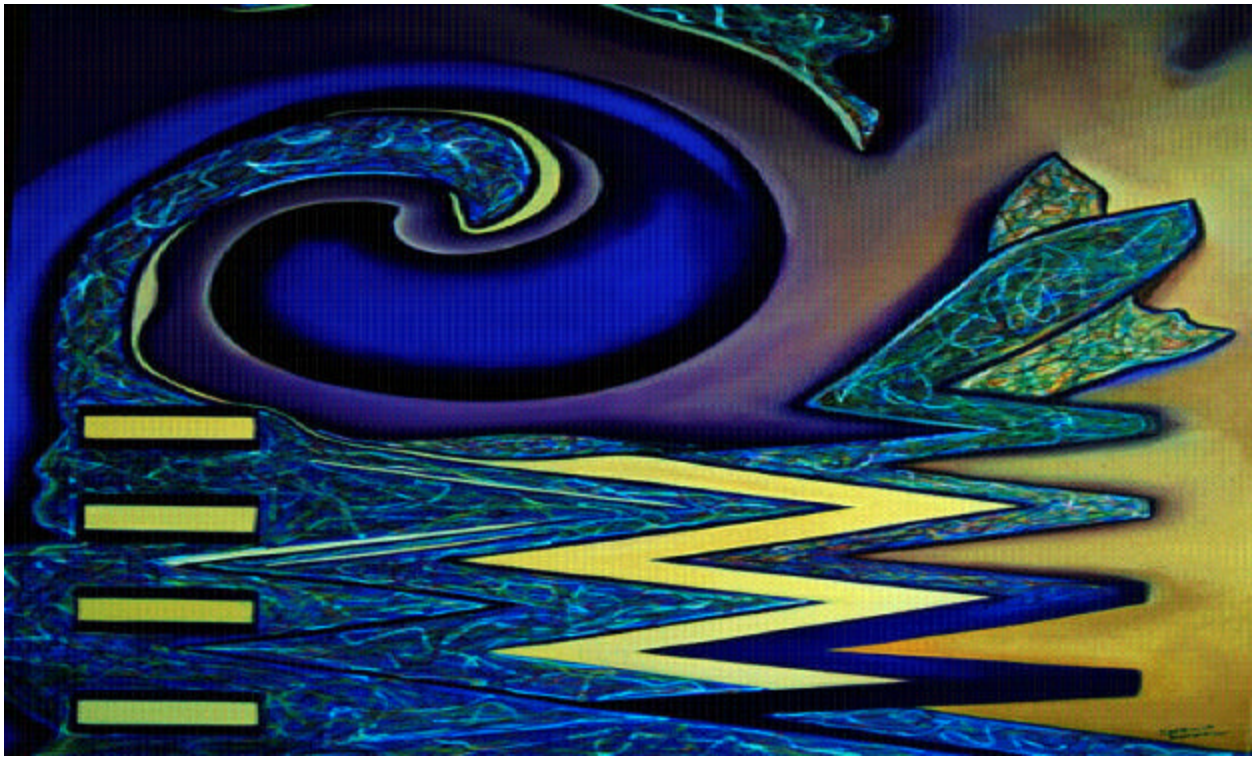
Into The Future



Lon W. House, Ph.D.

530.676.8956

www.waterandenergyconsulting.com

ACWA Spring Conference

May 5, 2005

San Jose, CA

ACWA IEPR Policy Recommendations

- Generation
  - **General -** allow aggregation of water agency meters to qualify for net metering, similar to what is happening on demand side
  - **Solar -** increase available pool of rebate money to allow additional water agencies to install solar, increase contracting timeframe after reservation notification to account for longer public agency decision making time.
- Demand Response Programs
- A multi-year program
  - so water agencies can have some investment recovery period
- A demand payment for participation in the program
  - to cover necessary capital investment costs
- Payment of a fixed risk premium
  - water customers won't be impressed if their district saved the state if they run out of water, pressure, fire protection, or are required to boil water.
- A per-event payment
  - to cover additional staffing requirements, component wear and tear, and replacement water costs
- Has a reasonable verification criteria
  - 10 day rolling average doesn't work. Need to be adjusted for load reduction from previous hour.
- Accurate and timely settlements
  - hassles with payments, or waiting months, cools ardor for the program
- Adequate curtailment notification
  - in time to prepare and staff up for curtailment event.
- Energy Impacts -
  - **New Regs** - Energy impacts and costs of new and existing water regulations should be specifically addressed.
  - **New Development** - Energy impact and costs of supplying water for new development needs to be considered.
  - **New Supply** - Energy requirements and costs of new/additional water supplies need to be addressed.

Recommendations (cont.)

- Utility incentives
  - **Water agency specific technologies** - such as increased storage, water parameter sensors, and controls - should be eligible for utility demand reduction incentives.

- Water Agency Backup Generation
  - Should be able to be used prior to blackouts to avoid them.
  - On site generation delivered to the system should net iu with other usage (other sites).

- Water Customer Demand Response Needs To Be Investigated
  - Time of Use Water Meters need to be developed and demonstrated and Time of Use Water Tariffs need to be developed, implemented, and their effectiveness in shifting demand analyzed.

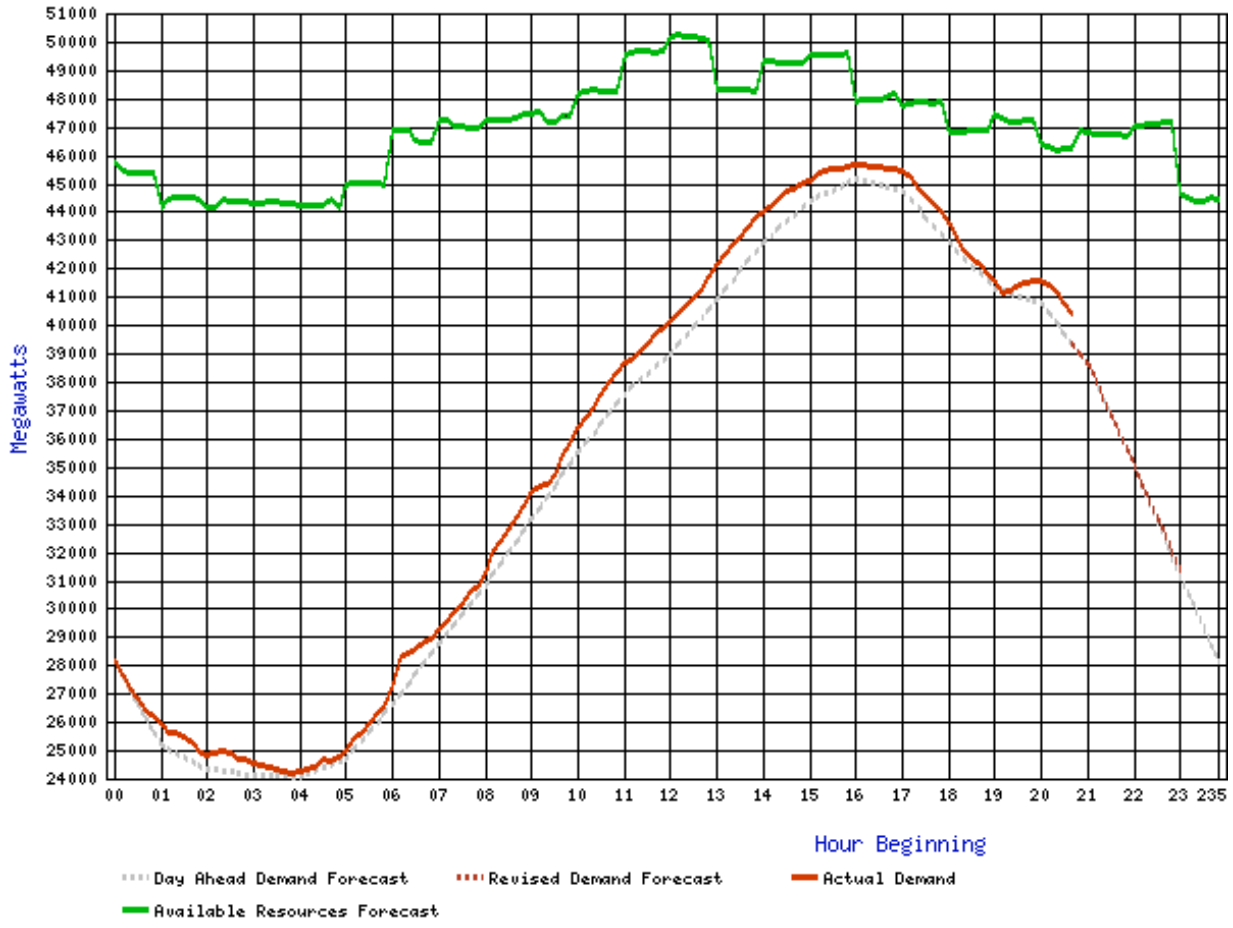
Additional Water Peak Demands Analysis to IEPR

- Existing Conjunctive Use in Drought/Dry Years ~ 350MW
  - does not include increased on farm pumping
- Proposed Conjunctive Use Development/Drought ~ 1350 MW
- Desalinization ~ 250 MW salt water plus ~250 MW desalting groundwater = 500 MW
- Electric conversion of diesel pumps ~380 MW
- Drought/Climate Change - unknown
- Increased Treatment Requirements - unknown
- Increased Population -unknown

State of the State

- Electricity rates 20% than prior to deregulation
  - Long term electricity contracts through 2013
  - Exit fees, Customer Responsibility Surcharges
- Surging demand, increasing generation retirements, slow new generation construction = Problems 2005-2008
- Natural gas $5-8/MMBTU
  - New LNG facilities being constructed available 2007/2008
- Regulatory agencies betting the ranch on conservation/demand response - you will conserve
  - mandatory CPP tariffs by next summer
- Opportunities/incentives for self generation, demand curtailment

September 8, 2004



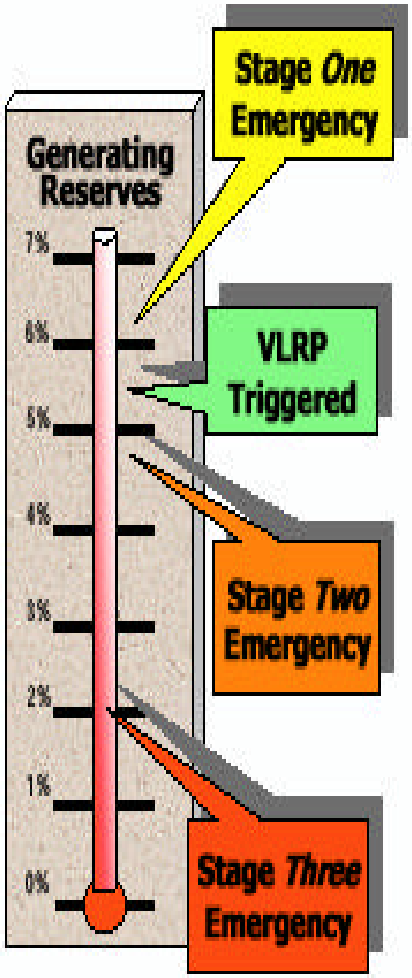
Previous energy use record of 43,609 MW, set in July 1999.

July 19 - 44,042 MW; July 20 - 44,330 MW; July 21 - 44,360 MW; August 10 - 44,497 MW; August 11 - 44,872 MW; September 7 - 45,165 MW; September 8 - 45,597 MW.

ISO Warnings

Electrical Emergency Communications and Voluntary Load Reduction Program

*Stages of Electrical Emergencies**



Generating reserves less than *requirements*

(Continuously recalculated. Between 6% & 7%)

- ✓ Issue Stage One news release calling for conservation
- ✓ Coordinate with public safety agencies

Voluntary Load Reduction Program

- ✓ Voluntary commercial customers reduce electricity use.
- ✓ Provides advance notice to businesses that power reserves are low and that business operations could be affected.

Generating reserves less than 5%

- ✓ Issue Stage Two news release
- ✓ Invoke UDC Interruptible Load Programs

Generating reserves less than *largest contingency*

(Continuously recalculated. Between 1.5% & 3%)

- ✓ Issue Stage Three news release
- ✓ Issue *Notice of Load Interruptions*
- ✓ Instruct utilities to implement rotating outages

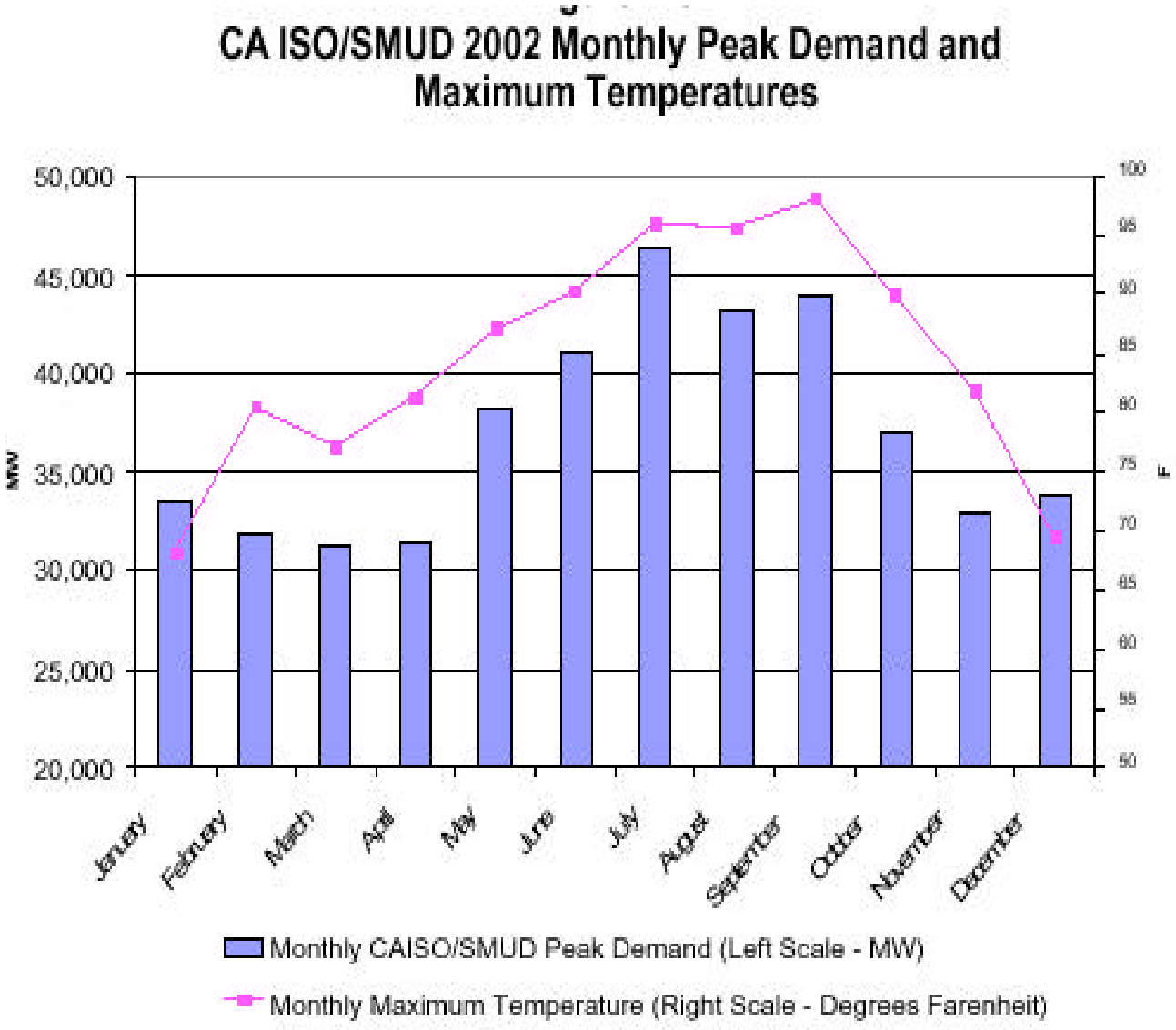
*Many emergencies are due to operating reserve levels, however, some emergencies are declared as a result of transmission line losses or limitations.

Generation Summary

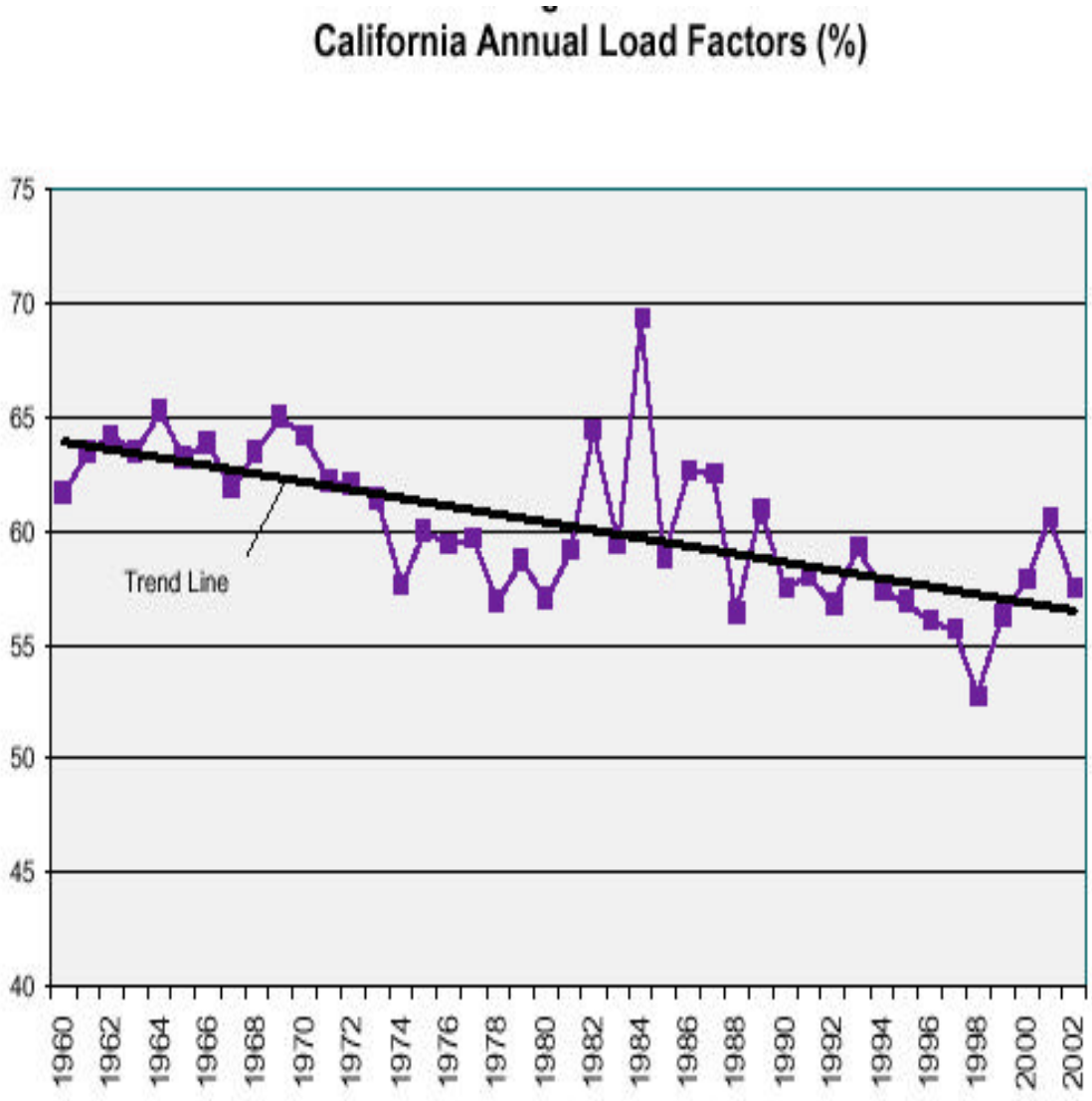
Changes in Generation Facilities within the ISO Control Area since 2001

		2001	2002	2003	2004	2005	Total Through August 2005	Net NP26	Net SP26
New Generating Units by Sub-Regions									
	NP26	1,328	2,400	2,583	3	939	7,253	7,253	
	SP26	639	478	2,247	745	1,292	5,401		5,401
Total New Generating Units		*1,967*	*2,878*	*4,830*	*748*	*2,231*	*12,654*		
Retirements by Sub-Regions									
	NP26	(28)	(8)	(980)	(4)		(1,020)	(1,020)	
	SP26		(1,162)	(1,172)	(176)	(450)	(2,960)		(2,960)
Total Retirements		*(28)*	*(1,170)*	*(2,152)*	*(180)*	*(450)*	*(3,980)*		
Net Change in Capacity		1,939	1,708	2,678	568	1,781	8,674	6,233	2,441

Electricity Use Depends Upon Temperature



Electricity Use Becoming More Peaked



Load Forecast

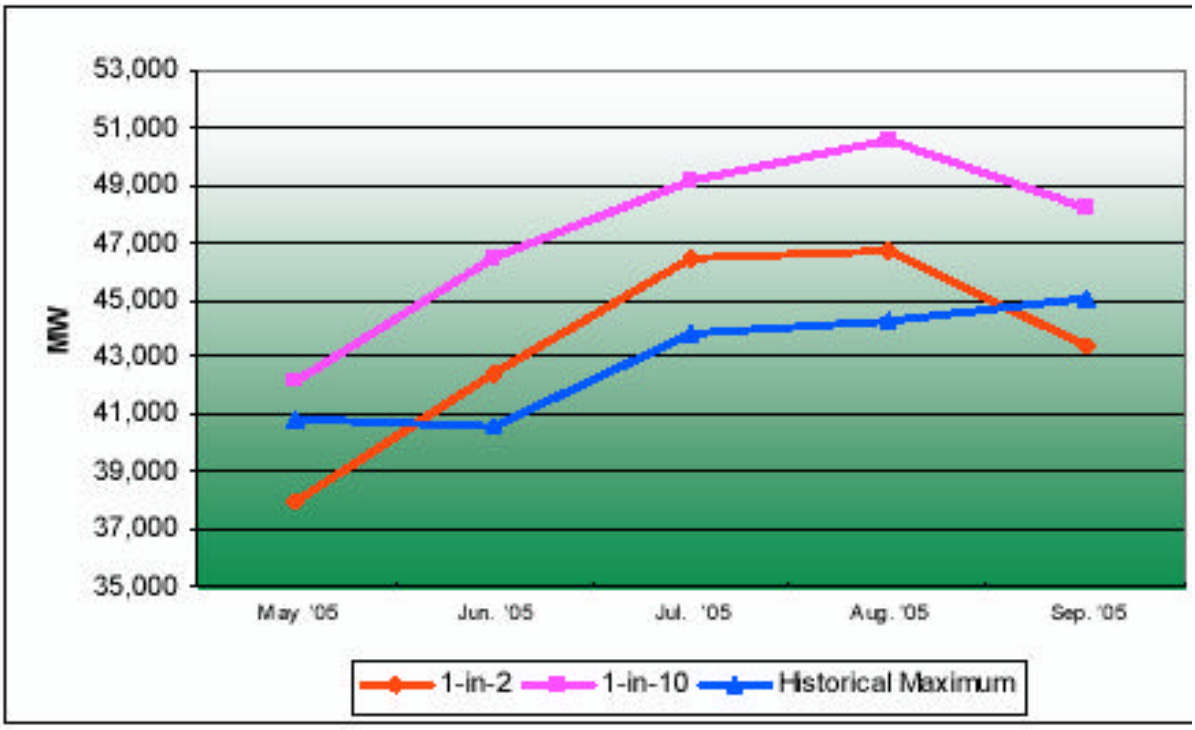


Table IV-1
ISO Control Area Monthly Forecast vs. Historical Maximum

Month	"1-in-2" Forecast *(MW)*	"1-in-10" Forecast *(MW)*	Historical Maximum (1998 – 2004)	
			Date	*MW*
May '05	37,928	42,172	05/03/04	*40,819*
Jun. '05	42,428	46,411	06/14/00	*40,593*
Jul. '05	46,414	49,152	07/21/04	*43,818*
Aug. '05	46,668	50,592	08/11/04	*44,271*
Sep. '05	43,405	48,157	09/08/04	*45,019*

Summer 2005

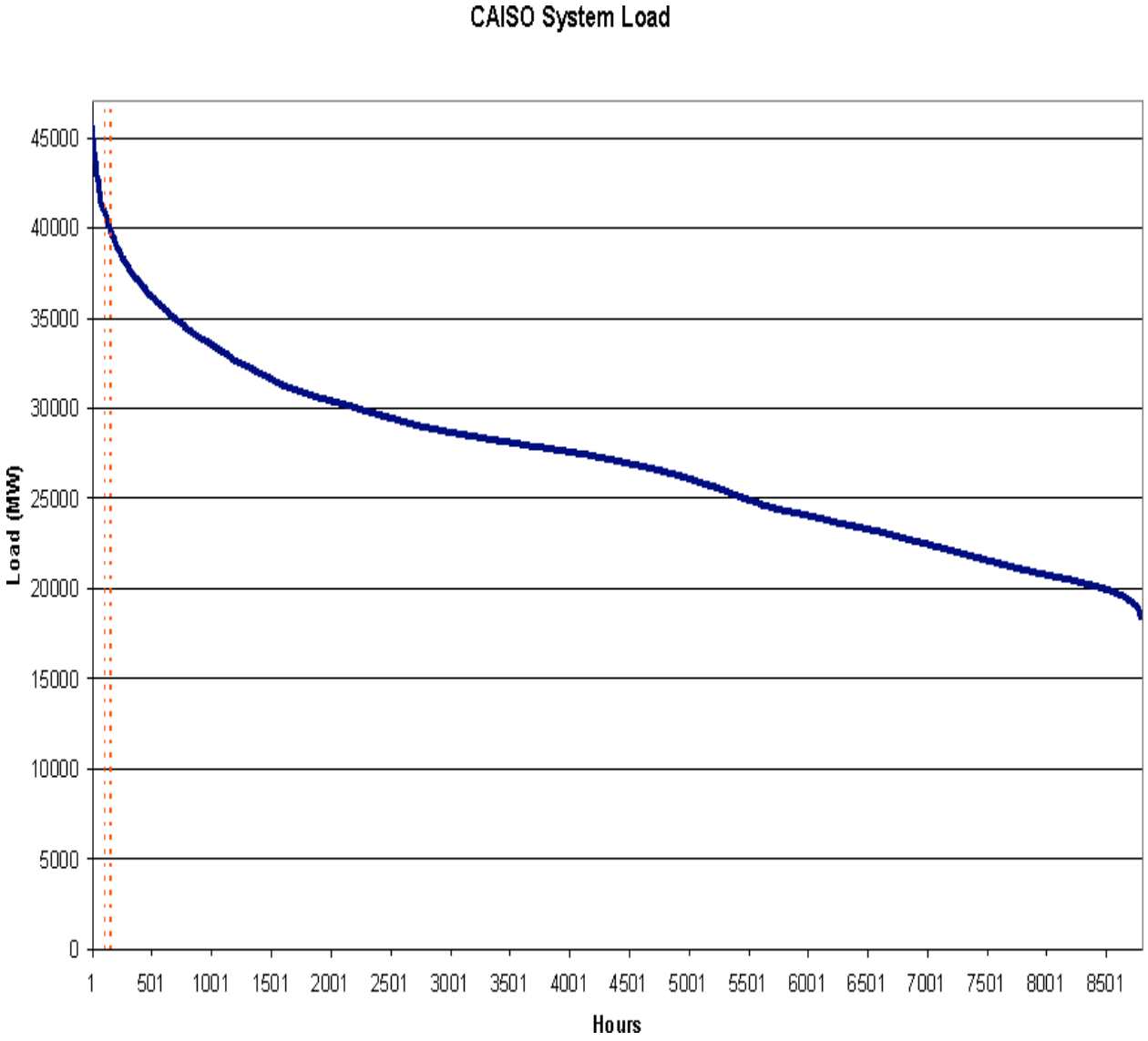
ISO 2005 Summer Assessment

- Adequate Resources to meet demand for expected "1-in-2" conditions; however, Southern California margins are thin.
- Challenges for Southern California and/or System, for "1-in-10" load condition.

	ISO Control Area	Northern CA (NP26)	Southern CA (SP26)
1-in-2 Load:	46,668	21,497	27,080
Surplus/(Deficiency)	+ 3,383	+ 3,643	+ 409
1-in-10 Load:	50,592	23,091	29,080
Surplus/(Deficiency)	(- 804)	+ 1,943	(- 1,725)

California Load Duration Curve

We don’t have to curtail demand for many hours to make it through the summer.



Demand Side Resources Now Highest Priority

- Integrated Energy Policy Report: 2004 Update, CEC
- "All investor-owned and municipal utilities should work aggressively to implement demand response programs to attain the 2007 statewide goal of reducing peak demand by five percent. In this vein, to address supply adequacy concerns for the summer of 2005, the CPUC should immediately require dynamic pricing tariffs for large electricity customers who already have advanced metering capability.
- **"**The state must accelerate its implementation of demand-response programs that signal the actual price of electricity to customers during peak-demand periods,"
  - "Rapidly deploying demand-response programs in the state is the most effective approach to address peak demand for the summers of 2005-2008," Without these, the state may not be able to "stave off another electricity crisis in the near term,"
  - "The committee recommends significantly increased efforts to achieve existing demand-response goals for the summer of 2005 through 2007, and accelerating and expanding demand-response goals wherever possible,"
- **GAO -** it is vital that consumers understand that the price of power is tied to supply and demand and demand response programs need be more widely implemented.
- **CPUC** "cost-effective conservation and energy efficiency are *first* in the IOUs' resource loading order—that is, energy efficiency is evaluated for cost-effectiveness and procured *before* supply-side resources are to be factored into the procurement plan," 971 MW in 2005; 1,816 MW in 2010; 3,026 MW in 2013

The Forces Are Lining Up

- The CPUC has a goal of reducing the states' peak-energy demand by 5 percent by 2007. For 2005, the reduction goal is 3 percent, or 450 MW for PG&E, 628 MW for Edison and 125 MW for SDG&E. They've got a long way to go, getting about 10% of their goals for 2004.
- The California Public Utilities Commission (CPUC) ordered the utilities to install advanced meters for all accounts with monthly loads of 200 kW or greater and put them on time-differentiated rates
- **Now is the time to analyze your system and operations and take advantage of some of the utility money for technical assessment and equipment purchase to allow you to shift some of your peak demands. Determine how much pumping you can shift out of the 2-6 pm weekday period, and how much additional you can curtail during critical peak events. Investigate going on one of the voluntary demand response rates (e.g. CPP) while you can participate and still get bill protection. And finally, start preparing your Board and customers for the potential for a doubling or more of your utility bill during the summer months starting in 2006 if you cannot shift pumping/operations out of the on peak period.**

Existing Utility Demand Side Options

- CPP - Critical Peak Pricing. >200kW (but can aggregate smaller accounts)
  - 12 summer (June-Oct) weekdays/year max, notification the day before (by 3 pm) generally temperature based
  - CPP Days - Peak (3-6) 5x, mid peak (noon - 3) 3x
  - Non-CPP days - energy costs discounted
  - Bill protection available - never pay more than under old tariff
  - 3 day max out of past 10 days energy baseline
  - can also participate in Scheduled Load Reduction Program (SLRP), Demand Bidding Program (DBP), Demand Reserves Program (CPA DRP)
  - $50/kW technical assistance, $100/kW hardware installation rebate
- DBP - Demand Biding Program
  - You offer amount (MW) and hours you're willing to curtail. Via Internet.
  - Between noon and 8pm weekdays
  - 2 hour - 6 hour option for curtailment
  - Day-ahead -triggered when energy price >15¢/kWh. Notified by 3pm day before
  - Day-of - triggered when ISO declares warning of system emergency ($.50/kWh). 3-8pm. Notified by noon.
  - Emergency test trigger twice a year for less than 4 hours, will pay you 50¢/kWh
- Technical Assistance/Incentives Available
  - $50/kW available from utilities for analysis/audit
  - Reduction = load drop from average of same hour in 3 highest use days during the past two weeks
- Hardware incentives available
  - $100/kW hardware installation incentives available from utilities
- With January decision you don't have to sign up for CPP or DBP to get technical assistance or hardware financial incentives

Summary of Curtailment Programs

Program	Called	What It Does	Requirements	Limits	Reward	Risk	Notification	Can Combine With
Base Interruptible Program	E-BIP	pays you to reduce load to a pre-determined level during a load curtailment event called by ISO	15% load reduction, 100kW min	1 4-hour event/day, 10 events/month, 120 hours/year.	$7/kW per Month	$6/kWh	30 minutes	E-DBP, E-OBMC, CPA DRP
Demand Bidding Program	E-DBP	allows you to bid a level of load reduction	100kW	2 hour minimum	$0.50/kWh	none	1 hour	E-CPP, E-SLRP, E-BIP
	E-DBP	at an offered price for each curtailment event.	100kW	2 hour minimum	>$0.15/kWh	none	day ahead	E-CPP, E-SLRP, E-BIP
Optional Binding Mandatory Curtailment	E-OBMC	avoid curtailments during rotating outages.	5-15% circuit reduction	no limits	exempt from rotating outages	$6/kWh	15 minutes	E-DBP, E-BIP, CPA DRP
Scheduled Load Reduction	E-SLRP	pays you to reduce load for a pre-determined time period during the week.	15% of average summer load	prescheduled 4 hour period each week in summer	$0.10/kWh	expelled from program after 5 failures	every week	E-DBP
Critical Peak Pricing	E-CPP	lowers bills by shifting or reducing electricity during critical peak summer afternoons.	max demand > 200kW	12 events/summer	lower prices in non peak days	higher on-peak prices on peak days	day ahead	E-DBP, CPA DRP
Power Authority Demand Reserve Partnership	CPA DRP ACWA agreement with ASC	pays for curtailed load	2, 4, or 8 hour blocks	max 24 hours/month, 150 hours/year	monthly capacity payment, energy payment when curtailed	penalties for non compliance	day ahead	E-CPP,

Value Comparison

- 1 MW comparison
- DBP
  - assuming 6 day ahead, 6 day of events
    - $50,000 technical assistance+$5,400 day ahead +$18,000 day of = $73,400
- CPP
  - Assuming 12 calls
    - $50,000 technical assistance +$8,804 net savings = $58,804
- CA DRP
  - Fixed Payment = $45,000
  - assuming 12 calls energy payment = $4,320
- Hardware Rebates
  - $100/kW for load shifting hardware installations
- Can participate in both DBP and CPP for $82,204 + $100,000
- Can participate in both CPP and CA DRP for total $108,124 + $100,000

Can Still Add Self Generation

- Self Generation - CPUC D.03-04-030 Departing Load Obligation - exemptions
  - Generating before February 1, 2001
  - Biogas digestors
  - <1 MW and subject to net metering (solar)
  - Eligible for CPUC/CEC self-generation programs: photovoltaics, wind turbines, fuel cells, microturbines, small gas turbines and internal combustion engines with waste heat recovery. No diesel or back-up
  - >1 MW "ultra-clean and low emissions" do not pay DWR ongoing charges or HPC
  - 3,000 MW cumulative total - do not have to pay DWR ongoing charges: 1500 MW renewable, nonrenewable generation amounts caps:
    - 2004 600 MW
    - 7/1/2008 500 MW
    - 2008+ 400 MW
- CEC has adopted a set of regulations governing the process for determining which departing load customers are eligible for an exemption from Cost Responsibility Surcharges. Fill out CEC Form 03-CRS-01.

Big Changes Coming

- Real Time (Dynamic) Pricing Is Coming
  - (CEC IEPR) To address concerns about the summer of 2005, the CPUC should immediately require dynamic pricing tariffs for large electricity customers with real-time pricing metering systems, which would significantly improve reliability of the electric system and reduce peak loads beginning in the summer of 2005.
  - Regulatory authority for dynamic pricing tariffs already exists and the IOUs are already required to reach demand response capability equivalent to three percent of system peak demand by July 2005, and five percent by 2007, using any combination of pricing incentives and command and control measures. In addition, the CPUC required IOUs to file demand response plans for summer 2005 by October 15,2005. Although the CPUC plans to issue a final decision by January 2005 specifying required tariffs and programs to allow compliance, the comparable goals for summer 2004 were not achieved, and preliminary discussions with IOUs about their proposed summer 2005 plans raise concerns that they do not expect to achieve these targets. Instituting a mandatory tariff for large customers with real-time pricing metering systems would remedy the situation.
- But first - mandatory Critical Peak Pricing rates
  - Supposed to be for this summer, but couldn't get it together in time.
  - CPP on peak prices of $1/kWh proposed
  - Will be in place by 2006, and apply to everyone

Conclusions/Recommendations

- High retail electricity prices (through 2011) as we pay off our 2000/2001 hangover
- High natural gas prices ($5-$8) around for awhile
- Changes are coming
  - Traditional tariffs (I-6) disappearing - being replaced with demand-response programs
  - Mandatory CPP tariffs for everyone by next summer
- Recommendations - know your system and what you can do
  - Take advantage of technical assistance $$ now, figure out what you can do before you have to do it.
  - Take advantage of hardware $$, get the utility to pay for shifting your demand
  - Look into demand reduction pilot programs (e.g. CPP, DBP, CA DRP) to determine which combination of programs is best for you
  - Test your operational changes while you are still protected on the down side
  - Look into self generation options
  - Look into more storage
  - Figure out what will happen to your budget when you go to mandatory CPP rates or real time pricing
- Flexibility is the key - the more flexible your operations are the more opportunities you can take advantage of
- Make sure your backup generation is working, and you have operational plans for electrical blackouts