natural gas demand for end use sectors, such as residential, commercial, and industrial, but not the natural gas used for electric generation.

Table ES-4: Comparison of *CED 2006* Forecast and Staff Draft and Revised Forecasts of Statewide End-User Natural Gas Consumption

End-User Consumption (MM Therms)					
	CED 2006	Staff Draft (June 2007)	Staff Revised (Oct. 2007)	Percent Difference Staff Revised/*CED 2006*	Percent Difference Staff Revised/Staff Draft
1990	12,893	12,893	12,893	0.0%	0.0%
2000	13,915	13,915	13,913	0.0%	0.0%
2005	13,550	13,041	13,039	-3.8%	0.0%
2008	13,528	13,970	13,445	-0.6%	-3.8%
2016	13,850	14,625	13,978	0.9%	-4.4%
Annual Average Growth Rates					
1990-2000	0.77%	0.77%	0.76%		
2000-2005	-0.53%	-1.29%	-1.29%		
2005-2008	-0.05%	2.32%	1.03%		
2008-2016	0.30%	0.57%	0.49%		
Historic values are shaded					
End-User Consumption excludes natural gas used to generate electricity					

Source: California Energy Commission, 2007.

Overview of Methods and Assumptions

The staff revised demand forecast is the product of essentially the same methods used to prepare earlier long-term staff forecasts. The commercial, residential, and industrial sector energy models are structural models that attempt to explain how energy is used by process and end use. The forecasts of agricultural and water pumping energy demand are made using econometric methods. After adjusting for historical temperatures and usage, the annual consumption forecast is used to project annual peak demand.

Economic and Demographic Assumptions

Population growth is a key driver for residential energy demand, as well as for commercial growth and demand for water pumping and other services. This forecast uses the California Department of Finance's most recent long-term population forecast, published in July 2007. The draft forecast used the Department of Finance's May 2004 projections. Population is now projected to grow at about 1.2 percent annually. By comparison, statewide population grew an average of 1.3 percent annually from 1990 to 2000. The declining growth rates over the forecast horizon reflect lower rates of fertility and immigration as the population of California ages. Other economic projections are from Economy.com.

Electricity Rate Projections

The 2005 forecast used rate projections developed by Energy Commission staff, which in general declined over time. For both this revised forecast and the draft forecast, the sector energy demand was forecasted with future real electricity rates held constant at their current levels. This change to higher forecasted rates, compared with those used in the *CED 2006* forecast, primarily affects commercial and industrial sector demand.

Climate Zone Forecasts

For the revised 2008-2018 forecast, the PG&E and SCE planning areas were forecast by several distinct climate zones. The PG&E planning area is divided into five zones and the SCE area into four. All other planning areas constitute one climate zone only. Historically the climate zones were used only to project energy use for heating and cooling equipment; all other end uses were assessed at the utility level. For this forecast, economic and demographic projections by climate zone were used to capture the effects of differential growth in households, income, commercial floor space, and industrial activity.

Conservation Quantification

This forecast report also includes estimates of conservation savings that are included in the baseline forecast. These estimates are made by broad program category. The estimates have been implicitly included in all of the previous forecasts but have not been explicitly identified since the 1990s era of demand forecasts.

Form 1.5b
California Energy Demand 2008-2018 Staff Revised Forecast
1-in-2 Electric Peak Demand by Control Area and Climate Zone (MW)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Average Annual Growth Rate 2008-2018
PG&E North	19,564	19,812	20,075	20,338	20,826	20,912	21,193	21,467	21,745	22,022	22,292	22,562	1.3%
PG&E Service Area by CEC Forecasting Climate zone:													
Zone 1 (North Coast end Mountain)	774	782	794	805	817	830	841	853	864	876	887	898	1.4%
Zone 2 (Sacramento Region)	2,141	2,187	2,244	2,298	2,357	2,420	2,480	2,542	2,805	2,668	2,732	2,798	2.5%
Zone 3 (Valley Region)	6,418	8,513	6,590	6,671	8,768	8,846	6,934	7,019	7,107	7,194	7,282	7,368	1.2%
Zone 4 (East Bay Region)	5,521	5,583	5,657	5,732	5,817	5,899	5,981	6,060	6,140	6,220	6,294	6,371	1.3%
Zone 5 (San Francisco Region)	3,523	3,546	3,574	3,603	3,832	3,659	3,684	3,707	3,731	3,752	3,772	3,791	0.7%
PG&E Service Area Total	18,377	18,812	18,860	19,109	19,382	19,654	19,921	20,182	20,446	20,710	20,968	21,225	1.3%
PG&E Direct Access	1,017	987	967	967	967	987	967	967	967	967	987	967	0.0%
PG&E Bundled	17,359	17,645	17,893	18,142	18,415	18,887	18,954	19,215	19,480	19,744	20,001	20,259	1.4%
Northern California Power Agency	510	517	524	531	538	545	552	559	566	573	580	586	1.3%
Silicon Valley Power	474	480	486	491	498	504	509	515	520	525	530	534	1.1%
CCSF	118	118	119	120	120	121	121	122	122	122	123	123	0.4%
Other Publicly Owned Utilities	85	86	87	87	88	89	69	90	91	91	92	93	0.8%
Dept of Water Resources - North	141	141	141	141	141	141	141	141	141	141	141	141	
Total North of Path 15	19,705	19,954	20,216	20,479	20,767	21,053	21,334	21,609	21,887	22,163	22,434	22,703	1.3%
Path 26 Pacific Gas & Electric - Bundled South	1,468	1,484	1,504	1,524	1,546	1,568	1,590	1,611	1,632	1,653	1,673	1,693	1.3%
Path 26 - Dept of Water Resources	233	233	233	233	233	233	233	233	233	233	233	233	0.0%
Total Zone Path 26	1,701	1,718	1,737	1,757	1,760	1,802	1,823	1,844	1,865	1,887	1,907	1,927	
Total NP15	21,406	21,671	21,954	22,236	22,547	22,855	23,158	23,453	23,752	24,050	24,340	24,630	1.3%
Turlock Irrigation District Control Area	**554**	**563**	**572**	**581**	**591**	**601**	**611**	**621**	**631**	**641**	**651**	**661**	1.6%
Sacramento Municipal Utilities District	3,138	3,174	3,216	3,261	3,311	3,363	3,415	3,465	3,515	3,559	3,603	3,645	1.4%
WAPA	220	220	220	219	219	219	219	218	218	218	218	217	-0.1%
Redding	248	252	258	265	273	279	285	290	296	302	308	314	2.2%
Roseville	330	338	346	355	364	374	383	392	402	411	421	431	2.5%
Shasta	33	34	34	34	35	35	35	36	36	36	36	37	0.8%
Modesto Irrigation District	698	710	722	734	747	760	773	786	799	813	828	839	
Total SMUD/WAPA Control Area	4,665	4,727	4,797	4,868	4,949	5,030	5,110	5,188	5,267	5,339	5,412	5,483	1.5%
Southern California Edison Planning Area Total	22,876	23,272	23,874	24,082	24,480	24,877	25,258	25,637	26,013	26,382	26,742	27,112	1.5%
SCE Service Area by CEC Forecasting Climate zone:													
Zone 7 (Southern San Joaquin Valley)	1,239	1,264	1,292	1,318	1,347	1,375	1,404	1,430	1,458	1,486	1,515	1,545	2.0%
Zone 8 (Coastal LA Basin)	8,687	8,787	8,888	8,992	9,096	9,198	9,289	9,377	9,464	9,542	9,616	9,695	1.0%
Zone 9 (Inland LA Basin)	3,903	3,960	4,018	4,076	4,138	4,194	4,250	4,304	4,358	4,410	4,483	4,509	1.3%
Zone 10 (Inland Empire)	7,260	7,484	7,652	7,841	8,017	8,199	8,378	8,561	8,743	8,927	9,107	9,294	2.2%
SCE Service Area Total	21,109	21,476	21,849	22,227	22,597	22,966	23,321	23,672	24,022	24,365	24,701	25,045	1.5%
SCE Direct access	1,615	1,815	1,615	1,615	1,615	1,815	1,815	1,615	1,615	1,615	1,615	1,615	0.0%
SCE Bundled	19,494	19,861	20,234	20,812	20,982	21,351	21,706	22,057	22,407	22,750	23,086	23,430	1.7%
Anaheim Public Utilities Dept.	566	572	578	584	591	597	602	607	612	617	621	625	0.9%
Riverside Utilities Dept	572	587	603	619	634	649	664	679	694	709	724	739	2.3%
Vernon Municipal Light Dept	180	182	182	184	185	187	186	189	190	190	191	191	0.5%
Metropolitan Water District	184	185	165	185	185	188	185	185	188	186	186	186	0.1%
Other Publicly Owned Utilities	264	270	278	282	288	293	299	304	310	315	321	326	1.9%
Pasadena Water and Power Dept	299	300	300	300	302	303	303	304	305	305	306	306	0.2%
San Diego Gas & Electric	4,506	4,568	4,641	4,712	4,784	4,856	4,925	4,994	5,063	5,131	5,198	5,263	1.4%
SDG&E Bundled Customers	3,907	3,970	4,043	4,114	4,186	4,258	4,327	4,396	4,465	4,533	4,599	4,665	
SDG&E Direct Access	598	598	598	598	598	598	598	598	598	596	598	598	0.0%
Dept of Water Resources - South	483	463	463	463	483	463	463	483	463	463	463	463	0.0%
Total South of Path 15	28,144	28,604	29,079	29,557	30,029	30,498	30,949	31,398	31,844	32,261	32,709	33,145	1.5%
Los Angeles Department of Water and Power	5,685	5,717	5,754	5,786	5,813	5,840	5,863	5,886	5,907	5,926	5,946	5,966	0.4%
Burbank Public Service Dept	292	292	292	293	294	295	295	294	297	297	298	298	0.2%
Glendale Public Service Dept	309	308	309	309	310	310	311	312	311	311	311	311	0.1%
Total LADWP Control Area	6,285	6,317	6,355	8,388	6,417	6,444	6,469	6,493	6,515	6,536	8,555	6,575	0.4%
Imperial Irrigation District Control Area	1,032	1,063	1,097	1,129	1,162	1,195	1,227	1,260	1,294	1,327	1,361	1,395	2.8%
Total CAISO	49,550	50,275	51,032	51,794	52,576	53,353	54,107	54,851	55,597	56,331	57,049	57,775	1.4%
Total State	62,085	62,946	83,652	64,760	65,895	66,623	67,524	68,413	69,302	70,174	71,027	71,889	1.3%
Coincident Demand													
Total CAISO Coincident Demand	48,363	49,071	49,810	50,553	51,317	52,076	52,811	53,537	54,265	54,982	55,683	56,392	1.4%
Total Statewide Coincident Demand	60,599	61,439	62,323	63,209	64,121	65,028	65,907	66,775	67,643	68,494	69,326	70,167	1.3%

Individual LSE Peaks are coincident with the transmission planning area peak.
*System requirements tables exclude load located in non-California based control areas; these are shown in Tables 1.1c and 1.4b in the "Other" planning area.