1 Market Structure and Design Changes

1.1 Introduction and Background

This chapter reviews some of the major market design and infrastructure changes that impacted market performance in 2007. There were two market design changes implemented in 2007. The first involved certain modifications to the current load scheduling requirement for the Day Ahead Market, which included a lower day-ahead scheduling requirement in off-peak hours, reducing the requirement from 95 to 75 percent of each SC's forecasted load. Accompanying the reduction in scheduling requirement was an exemption during all hours for *de minimus* deviations below the scheduling requirement (i.e., the minimum of 3 MWh or 5 percent of forecasted demand). The other market design change implemented in 2007 was the enforcement of local capacity requirements in the CPUC's Resource Adequacy program, where load serving entities became required to procure capacity to satisfy specific local requirements determined by the CAISO. This more granular requirement complements the system-wide capacity requirements that were enforced beginning June of 2006.

The infrastructure changes discussed below include changes in generation retirements and additions and various transmission upgrades implemented in 2007 and potential future projects. The chapter concludes with an overview of some notable activities in 2007 relating to the CAISO Enforcement Protocols.

1.2 Market Design Changes

1.2.1 Day Ahead Load Scheduling Requirement

On April 24, 2007, FERC issued an order accepting several key changes to the day-ahead load scheduling requirements initially established in October 2005 under Amendment 72. The major change taking effect in 2007 was to lower the day-ahead scheduling requirement in off-peak hours from 95 to 75 percent of each SC's forecasted load. Another change provided an exemption during all hours for *de minimus* deviations below the scheduling requirement (i.e., the minimum of 3 MWh or 5 percent of forecasted demand). The changes were proposed by the CAISO in response to concerns expressed by Load Serving Entities (LSEs) about the costs and difficulty of complying with the 95 percent scheduling requirement during all hours, and to reduce over-scheduling of load,[1] particularly during off-peak hours, which can create operational challenges in real-time.

The modifications in day-ahead load scheduling provisions appear to have resulted in a moderate decrease in over-scheduling and a reduced need to routinely decrement energy in the Real Time Market. As expected, these impacts occurred primarily during off-peak hours. As

[1] Over-scheduling can arise under this requirement because in order to meet a 95 percent scheduling requirement in all hours, LSEs would sometimes have to purchase multi-hour blocks of energy from the inter-ties, which in some cases resulted in over-scheduled load during some hours – particularly off-peak hours.

shown in Table 1.1, analysis of scheduling and dispatch data in the weeks before and after these changes went into effect shows a reduction in three key indicators of over-scheduling and excessive energy in real-time:

- **Day Ahead Over-scheduling**. The amount of day-ahead over-scheduling – measured by the degree to which day-ahead load schedules exceed the CAISO's day-ahead load forecast – dropped by an average of about 218 MW during off-peak hours and about 34 MW during peak hours. This represents an average drop in day-ahead over-scheduling of about 1 percent of total CAISO load during off-peak hours.

- **Average Net Energy Dispatched in Real Time Market**. In the CAISO's Real Time Energy Market, the CAISO dispatched an average of 409 MW of net decremental energy during off-peak hours before the changes, but dispatched an average of only 22 MW of net decremental energy since the modifications. During peak hours, the average amount of real-time energy dispatched dropped from 462 MW of net decremental energy to an average of 345 MW of net decremental energy.

- **Percent of Hours with Net Decremental Energy Dispatched in Real Time Market**. The percentage of off-peak hours during which the total energy dispatched by the CAISO in the Real Time Market was negative – indicating a net dispatch of decremental energy (i.e., a net dispatch that requires generation to operate at levels below what was originally scheduled) – dropped from 82 percent to 58 percent of hours after the scheduling requirement was lowered to 75 percent for off-peak hours.

While the reduction in over-scheduling and over-generation during off-peak hours has been relatively moderate, this may be in part attributable to the relatively low hydro conditions experienced in 2007.[2] In addition, while some participants opposing a lower scheduling requirement for off-peak hours expressed concerns that these changes would cause the need to dispatch significant amounts of incremental energy in real-time, there is no evidence that such impacts materialized.

[2] The overall level of over-generation and decremental energy dispatched by the CAISO was significantly higher in the spring and early summer of 2006 than 2007, largely due to the much higher hydro conditions in 2006 than in 2007. Consequently, analysis of the potential impacts of changes in load scheduling requirements in this report was not based on a comparison of 2006 and 2007 data since this could overestimate impacts under actual hydro conditions in 2007. However, one of the key reasons for modifying off-peak scheduling requirements was to avoid the problems that the 95 percent scheduling requirement created during off-peak hours under the extremely high hydro conditions that did occur in 2006.

Table 1.1 Key Indicators of Over-scheduling Before and After Modification of Day Ahead Scheduling Requirement

	Before	After	Reduction
Average Day Ahead Over-scheduling			
Off-Peak Hours	406 MW (1.8%)	188 MW (8%)	218 MW (1.0%)
Peak Hours	174 MW (.6%)	140 MW (5%)	34 MW (1%)
Average Net Real Time Dispatch (MW/hour)			
Off-Peak Hours	-409 MW	-22 MW	-387 MW
Peak Hours	-462 MW	-345 MW	-117 MW
Percent of Hours with Net Decremental Energy Dispatch in Real Time Market			
Off-Peak Hours	82%	58%	-24%
Peak Hours	78%	75%	-3%

Note: Analysis based on comparison of data for six weeks prior to the April 26, 2007 effective date of changes in day-ahead scheduling requirements with data for seven weeks after the effective date of changes.

Modifications in day-ahead scheduling requirements taking effect in late April 2007 also did not appear to have any detrimental effects on scheduling during high load days during the summer months. For example, as shown in Figure 1.1:

- Day-ahead schedules tended to slightly exceed actual loads during the off-peak hours during typical high load summer days in 2007 (i.e., when loads ranged from 40,000 to 45,000 MW). During peaks hours, day-ahead schedules tended to be slightly lower than actual loads. Specifically, during Hour Ending 16 of these high load summer days, day-ahead schedules averaged about 98 percent of actual loads in 2007.

- Meanwhile, hour-ahead schedules were even closer to actual load during both peak and off-peak hours. During Hour Ending 16 of these high load summer days, hour-ahead schedules averaged about 99.7 percent of actual loads in 2007.

Figure 1.2 shows a similar comparison of day-ahead and hour-ahead schedules to actual loads during days in 2006 with comparably high loads of 40,000 to 45,000 MW. As shown in Figure 1.2:

- During high load days in 2006, day-ahead schedules tended to exceed actual loads during the off-peak hours slightly more than in 2007, while day-ahead schedules tended to fall short of actual loads by a slightly higher level.

- For example, during Hour Ending 16 of high load summer days in 2006, day-ahead and hour-ahead schedules averaged about 97 and 99 percent of actual loads, respectively, compared to about 98 and 100 percent, respectively, during similar days in 2007.

These trends are further illustrated in Figure 1.3, which show the difference in day-ahead schedules and actual loads during similar high load days in 2006 and 2007. Negative values in Figure 1.3 indicate hours when hour-ahead schedules were less than actual loads on average, while positive numbers indicate hours when hour-ahead schedules tended to be greater than actual loads. As shown in Figure 1.3, during most hours, final hour-ahead schedules tended to track actual load somewhat more closely during high load days in 2007 than in 2006. This provides further indications that the modification made in day-ahead scheduling requirements for off-peak hours did not have any detrimental effects on overall scheduling trends.

Figure 1.1 Day Ahead and Hour Ahead Schedules Compared to Actual Load for Days with Peak Loads of 40 to 45 GW in 2007

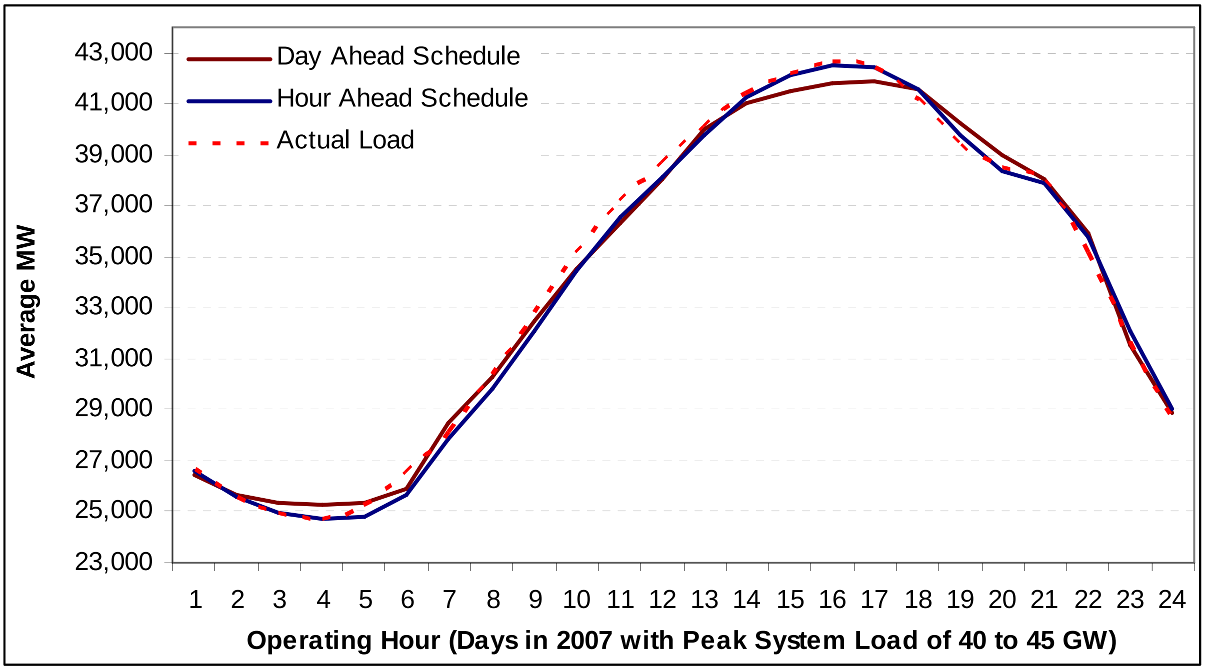


Figure 1.2 Day Ahead and Hour Ahead Schedules Compared to Actual Load for Days with Peak Loads of 40 to 45 GW in 2006

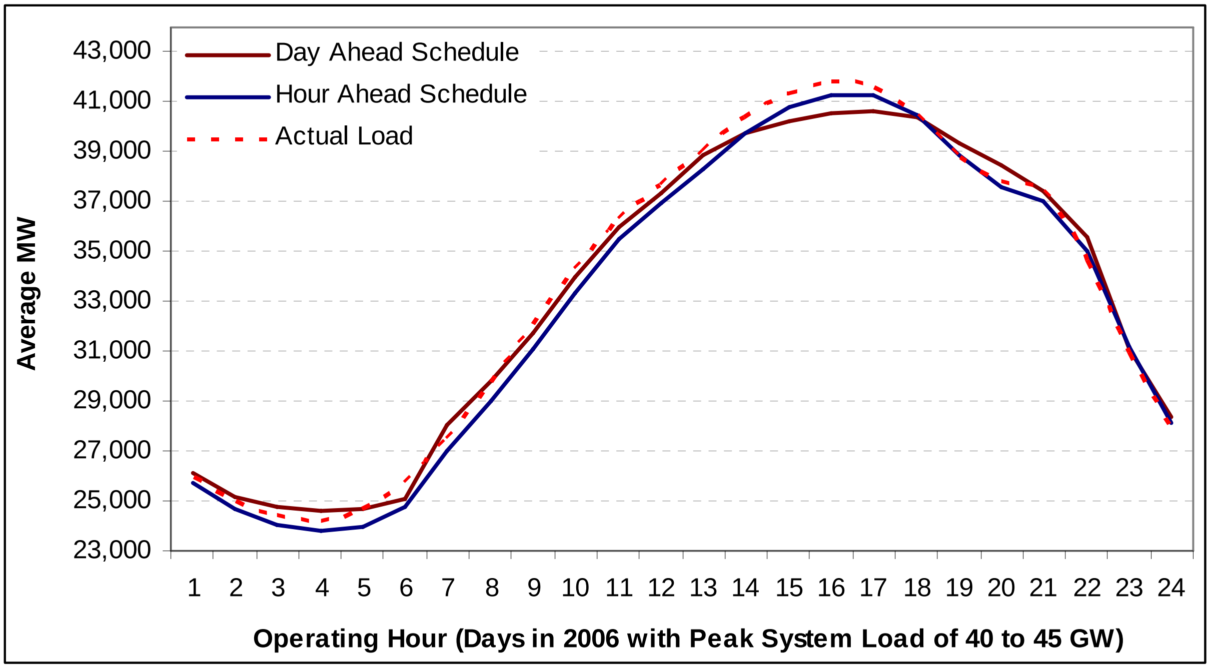
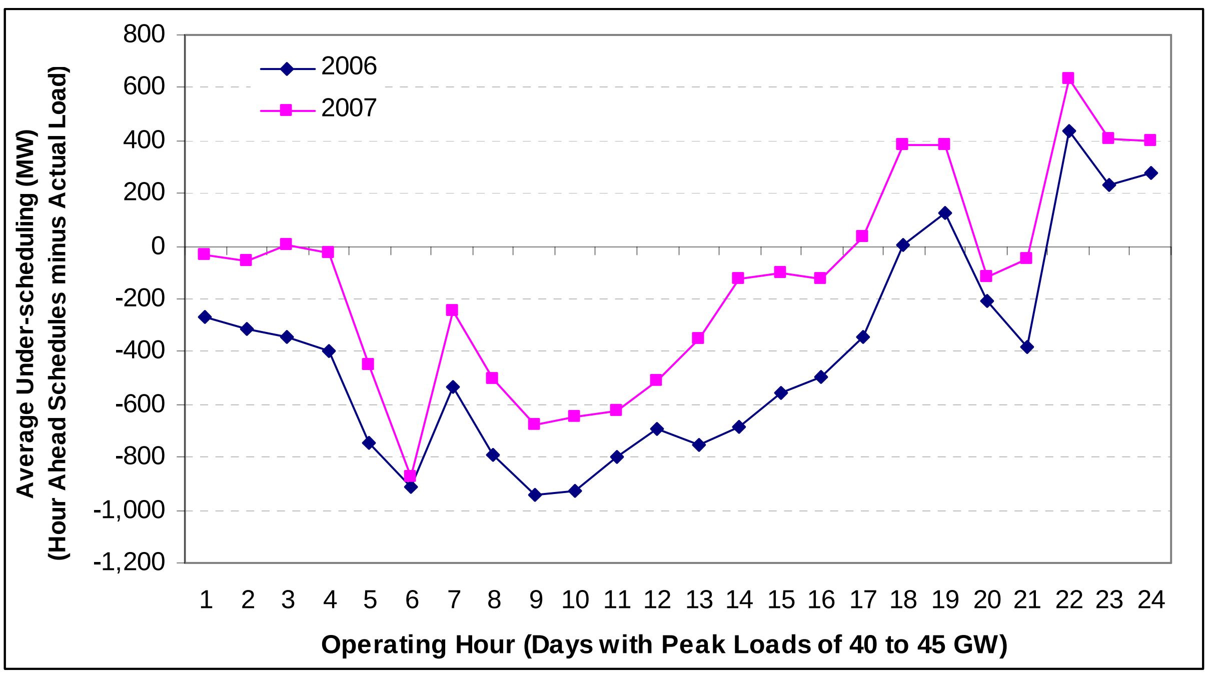


Figure 1.3 Average Difference Between Hour Ahead Schedules and Actual Loads during High Load Days in 2006 and 2007



1.2.2 Local Resource Adequacy Requirements

In 2006, the Resource Adequacy (RA) program developed by the CPUC became effective. This program requires that LSEs procure sufficient resources to meet their peak load along with appropriate reserve margins.[3] In addition to the CPUC RA program, non-CPUC jurisdictional LSEs have also instituted similar capacity reserve margins. In 2006, the RA program was limited to imposing system-wide capacity requirements. In 2007, the program was expanded to include Local Resource Adequacy Requirements (LRAR) for LSEs subject to CPUC jurisdiction.[4] Under this component of the state's RA program, LSEs are required to seek to procure minimum level of RA capacity within various Local Capacity Areas (LCAs), or transmission constrained "load pockets" within the CAISO system. Minimum capacity requirements for LCAs are established through technical studies performed by the CAISO based on NERC Planning Standards and any other local reliability criteria established by the CAISO or Participating Transmission Owners (PTOs).[5] LCAs are defined based on the same areas that have been used in Local Area Reliability Services (LARS) studies conducted in previous years to determine requirements for capacity under Reliability Must Run (RMR) contracts.

One of the goals of the CAISO management and the CPUC is to rely on capacity contracted by LSEs to meet local RA requirements, and thereby reduce reliance on RMR contracts or any other "backstop" procurement that may be done by the CAISO. For example, as noted in last year's Annual Report on Market Issues and Performance, the CAISO's Reliability Capacity Services Tariff (RCST) provisions, which were established pursuant to a settlement filed in 2006, authorizes the CAISO to designate non-RA units to provide services under the RCST tariff as a "backstop" in the event that the CAISO determined that RA resources procured by LSEs did not meet projected reliability needs.

In 2007, substantial progress in the goal of reducing reliance on RMR contracts was achieved, as the total volume of capacity under RMR contracts was reduced from approximately 9,300 MW to only 3,300 as seen in Table 1.2. In addition, all local reliability requirements were met by units under RA and RMR contracts. Consequently, the CAISO did not need to designate any capacity under RCST provisions as a "backstop" to RA resources procured by LSEs.

Table 1.2 and Figure 1.4 provide a more detailed comparison of capacity under RMR and RA contracts in 2006 and 2007, along with the minimum capacity requirement for each of the major three LCAs in the CAISO system. Since the minimum capacity requirement for each LCA is based on peak summer conditions, RMR and RA capacity in Table 1.2 and Figure 1.4 are based on each unit's Net Qualified Capacity (NQC) for the month of July, which represents the amount of a unit's capacity that may be used to meet local RA requirements for this peak summer month.[6] The NQC for each unit is determined through accounting rules used in the RA program, which are designed to reflect the amount of each unit's nameplate capacity that will actually be available during peak hours each month, after accounting for factors such as the

[3] Background information on other components of the Resource Adequacy program, which became effective in 2006, are provided in DMM's *2006 Annual Report on Market Issues and Performance,* pp.6-7 and 1.2-1.5.

[4] Opinion on Local Resource Adequacy Requirements, Before the Public Utilities Commission of the State of California, Decision 06-06-64, June 29, 2006.

[5] A description of the CAISO's methodology for establishing minimum capacity requirement for each LCA is provided in the Manual for the *2009 Local Capacity Area Technical Study*, December 2007.

[6] In addition, some units that are under RA contracts were still designated as RMR in 2007, based on a determination that RA contract provisions did not satisfy all of the reliability services that are provided and needed under an RMR contract, such as black-start and dual fuel capability. In Table 1.2 and Figure 1.4, units under both RMR and RA contracts are counted as RMR capacity, but are not also counted under the RA category.

intermittent nature of renewable energy resources or other environmental factors affecting unit availability.

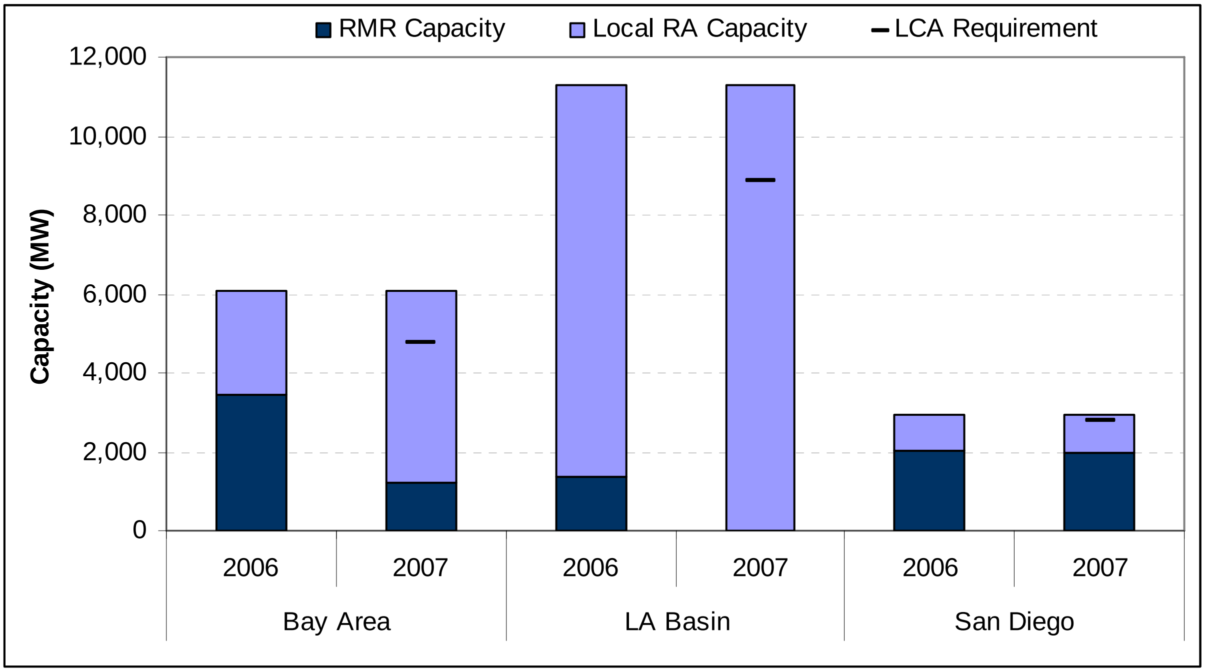
As shown in Table 1.2 and Figure 1.4, reliance on RMR contracts in the LA Basin was eliminated in 2007, and was significantly reduced in the San Francisco Bay Area. In addition, since the minimum reliability requirement for each LCA was met through a combination of RA and RMR capacity, the CAISO did not need to designate any additional capacity through the RCST provisions of the CAISO. As discussed in Chapter 6, the reduction in capacity under RMR contracts and lack of RCST designations as a "backstop" to the RA process were a major factor underlying the reduction in overall reliability related costs incurred by the CAISO.

Table 1.2 Comparison of RMR and Local Resource Adequacy Capacity with Local Capacity Area (LCA) Requirements

Local Capacity Area (LCR	Year	RMR Capacity (MW)*	RA Capacity (MW)**	Total Capacity (MW)	LCA Requirement (MW)
LA Basin	2006	1,390	9,889	11,279	
	2007	0	11,279	11,279	8,843
Bay Area	2006	3,434	2,651	6,085	
	2007	1,218	4,867	6,085	4,771
San Diego	2006	2,010	912	2,922	
	2007	1,963	959	2,922	2,781
Other LCRs	2006	2,451	21,516	26,916	
	2007	130	23,436	26,916	
Totals	2006	9,259	37,943	47,202	
	2007	3,311	43,891	47,202	

* RMR capacity based on each unit's NQC rating for month of July under the RA program.
** Excludes units under both RMR and RA contracts.

Figure 1.4 Comparison of RMR and Local Resource Adequacy Capacity with Local Capacity Area (LCA) Requirements



1.3 Generation Additions and Retirements

Trends in the net-generation capacity being added to the CAISO Control Area each year provides important insight into the effectiveness of the California market and regulatory structure in bringing about new generation investment and facilitating the retirement of older inefficient plants. The Department of Market Monitoring tracks changes in the portfolio of installed capacity in the CAISO Control Area and conducts revenue analysis for new generation investment to determine the extent to which the California market is providing sufficient incentives for new generation investment.[7]

1.3.1 Generation Additions and Retirements in 2007

Approximately 598 MW of new generation began commercial operation within the CAISO Control Area in 2007. The majority of new capacity was added in the South. Table 1.3 shows the new generation projects that began commercial operation in 2007.

[7] Generator revenue analysis is provided in Chapter 2.

Table 1.3 New Generation Facilities in 2007

Generating Unit	Net Dependable Capacity (MW)	Commercial Operation Date	Zone ID
Midsun	22.0	01-Feb-07	NP 26
Santa Clara Wind Project	24.1	03-May-07	NP 26
Lake Mendocino Hydro	3.5	02-Jul-07	NP 26
Marina LFG2 Power Plant	2.6	01-Sep-07	NP 26
Bottle Rock Power Plant	55.0	01-Oct-07	NP 26
Palo Alto	5.2	15-Oct-07	NP 26
NP26 New Generation in 2007	***112.4***		
Long Beach Unit 1, 2, 3, 4	280.0	01-Aug-07	SP26
Center Peaker	49.0	20-Sep-07	SP26
Barre Peaker	49.0	20-Sep-07	SP26
Grapeland Peaker	49.0	20-Sep-07	SP26
Mira Loma Peaker	49.0	20-Sep-07	SP26
Puente Hills GTE Facility Phase II	9.3	07-Dec-07	SP26
SP26 New Generation in 2007	***485.3***		
Total New Generation in 2007	**597.7**		

Source: California ISO Grid Planning Department

No generation capacity was retired from service in 2007. Therefore, the net capacity increase in the CAISO Control Area was 598 MW. Table 1.4 summarizes the net change in installed generation by region.

Table 1.4 Generation Capacity Change in 2007 by Region

Region	Generation Additions (MW)	Generation Reductions (MW)	Net Change in Generation (MW)
NP26	112	0	112
SP26	485	0	485
CAISO Control Area	**598**	**0**	**598**

1.3.2 Anticipated New and Retired Generation in 2008

The CAISO projects construction of 1,810 MW of new generation in 2008, of which roughly 941 MW are expected to be commercially available prior to the anticipated summer peak season. Most significantly, there are two 405 MW resources, the Inland Empire units shown in Table 1.5 below, that are expected to be operational in May 2008.

Table 1.5 Planned Generation Facilities in 2008

Generating Unit	Resource Owner / QF ID	Resource Capacity (MW)	Expected Operational Date	Zone ID
Chowchilla Biomass	Global Common LLC	12.5	31-Jan-08	NP26
Keller Canyon Landfill Generating Facility	Ameresco Keller Canyon LLC	3.8	06-Aug-08	NP26
Gateway Generating Station	PG&E	530	01-Sep-08	NP26
Shiloh Wind Farm II	enXco	150	01-Sep-08	NP26
Ox Mountain Landfill Gas Generation	Ameresco Renewables	11.4	04-Sep-08	NP26
Eastshore Energy Facility Project	Tierra Energy	118	01-Nov-08	NP26
NP26 Planned New Generation in 2008		***826***		
Dillon Wind Project	PPM Energy	45.0	15-Feb-08	SP26
Wintec III	Wintec Energy, LTD	11.57	28-Feb-08	SP26
El Nido	Global Common LLC	12.5	29-Feb-08	SP26
Inland Empire Energy Center Unit 1	Inland Empire Energy Center, LLC	405	15-Mar-08	SP26
Inland Empire Energy Center Unit 2	Inland Empire Energy Center, LLC	405	01-May-08	SP26
Wellhead Power Margarita	Wellhead Electric Company	49.0	01-May-08	SP26
Garnet Wind Project	Garnet Energy Corporation	6.5	01-Jun-08	SP26
Olivenhain-Hodges Pumped Storage Unit 1	San Diego County Water Authority	20	01-Sep-08	SP26
Olivenhain-Hodges Pumped Storage Unit 2	San Diego County Water Authority	20	01-Sep-08	SP26
Chiquita Canyon Landfill	Ameresco Renewables	9.2	15-Nov-08	SP26
SP26 Planned New Generation in 2008		***984***		
Total Planned New Generation in 2008		**1,809**		

Currently there are no planned generation retirements in 2008; however, unlike the lengthy process for constructing a new resource and bringing it online, a generation owner can retire an existing resource 90 days after notifying the CAISO.

Table 1.6 below shows an annual accounting of generation additions and retirements since 2001, with projected 2008 changes included along with totals across the seven year period (2001-2008).

Table 1.6 Changes in Generation Capacity Since 2001

	2001	2002	2003	2004	2005	2006	2007	Projected 2008	Total Through 2008
SP15									
New Generation	639	478	2,247	745	2,376	434	485	826	8,230
Retirements	0	(1,162)	(1,172)	(176)	(450)	(1,320)	0	0	(4,280)
Forecasted Load Growth*	491	500	510	521	531	542	553	564	4,212
Net Change	**148**	**(1,184)**	**565**	**48**	**1,395**	**(1,428)**	**(68)**	**262**	**(262)**
NP26									
New Generation	1,328	2,400	2,583	3	919	199	112	984	8,528
Retirements	(28)	(8)	(980)	(4)	0	(215)	0	0	(1,235)
Forecasted Load Growth*	389	397	405	413	422	430	439	447	3,342
Net Change	**911**	**1,995**	**1,198**	**(414)**	**497**	**(446)**	**(326)**	**536**	**3,951**
ISO System									
New Generation	1,967	2,878	4,830	748	3,295	633	598	1,810	16,758
Retirements	(28)	(1,170)	(2,152)	(180)	(450)	(1,535)	0	0	(5,515)
Forecasted Load Growth*	880	897	915	934	953	972	991	1,011	7,554
Net Change	**1,059**	**811**	**1,763**	**(366)**	**1,892**	**(1,874)**	**(394)**	**798**	**3,689**

* Forecasted load growth is based on an assumed 2 percent peak load growth rate applied each year.

As shown in Table 1.6, there was a 598 MW net increase in installed generation in the CAISO Control Area in 2007 with no unit retirements. Although this positive turn in net change in installed capacity was significant at nearly 600 MW, adjusted for projected load growth of 991 MW the net ability of installed generation to meet load was decreased somewhat as indicated by the last row in Table 1.6. The total net increase in installed generation in the CAISO Control Area over the eight years spanning 2001-2008 is roughly 11,250. When adjusted for annual load growth, the net increase in installed generation drops from 11,250 MW to just under 3,700 MW over this eight year period.

1.4 Transmission System Enhancements

Though there were no major transmission projects completed in 2007, various upgrades throughout the system did result in approximately 1,175 MW of new transmission capacity. A few major transmission projects were approved by the CAISO in 2007 and are currently awaiting environmental permits and other regulatory approvals, which are discussed below.

- Palo Verde Devers #2 Project, sponsored by Southern California Edison, was approved by the CAISO board in February, 2005. The project consists of a second Palo Verde to Devers 500 kV line running between the Palo Verde Hub (Hassayampa Substation) in Arizona and the Devers Substation in California. On May 31, 2007, the Arizona Corporation Commission (ACC), which has state regulatory jurisdiction over the portion of the line to be built in Arizona, denied approval of the project. SCE appealed that decision and is pursuing all options to obtain approval of the project in Arizona, including potential federal remedies under Section 216 of the Energy Policy Act of 2005. If ACC or other regulatory approvals can be obtained by July 2008, construction may start as early as November 2008. Construction of the Devers-Valley No. 2 segment of the project within California may be completed by June 2010 to support the interconnection of new generation projects.

- The Tehachapi Transmission Project was approved by the CAISO board on January 24, 2007 and is sponsored by Southern California Edison. The project will interconnect 4,350 MW of generating resources in the Tehachapi area, which will address reliability needs in the Antelope Valley and South of Lugo areas and set up a foundation to integrate renewable generation in the future. There are eleven proposed segments to the overall Tehachapi Transmission Project. Segments 1 through 3 have received approval from the CPUC by means of a Certificate of Public Convenience and Necessity (CPCN). Southern California Edison has submitted an application for a CPCN for segments 4 through 11, which remain pending before the CPUC.

- The Sunrise Powerlink Project, sponsored by San Diego Gas & Electric, was approved by the CAISO board in July 2006. The project consists of a new 91 mile 500kV line between the existing Imperial Valley Substation to a proposed new SDG&E owned substation, “Central”, and a new 59 mile 230 kV line between the new Central Substation and SDG&E’s existing Penasquitos Substation. The project will increase reliability in the San Diego area and provide access to renewable resources in the Imperial Valley and Salton Sea areas. SDG&E filed for a Certificate of Public Convenience and Necessity (CPCN) for Sunrise with the CPUC in August 2006 and the case is still pending. The Draft Environmental Impact Report (DEIR/EIS) was issued jointly by the CPUC and the

Bureau of Land Management in January 2008 and a final decision is expected in August 2008. The CAISO has been actively involved in the regulatory approval process.

In addition to these planned transmission projects, a total of 1,175 MW of new capacity was added to the transmission system through several upgrades. The various upgrades associated with individual lines or equipment and the additional capacity generated by each are listed below in Table 1.7.

Table 1.7 2007 Transmission Projects*

Transmisison Project	Net Capacity Increase	In-Service Date
New Miguel 230kV Capacitors	150 MW	Jun-07
Henrietta - Gregg 230kV Line Reconductoring	50 MW	Feb-07
Davis - UC Davis 60kV Line conversion to 115kV	79 MW	Mar-07
Replace the existing Ignacio 115/60kV Transformer	140 MW	May-07
Mountain Quarries 60kV Tap Reconductoring	34 MW	May-07
Newark - Dumbarton 115kV Line Reconductoring		Dec-06
Vasona - Metcalf 203kV Line Reconductor		Oct-07
Hicks - Metcalf 230kV Line Reconductor	207 MW	Oct-07
Ravenswood Reactive Support		Jun-07
Metcalf - Monta Vista 230kV Nos. 1 and 2 Reconductoring		Oct-07
Bair - Belmont 115kV Reconductoring		Jun-07
Install Second Henrietta 230/70kV Transformer	7 MW	Jun-07
New Plumas Sierra - Sierra Pacific 60kV Interconnection	15 MW	Feb-07
Valley 500 kV Shunt Capacitors	50 MW	May-07
Replace Mesa 230/115kV Transformers	285 MW	Apr-07
Network Upgrades for the Interconnection of Fresno Cogen Expansion	22 MW	Mar-07
Install 200 MVAR 230kV SVC at Rector	50 MW	Jun-07
Replace Schindler 115/70 kV No. 1	9 MW	Apr-07
Replace Herndon 230/115 kV No. 2	17 MW	Feb-07
Replace Contra Costa 230/115 kV No. 3	60 MW	May-07
Total	**1,175 MW**	

* Certain projects completed in 2007 that are listed in the table above have no MW value in the "Net Capacity Increase" column. These projects are included in this table despite having no net capacity increase because they were performed to provide other reliability benefits.

1.5 Administration of the Enforcement Protocol

DMM's responsibilities include administering the Enforcement Protocol of the CAISO Tariff. The Enforcement Protocol is designed to provide clear Rules of Conduct specifying the behavior expected of market participants, and establish in advance the sanctions and other potential consequences for violations of the specified Rules of Conduct. The CAISO has the authority to enforce penalties only for objectively identifiable violations of the CAISO Tariff for which specific penalties are established in the Enforcement Protocol. FERC rules require that all other potential violations of the CAISO Tariff or FERC market rules be referred to FERC's Office of Enforcement for potential investigation and sanction.

Last year's Annual Report on Market Issues and Performance described two tariff requirements with specific penalties in the Enforcement Protocol for non-compliance for which DMM was initiating enforcement programs: (1) submission of daily load forecasts as part of the 95 percent load scheduling requirement, and (2) the requirement to submit generation outage reports. In 2007, following DMM's enforcement of the requirement to submit daily load forecasts, compliance with this requirement has been virtually 100 percent. As described in more detail below, compliance with the generation outage reporting requirements has vastly improved since DMM began to enforce these requirements in July 2007.

Finally, in the spring of 2007, the CAISO experienced increased non-delivery, or “declines,” of pre-dispatched bids of supplemental energy at the inter-ties. As described in more detail below, the CAISO is proposing a settlement charge to deter this behavior.

1.5.1 Outage Reporting

Beginning in July 2007, DMM began to enforce penalties for two key generation outage reporting requirements incorporated in the CAISO Tariff:

- **Forced Outage Reporting within 30 Minutes**. Forced outages of generating units must initially be reported within 30 minutes from the time outages are discovered. Sanctions for non-compliance with this requirement start with a warning letter, and then escalate up to $5,000 per outage with each additional violation for each unit within each 12 month period.

- **Forced Outage Explanations within Two Days.** Generators must also provide a follow-up explanation of forced outages within two working days. The penalty for not providing a follow-up explanation of a forced outage within two working days is $500 per day the explanation is late.

These requirements and associated penalties were included in the CAISO Tariff because timely and accurate information on unit availability was deemed to be critical for reliable operation of the grid. Implementation of penalties for non-compliance with these requirements on July 1, 2007 coincided with marked improvement in market participants' compliance with the forced outage reporting requirements. The significant improvement in compliance likely contributed to reliable grid operations during the critical peak summer months as it gave operators more accurate and timely information on the status of the generation fleet. It also shows that penalties, when structured and implemented correctly, can provide an effective incentive for market participants to comply with tariff requirements.

DMM's initiation of enforcement of these penalties followed a stakeholder process conducted in the second half of 2006 to modify the reporting requirements and the reporting tools. The CAISO requested and FERC approved a suspension of the penalties until July 1, 2007 to allow the CAISO time to make needed improvements to the reporting tools and to allow market participants time to become familiar with the new tools and the revised reporting requirements.

Compliance with the forced outage reporting requirements has improved significantly since the outage reporting penalties went into effect.[8]

- **Forced Outage Reporting within 30 Minutes.** As shown in Figure 1.5, in the months prior to July 2007, an average of about 8 to 12 percent of forced outages were not reported within the 30 minute requirement. Since then, an average of less than 2 percent

[8] Because DMM did not investigate all individual instances of apparent non-compliance with the reporting requirements prior to the time penalties went into effect, the data for months prior to July 2007 may slightly overstate non-compliance rates.

of forced outages have been reported late each month. This translates to about 20 to 70 late reports of forced outages per month prior to penalties going into effect, compared with 6 to 12 late reports per month since the penalties went into effect.

- **Forced Outage Explanations within Two Days.** As shown in Figure 1.6, during the months prior to July 2007, market participants submitted forced outage explanations late (or did not submit the explanations at all) for about 30 to 40 percent of forced outages. After penalties went into effect, non-compliance with this two-day requirement dropped to under 3 percent in the months from August 2007 onward. Also, while forced outage explanations were sometimes never provided prior to July, market participants have submitted explanations for all forced outages since penalties went into effect on July 1.

Figure 1.5 Non-Compliance with 30-minute Outage Reporting Requirement, July 2006 through December 2007

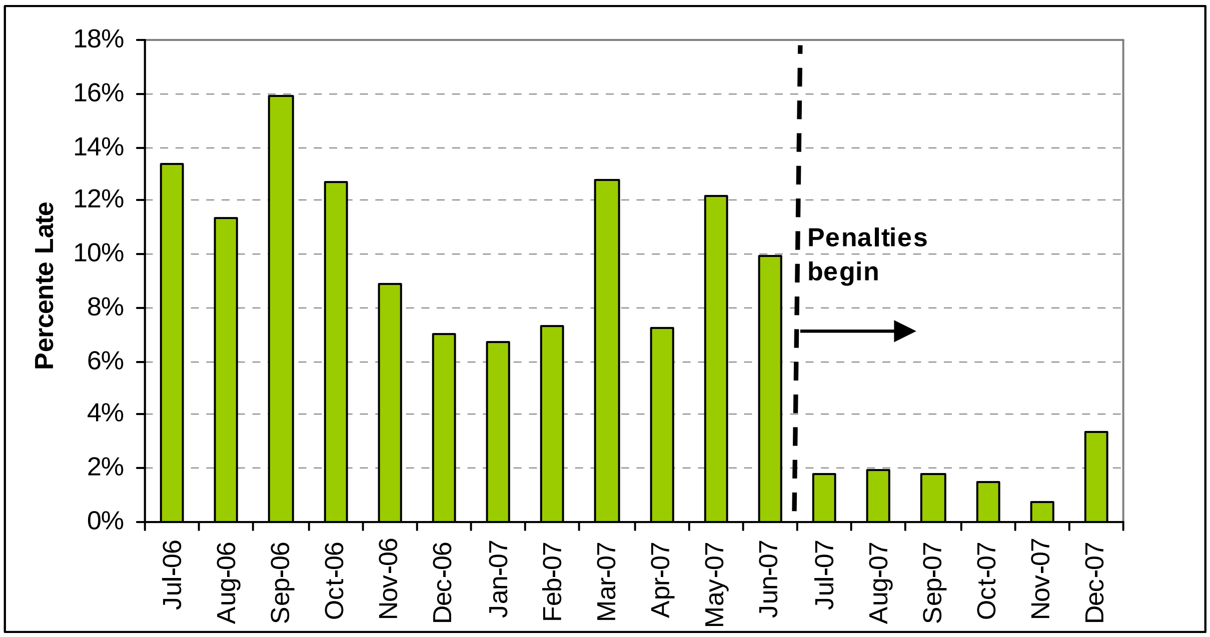


Figure 1.6 Non-Compliance with Two-day Outage Explanation Requirement, July 2006 through December 2007