2. Supply and Demand Conditions

Supply and demand conditions throughout the West were tight much of the summer, with emergency conditions concentrated in California. The broad factors were hot weather, in some cases extreme hot weather, coupled with continued demand increases without corresponding increases in power production capability. The main findings of the report on demand and supply conditions are:

- *Overall demand increased significantly*. Driven by hot weather, load increases over previous years were most pronounced in May and June. Average summer demand in the California Independent System Operator (Cal-ISO) area increased 8 to 9 percent over the previous 2 years. Peak hour demand forecasts increased slightly over 1999, but actual hourly peaks fell slightly, reflecting in part the response to emergency declarations and actions. Offpeak demands increased significantly in July and August, in part to meet increased pumping demands and to conserve water stored at hydropower facilities, needed for peaking purposes both inside and outside the Cal-ISO area.

- *Exports from California increased significantly, with little overall change in the level of imports*. As a result, net import decreases averaging up to 3,000 megawatts (MW) needed to be offset by increases in generation internal to the ISO control area. The ability to increase imports was limited by hydro conditions in the Northwest, which actually declined in July and August, and tight load conditions in other western subregions. Weather conditions in the desert southwest were among the hottest on record. These conditions led to increased exports in July and August, corresponding to the decreases in the ISO price cap from $750 to $500 in July and to $250 in August.

- *Outages increased significantly*. Compared with 1999, outages in the Cal-ISO area increased as much as 2,900 MW. Planned outages in January through April were significantly lower in 2000 than in 1999. However, unplanned outages in May through August, particularly in July and August, were much higher in 2000 than in 1999.

- *Increased quantities of demand and supply were left unscheduled in day-ahead and hour-ahead markets*. When loads increased above 35,000 MW in June, and at lower levels in July and August, the Cal-ISO was forced to buy substantial amounts of power in the form of replacement reserves or out of market purchases in real time.

- *Non-hydro generation resources throughout the West were more heavily utilized in 2000 than in 1999*. In 2000, non-hydro resources generated 15.1 percent more power in May and 24.9 percent more power in June, compared with 1999. Based on an analysis of WSCC capacity during the week of July 31 to August 4, little additional capacity appears to have been available at such peak times.

Section 2.A. provides background on supply and demand: the bulk power system in the West, distribution of resources and expectations for the summer of 2000 in the spring. Each of the main findings summarized above is discussed in Section 2.B.

A. Supply and Demand Background

1. Brief Description of Bulk Power System in the West

The Western Grid encompasses 1.8 million square miles within 14 western states, two Canadian Provinces, and a portion of Baja California Norte Mexico. Figure 2-1 illustrates the configuration of the Western Grid. The Western Interconnection transfer capability with other regions is limited to around 1,000 megawatts.

The Western Grid operates under the North American Electric Reliability Council (NERC) guidelines as administered by the regional reliability council: the Western Systems Coordinating Council (WSCC). The WSCC is divided into four reporting subregions and 30 load control areas. The subregions are shown in Table 2-1.

Table 2-1. Subregions in the WSCC

Subregion	States Comprised
AZ/NM/SNV (Arizona)	Arizona, most of New Mexico, the western part of Texas, southern Nevada, and a portion of southeastern California
CA/MX (California)	Most of California and the northern portion of Baja California, Mexico
NWPP (Northwest)	Washington, Oregon, Idaho and Utah, British Columbia and Alberta, and portions of Montana, Wyoming Nevada and California
RMPA (Rockies)	Colorado, eastern Wyoming, and portions of Western Nebraska and South Dakota

Within the California-Mexico subregion (California) of the WSCC is the California power grid, which carries bulk electricity to local utilities for distribution to their 27 million customers and transports significant amounts of power for other generation or local distribution entities in the region. The Cal-ISO assumed control of 75 percent of the California power grid (Cal-ISO grid) in 1998, consolidating the transmission systems of the three investor-owned utilities into one large system. The network comprises 21,000 circuit miles of power lines that deliver about 165 billion kilowatt-hours of electricity each year. Power plants connected to the Cal-ISO grid have a total capacity of approximately 45,000 megawatts.

2. Historical Load Growth and Resource Mix

Peak load in the WSCC has been steady over the last 17 years, as shown in Figure 2-2. Over this period, growth in peak summer demand was highest in the Arizona/New Mexico/Southern Nevada (Arizona) region, at an overall annual average of 7.9 percent, followed by California at 3.2 percent, the Rockies at 2.8 percent and the Northwest at 2.4 percent. Table 2-2 shows load growth for two recent 3-year periods. California and Northwest show large differences in growth rates between the two 3-year periods, while growth rate differences in the Rockies and Arizona are small. These variations can be driven by many factors, but two major ones include changes in weather patterns and increases in economic activity.

The WSCC region has approximately 160 gigawatts (GW) of generation capacity. From 1991 to 1998, an average of 1,197 megawatts (MW) were added per year, a growth rate of under 1 percent.[1] Current and planned (as of January 1, 2000) capacities by subregions are shown in Table 2-3. Planned capacities in this table represent all active plans and are adjusted for planned deratings and retirements of current capacity. Only small amounts of capacity were planned for 1999 and 2000 (only around 1 percent in each year.) Significant capacity additions have been planned for 2001 and 2002, but may be subject to cancellation depending on investors' perceptions of market and regulatory stability.

Figure 2-3 shows the wide variation in the types of generation resources across the WSCC region. The Northwest is dominated by hydropower (65% of capacity). The output of the many federally owned and operated hydropower facilities is marketed by the Bonneville Power Administration. The Rockies have largely coal generated resources (68%). Arizona has a large amount of coal capacity (41%); these coal resources are more expensive to produce than the coal resources in the Rockies, but still well below the cost of producing power from oil or natural gas sources. Many of the resources in California are oil and/or natural gas generation.

[1] Resource Data International, RDI Powerdat Information System, September 2000.

Figure 2-1. Western Power Grid

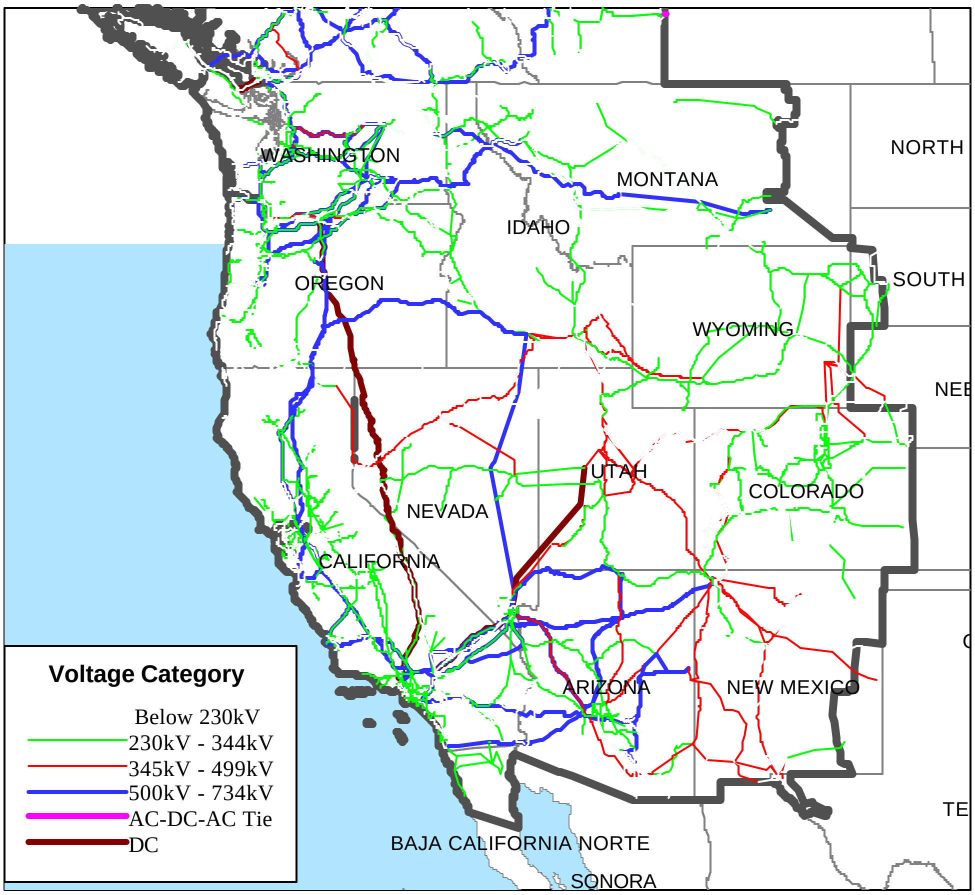


Table 2-2. Comparison of 3-Year Average Growth in Summer Peak, in the WSCC, 1998 and 1995

Subregions	Average Growth Percentage 1996 to 1998	Average Growth Percentage 1993 to 1995
Arizona	4.3	4.3
California	3.9	0.6
Northwest	3.4	0.8
Rockies	3.0	4.3

The pattern of imports and exports of power among the four subregions and Canada is to a large extent determined by the distribution and cost of generating resources. The Northwest and the Rockies subregions are significant exporting areas at peak times: the former based on the availability of hydropower capacity and the latter based primarily on coal-fired generation. California is the major importing subregion, both because its capacity is below its peak load, but also because this capacity is more expensive. The import and export patterns are generally seasonally based, with California importing in the summer and exporting to the Northwest in the winter. Table 2-4 shows annual trends in generation, imports and exports from 1990 to 1998. Steady increases in imports are shown into the California and Arizona subregions, with the increased exports coming largely from the Northwest. A particularly large increase in exports from the Northwest (and corresponding imports into California and Arizona) is shown for 1997 and 1998.

Table 2-3. Current and Planned Generation Capacity in the WSCC, as of January 1, 2000
(Megawatts)

		Planned Plants by Planned Online Year					
Subregion	**Current**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**
Arizona	24,562	132	1,919	4,885	4,055	0	500
California	52,709	620	2,505	3,110	1,594	0	255
Northwest	72,443	1,426	1,115	1,391	836	51	-67
Rockies	9,381	358	251	799	672	339	85
Total WSCC	159,095	2,536	5,790	10,185	7,157	390	743

Source: WSCC-Existing Generation and Significant Additions and Changes to System Facilities, 1999-2009, issued May 2000.

Notes: Planned capacity includes all active plans, with reductions for retirements. Northwest includes Canada.

Figure 2-2. Peak Summer Demand in WSCC

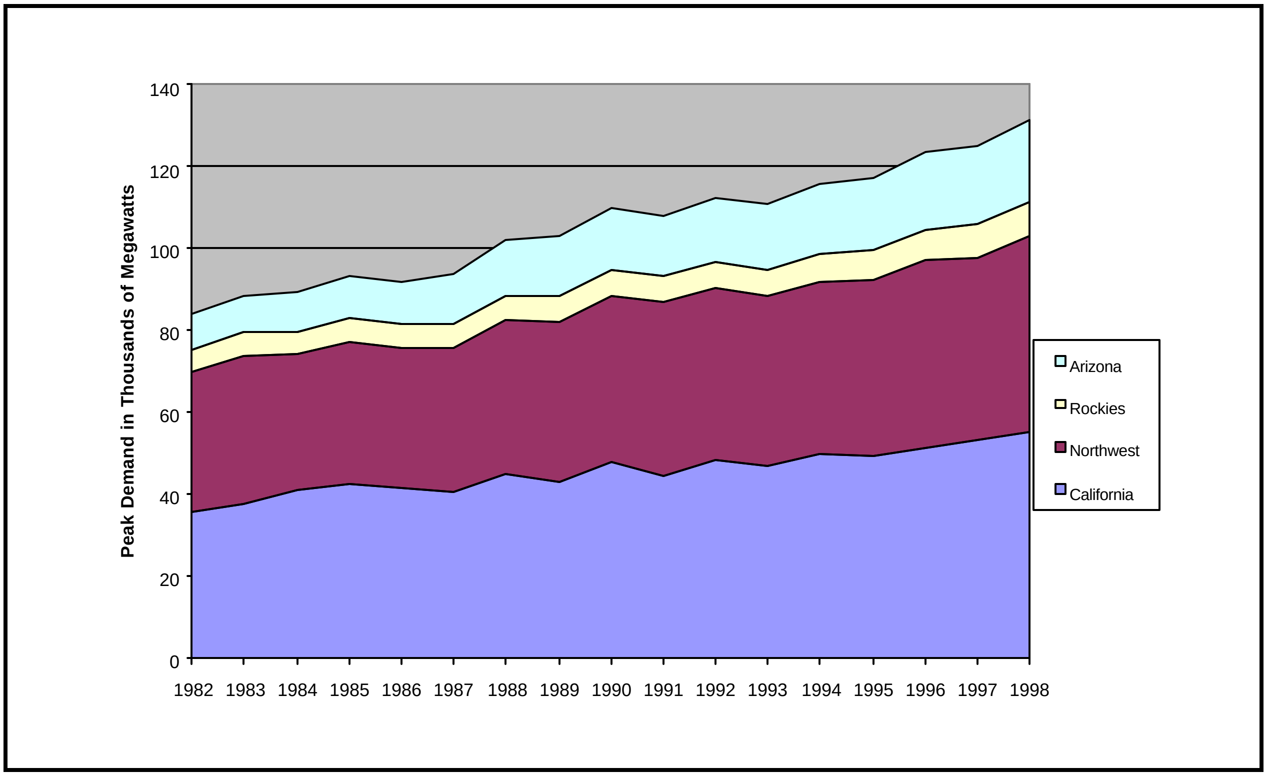


Figure 2-3. Capacity Resource Percentages by WSCC Subregions

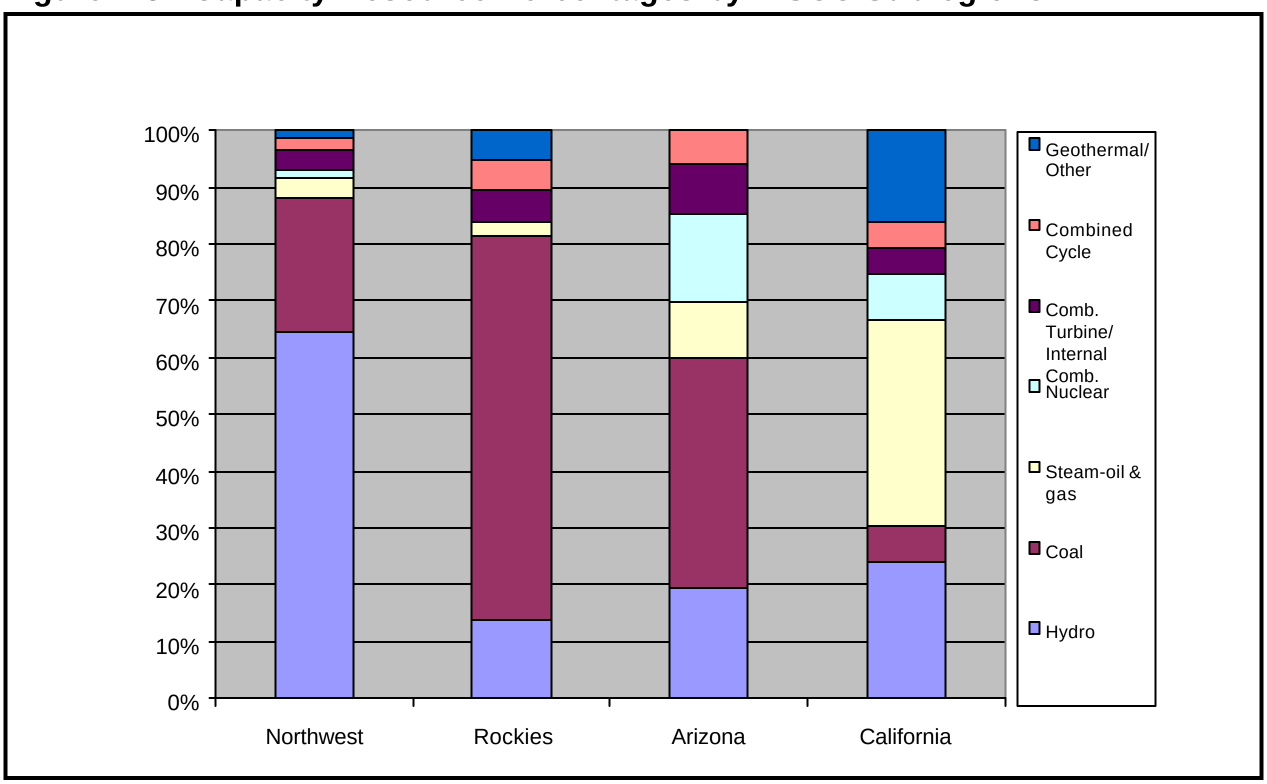


Table 2-4. Generation, Imports and Exports in WSCC, 1990 to 1998
(Thousand Megawatthours)

	1990	1991	1992	1993	1994	1995	1996	1997	1998
Internal Generation									
Arizona	66,852	72,811	72,998	77,373	76,091	79,271	76,035	77,467	94,155
California	208,350	199,435	195,099	215,474	221,911	230,660	225,384	218,720	205,246
Northwest	214,623	235,047	235,190	217,682	219,935	221,970	239,155	265,852	278,699
Rockies	43,315	42,141	42,603	42,997	43,505	44,166	45,844	48,187	52,431
Total WSCC	533,140	549,434	545,890	553,526	561,442	576,067	586,418	610,226	630,531
Imports									
Arizona	7,222	5,526	4,649	4,355	5,826	5,641	7,117	14,142	15,374
California	30,814	46,665	45,336	33,187	31,011	30,814	30,738	45,730	51,125
Northwest	11,278	8,115	9,465	17,204	21,274	19,009	11,069	17,098	12,711
Rockies	2,999	3,723	2,856	3,355	4,230	5,278	4,342	3,929	3,676
Exports									
Arizona	12,882	14,594	13,648	15,432	13,585	12,613	9,406	12,362	10,998
California	4,011	2,799	2,409	4,980	10,183	9,207	7,191	6,477	6,236
Northwest	19,769	30,445	29,729	19,104	23,510	21,406	30,156	52,442	66,526
Rockies	8,293	7,377	7,021	6,366	7,186	7,391	6,764	8,194	9,028

Source: NERC Electricity Supply and Demand 2000 Database (ES&D)

3. Spring Expectations for the Summer of 2000

The WSCC forecasts include a separate forecast for each of the four subregions and for the WSCC region as a whole. The subregion forecasts are required due to differences in demand, installed generation, and limitations in the western transmission grid. In its updated May forecast for the summer of 2000, the WSCC concluded that if normal temperatures were to prevail during the summer period, projected regional capacity margins and reliability should be adequate. It also stated that if higher than normal unplanned generator outages occur, an area experiences significantly higher than normal temperatures, or the loads in multiple areas peak simultaneously, portions of the region may need to issue public appeals for customers to reduce their electrical consumption or other measures may be necessary.

WSCC concluded that the southwest portion of WSCC (New Mexico, Arizona, southern Nevada, California, and Baja California, Mexico) might not have adequate resources to accommodate a widespread severe heat wave or higher than normal generating outages. Table 2-5 shows the WSCC projected total demand, resources and anticipated margins for the summer months for those portions of the WSCC region located wholly within the United States.

Table 2-5. WSCC-U.S. Forecasted Demand and Supply, Summer 2000
(Megawatts)

	May	June	July	August	September
Total Load	96,908	108,635	116,440	114,899	107,616
Total Resources	136,023	136,868	136,771	136,586	137,166
Unavailable	10,959	3,780	2,830	2,927	5,944
Net Resources	125,064	133,088	133,941	133,659	131,222
Net Imports and Exports	533	483	483	283	283
Margin MW	29,034	28,228	21,281	22,697	27,645
Margin %	30.4	27.0	19.0	20.5	26.8

The forecast for the summer from the California subregion is summarized in Table 2-6. The Cal-ISO also prepared a forecast containing two different weather assumptions, and consequently two different peak and net import forecasts (see Table 2-7). The WSCC and ISO forecasts agreed that exceptionally high temperatures could lead to a capacity shortage.

Table 2-6. WSCC-California Forecasted Demand and Supply, Summer 2000
(Megawatts)

	May	June	July	August	September
Total Load	38,906	47,457	52,057	51,487	47,978
Total Resources	54,516	54,497	54,497	54,497	54,497
Unavailable	1,718	118	0	0	1,656
Net Resources	52,578	54,379	54,497	54,497	52,841
Net Imports and Exports	-4,960	-5,605	-5,605	-5,602	-5,634
Margin MW	15,193	11,738	8,728	8,489	9,628
Margin %	39.1	26.3	17.7	17.4	21.3

Table 2-7. Projected Cal-ISO Peak Loads and Resources
(Megawatts)

Load Condition	Peak In-Area Load	Generation	Net Imports	Excess (+) or Deficiency (-)
Normal	46,250	38,000	8,400	150
High	48,940	38,000	7,000	-3,940

B. Summer 2000

This section presents the results of staff's examination of the performance of western markets during the summer of 2000, concentrating on the key findings from the study relating to supply and demand conditions. Much discussion and attention have been focused on the problems in California and its market, but review of the events of the summer needs to start with the overall western pattern of load and supply. Accordingly, this section starts with a review of western demand and its underlying determinants.

1. Demand Growth

Demand has been steadily growing in the West, particularly in areas driven by technology such as California and the Northwest. In addition, summer demand in 2000 was driven by extreme weather conditions throughout the West. Figure 2-4 summarizes the May through August 2000 temperature patterns in western regions. California is shown separately from the California/Nevada region. The figure shows the rank of the regional temperature over the last 106 years. It is clear from the figure that the Southwest, including Arizona, New Mexico, Utah and Colorado, was very hot for the entire summer. It is also clear that all areas were hot early in the summer, in May and June, when signs of high prices and price spikes first surfaced in California.

While May and June were extremely hot throughout the West, July and August show a mixed pattern, with moderate to below normal temperatures outside the Southwest in July and hotter than normal temperatures throughout the region in August, but falling short of the extreme hot weather of June. The weather pattern in June over the last 3 years is shown in Figure 2-5. Regardless of the absolute rank of the summer of 2000, it is easily seen that the summer marked a departure from the mild summers since 1998 when California began to implement restructuring. The wide geographic distribution of hot weather in June 2000 placed new stresses on the generation and transmission system throughout the West, taxing the ability of exporting areas to keep up with both internal and external demands.

Figure 2.4. Rank of Regional Temperatures: May to August 2000

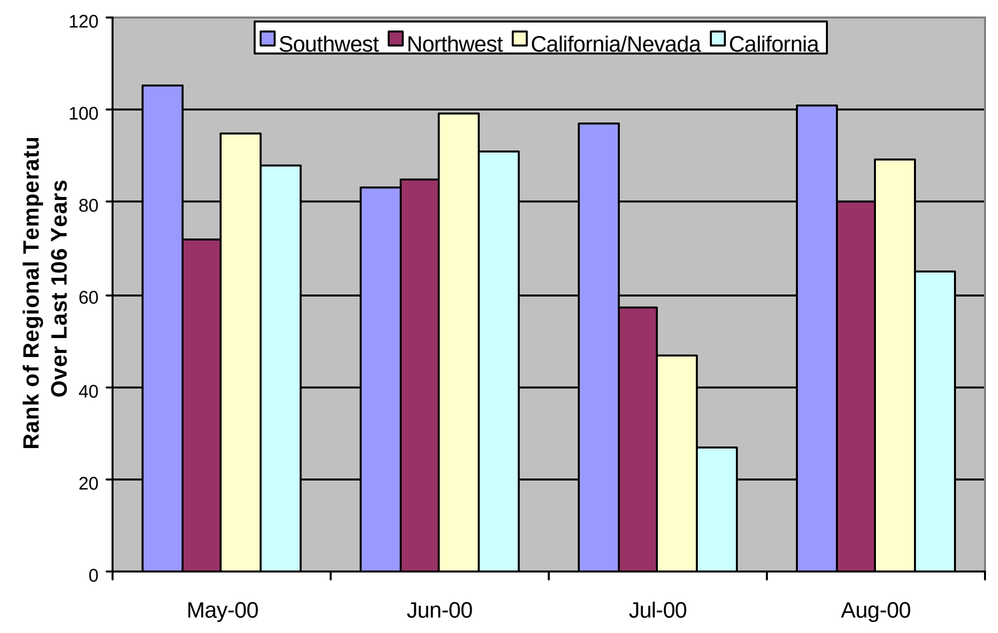
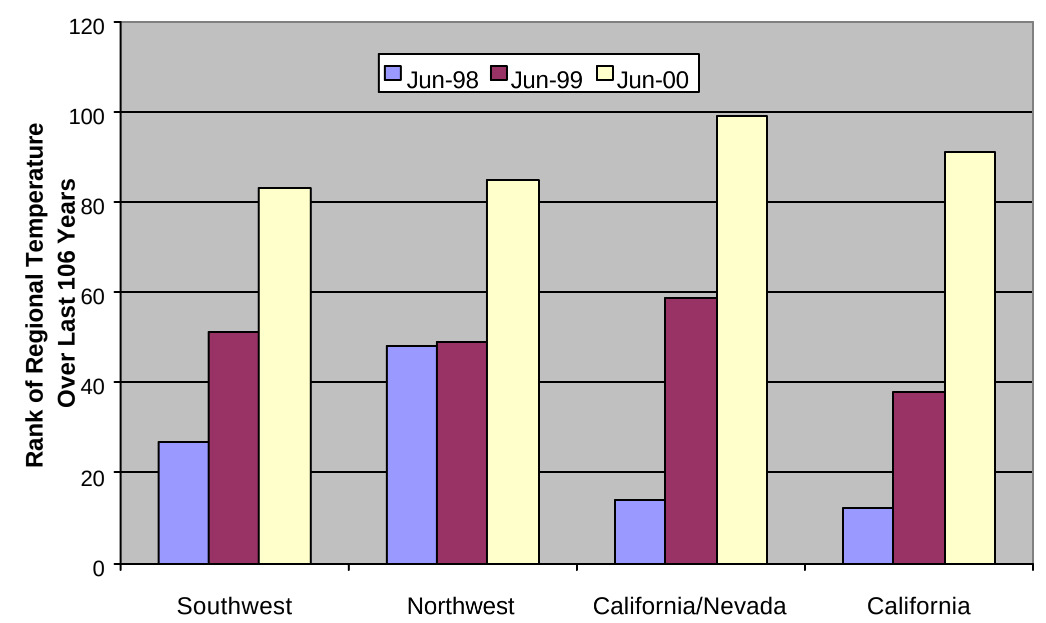


Figure 2.5. Rank of Regional Temperatures: June 1998 to 2000



Source: NOAA web site: @http://www.ncdc.noaa.gov/ol/climate/climateresearch.html

These weather patterns are reflected in the load growth statistics for western states in May and June, shown in Table 2-8, which compares loads in 2000 for May and June with corresponding loads in 1999. In June, overall load is estimated by EIA to have grown 13.7 percent in California and 7.3 percent in the West outside California. Heat-sensitive residential load grew even more: 23.8 percent in California and 9.0 percent outside California. States bordering California, Nevada and Arizona, experienced comparable or higher changes from 1999 to 2000: Arizona residential load grew 22.3 percent in June, and Nevada grew 27.2 percent.

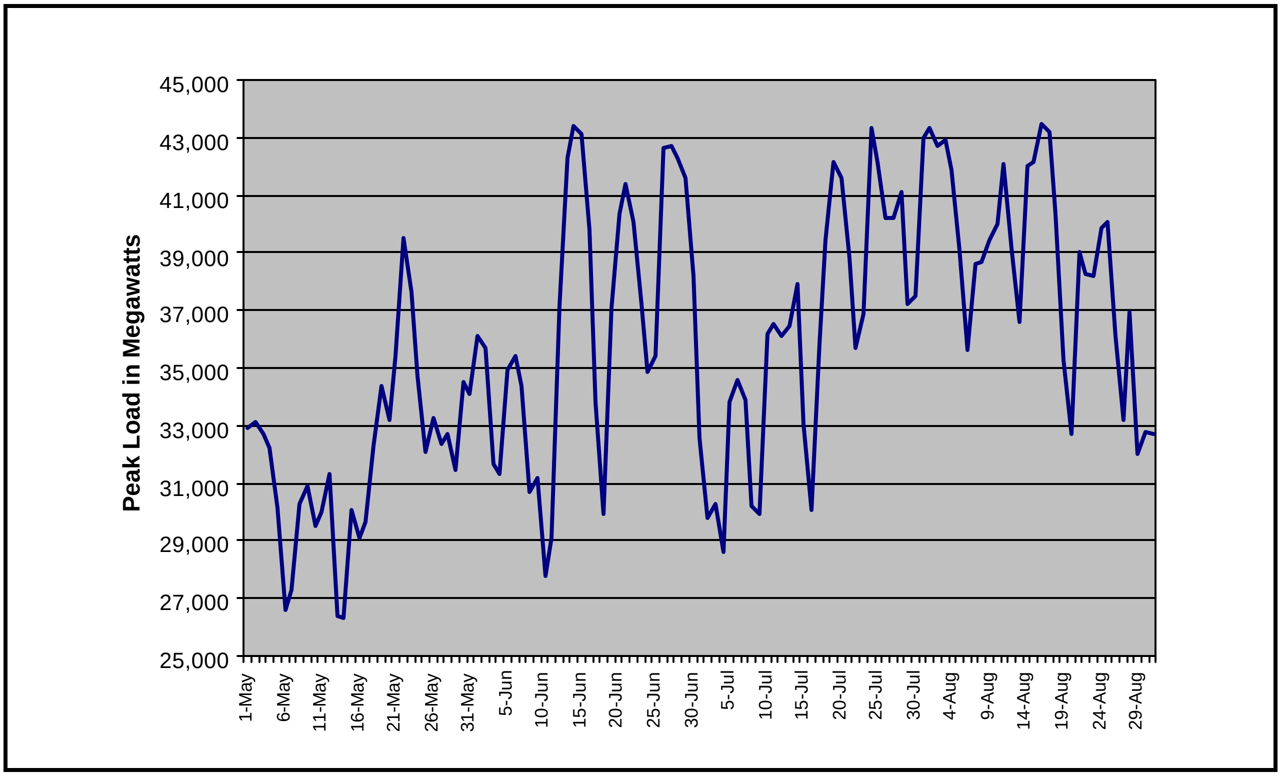
Table 2-8. Load Growth in the West, May and June 1999 to May and June 2000

(Thousand Megawatthours)

	All Sectors			Residential		
State	**1999**	**2000**	**% Change 1999 to 2000**	**1999**	**2000**	**% Change 1999 to 2000**
			May			
Arizona	4,421	5,247	18.7	1,415	1,928	36.3
Colorado	3,096	3,580	15.6	972	974	0.2
Idaho	1,730	1,787	3.3	483	431	-10.8
Montana	906	787	-13.1	298	241	-19.1
Nevada	2,125	2,518	18.5	583	786	34.8
New Mexico	1,549	1,542	-0.5	341	358	5.0
Utah	1,670	1,849	10.7	434	446	2.8
Wyoming	994	1,041	4.7	169	148	-12.4
Oregon	3,897	4,064	4.3	1,339	1,224	-8.6
Washington	7,768	7,061	-9.1	2,595	2,456	-5.4
West Outside California	28,156	29,476	4.7	8,629	8,992	4.2
California	17,626	18,649	5.8	5,194	5,625	8.3
			June			
Arizona	5,248	5,827	11.0	2,058	2,517	22.3
Colorado	3,130	3,823	22.1	949	1,060	11.7
Idaho	1,898	2,249	18.5	460	446	-3.0
Montana	626	825	31.8	262	247	-5.7
Nevada	2,475	2,730	10.3	850	1,081	27.2
New Mexico	1,554	1,601	3.0	373	414	11.0
Utah	1,952	1,979	1.4	528	533	0.9
Wyoming	1,037	1,039	0.2	139	145	4.3
Oregon	3,859	4,312	11.7	1,139	1,185	4.0
Washington	7,462	6,978	-6.5	2,233	2,171	-2.8
West Outside California	29,241	31,363	7.3	8,991	9,799	9.0
California	19,225	21,867	13.7	5,720	7,084	23.8

Source: Energy Information Administration, *Electric Power Monthly*, August and September 2000.

Figure 2-6. Cal-ISO Load Curve, May to August 2000



Turning to the Cal-ISO area, Figure 2-6 shows daily peak-hour load from May to August 2000. As the figure shows, peak load is volatile over a fairly wide range, sometimes swinging rapidly from under 30,000 MW to over 40,000 MW. Managing these fluctuations is a complex task under any circumstance, but it becomes even more difficult in a complex market environment in transition. Forecasting load then becomes particularly important for maintaining the reliability of the system.

Table 2-9 shows the average, day-ahead forecast and actual loads for the Cal-ISO area over the last three summers. These data confirm the main conclusions from the temperature and the state-level load data in Table 2-8. The Cal-ISO experienced much higher loads in May and June compared with previous years. July was much more moderate and August loads were higher but not as high relative to previous years as June loads. The percentage differences in actual average loads from previous years, shown in Figure 2-7, bear these conclusions out.

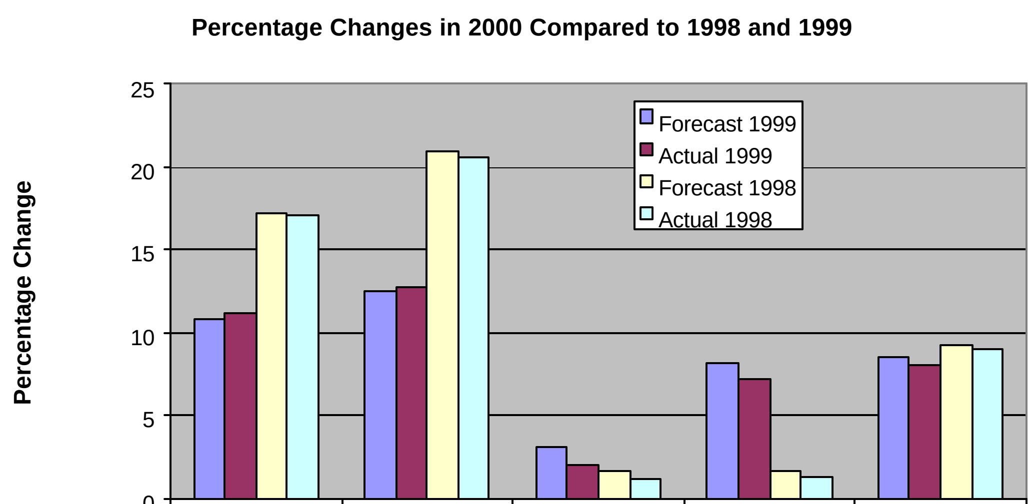
Figure 2-7 also shows that, on average, day-ahead forecasts and actual loads are close as one would expect. While examining average loads is instructive, peak load forecasting is central to reliable system operation. Accurate forecasting of peak loads is

Table 2-9. Cal-ISO Day-Ahead Forecast and Actual Average Loads, 1998 to 2000

	May	June	July	August	May-August
Forecasts					
1998	22,963	24,847	29,423	30,996	27,075
1999	24,276	26,736	29,022	29,113	27,291
2000	26,906	30,075	29,926	31,505	29,599
Actuals					
1998	22,960	24,852	29,122	30,691	26,923
1999	24,171	26,609	28,878	29,016	27,173
2000	26,883	29,981	29,461	31,104	29,352

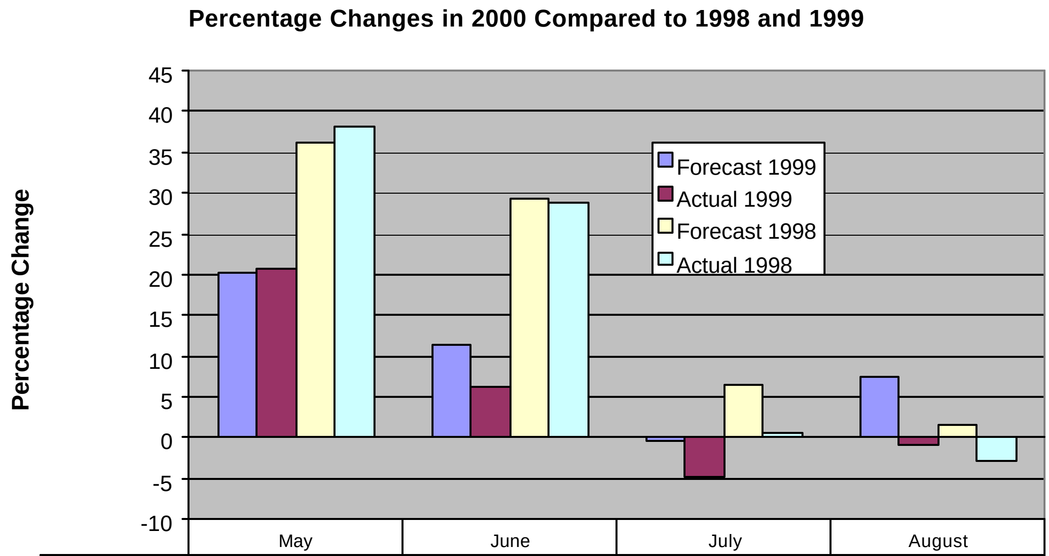
essential for estimating peak supply requirements. The peak forecast and actual loads shown in Figure 2-8 indicate how difficult peak conditions and forecasting became in 2000. While May forecasts and actuals both tracked 1999 and 1998, the forecasts in 2000 began to deviate as the summer progressed. Forecasts consistently exceeded actual loads. In August, for example, forecasted loads increased over previous years (e.g., by 7.5 percent over 1999), but actual loads decreased (e.g., by 0.9 percent over 1999) .

Figure 2-7. Average Loads in the Cal-ISO, Day Ahead Forecast and Actual



	May	June	July	August	May-Aug
Forecast 1999	10.8	12.5	3.1	8.2	8.5
Actual 1999	11.2	12.7	2	7.2	8
Forecast 1998	17.2	21	1.7	1.6	9.3
Actual 1998	17.1	20.6	1.2	1.3	9

Figure 2-8. Peak Loads in the Cal-ISO, Day-Ahead Forecast and Actual



	May	June	July	August
Forecast 1999	20.3	11.4	-0.5	7.5
Actual 1999	20.8	6.2	-4.9	-0.9
Forecast 1998	36.2	29.3	6.4	1.6
Actual 1998	38.1	28.9	0.5	-2.8

Part of this deviation between forecast and actual loads can be attributed to the number of system emergencies that the Cal-ISO experienced in 2000, since during these emergencies interruptible customers must reduce loads and public appeals are made for voluntary load reduction. Cal-ISO issued 38 emergency notices over the summer, far more than in prior years. These actions are summarized in Table 2-10.

The discussion thus far has concerned overall average or peak loads, but the offpeak period (from 11:00 p.m. to 6:00 a.m.) also can be critical during the summer. This time is used to pump water at pumped storage hydropower facilities, so these facilities can be used to meet peak demands. These requirements create additional demand for energy to pump the water and can be important in years with high temperature and low water such as 2000. Other shifts in demand to offpeak can occur if customers can shift loads to avoid high onpeak energy costs. Table 2-11 shows how the average offpeak loads increased in 2000 compared with 1999.

Table 2-10. Electrical Emergencies Declared by the Cal-ISO (May-August)

Emergency Type	Action Taken	1998	1999	2000
Stage One: May be declared when operating reserves of less than 7 percent are unavoidable or exist in real time.	Utility customers are urged to reduce their use of electricity voluntarily to avoid more severe conditions	3	3	24
Stage Two: May be declared when operating reserves of less than 5 percent are unavoidable or exist in real time.	Voluntary interruption of services to select customers is required to avoid more severe conditions. These customers receive a reduced rate electrical service as compensation for their willingness to be curtailed	3	0	14
Stage Three: May be declared when it is clear that operating reserves of less than one-and-a-half percent are unavoidable or exist in real time.	Utility customers are advised that involuntary interruptions of service have begun and will continue until the emergency has passed.	0	0	0
Total		6	3	38

Table 2-11. Offpeak Loads in the Cal-ISO Area
(Megawatts)

	Average Hourly Loads		Maximum Hourly Loads	
	1999	2000	1999	2000
May	20,036	21,609	25,475	29,043
June	21,245	23,567	30,096	32,439
July	23,007	23,318	33,702	31,848
August	23,035	24,268	31,132	32,946
May-August	21,835	23,187	33,702	32,946

2. Increased Exports from California

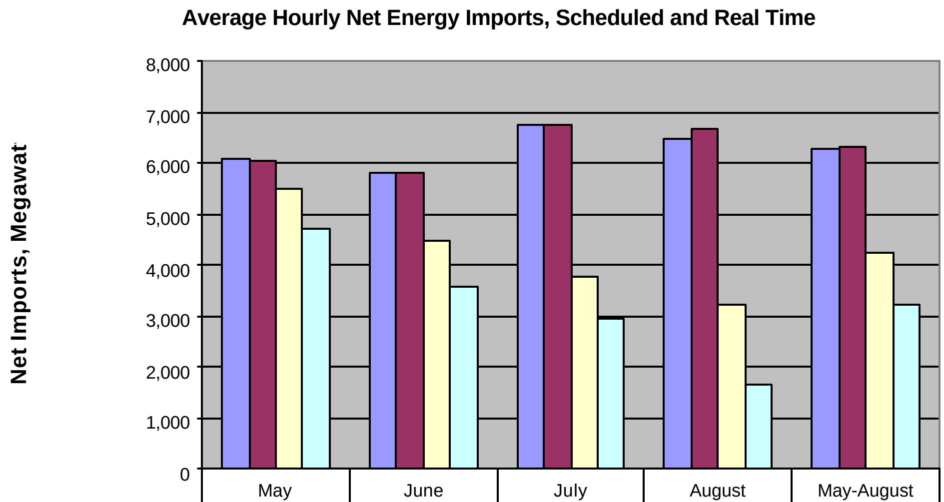
Increased exports from California are a key factor in understanding western supply in the summer of 2000. These increases require offsetting imports to meet any given level of load within the Cal-ISO area. Net imports, the total imports reduced by the amount of exports, were significantly lower in 2000 compared with 1999. Figure 2-9 shows both scheduled (through the hour ahead) and actual imports in real time in 1999 and 2000. Net imports fell dramatically throughout the summer, in both scheduled and real-time categories. The biggest differences between 1999 and 2000 occurred in the scheduled net imports in August, when scheduled net imports were 6,502 megawatts per hour in 1999 and 1,673 in

2000. An additional 1,542 megawatts of imports appeared in real time, reducing the difference from last year.

The decrease in net imports is generally attributable to increases in exports, not decreases in imports, as Figure 2-10 clearly shows. In 2000, imports remained virtually unchanged throughout the summer. In 1999, some increases in imports occurred, but the leading fact shown in Figure 2-10 is the increase in exports for each month from May to August 2000, from an hourly average of 1,831 megawatts in May to 4,851 megawatts in August, an increase of 3,020 megawatts. Comparable export increases in 1999 occurred, but they were small. Compared with August of 1999, August 2000 exports averaged 3,136 megawatts above the August 1999 level. This period of increased exports corresponds to the periods in July and August when the price cap in the ISO was reduced from $750 to $500 and then to $250. This correspondence does not necessarily show price caps caused increased exports; however, other things being equal, lower price caps may provide for greater profits from exports if conditions outside California lead to high prices and create greater opportunity costs.

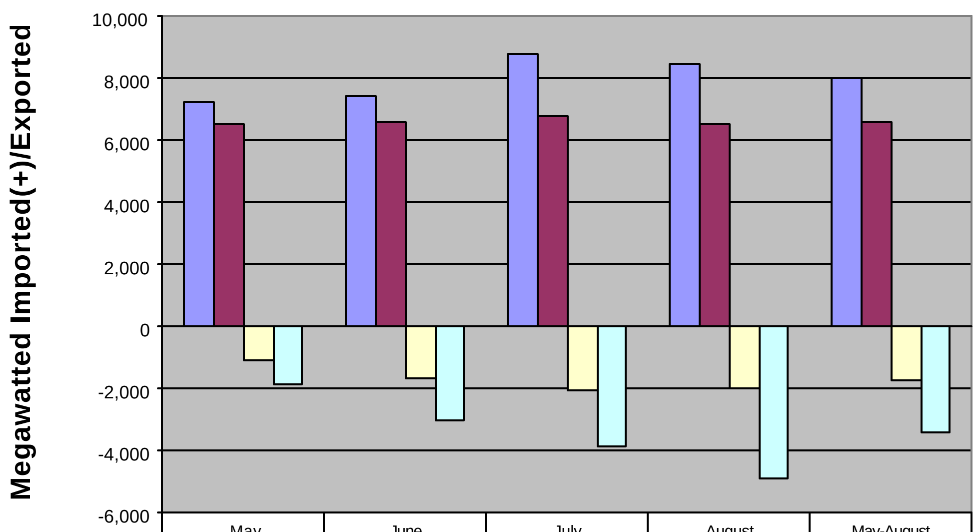
Although most exports are from the SP15 zone in southern California, increases were not limited to SP15 (see Table 2-12). SP15 experienced an increase in offpeak exports from May to August of 1,385 megawatts over a May quantity of 1,038; the NP15 zone in northern California had an increase of 766 megawatts over the much smaller base of 223 megawatts in May. Exports from the NP15 zone are typically offpeak and may be related to pumping at hydropower facilities or maintaining storage levels at conventional hydro facilities to conserve water, particularly later in the summer. Offpeak exports followed the same pattern as overall exports, as the daily graph of offpeak exports in Figure 2-11 shows, when compared to the overall pattern of increases from May through August.

Figure 2-9. Net Summer Imports into Cal-ISO, 1999 and 2000



	May	June	July	August	May-August
Scheduled 1999	6107	5804	6748	6502	6294
Real Time 1999	6050	5812	6740	6664	6321
Real Time 2000	5489	4501	3770	3215	4241
Scheduled 2000	4704	3598	2960	1673	3231

Figure 2-10. Imports and Exports, Average Hourly, 1999 and 2000

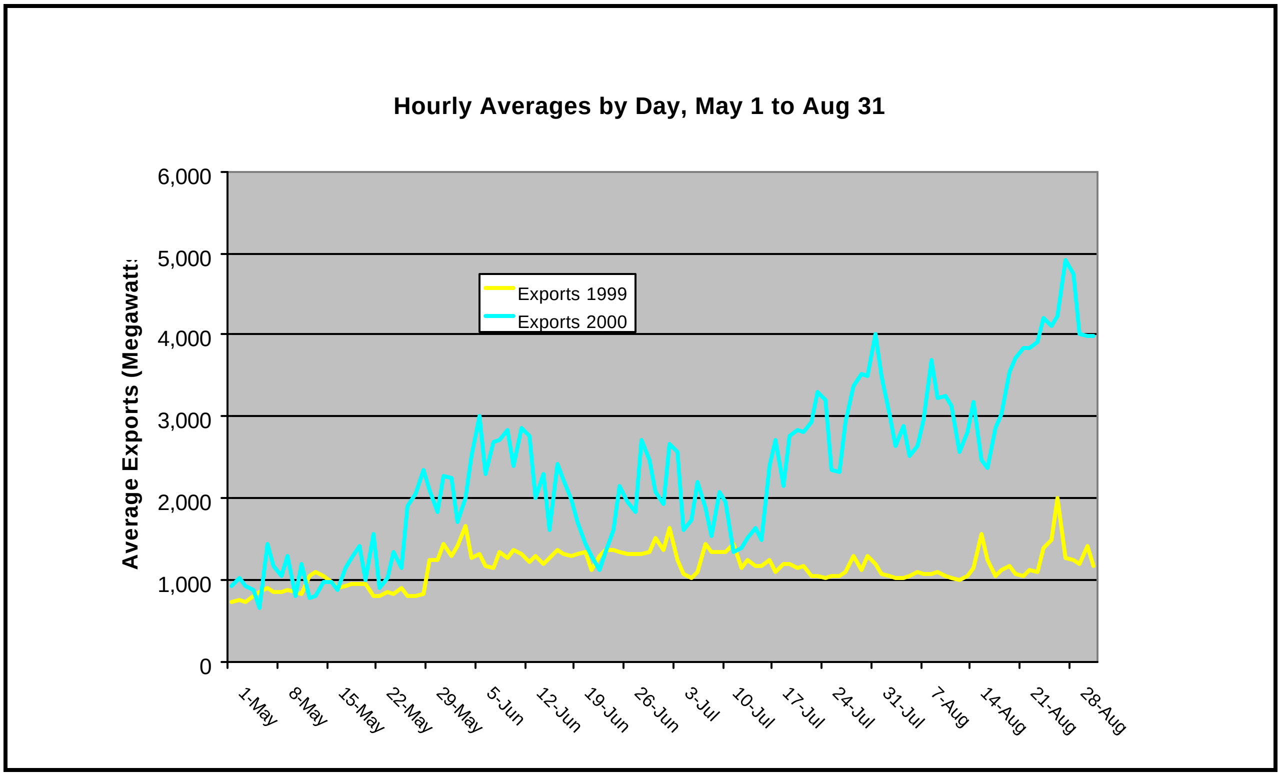


	May	June	July	August	May-August
Imports 1999	7214	7471	8784	8489	7994
Imports 2000	6534	6593	6807	6524	6615
Exports 1999	-1107	-1667	-2036	-1987	-1700
Exports 2000	-1831	-2995	-3846	-4851	-3384

Table 2-12. Summary of California Exports and Imports by Zone

	May	June	July	August	May-August
SP15 Zone					
Imports 1999	4,441	4,222	5,426	5,645	4,939
Imports 2000	4,590	4,841	4,547	4,790	4,691
Exports 1999	-859	-1,310	-1,171	-1,088	-1,105
Exports 2000	-1,038	-1,758	-1,828	-2,423	-1,762
Net Imports 1999	3,582	2,912	4,255	4,557	3,834
Net Imports 2000	3,552	3,083	2,719	2,368	2,929
Real Time 1999	3,554	2,811	4,132	4,533	3,765
Real Time 2000	3,784	3,169	2,846	2,447	3,061
NP15 Zone					
Imports 1999	1,561	2,147	2,408	2,090	2,051
Imports 2000	1,074	1,210	1,113	1,182	1,144
Exports 1999	-61	-7	-34	-91	-49
Exports 2000	-223	-385	-580	-989	-546
Net Imports 1999	1,500	2,140	2,374	1,999	2,002
Net Imports 2000	851	825	533	193	598
Real Time 1999	1,444	2,123	2,335	2,029	1,981
Real Time 2000	1,187	1,177	770	717	961

Figure 2-11. Offpeak Export Demand, 1999 and 2000



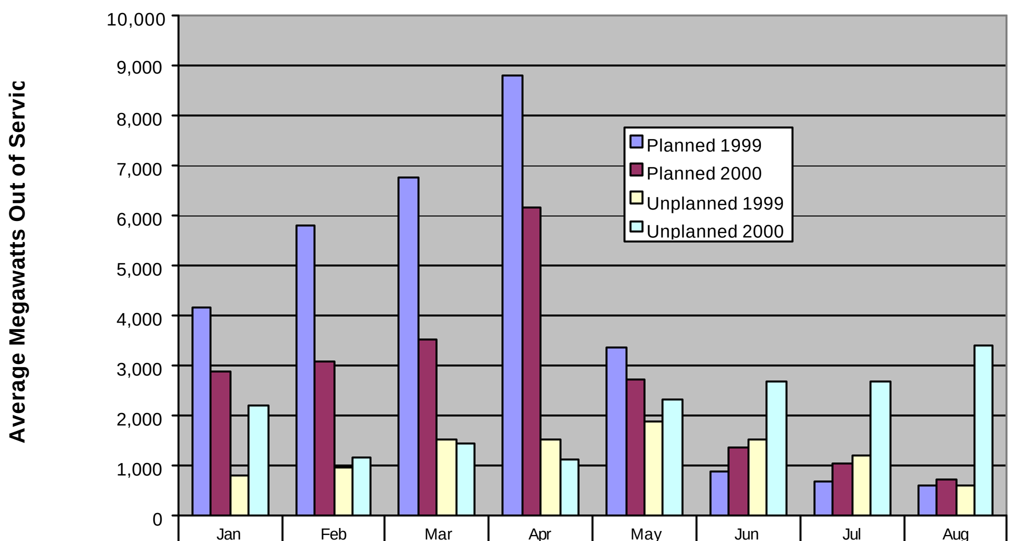
3. Increased Plant Outages

An increased level of unplanned outages at generating plants is another key factor limiting available generation supply in 2000. California has a large number of natural gas fired plants. Natural gas steam plants make up most of this capacity and constitute 36 percent of the total generating capacity in the state. These steam plants are old and hence prone to outages; 82 percent of these plants are over 30 years old, and 37 percent are over 40 years old.[2] Outages in 1999 and 2000 are shown in Figure 2-12 for January through August. The level of unplanned outages increased through August compared with last year; there were 3,391 megawatts out of service (hourly average megawatts out during the month) in August 2000 compared with 604 megawatts in August 1999. This difference of 2,787 megawatts has a clear effect on supply at peak times, even though the level as a percentage of the 45,000 megawatts of installed capacity may not be out of the normal range for comparable plants. It is not clear exactly why these plants went out of service. Detailed analysis of specific causes was not possible for this investigation. Review of cited reasons by plant operators in available records showed the normal pattern of explanations for a peak summer period, such as tube leaks at steam facilities and other

---

2 RDI Powerdat, September 2000.

Figure 2-12. Comparison of Average Megawatts Out of Service in the Cal-ISO Planned and Unplanned, 1999 and 2000



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug
Planned 1999	4145	5791	6735	8774	3361	882	660	586
Planned 2000	2886	3083	3531	6140	2702	1349	1039	724
Unplanned 1999	801	957	1506	1508	1877	1516	1204	604
Unplanned 2000	2187	1158	1420	1124	2331	2688	2666	3391

similar causes, but it was not possible to confirm the accuracy of such judgments. Most outages were for short durations (see Table 2-13), with 59 percent occurring for one day or less, so a detailed analysis would be very time consuming.

There are several potential explanations for the increased level of outages. Figure 2-12 indicates a much lower level of planned maintenance in January through April 2000 compared with January through April 1999, so one possibility is that fewer resources are being devoted to planned maintenance. Lack of planned maintenance could be particularly important for older facilities. Given the short duration of outages, the increased number could reflect attempts to fix small problems in preparation for high load conditions. New owners, for example, could be attempting to maximize the availability of their facilities at peak times when the price is high. A final possibility is just the opposite: owners could be withholding by taking plants out of service at critical times to drive up prices. The difficulty here is twofold. First, the same general pattern of events permits completely contrary explanations in terms of efficient behavior. Second, specific instances alone may not serve to prove a general pattern, will be hard to substantiate, and cannot be fairly attributed to individual participants without further investigation of these specific cases.

Table 2-13. Percent of Unplanned Outages by Duration, Cal-ISO Units, 1999 and 2000

Duration	1999	2000
1 day or less	65.0	59.0
1 to 2 days	69.9	67.6
Less than 2 weeks	85.7	91.7

Some information can be gained by examining the level of outages and their timing. By examining the correlation between outage levels and price increases in the PX, one can roughly measure the association of the two series. These correlations are presented in Table 2-14, which shows the correlation of outage levels and PX prices, as a function of when the outage occurs. For example, the correlations in the category "Day of price increase" is measured between the outages on a particular day and the PX price on that day for deliveries on the following day. The category "1 Day before price increase" measures the correlation based on the level of outages on the day before the price is determined in the PX, and so on.

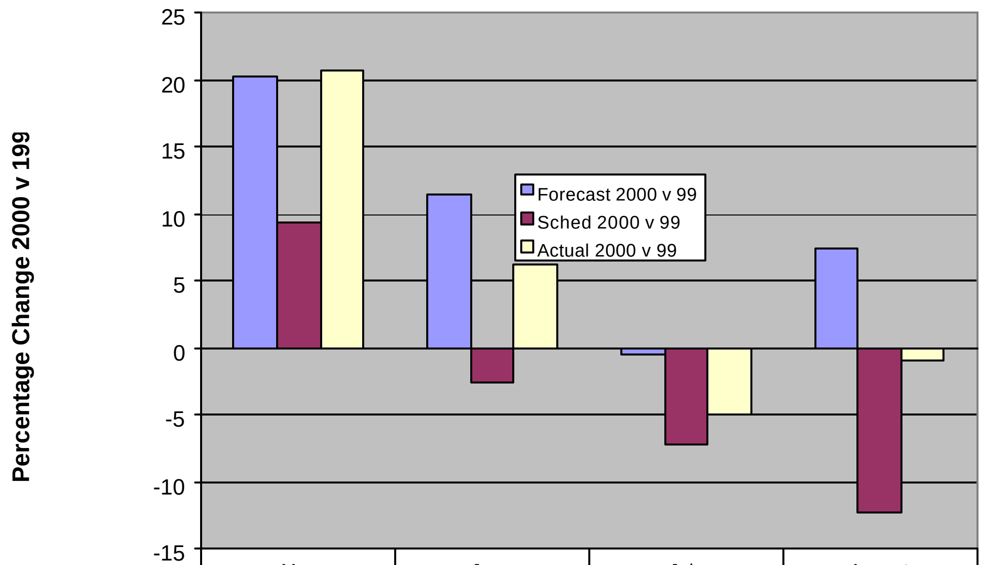
Table 2-14. Correlation of Outages with the PX UMCP, May to August 2000

Outage Occurs	Correlation
2 days before price increase	0.38
1 day before price increase	0.50
Day of price increase	0.46
1 day after price increase	0.40

The correlations show an association between outage levels and price increases, which is not surprising in itself. Outage levels would be expected to increase when prices are high, simply because loads increase and less reliable facilities are pressed into service under conditions of stress. The data also indicate, however, that the correlation is highest when the outages occur one day before the price increase. As noted above, facts such as these can be explained in a number of ways, but they do suggest that there may be more to the explanation than a simple physical response to running generating plants at higher levels under high load and price conditions.

4. Scheduling of Supply and Demand in California

Figure 2-13. Percentage Change from 1999 in Year 2000 Peak Forecast Scheduled and Actual Loads



	May	June	July	August
Forecast 2000 v 99	20.3	11.4	-0.5	7.5
Sched 2000 v 99	9.4	-2.5	-7.2	-12.3
Actual 2000 v 99	20.8	6.2	-4.9	-0.9

California day-ahead and hour-ahead markets saw a marked migration of supply and demand to real time markets and exports. Many of the imports were not scheduled and arrived in real time. A similar pattern for loads is shown in Figure 2-13, which shows the degree of underscheduling relative to day-ahead markets faced by the Cal-ISO. Figure 2-13 shows the change in underscheduling from 1999, as well as the amounts forecast and the actual results. As seen from the figure, in June and August, forecasts of load were much higher than in 1999, but scheduled load was much lower. The result is that the Cal-ISO is forced to purchase supplies in order to be able to meet load in real time. It can do this either by buying more replacement reserve or going out of market for real-time energy when insufficient generation is scheduled to meet final hourly forecast quantities. The Cal-ISO pursued both of these approaches in 2000.

The problem of underscheduling is not new in 2000, as can be seen in Figure 2-14, which examines day-ahead underscheduling. What has changed, however, is the level of load at which underscheduling occurs. In Figure 2-14, which shows the detailed pattern of

Figure 2-14. Scatter Diagram of Underscheduling, PX Day-Ahead Market

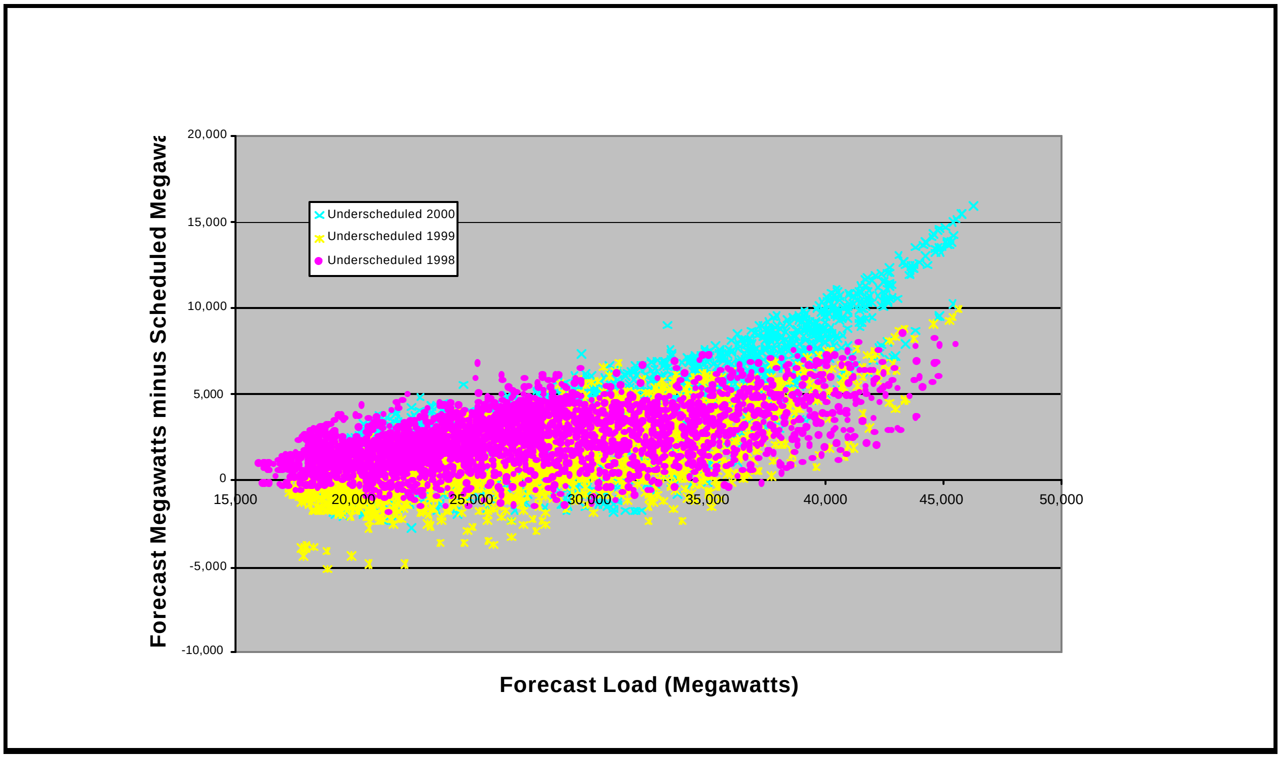
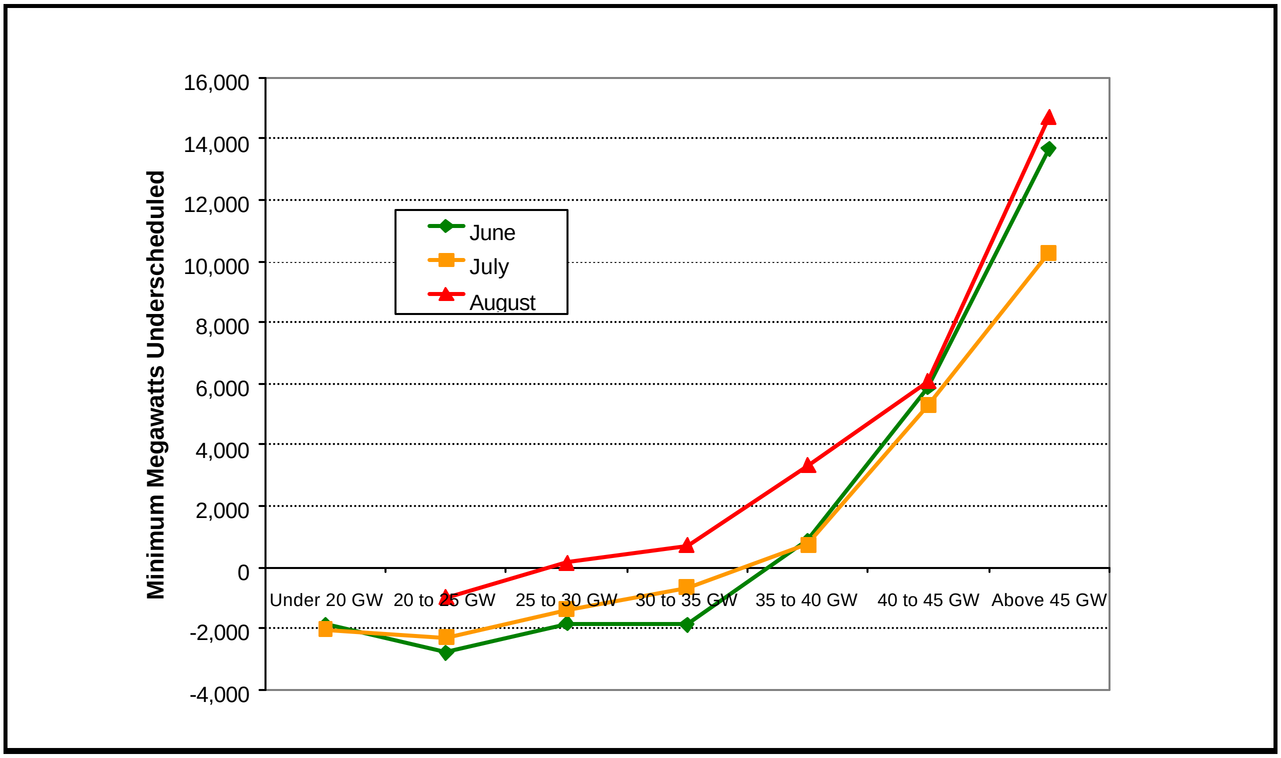


Figure 2-15. Underscheduling: Minimum Megawatts Underscheduled in PX Day-Ahead Market, by Load Range and Month



underscheduling as a function of load levels in 1998, 1999 and 2000, the observations for 2000 stretch out above the observations for 1998 and 1999 whenever the load grows above 35,000 megawatts. It also appears as if the load levels where underscheduling begins were lower in August than in June or July. Figure 2-15 shows the minimum underscheduling within load ranges. The minimum is the smallest difference between the forecasted load (day ahead) and the amount of load scheduled day ahead, for all hours when load fell within the range. This number will be negative if more supply/load is scheduled than forecast (overscheduling), and positive if less load/supply is scheduled (underscheduled.) Underscheduling normally increases as load increases, so that when load reaches a certain level, underscheduling always occurs and the minimum underscheduling will be positive. In August, the graph shows that underscheduling always occurred when the load was above 25,000 to 30,000 megawatts. The graph shows that underscheduling began to occur at lower and lower load levels from June through August, indicating that the problem of underscheduling became greater through the summer.

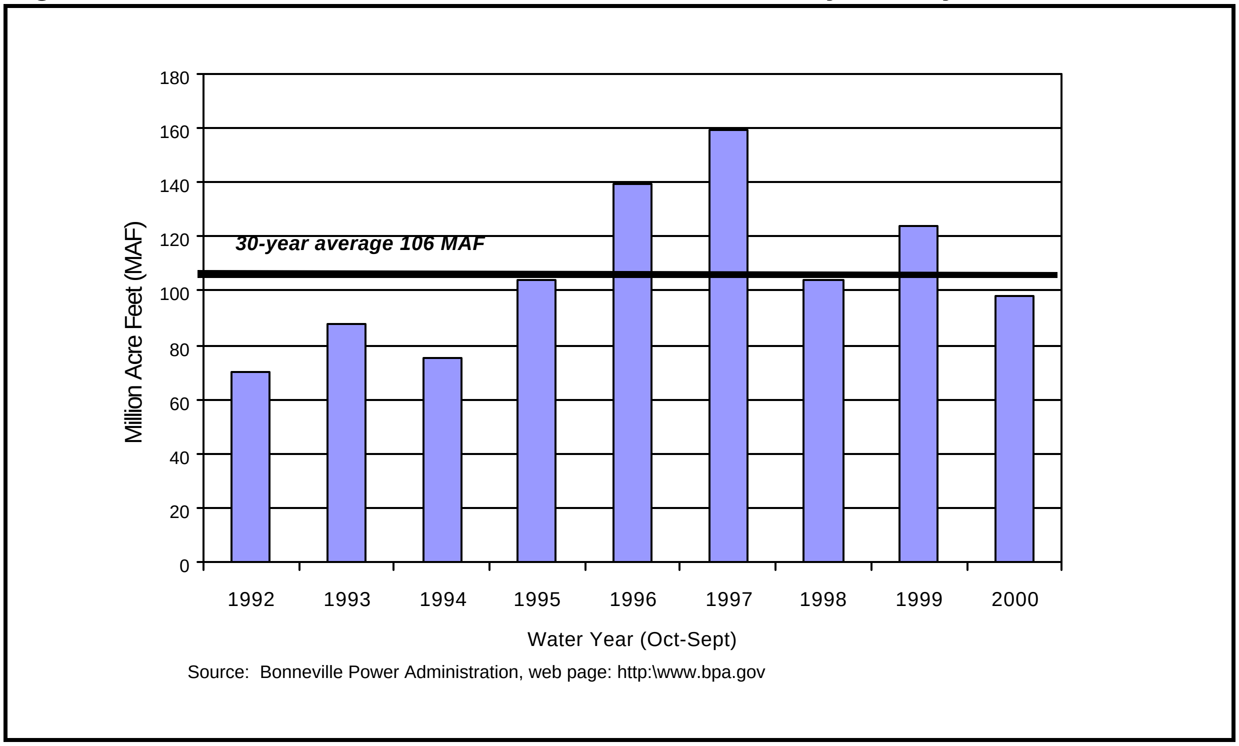
5. Generation Capacity Availability and Utilization

Previous sections have discussed factors contributing to limiting supplies of generation capacity in California and the western states generally. These factors bear on the reasons for any scarcity of available generation capacity. In this section, we review the evidence available to this investigation to assess the degree of that scarcity. We first review the role of hydropower in the supply of power in the West, and note the impact of hydropower availability on generation in May and June. Next we describe the availability of generation in the WSCC for a key summer week when California experienced several emergency periods and made a number of out of market calls for emergency imports of energy. Finally we look in greater detail at the availability of generation within the Cal- ISO during one hour of that week.

Hydropower Availability

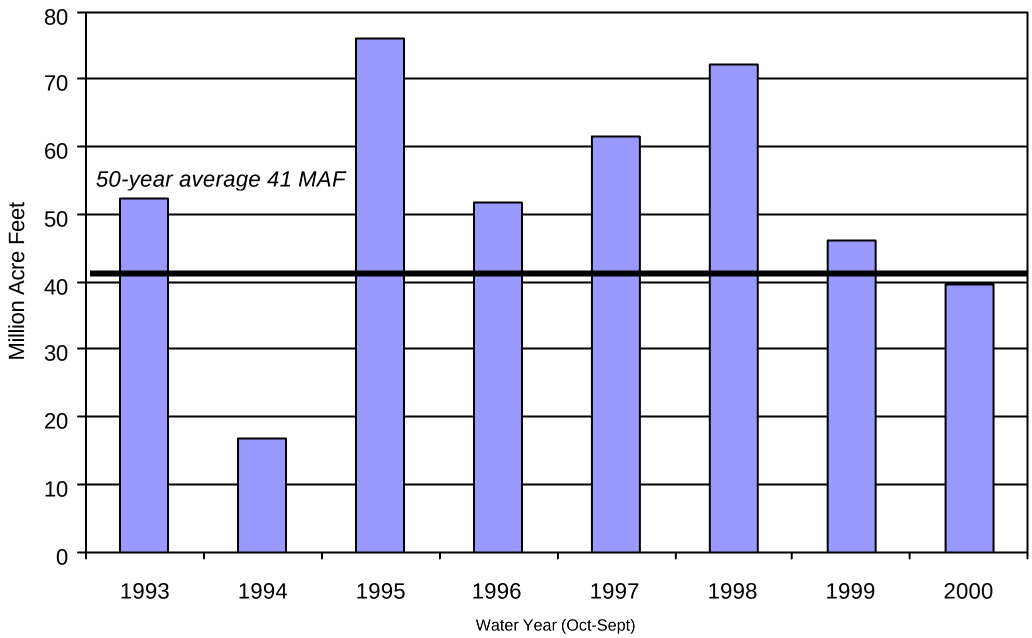
Hydropower resources are central to the western resource mix. Although most regions depend on hydropower to some degree, the presence of such a large proportion of hydropower resources in the West introduces operational complexities not present in power systems in other regions. The capacity to produce power from hydro facilities depends on the availability of water, which in turn is heavily dependent on the amount of water run-off in the spring. Adding to these limitations are environmental restrictions that determine the amount of water that must be “spilled,” that is, the amount required to pass

Figure 2-16 Volumes of Run-Off at the Dalles, January to July



over a dam or through a generating facility without going through the turbines and generating electricity. Because these types of restrictions vary with time, and in order to put the water to its highest-valued use, the dispatch of hydropower needs to carefully balance current and future values to optimize the use of the underlying resources. As a result of these factors, the actual physical capability of a generating unit is often not the element limiting the ability of a hydropower facility to provide power to the grid.

Figure 2-17. Volumes of Run-Off, California Statewide Total, October to July



Source: California Department of Water Resources, web page: http:\cdec.water.ca.gov

These limitations played a large role in the availability of hydropower in the summer of 2000. The volume of spring run-off was the lowest in several years in the Northwest, as shown in Figure 2-16. In California, the run-off fell below the 50-year average after 5 years of higher than normal flows (see Figure 2-17.) The impact of low water levels was seen in dramatically reduced generation from hydropower in May and June 2000 compared with 1999. Table 2-15 shows how extensive the shortfall in generation was: outside California, June 2000 generation from hydropower was 23.2 percent below June 1999 levels.

With reduced hydropower generation and increased load, the West needed much more generation from thermal and other non-hydropower resources. Generation from non-hydro resources increased by 15.1 percent in May and 24.9 percent in June (Figure 2-18).

Table 2-15. Hydroelectric Generation in the West, 1999 to 2000

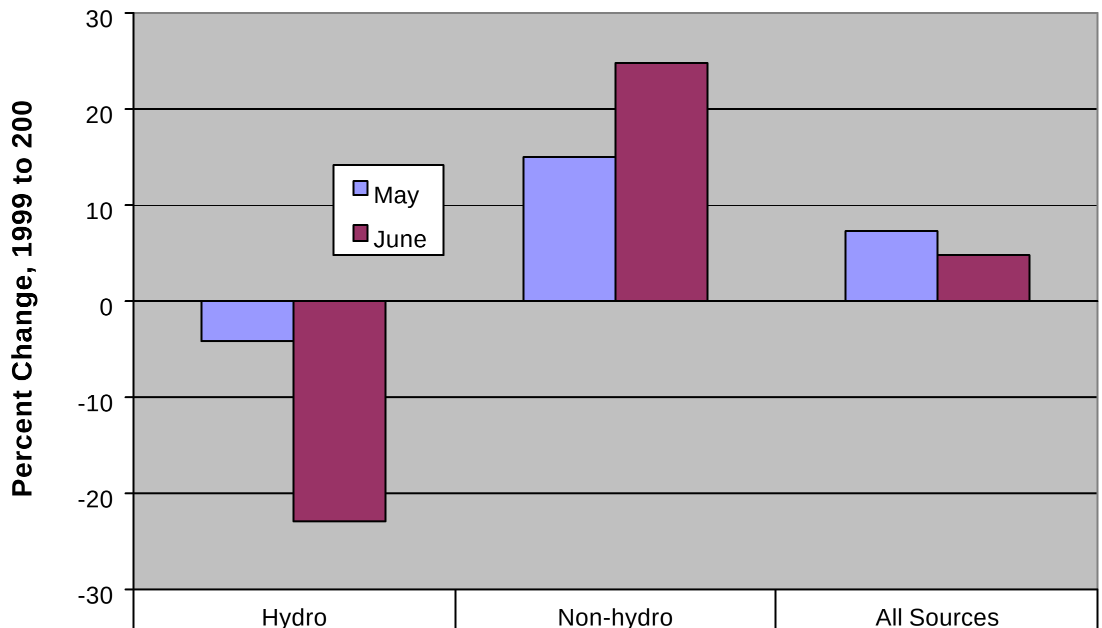
(Thousand Megawatthours)

	May			June		
State	1999	2000	% Change 1999 to 2000	1999	2000	% Change 1999 to 2000
Arizona	1,005	1,051	4.6	937	654	-30.2
Colorado	166	163	-1.8	161	178	10.6
Idaho	1,262	814	-35.5	1,201	939	-21.8
Montana	1,057	564	-46.6	1,328	757	-43.0
Nevada	279	294	5.4	254	208	-18.1
New Mexico	27	21	-22.2	31	24	-22.6
Utah	156	105	-32.7	160	80	-50.0
Wyoming	173	96	-44.5	205	127	-38.0
Oregon	3,999	3,576	-10.6	4,277	2,853	-33.3
Washington	8,087	8,131	0.5	8,131	6,988	-14.1
West Outside California	16,211	14,815	-8.6	16,685	12,808	-23.2

WSCC Capacity and Generation, July 31 to August 4, 2000

Aggregate monthly totals suggest that power supplies were often tight during the summer, but they do not provide very specific evidence about whether overall western supplies were scarce when California experienced emergency conditions and required emergency imports to prevent the loss of firm load. The week of July 31 to August 4 was such a period in California. The Cal-ISO had emergency conditions each day during that week and had a high number of out of market calls for power from external sources. To determine what other supplies were available in the West, each control area in the WSCC was asked to provide information on loads, generating capacities and generation for hour 16 on each day. From this information, it was possible to determine the percentage of capacity in the West available and used for generating electricity. The results are shown in Table 2-16.

Figure 2-18. Percent Change in MWh Generated in WSCC, 1999 to 2000



	Hydro	Non-hydro	All Sources
May	-4	15.1	7.3
June	-22.9	24.9	4.8

The first line in Table 2-16 shows the percent of projected capacity that was unavailable. This percentage is approximately equal to the forced outage rate, because the projected August capacity included reductions for any planned outages.[3] These percentages range from 4.4 to 5.4. Given the way hydropower resources are used, some hydropower capacity that was not forced out may have been available, but not placed online for generating power due to environment and other limitations on its use for power generation, discussed above. For this reason, a separate category was used for resources available but not on line. As shown in Table 2-16, this percentage varied from 3.6 to 6.2 during the week.

[3] The forced outage rate depends on how the category, "capacity online but not generating" was treated in the projected August capacity, and could be higher if these capacities were not included in the projected amounts.

Table 2-16. Summary of WSCC Capacity Availability During the Week July 31 to August 4, 2000

	31-Jul	1-Aug	2-Aug	3-Aug	4-Aug
	Percentages				
Projected August Capacity Unavailable	4.8	5.0	5.0	4.4	4.7
Capacity Available but Not Online	4.3	4.7	3.6	4.7	6.2
Available Capacity Online but Not Generating	11.0	9.5	12.0	11.0	10.1
Online Hydro not Generating	17.6	16.0	20.1	17.2	17.6
Online Non-Hydro Not Generating	6.6	5.0	6.4	6.8	4.8
Projected August Generating Capability=155,283 MW.					

Finally, the remaining capacity after the reductions discussed in the last paragraph will be online for use either to generate electricity or to provide reserves. The percentages of total online capacity not generating output vary from 9.5 to 12.0 percent. For non-hydropower resources, these percentages are much lower than for hydropower resources: from 4.8 to 6.8 percent of online capacity. Hydropower resource percentages are higher, from 16.0 to 20.1 percent, but these resources may not be available for export outside the local control area, or may be available only for short periods.

These data show that online supplies of non-hydropower resources were very limited during the week of July 31 to August 4, not more than 6.8 percent, and do not suggest that additional online hydropower was likely to be available for export to California.

Capacity Utilization at the Cal-ISO on August 4

Further specific information on the use of resources in California is provided in Table 2-17, which shows the use of resources by category of resource at hour 16 on August 4. The table shows high utilization of all resources except hydro and must take resources. The percentage of hydro resources not generating was 26.0 percent, the percentage of non-nuclear must take resources not generating was 30.9 percent. The hydropower resources may be subject to the types of limitations discussed above, and the percentages shown are only slightly higher than those in the overall statistics for the West discussed above. Thermal must-take resources include a large number of qualifying facilities, which includes capacity used for other purposes, such as internal uses or steam generation, so these resources may be used for alternate purposes. Discussions with Cal-ISO staff confirmed that these resources are generally limited by the quantity of energy available for bid, rather than by the total physically installed capacity. For all remaining resources combined (coal, nuclear, and other thermal categories,) only 2.7 percent were not scheduled or bid. One category where the owner of the facility has the discretion to bid or schedule the unit without bidding, the "Other

Thermal (excluding RMR)" category, shows a higher percentage unscheduled or not bid than others, 8.6 percent. This quantity may represent owners holding back capacity to use if other scheduled units have outages, but it is not clear whether this is the reason or not. In any case, this quantity is a small amount of the total capacity neither scheduled nor bid, and does not suggest a large amount of withholding, regardless of the intent underlying the failure to schedule the capacity.

Table 2-17. Summary of Capacity Available and Energy Supplied in the Cal-ISO at Hour 16 on August 4, 2000

	Resource Category						
	Coal	**Hydro**	**Nuclear**	**Other Thermal (Excluding RMR)**	**Reliability Must Run (RMR)**	**Must Take**	**All Categories**
Total Capacity	1,540	12,117	4,414	5,533	14,175	8,579	46,358
Capacity Unavailable for Scheduling	790	26		572	1,889		3,277
Net Available	750	12,091	4,414	4,962	12,286	8,579	43,081
Capacity Scheduled/Bid	680	8,952	4,347	4,533	12,241	5,927	36,680
Capacity Not Scheduled or Bid	70	3,138	67	429	45	2,652	6,401
Percent Not Scheduled or Bid vs. Net Available	9.3	26.0	1.5	8.6	0.4	30.9	14.9

For the peak hour shown in Table 2-17, there does not appear to be a significant concern about resources not used. It is possible that resources are fully used at peak times when prices are high, but resources that are economic at other times are held off the market in an attempt to drive up prices. Further work would be necessary to study other hours to examine whether patterns vary at other times. This work could not be conducted within the time frame of the present investigation.

6. Transmission Congestion

Transmission patterns on California paths during May through August shifted from 1999 to 2000. Table 2-18 shows the percent of hours when transmission congestion occurred on major California paths in 1999 and 2000. In 1999 during peak hours, there was a lot of congestion on paths into California from the Northwest. The California Oregon intertie (COI) and the DC tie (NOB) were both congested a substantial portion of the time, as seen in Table 2-18. In 2000, much of this congestion was not present, due in part to the reductions in net imports, but a greater amount of congestion occurred on the major paths within California, Path 15 and Path 16.

Offpeak periods saw shifts as well. Congestion arising from imports from the Northwest and the Southwest virtually disappeared, but export congestion, mainly on paths from south to north, began to be important. These flows from south to north became more prominent in July and August. For example, NOB was congested for exports (south to north) for 40 percent of the offpeak hours and Path 15 south to north was congested 88 percent of the time during offpeak hours.

Table 2-18. Percentage of Time Major California Transmission Paths Congested, May through August, 1999 and 2000

Transmission Path	1999	2000	Difference (2000 minus 1999)
Onpeak Congestion			
Imports over Cal-Oregon Intertie (COI)	36.1%	0.3%	-35.8%
Imports from Oregon over DC Tie (NOB)	17.6%	8.0%	-9.6%
North to South on Path 15	1.0%	7.9%	6.9%
North to South on Path 26	0.0%	29.2%	29.2%
Offpeak Congestion			
Imports over Cal-Oregon Intertie (COI)	21.9%	0.0%	-21.9%
Imports from Southwest over Eldorado Path	21.0%	3.0%	-18.0%
Exports Oregon over DC Tie (NOB)	0.2%	13.5%	13.3%
South to North on Path 15	28.1%	49.6%	21.5%