CALIFORNIA ISO

California Independent
System Operator

California ISO

2003 – 2004 Winter Assessment / 2003 Post Summer Assessment

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Operations Engineering
California ISO
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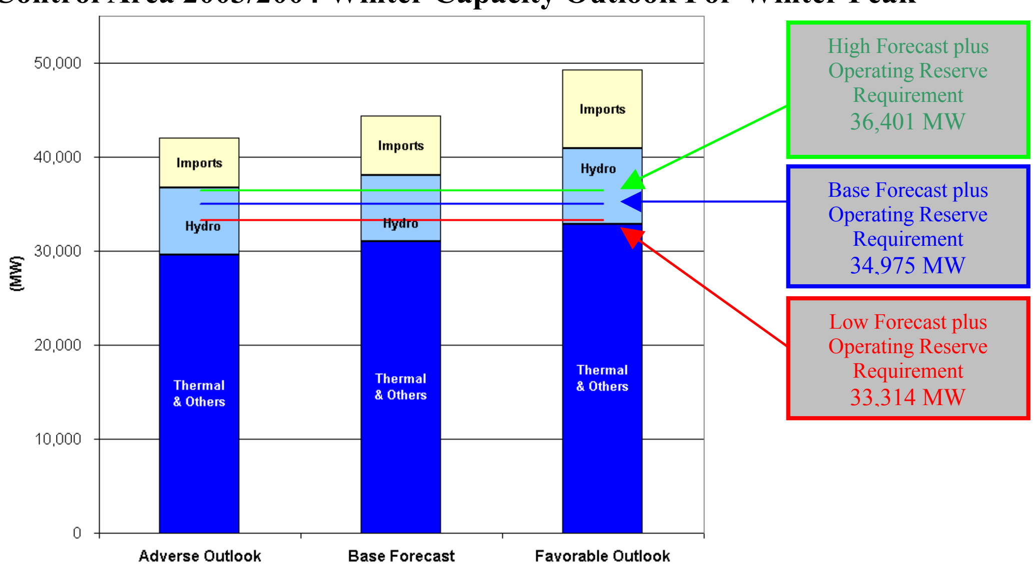
This report was prepared in response to the North American Electric Reliability Council (NERC) and Western Electricity Coordinating Council (WECC) request for an assessment of reliability and system adequacy for the anticipated 2003/2004 Winter season. The report assesses the operating forecasts of monthly peak demand levels, resource adequacy, demand response, and includes an assessment of the ISO controlled transmission system for the 2003/2004 Winter season (November 2003 to April 2004)[1]. This report also provides a brief Post Summer 2003 Assessment, plus a comparison of summer peak loads and resources for 2001 – 2003.

How does the 2003/2004 Winter Season look?

The assessment anticipates that there are ample resources to meet forecasted monthly peak demand levels in the ISO Control Area for Winter 2003/2004(shown in Figure I). There is excess thermal generation forecasted due to recent new construction; gas reserves are full and are forecast to meet the winter season needs; and the upcoming winter precipitation forecasts are above average. The continued grid management concerns that the ISO will face this winter are the mitigation of numerous transmission constraints and local reliability issues, outages from environmentally constrained units, and outages from winter storms.

Figure I
ISO Control Area 2003/2004 Winter Capacity Outlook For Winter Peak[2]



(MW)	Adverse	Base	Favorable
Thermal, Solar, Wind	29,660	31,048	32,877
Hydro and Pumped Storage	7,089	7,089	8,089
Net Imports and Dynamics	5,339	6,339	8,339
Total	**42,088 MW**	**44,476 MW**	**49,305 MW**

[1] A longer-term assessment for the next five years of the ISO Control Area can be found on the ISO web page www.caiso.com.

[2] The ISO Control Area Winter Peak Demand requirement is forecasted to occur during the month of December 2003.

Table I provides an itemized breakdown of the ISO Peak Load and Resource Forecast for the winter season, November 2003 to April 2004. Line Items are defined in Appendix A.

Table I
Peak Load and Resource Forecast Summary for
November 2003 through April 2004

	(MW)	Nov-03	Dec-03	Jan-04	Feb-04	Mar-04	Apr-04
1	Forecasted Peak Demand - (Base Forecast)	32,037	32,995	32,842	31,796	31,556	32,518
2	Operating Reserve Requirement (Base Forecast)	1,916	1,980	1,970	1,901	1,885	1,948
3	Estimated Control Area Capacity Requirement including Operating Reserve (Base Case)	33,953	34,975	34,812	33,697	33,440	34,466
	ISO Control Area Generation Resources						
4	Maximum Net Dependable Capacity of Participating Thermal Units	34,682	34,682	34,682	34,682	34,682	34,682
5	Maximum Capacity of Non-Participating Thermal Units	8,593	8,593	8,593	8,593	8,593	8,593
6	Maximum Capacity of Solar Units	466	466	466	466	466	466
7	Maximum Net Dependable Capacity of Pumped Storage Units	2,734	2,734	2,734	2,734	2,734	2,734
8	Maximum Capacity of Hydro Units	8,507	8,507	8,507	8,507	8,507	8,507
9	Maximum Capacity of Wind Units	1,820	1,820	1,820	1,820	1,820	1,820
10	Accumulative New Generation Capacity Under Construction	23	110	110	110	110	110
11	**Total ISO Control Area Generation Resources**	**56,825**	**56,912**	**56,912**	**56,912**	**56,912**	**56,912**
12	Net Dynamic Schedules into the ISO Control Area	1,312	1,312	1,312	1,312	1,312	1,312
13	**Total ISO Control Area Generation Capacity including Dynamic Schedules**	**58,137**	**58,224**	**58,224**	**58,224**	**58,224**	**58,224**
	ISO Control Area Generation De-Rates						
14	Scheduled Participating Thermal Outages	(4,945)	(3,524)	(4,867)	(6,672)	(5,433)	(6,525)
15	Scheduled Pumped Storage Outages	(152)	(152)	(132)	(100)	(539)	(132)
16	Scheduled Dynamic Outages	(973)	(973)	-	-	-	(973)
17	Estimated Forced Outages (Participating Thermal, Pumped Storage, Dynamic Schedules)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)
18	Estimated Non-Participating Thermal Limitations	(4,800)	(4,800)	(5,000)	(5,000)	(4,800)	(4,800)
19	Estimated Solar Limitations	(400)	(400)	(400)	(400)	(400)	(366)
20	Estimated Hydro Limitations	(4,000)	(4,000)	(3,000)	(3,000)	(3,000)	(3,000)
21	Estimated Wind Limitations	(1,620)	(1,620)	(1,620)	(1,385)	(1,385)	(1,385)
22	Estimated Transmission Limitations	(309)	(309)	(309)	(309)	(309)	(309)
23	Accumulative Retirements	(625)	(625)	(745)	(745)	(745)	(745)
24	Estimated Environmental Constraints	(345)	(345)	(150)	(150)	(150)	(150)
25	**Total Generation Limitations**	**(21,169)**	**(19,748)**	**(19,223)**	**(20,762)**	**(19,762)**	**(21,385)**
26	Estimated Control Area Resource Capacity (at time of peak)	36,968	38,476	39,001	37,463	38,463	36,839
27	Surplus / Deficiency before Imports (Base Forecast)	3,015	3,501	4,189	3,766	5,022	2,373
28	Expected Existing Net Imports (Excluding Dynamics)	6,000	6,000	6,000	6,000	6,000	6,000
29	Accumulative New Imports from increased Generation and Tie Line Capacity	-	-	-	-	-	-
30	Surplus / Deficiency after Imports (Base Forecast)	9,015	9,501	10,189	9,766	11,022	8,373
31	**% Projected Reserve (Base Forecast)**	**34.1%**	**34.8%**	**37.0%**	**36.7%**	**40.9%**	**31.7%**

Peak Demand Forecast

Demand for electricity is influenced by numerous economic and non-economic factors. The methodology used to forecast monthly peak loads is based on multiple statistical simulation models that consider the economic, demographic, and weather assumptions for the forecasting horizon. Due to some uncertainty in predicting the demand-determining factors used in the model (energy prices, level of conservation efforts, weather conditions, economic outlooks, etc.), the actual demand is likely to vary. A range in forecast for an expected load is more meaningful and desirable from a statistical reasonableness and a decision-making point of view. The actual load is expected to vary from a base forecast, and will occur within a range bounded by a "High", and "Low" forecast.

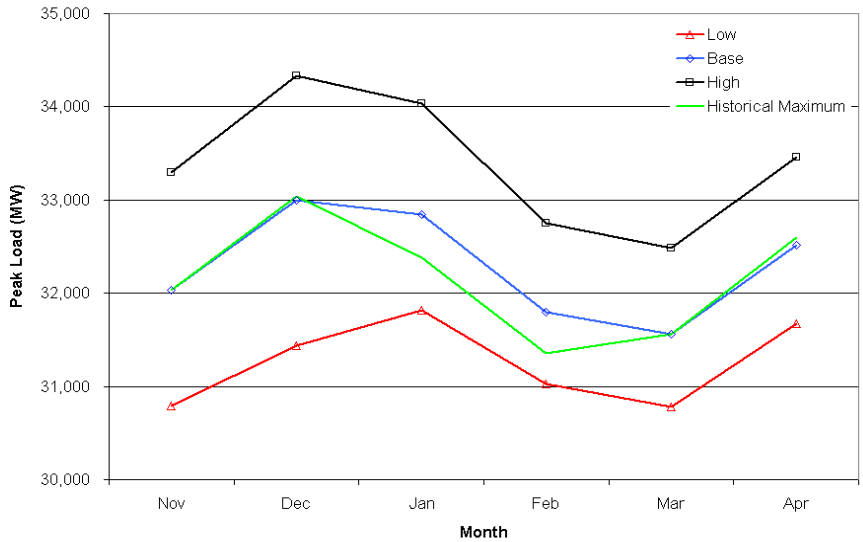
The Load Forecast range is determined using local and statewide demographics, and energy prices. The forecast has a 95% confidence interval using the following assumptions to determine the risk variance and uncertainty under High Case, Base Case, and Low Case scenarios:

- The High Case load forecast assumes that the California economy will grow at a rate of 2.20% annually, and the weighted average peak hour temperature in the ISO Control Area will reach its most extreme[3] experienced over the last five years.
- The Base Case (most likely) load forecast assumes that the California economy will grow at a rate of 1.50% annually, and the temperature will be at the weighted average peak hour temperature in the ISO Control Area over the last five years.
- The Low Case load forecast assumes that the California economy will grow less than one percent (0.95%), and the temperatures will vary 10% from the weighted average peak hour temperature in the ISO Control Area over the last five years.

Figure II compares the Winter 2003/2004 monthly peak demand forecasts with the all-time monthly peak.

[3] The most extreme temperature is the coldest temperatures reached during winter months (October through April) and the warmest temperatures reached during summer months (May – September).

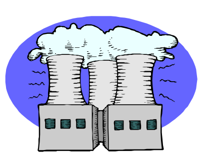
Figure II
Historical Maximum[4] and Forecasted Monthly Peak Demand Range



Note:
The base scenario of the Peak Load Forecast is developed assuming normal weather conditions. The actual demand is anticipated to range between the Forecast Low for moderate conditions and the Forecast High for extreme conditions.

Month *(MW)*	Low Case	Base Case	High Case	Historical Maximum (1998 – 2002)		
				Date	MW[1] (No SMUD)	MW (recorded)
Nov. '03	**30,788**	**32,037**	**33,293**	11/27/00	**31,983**	*33,338*
Dec. '03	**31,437**	**32,995**	**34,333**	12/13/99	**33,157**	*34,432*
Jan. '04	**31,818**	**32,842**	**34,036**	1/29/02	**31,969**	*33,488*
Feb. '04	**31,029**	**31,796**	**32,752**	2/22/00	**30,970**	*32,394*
Mar. '04	**30,778**	**31,556**	**32,488**	3/7/00	**31,214**	*32,552*
Apr. '04	**31,673**	**32,518**	**33,465**	4/13/00	**32,768**	*33,991*

1. Note: Historical recorded maximum loads have been adjusted to exclude the SMUD load from the California ISO Control Area.



New Generation Capacity and Retirements

The ISO net increase in generation since 2001 is 8,752 MW. Appendix B lists new generation added in 2003, and Appendix C lists retired and mothballed generation in 2003. As of October 1, 2003, it has been reported to the ISO that there are an additional 110 MW of generation scheduled to be commercially available by December 1, 2003 (shown in Table II)[5]. Presently, no additional generation (0 MW) is confirmed for

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[4] The ISO's historical Maximum Load is adjusted to exclude the Sacramento Municipal Utility District (SMUD), which became its own control area on June 19, 2002.

[5] The ISO considers only those generation projects that have started construction in the forecast.

Winter 2004. Furthermore, the ISO has been notified that 745 MW of existing generation will retire during Winter 2003/2004 (shown in Table III).

Table II
Planned Commercial Generation Capacity Additions for November 2003 to April 2004
COD – Commercial Operation Date

Developer	Generation Project	PTO Area	COD Estimated as of October 1, 2003	Unit/Fuel Type	ISO Net Dependable Capacity
Waste Management Energy Solutions	El Sobrante	SCE	10/15/2003	Landfill Gas	2.7
El Dorado Irrigation District	El Dorado Power House Unit 1	PGAE	10/30/2003	Hydro	10.0
El Dorado Irrigation District	El Dorado Power House Unit 2	PGAE	10/30/2003	Hydro	10.0
City of Pasadena	Glenarm Unit 3	SCE	10/30/2003	CT - Nat. Gas	43.7
City of Pasadena	Glenarm Unit 4	SCE	10/30/2003	CT - Nat. Gas	43.7

Table III
Winter 2003/2004 Retirements

Generators to Retire	MW	Retirement Date
Pittsburg units 1-4	625	10/1/2003
Etiwanda Unit 5	120	12/31/2003

Transmission Assessment

The ISO anticipates that it will continue to mitigate both **inter- and intra-zonal congestion** during Winter 2003/2004. The most significant mitigation will involve the northern Mexican generation connected at Imperial Valley (IV) Substation. Since the commercial operation this summer of the IV Generation (Generating units located in the Mexicali area and directly connected to the Imperial Valley 230 kV Substation), the ISO has mitigated significant congestion in real time (per the Miguel Import Nomogram) for nearly every hour.

A new 500/230 kV, 1120 MVA transformer bank has been installed at the Imperial Valley Substation which increases the possible transfer capability from 800 MW to 1100 MW. This improvement increases the ability to transfer additional capacity from the new generation coming into Imperial Valley from Mexicali and exports from the Comision Federal de Electricidad (CFE) Control Area to the ISO Control Area (south to north). The maximum simultaneous transfer capability for power flowing out of the Miguel substation into San Diego is rated at 1,100 MW. Actual transfer capability will vary as low as 500 MW due to the restrictions represented in the Miguel Import Nomogram, the capacity of the Miguel 500/230 kV transformer bank, and the capacity of Imperial Irrigation District's (IID) El Centro 230/161 kV transformer bank. Operations Engineering studies and the Miguel Import Nomogram require the ISO to either redispatch generation or cut schedules for three reasons: to maintain the Miguel 500/230 kV Bank 80 thermal capability; to control loading on IID's

El Centro 230/161 transformer bank, or to guard San Diego Gas & Electric's (SDG&E) internal 138 kV lines from overloads. Due to reliability requirements both IV Generation and San Diego area generation are continuously constrained in real-time. Congestion costs at Miguel are averaging approximately $88,000 per day.

This mode of operation is likely to continue through and beyond winter 2003/2004, and no new transmission infrastructure is expected for several years. The ISO is seeking approval to create additional active congestion zones to mitigate the Miguel intra-zonal congestion prior to Real-Time operations.[6]

Local Areas of most concern during winter are the **Pacific Gas and Electric's** Humboldt, and San Francisco Peninsula areas. These two areas feature winter-peaking loads, limited transmission capabilities, and dependence upon old and environmentally constrained generators. In addition, the **Southern California Edison** area may experience low system voltages (for certain N-2 contingencies during low load and high import conditions), and overloading of the 115 kV lines out of Devers substation (when wind generation is high and load is low in the Devers – Mirage area).

The **Humboldt Area** is winter peaking and is very dependent on local area generation to maintain reliability. The Humboldt grid is susceptible to voltage collapse, and thermal overload issues if local area generation is not available. The capacity available from local area generation is sporadic because the existing thermal generation is nearly 50 years old and requires innumerable maintenance outages. Additionally, this area is susceptible to potential shortages or limitations of fuel (natural gas, oil). The ISO is working with PG&E to explore ways to improve area reliability through additional local RMR generation and/or transmission upgrades. For winter 2003/2004, PG&E has mitigated one of the area's former dynamic stability concerns by installing high speed relay protection for the Humboldt 60 kV bus.

Demand on the **San Francisco Peninsula** tends to peak in the winter as well as the summer. Under extreme cold temperatures, loads of 930 MW or more can occur in San Francisco. The San Francisco Peninsula remains dependent upon limited transmission capability and local generation at PG&E's Hunters Point and Mirant's Potrero Power Plants (the combined capacity of these plants is 476 MW). However, the output of these plants may be constrained by a new NOx Emission Limit[7] effective on January 1, 2004. The winter season also brings additional planned transmission outages and Generating Unit outages/overhauls, heightening the importance of the outage coordination. The ISO can expect difficulties in meeting the

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[6] The ISO Tariff (Sec. 7.2.7.2 and 7.2.7.3) provides that the ISO may create a new zone when two criteria are met. First, the annual cost of congestion on an Intra-Zonal Interface exceeds five percent of the product of the relevant annual transmission access charge and the capacity rating of the interface ("the Five Percent Criterion"), and second, there is workable competition on both sides of the interface ("the Workable Competition Criterion").

[7] All Bay Area Generation owners must comply with the Bay Area Air Quality Management District's Rule 9-11. When an owner's fleet of generation is located in the SF Bay Area, Rule 9-11 requires the owner's fleet of steam generation units to collectively comply with a limit of hourly averaged NOx produced per MW. The limit will be reduced from 47 ppm to 31 ppm effective January 1, 2004.

next worst local contingencies if there are prolonged outages of Potrero Unit 3, Hunters Point Unit 4, generation in the East Bay that offset the Mirant NOx bubble, and/or transmission that reduces imports from the East Bay. The ISO is working with PG&E and Mirant to develop operational procedures to address these issues.

Bulk Transmission Operating Transfer Capability

In WECC, Operating Transfer Capability (OTC) limits are established on a seasonal basis through a process administered by the WECC OTC Policy Committee. Table IV lists the critical paths in the California-Mexico (CA-MX) sub-region and in the 2003/2004 Winter Operating Transfer Capabilities. The ISO expects these OTCs to be adequate for the anticipated system conditions during the 2003/2004 winter peak.

Table IV
2003/2004 Winter Operating Transfer Capabilities

	Transfer Capabilities
California-Oregon Intertie (COI)	4,800 MW North to South 3,675 MW South to North
Pacific Direct Current Intertie (PDCI)	3,100 MW bi-directional*
Southern California Import Transmission (SCIT)	14,500 MW
Path 45 (ISO – CFE)	408 MW North to South 800 MW South to North
Path 15 (Midway – Los Banos)	3,950 MW South-to-North
Path 26 (Northern CA to Southern CA)	3,000 MW bi-directional

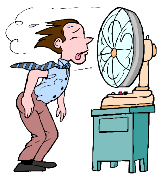
**The PDCI has a 2,200 MW Scheduling Limit in the South to North direction.*

<u>Environmental Constraints</u>

The Bay Area Air Quality Management District (BAAQMD) Rule 9-11 has set increasingly stringent NOx emission limitations for existing electric generation steam boilers. This rule affects PG&E's Hunters Point Unit 4, and Mirant's Contra Costa Units 6 - 7, Pittsburg Units 5 – 7, and Potrero Unit 3. The collective NOx emissions from plants located in the BAAQMD and owned by the same owner are referred to as a "bubble", (e.g., PG&E bubble, and Mirant bubble). NOx emissions from each bubble must not exceed emissions levels of 0.037 lb/MMBTU (~ 31 ppm) on January 1, 2004. The limit in 2003 was previously 0.057 lb/MMBTU (~ 47 ppm).

The Mirant bubble presents a challenge to Mirant and the ISO Operations team. Under the 2003 requirement, all Mirant units cannot run at the same time. Careful coordination is required to dispatch units to mitigate local area reliability while also meeting the BAAQMD Rule 9-11 requirements. Mirant is planning to install SOFA (Sulfur Flue Gas Re-circulation) on Contra Costa Unit 6 to improve NOx emissions, and is retiring its four highest NOx emitters (Pittsburg Units 1-4) prior to January 1, 2004 when the limitation becomes more stringent. With these changes, it is expected that Mirant can operate all remaining units at maximum capacity levels and remain within the 2004 limitation. However, most of the time these units operate at less than maximum output. The availability and dispatch of on-line units will need to recognize and balance the start-up of other units, since NOx emissions are greater when running at low/start-up levels.

Assessment of the 2003 Summer Season.



Summer Peak Day

The 2003 Summer peak day occurred on July 21, 2003. The actual peak demand for July (42,689 MW) exceeded the ISO's base forecast for July, but was still within the range of the High forecast for Summer 2003. In addition, the forecast did not exceed the overall 2003 Summer Season Peak Base Forecast of 42,894 MW which was forecasted to occur in August. The July 2003 peak occurred after temperatures exceeding 100 degrees were sustained for over a week in much of Northern California. Temperatures were moderate in Southern California during that week. The loads experienced were higher than those for the same temperatures in previous years, indicating load growth and less energy conservation.

The demand for electricity within neighboring control areas can affect the level of imports available to the ISO. On July 21, 2003, not only did the ISO peak, the WECC California Mexico region peaked at 53,437 MW. Regions connected to the California Mexico region also experienced high demand levels on that day. The Pacific Northwest Security Center (PNSC) had a peak of 49,473 MW with reserves of 6,132 MW. The Rocky Mountain and Desert Southwest peaked at 32,830 MW with reserves of 3,487 MW (This region's highest 2003 summer peak was 33,886 MW on July 14.) Sierra Pacific Power reached an Energy Emergency Alert Level 2. The SMUD Control area reached a peak of 2,792 MW at 16:48. [On the following day (July 22), SMUD experienced an increased peak of 2,825 MW. Similarly, temperatures also continued to rise in the Northwest and the PNSC reached its summer peak at 49,997 MW.]

Southern California Edison area reached an all time ISO recorded peak of 20,769 MW on September 15, 2003. This peak was 6.62% higher than the last recorded peak of 19,264 MW on July 12, 1999. ***Pacific Gas & Electric*** reached an all time peak of 21,103 MW on July 17, 2003, 2.1% higher than the last historic peak. ***San Diego Gas & Electric*** peaked at 3,840 MW on August 27, 2003, which was 3.3% less than its historic peak load of 3,970 MW on August 31, 1998.

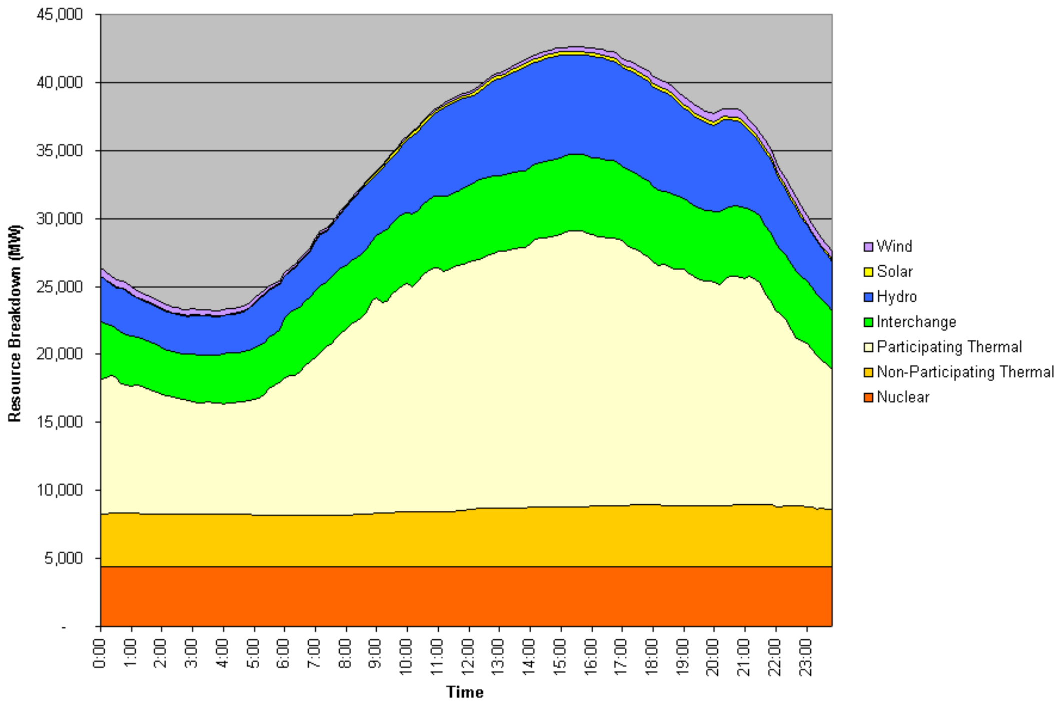
The ISO 2003 coincidental summer peak was lower than the all-time peak demand of 43,541 MW on August 12, 1998 (not including SMUD), however, it was greater in than the 2001 and 2002 summer peaks (See Table V).

Table V
Comparison of Peak Loads (2001 – 2003)

	Historical Summer Peaks		No. Days Peak above 40,000 MW	No. Days State-wide Ave. Temp. exceeded 90^0F
	MW	*Date*		
2001	39,124[8]	*8/7/01*	0	27
2002	42,441	*7/10/02*	8	19
2003	42,689	*7/21/03*	24	34[9]

Figure III shows the resource mix for meeting the load requirement on July 21, 2003.

Figure III
The ISO Control Area 2003 Peak Day Resource Summary by Technology for Monday, July 21, 2003



The ISO has experienced a net increase of 8,752 MW of capacity in the ISO Control Area since the beginning of 2001. As of October 1, 2003 there is now 56,802 MW of gross capacity in the ISO Control Area. However, the amount of actual resource capacity available to serve load is limited by outages for maintenance, load netted behind the meter, and system

[8] SMUD formed it's own Control Area on June 19, 2002. The Peak demand of 39,124 MW does not include SMUD's load.

[9] The average July 2003 temperature was 2.4^0F higher than the recorded data spanning the years 1885-2003.

constraints. The actual capacities available to serve load during the previous summers were as follows:

Table VI
Resource Capacity Available to Serve Load

	Resource Capacity at Summer Peak	Minimum Resource Capacity During Summer Seasons	Maximum Resource Capacity during Summer Seasons
2001	37,822 MW	23,771 MW	38,798 MW
2002	40,491 MW	30,999 MW	43,177 MW
2003	41,945 MW	34,656 MW	44,698 MW

Net Imports in the ISO Control Area are dependent upon snow-pack conditions in the Northwest, surplus resource capacity of neighboring Control Areas, and market conditions. Since 2001, resources built outside of the ISO Control Area have exceeded the load growth in some of those areas. As a result, the imports available to the ISO have been more abundant in 2003 than in previous years (See Table VII).

Table VII
Net Import Levels Available to Serve Load

	Net Imports at Summer Peak	Maximum Net Imports during Summer Seasons	Minimum Net Imports During Summer Seasons
2001[10]	3,703 MW	6,560 MW	(3,332 MW)
2002	3,703 MW	7,887 MW	1,105 MW
2003	4,180 MW	7,731 MW	2,608 MW

During the hour of the summer peak day the actual financial import and export transactions were as follows:

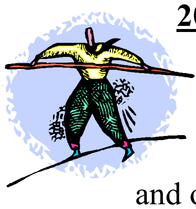
Table VIII
Import and Export Transactions at the hour of Summer Peak

	Imports	Exports
2001[11]	9,520 MWh	3,372 MWh
2002	9,171 MWh	3,967 MWh
2003	9,724 MWh	4,046MWh

[10] The 2001 Net Imports were adjusted to remove net flows into SMUD. The ISO Control Area is typically a net importer at peak, however during 2001 was a net exporter at some times. Hence, the minimum Net Imports in 2001 is negative. The Net Imports at peak is the same for the years 2001 and 2002 when rounded to the MW.

[11] The 2001 Import and Export Transactions are not adjusted for SMUD.

2003 Summer Challenges



For Summer 2003, the ISO Operations Team encountered widespread real-time transmission congestion, complex dispatching of environmentally constrained Bay Area generation (see page 8, “Environmental Constraints”), and one resource shortage that resulted in a Stage One Emergency.

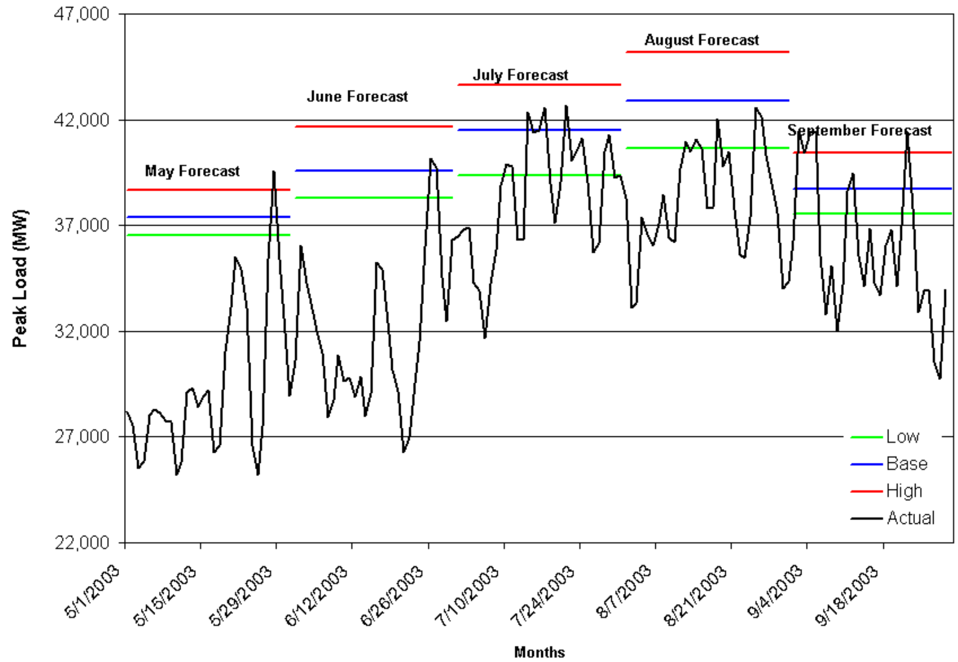
The most significant and continuing challenge faced in the 2003 summer season was the continuous real-time mitigation of congestion as discussed on page 6.

There was one Stage One Emergency that occurred on May 28, 2003 at 3:00 PM when the ISO faced resource shortages in Real Time. Temperatures had soared throughout much of the state, exceeding 100 degrees in many parts of both Northern and Southern California. The actual peak demand for May 28 exceeded both the day ahead forecast and the monthly forecast for May (shown in Figure IV). The accuracy of these demand forecasts strongly depends on accurate temperature forecasts. For this day, the ISO reviewed temperature forecasts from three independent sources as well as those from local news media and various Internet sources. None proved accurate, and ultimately all under-forecast the temperatures for all the major cities in California. The lower demand forecast had two effects: 1) because the ISO underestimated the peak demand, the ISO revoked fewer Must Offer Waivers for generation than it otherwise would have, and 2) Scheduling Coordinators significantly under scheduled Day Ahead and Hour-Ahead load demands. The Stage One Emergency ended at 6:00 PM when loads began to decrease.

Summer 2003 Actual versus Forecasted Peak Demand

Figure IV compares the ISO monthly forecasts of peak demand with the actual daily peaks for the 2003 summer season.

Figure IV
Comparison of Actual Daily Peak Loads versus Forecasted Monthly Peak Loads
May 2003 through August 2003



Summer 2003 Actual versus Forecasted Resources and Net Imports

Figure V compares the ISO monthly forecasts of Summer Resources for the ISO Control Area to the actual resource levels at the time of daily peaks for the summer season.

Figure V
Summer 2003 Monthly Control Area Resource Capacity
Forecast Vs. Actual

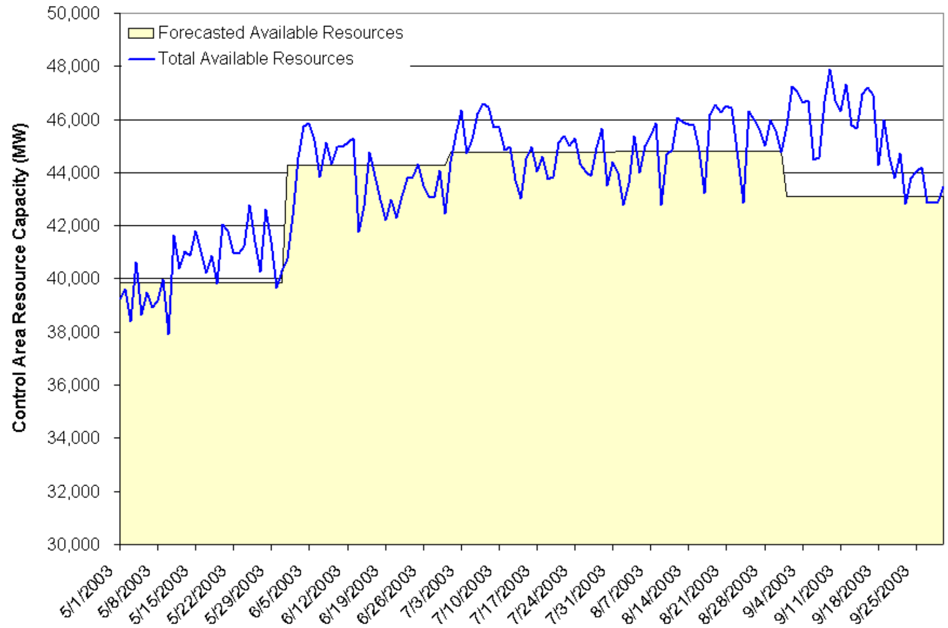
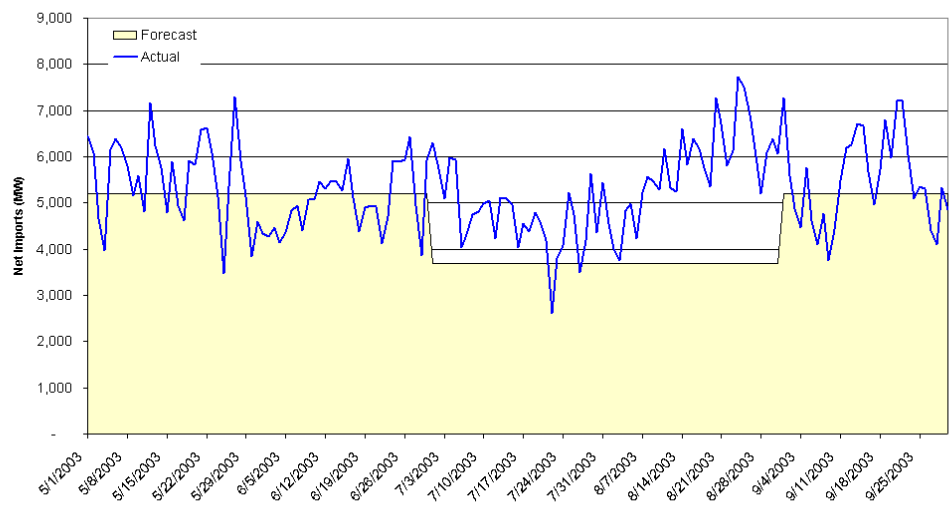


Figure VI compares the ISO monthly forecasted net imports with the actual net imports at the time of daily peaks for the 2003 summer season.

Figure VI
Summer 2003 Monthly Net Interchange
Forecast Vs. Actual



Appendix A
Table I Description

The following is a brief commentary regarding each line item for Table I.

1. **Forecasted Peak Demand (Base Forecast)** – The forecasted monthly peak demands (including transmission losses) are based on historical demand levels, economics, demographics, and typical weather conditions. This estimate does not include adjustments for proposed interruptible reduction programs or other conservation programs. This forecast is based on a best estimate of most likely operating conditions.
2. **Operating Reserve Requirement** – The estimated minimum WECC Operating Reserve requirement based on the current criteria. The minimum operating reserve is estimated as 6.6% of the generation capacity within the ISO Control Area including net dynamically scheduled generation, and unit contingent net imports used to meet the ISO system wide Peak Demand Forecast. It is assumed that all available net imports, including net Unit Contingent imports will be used to meet peak demand with the remaining capacity coming from ISO Control Area Generating Units, and Dynamic Schedules. Net Unit Contingent imports are at times as high as 3,000 MW per month.
3. **Estimated Control Area Capacity Requirement (Base Forecast)**– The sum of "Forecast Peak Demand" (line item 1) and "Operating Reserve Requirement" (line item 2).
4. **Maximum Net Dependable Capacity of Participating Thermal Units –** The maximum Net Dependable Capacity (NDC) of thermal generation resources that are located within the ISO Control Area and whose owners have signed a Participating Generator Agreement (PGA) or Metered Subsystem Agreement (MSA) with the ISO as of August 29, 2003. Participating Thermal Units are counted regardless of whether they are scheduled inside or outside the ISO Control Area. The NDC does not include contractual or ownership rights of resources located outside of the ISO Control Area. The maximum NDC is not adjusted to account for reduced energy production as a result of outages, environmental limitations, geothermal steam fields, etc.
5. **Maximum Capacity of Non-Participating Thermal Units –** The Non-Participating thermal generators' (those generators who have not signed a PGA or MSA) total capacity reported to the ISO as of August 29, 2003, prior to de-rates for actual availability. These units include Generating Units owned by Non-Participating Municipals, Generating Units operating under a pre-existing contract (i.e. Qualifying Facilities), and Generating Units greater than 1 MW that are privately owned and operated to meet their own (end-use) electric needs.
6. **Maximum Capacity of Solar Units –** The solar generators' total capacity reported to the ISO as of August 29, 2003, prior to de-rates for actual availability.

7. **Maximum Net Dependable Capacity of Pumped Storage Units –** The maximum NDC of pumped storage resources located within the ISO Control Area as of August 29, 2003. Outages of pumped storage resources are reflected in the Scheduled Pumped Storage Outages on line item 15 and Forced Outages on line item 17.

8. **Maximum Capacity of Hydro Units –** The Run-of-River and Pond Storage hydro generators' total capacity reported to the ISO as of August 29, 2003 prior to de-rates for hydro limitations. Note that in previous Seasonal Assessments Pumped Storage generation had been included in this line item, but is a now separately itemized. De-rates for hydro limitations at the time of monthly peak are shown in line item 19.

9. **Maximum Capacity of Wind Units –** The total wind turbine capacity reported to the ISO as of August 29, 2003, prior to de-rates for wind.

10. **Accumulative New Generation Capacity Under Construction–** Accumulative new generation capacity captures future facilities that are expected to be sited and operational within the ISO Control Area. The Net Dependable Capacity has been de-rated to include any constraints in the transmission system that limit the ISO from obtaining the full generation capacity of the plant.

11. **Total ISO Control Area Generation Resources –** The sum of all generation located in the ISO Control Area prior to de-rates (sum of line items 4 through 10).

12. **Net Dynamic Schedules into the ISO Control Area –** The maximum dynamically scheduled capacity into and out of the ISO Control Area. The dynamic schedules include both IOU and Municipal shares of Palo Verde, Four Corners, Hoover, and Yuma Cogeneration Project that are scheduled into the ISO Control Area; and Mohave's generation that is scheduled out of the ISO Control Area.

13. **Total ISO Control Area Generation Capacity including Dynamic Schedules** – The sum of all generation located in the ISO Control Area (prior to de-rates) plus the net sum of generation that are dynamically scheduled into the ISO Control Area (sum of line items 11 and 12).

14. **Scheduled Participating Thermal Outages –** The maximum Participating thermal generators' scheduled outages logged in the "Scheduling and Logging for the ISO and California" database (SLIC) as of August 29, 2003. For planning purposes, this assessment used the maximum total of expected outages for each month, occurring between the hours of noon and 6:00 PM.

15. **Scheduled Pumped Storage Outages –** The maximum Pumped Storage generators' scheduled outages expected for each month, occurring between the hours of noon and 6:00 PM for each month (logged in SLIC as of August 29, 2003).

Note: Limitations for pumped storage units in previous Winter Assessments were included under Hydro Limitations.

16. **Scheduled Dynamic Outages** – The maximum Dynamic Scheduled generators' outages expected for each month, occurring between the hours of noon and 6:00 PM for each month (logged in SLIC as of August 29, 2003).

17. **Estimated Forced Outages (Participating Thermal, Pumped Storage, and Dynamic Schedules) –** The monthly average of forced outages recorded in SLIC from the previous 2 years.

18. **Estimated Non-Participating Thermal Limitations –** The de-rate for Non-Participating thermal generation (including Non-Participating Muni Thermal) is based on actual historical Non-Participating thermal generation operating levels recorded through the ISO Energy Management System (EMS). The NDC for these units is the difference between the Maximum Capacity of Non-Participating thermal units (line item 5) and this limitation. The limitation for these units is attributed to: load netted behind metering; station service load; lack of EMS visibility on smaller resources; retired or de-rated unit capabilities; maintenance; and reduced capacity levels of steam for geothermal resources.

19. **Estimated Solar Limitations** – The estimated solar capacity limitations are based on solar capacity limitations previously experienced during similar months. The limitation for these units is attributed to: station service load; lack of EMS visibility; maintenance; and cloud conditions. The NDC for these units is the difference between the Maximum Capacity of Solar units (line item 6) and this limitation.

20. **Estimated Hydro Limitations –** The estimated hydro capacity limitations are based on hydro capacity limitations previously experienced during similar months. The NDC for hydro units is the difference between the Maximum Capacity of hydro units (line item 8) and this limitation. Capacity of Hydro resources are limited during certain times of the day and/or month for a variety of reasons, including interplay between hydro units on common river system, environmental constraints, and regulation of water releases.

21. **Estimated Wind Limitations –** The estimated wind capacity limitations are based on wind capacity limitations previously experienced during similar months. The limitation for these units is attributed to: station service load; lack of EMS visibility; maintenance; and wind conditions. The NDC for these units is the difference between the Maximum Capacity of Wind units (line item 9) and this limitation.

22. **Estimated Transmission Limitations –** The estimated limitations that restrict plants from delivering full capacity due to transmission constraints.

23. **Accumulative Retirements –** The capacity of ISO Control Area generation that is anticipated to retire in winter 2003/2004.

24. **Estimated Environmental Constraints** – Temporary shutdowns or de-rates of Generating Units at time of daily peak due to the plant's inability to meet environmental mandates such as air quality, water, and noise limits that are ordered by an authorized agency.

25. **Total Generation Limitations** - The sum of all generation limitations that affect Generating Units located in the ISO Control Area (sum of line items 14 through 24.)

26. **Estimated Control Area Resource Capacity (at time of peak) –** The forecasted total available generation capacity (including dynamic schedules) located within the ISO Control Area after adjusting for estimated outages, and other capacity limitations (Line item 13 minus line item 25).

27. **Surplus/Deficiency before Imports (Base Forecast) –** The total estimated capacity surplus or deficiency served by Control Area generation and dynamic schedules prior to net imports.

28. **Expected Existing Net Imports (Excluding Dynamics) –** The forecast for existing net imports is based on historical import levels.

29. **Accumulative New Imports from increased Generation and Tie Line Capacity -** Expected net increase of imports due to an increase in Tie Line capacity and imports from new generation built outside the State of California.

30. **Surplus/Deficiency after Imports (Base Forecast) –** The estimated surplus or deficiency in capacity during peak-load period, considering all preceding assumptions, including imports. This capacity does not take into account load conservation or demand relief measures; these impacts cannot be dependably predicted and are not included in this assessment (sum of line items 27 and 28.)

31. **Projected Reserve (Base Forecast)** – For the Base Forecast, the projected operated reserve is calculated as:

$$\frac{Operating\ Reserve\ Requirement\ (line\ 2) + Surplus\ /\ Deficiency\ after\ imports\ (line\ 30)}{Forecasted\ Peak\ Demand\ (line\ 1)} \times 100$$

Appendix B
New Generation in the ISO Control Area since January 1, 2003
(As of October 1, 2003)

	Generating Unit	Net Dependable Capacity (MW)	Class	ISO Classification	Fuel Type	Demand Zone	PTO Area	Owner or QF ID	Commercial Date
1	Creed Energy Center	48.7	Participating	Peaker	N. Gas	NP 15	PGAE	Calpine	1/6/2003
2	Goose Haven Energy Center	48.7	Participating	Peaker	N. Gas	NP 15	PGAE	Calpine	1/6/2003
3	Lambie Energy Center	48.7	Participating	Peaker	N. Gas	NP 15	PGAE	Calpine	1/6/2003
4	La Paloma Unit 1	227.4	Participating	Thermal	N. Gas	ZP 26	PGAE	La Paloma Generating Company	1/10/2003
5	La Paloma Unit 3	231.5	Participating	Thermal	N. Gas	ZP 26	PGAE	La Paloma Generating Company	1/13/2003
6	La Paloma Generating Project, Unit 2	234.9	Participating	Peaker	N. Gas	ZP 26	PGAE	La Paloma Generating Company	3/5/2003
7	La Paloma Generating Project, Unit 4	235.3	Participating	Peaker	N. Gas	ZP 26	PGAE	La Paloma Generating Company	3/5/2003
8	Los Esteros Critical Energy Facility, Unit 1	195.0	Participating	Peaker	N. Gas	NP 15	PGAE	Calpine	3/7/2003
9	Wolfskill Energy Center	48.7	Participating	Peaker	N. Gas	NP 15	PGAE	Calpine	3/22/2003
10	Colton Landfill Project	1.2	Non-Participating	Biomass	Landfill Gas	SP 15	SCE	NM Colton Genco, LLC	4/14/2003
11	High Desert Power Project	850.0	Participating	Peaker	N. Gas	SP 15	SCE	Constellation Power	4/21/2003
12	Mid Valley	2.4	Participating	Thermal	N. Gas	SP 15	SCE	NM Mid Valley Genco, LLC	4/21/2003
13	Riverview Energy Center (GP Antioch)	48.7	Participating	Peaker	N. Gas	NP 15	PGAE	Calpine	5/2/2003
14	Tracy Peaker Plant Unit 1	85.0	Participating	Peaker	N. Gas	NP 15	PGAE	GWF	5/30/2003
15	Tracy Peaker Plant Unit 2	85.0	Participating	Peaker	N. Gas	NP 15	PGAE	GWF	5/30/2003
16	Sunrise Power Project, Phase II, Unit 3	251.0	Participating	Thermal	N. Gas	ZP 26	PGAE	Edison Mission Energy	6/1/2003
17	Agua Mansa Power Project	43.0	Non-Participating	Peaker	N. Gas	SP 15	SCE	City of Colton	6/27/2003
18	San Diego State University GT #1	5.3	Non-Participating	Peaker	N. Gas	SP 15	SDGE	San Diego State University	7/10/2003
16	San Diego State University GT #2	5.3	Non-Participating	Peaker	N. Gas	SP 15	SDGE	San Diego State University	7/10/2003
17	San Diego State University SGT	4.0	Non-Participating	Thermal	N. Gas	SP 15	SDGE	San Diego State University	7/10/2003
18	Milliken Landfill Project	4.8	Participating	Biomass	Landfill Gas	SP 15	SDGE	NM Milliken Genco, LLC	7/17/2003
19	Ciclo Combindado Mexicali	170.0	Participating	Thermal	N. Gas	SP 15	SDGE	Intergen	7/20/2003
20	Central La Rosita II Combined Cycle	310.0	Participating	Thermal	N. Gas	SP 15	SDGE	Energia de Baja California	7/22/2003
21	Elk Hills Generating Project	549.0	Participating	Thermal	N. Gas	ZP 26	PGAE	Elk Hills Power	7/24/2003
22	Termoelectrica De Mexicali	600.0	Participating	Thermal	N. Gas	SP 15	SDGE	Termoelectric De Mexicali	7/30/2003
23	Highwinds Project	145.8	Participating	Wind	Wind	NP 15	PGAE	Highwinds, LLC	8/1/2003
24	Woodland Combined Cycle Plant	83.0	Muni	Thermal	N. Gas	NP 15	MID1	Modesto Irrigation District	8/1/2003
25	Huntington Beach Unit 4	227.4	Participating	Thermal	N. Gas	SP 15	SCE	AES	8/7/2003
Total Capacity Commercial in 2003 as of October 1, 2003		***4,790***							

Appendix C
Retired and Mothballed Generation Capacity in the ISO Control Area
(As of October 1, 2003)

Unit	Demand Zone	MW	Retired/Mothballed	Date
Jefferson Smurfit Corporation	SP15	29	Mothballed	2/28/2003
Sunlaw Energy - Federal	SP15	28	Retired	4/16/2003
Sunlaw Energy - Growers	SP15	28	Retired	4/16/2003
Alamitos Unit 7	SP15	134	Retired	6/7/2003
2003 Retirements		**218.50**		