1. 2003 Market Structure Changes

1.1 Market Power Mitigation Rules

1.1.1 Overview of October 1, 2002 Design Elements

In May 2001, the CAISO requested that the West-wide Mitigation, currently in effect, be continued beyond its September 2002 sunset date. The CAISO argued that the mitigation should not end arbitrarily but rather its termination should be based on a finding that the western markets are workably competitive. In the event the Commission chose not to continue the West-wide Mitigation, the CAISO proposed an alternative comprehensive market power mitigation plan. This plan contained several elements to address physical and economic withholding at both system-wide and local levels. The CAISO's May 1 filing addressed economic withholding through a damage control bid cap (DCBC) and automatic mitigation procedures (AMP). It addressed physical withholding through the continuation of the Must-Offer requirement and requested stringent measures to address local market power. These provisions, referred to as the "October 1, 2002 Design Elements", were partially approved by FERC in a July 17, 2002 Order. However, due to an insufficient time to develop and implement all of the market power mitigation components approved in this Order, the CAISO was granted a one-month extension of West-wide Mitigation. The CAISO began operating under the market power mitigation provisions of the July 17, 2002 Order on October 30, 2002. In the following sections, we summarize each provision, as filed on May 1, 2002 and subsequently modified by FERC in its July 17, 2002 Order.

1.1.1.1 $250 DCBC

The CAISO proposed in its May 1 filing to address economic withholding through the application of a damage control bid cap (DCBC) and an automatic mitigation procedure (AMP). The CAISO initially proposed a bid cap of $108/MWh that could increase with the price of natural gas and also could be increased over time as additional elements of MD02 are phased in and capacity conditions improve.

In its July 17, 2002 Order, the Commission adopted the CAISO Market Surveillance Committee's recommendation and established a bid cap of $250/MWh to begin on November 1, 2002. The Commission agreed that the price cap mitigation was needed to mitigate the potential for market power abuse but felt that a price cap below $250/MWh would create disincentives for out-of-state suppliers to bid into the California market and could potentially result in a significant amount of out of market (OOM) calls above the price cap.

The bid cap of $250/MWh would also apply to the forward energy markets once implemented by the CAISO. The Commission further ruled that this price cap was effective for all sales in WECC spot markets to eliminate incentives for "megawatt laundering". In its Order on Rehearing and Compliance Filing on October 11, 2002, the Commission further clarified that market participants may continue to submit bids above the bid cap with the understanding that such bids cannot set the market clearing price and that bids above the cap would be subject to justification and refund.

1.1.1.2 AMP

The CAISO's AMP proposal would apply to bids that substantially exceed historical levels and threaten to materially impact market clearing prices (MCP). The AMP would apply to both the forward energy market (once developed) and the real-time energy market beginning on October 1, 2002. The CAISO proposed thresholds that would trigger AMP when a given resource's bid is:

- The lower of 100 percent or $50/MWh above its accepted bid levels during the previous three months (conduct test); and
- Would increase real-time MCP by the lower of 100 percent or $50/MWh (market impact test).

This proposed measure would apply to all bids, including hydroelectric resources and imports. It would not apply during hours in which the CAISO had a day-ahead demand forecast exceeding 40,000 MW. Bids accepted during these hours would not count toward a resource's historical bid average (Reference Level) for mitigation purposes.

In its July 17, 2002 Order, the Commission approved the CAISO AMP subject to several modifications. The Commission directed that an additional price screen test be performed to determine whether AMP should be applied and ordered more generous thresholds for the conduct and market impact tests. The Commission also ruled that, consistent with the CAISO proposal, hydroelectric resources and imports would also be subject to AMP. The Commission directed that small portfolios should be exempt from AMP once the full network model was in effect and bids below $25/MWh be exempt from AMP. Finally, the Commission rejected the CAISO's proposal not to apply AMP when load forecasts exceed 40,000 MW and ordered that accepted bids at all load levels be included in the reference level calculation. In addition, the Commission ordered that the CAISO select an independent entity to perform the task of determining reference prices.

In a following Order on Rehearing and Compliance Filing on October 11, 2002, the Commission reversed its decision and exempted imports from AMP. To address potential MW laundering concerns (i.e., internal generators exporting generation in the forward market and offering it back to the CAISO real-time market as an import), the Commission required that import bids to the CAISO real-time market must be price-takers (bid in at $0/MWh). The CAISO filed a request for rehearing of the October 11, 2002 Order in which, among other things, it requested that the Commission reverse its decision requiring import bids to be submitted at $0/MWh. In a January 17, 2003 Order, the Commission agreed to reverse its position and allow system resources to submit bids greater than $0/MWh, but retained the prohibition on imports setting the price. However, the Commission believed it appropriate to maintain the zero-bid requirement for imports until Phase 1B of MD02 was implemented. That implementation was expected to occur before summer 2003. Table 1.1 summarizes these provisions.

Table 1.1 Conduct and Market Impact Tests

Design Element	**CAISO Proposal**	**Commission Ruling**
Minimum Price Screen	None	$91.87/MWh for all zones
Conduct Threshold	The lower of 100% or $50 increase over reference price	The lower of 200% or $100 increase over reference price
Impact Threshold	The lower of 100% or $50 increase in MCP	The lower of 200% or $50 increase in MCP
Applicability	➢ Hydro and imports included ➢ No exemption for small portfolios ➢ No exemption for new generation ➢ No minimum price offer exemption ➢ Not applicable when load forecast exceeds 40,000 MW	In July 17, 2002 Order: ➢ Hydro and imports included ➢ Small portfolios exempt from AMP once full network model is in effect. ➢ No exemption for new generation. ➢ Price offers below $25/MWh exempt. ➢ Applicable in all hours even if forecasted load exceeds 40,000 MW October 11, 2002 Rehearing Order: ➢ Reverse the July17 order to exempt bids from outside California from AMP and require imports to submit zero bids into CAISO markets

Due to a delay in the Phase 1B implementation, the CAISO filed Amendment 52 with FERC on May 27, 2003, in which it sought approval for expedited implementation of removing the zero bid requirements for imports to help ensure sufficient resources would be available to meet peak demand during the summer months. In a June 24, 2003 Order, the Commission approved the CAISO's request to eliminate the zero-bid requirement for imports. This change took effect on June 25, 2003.

1.1.1.3 LMPM

Local market power can be exercised when the CAISO has to dispatch a resource out of economic merit order to serve local reliability needs. Local market power can occur both in the incremental and decremental bid markets. Local market power mitigation (LMPM) mitigates suppliers' bids in the real-time spot markets and would provide similar mitigation in the forward energy markets once developed. The CAISO proposed that when it must dispatch a unit out of merit order to alleviate intra-zonal congestion, the unit's bid would be mitigated to a proxy price using an estimate of its short-run variable costs. The Scheduling Coordinator for that generating unit would then be paid the higher of its proxy price or the applicable MCP for the incremental dispatch. It would be charged the lower of its proxy price or the applicable MCP for decremental dispatch. The CAISO also proposed to construct a bid curve for each unit based on the cost data submitted by the unit's Scheduling Coordinator.

In the July17, 2002 Order, the Commission rejected the ISO's LMPM proposal and directed that, under the situation where RMR resources are not available and bids must be taken out of merit for the specific purpose of alleviating intra-zonal congestion, the CAISO must apply an AMP procedure to mitigate the local market power. Under the July 17, 2002 Order, a bid less than $91.87/MWh that was taken out of merit order would not be subject to any mitigation. If a bid was taken out of merit order and was greater than $91.87, a conduct test would be applied to determine if the bid was $50/MWh or 200 percent greater than the MCP. If so, the bid would be mitigated and the generator would be paid the higher of its reference price or the MCP. An out-of-merit bid (whether mitigated or not) is ineligible to set the MCP.

In its Order on Rehearing and Compliance Filing, the Commission reversed the July 17, 2002 Order on the issue of the $91.87/MWh price screen. The Commission removed the requirement of a price screen test when the CAISO must take bids out of merit order to address intra-zonal congestion.

On March 31, 2003, the CAISO submitted a filing to FERC to amend the local market power mitigation provisions (Amendment 50). Specifically, the CAISO proposed that, in cases where it foresees intra-zonal congestion due to abnormal system conditions, the CAISO would publish the total allowable output for the units constrained by the congestion by 1800 hours two days before the operating day. The CAISO would update that information following the day-ahead scheduling process. Generators would then have the choice to submit hour-ahead schedules that conform to the CAISO published limits (i.e. self-manage congestion). If generators successfully managed congestion, no further action would be required. If they did not, the CAISO would adjust their schedules based on cost-based proxy bids. This mitigation would apply in both incremental and decremental directions. Incremental dispatches would be paid the higher of the zonal real-time price or the mitigated bid plus 10 percent.

Decremental dispatches would be charged the lower of the zonal real-time price or the mitigated bid less 10 percent. The CAISO proposed the plus or minus 10 percent factor to compensate for potential inaccuracies in the cost-based bid estimate and potential differences in the variable cost of increasing versus decreasing a unit's output.

The mitigation of decremental bids was proposed to address a gaming opportunity referred to as the "DEC game". The "DEC game" occurs primarily in generation pockets within a zone. Because transmission constraints out of these pockets are not enforced in the forward congestion management process, it creates an opportunity for generators within the pocket to over-schedule so as to cause congestion in real-time. They then submit negative energy bids to have their schedules adjusted down to relieve the constraint. An accepted negative decremental energy bid implies that the generator is being paid not to generate energy.

In a May 30, 2003 Order, the Commission rejected the CAISO's request to post aggregate generation limits to facilitate self-management of congestion on the grounds that it would potentially expose generators to allegations of collusion. The Commission further rejected the proposed local market power mitigation for incremental bids but approved, subject to modification, mitigation for decremental bids. Specifically, the Commission rejected cost-based proxy bids for decremental bid mitigation. Instead, they directed a "reference price" alternative to such a proxy, arguing that a "market-based" proxy is superior to cost-based given the inherent inaccuracies of trying to measure a unit's marginal cost. The Commission directed the independent entity that calculates reference prices for AMP (Potomac Economics) to develop "reference prices" for decremental bids.

On July 18, 2003, the CAISO filed a methodology developed by Potomac Economics for determining decremental reference prices. The methodology determined decremental reference prices by applying the following steps in order as needed:

1. The lower of the mean or the median of a resource's accepted decremental bids during competitive periods for the previous 90 days for peak and off-peak periods, adjusted for monthly changes in fuel prices and excluding proxy bids, mitigated bids, and bids used out of merit order for Intra-Zonal Congestion.
2. A level determined in consultation with the market participant, provided such consultation has occurred prior to the submittal of the bids being examined.
3. 90% of a unit's Default Energy Bid determined monthly as set forth in the CAISO Tariff. In the case of gas-fired generation, Default Energy Bids are based on the incremental heat rate submitted to the CAISO and the variable O&M cost filed with the CAISO, or the default O&M of $6/MWh.
4. 90% of the mean of the economic market clearing prices for the unit's relevant location during the lowest-priced 25 percent of the hours that the unit was dispatched or scheduled over the previous 90 days for peak and off-peak period, adjusted for changes in fuel prices; or

5. If sufficient data do not exist to calculate a reference level on the basis of the first, second, or fourth methods and the third method is not applicable or an attempt to determine a reference level in consultation with a market participant has not been successful, the CAISO shall determine a reference level on the basis of:
    a. The CAISO's estimate of the cost to operate an electric facility, taking into account available operating cost data, opportunity cost, and appropriate input from the market participant, and the best information available to the CAISO; or
    b. An appropriate average of competitive bids of one or more similar electric facilities.

Under Amendment 50, generating units that have to be decremented in real-time due to intra-zonal congestion constraints would be dispatched and paid according to their decremental reference prices. This mitigation procedure took effect on July 28, 2003 and has been used quite frequently in addressing intra-zonal congestion problems in the San Diego service territory.

1.1.1.4 Must-Offer

In its May 1, 2002 filing, the CAISO requested that the Commission extend the existing must-offer requirement for generating resources within California operating under CAISO Participating Generator Agreements.[1] In its July 17, 2002 order, the Commission agreed to extend the West-wide must-offer requirement. However, the Commission noted that it would consider removing the must-offer requirement in the future if it determines that adequate infrastructure and market design improvements have been made and western market prices reflect competitive outcomes on a more consistent basis.

1.2 Generation Additions/Retirements

1.2.1 New Generation

Approximately 4,877 MW of new generation began commercial operation within the CAISO control area in 2003. Most units have signed Participating Generator Agreements with the CAISO. Of the total, 3,973 MW were natural gas-fired combined cycle facilities and 709 MW were natural gas-fired combustion turbine facilities. By congestion zone, 854 MW was constructed in NP-15, 1729 MW was constructed in ZP-26, and 2294 MW was constructed in SP-15. Table 1.2 shows the new generation projects that began commercial operation in 2003.

[1] PGA generating resources include the utility owned generation and the merchant thermal generation units owned by entities such as Calpine, Reliant, Duke, Dynegy, Mirant, and AES/Williams.

Table 1.2 New Generation Facilities Entering Commercial Operation in 2003

Generating Unit	*Owner or QF ID*	*Net Dependable Capacity (MW)*	*Commercial Operation Date*
Creed Energy Center	Calpine	48.70	6-Jan-03
Goose Haven Energy Center	Calpine	48.70	6-Jan-03
Lambie Energy Center	Calpine	48.70	6-Jan-03
La Paloma Generating Project, Unit 1	La Paloma Generating Company	227.35	10-Jan-03
La Paloma Generating Project, Unit 3	La Paloma Generating Company	231.53	13-Jan-03
THUMS Generation (Self-generation)	THUMS Long Beach Company	47.0	1-Feb-03
La Paloma Generating Project, Unit 2	La Paloma Generating Company	234.86	5-Mar-03
La Paloma Generating Project, Unit 4	La Paloma Generating Company	235.29	5-Mar-03
Los Esteros Critical Energy Facility, Unit 1-4	Calpine	195.00	7-Mar-03
Wolfskill Energy Center	Calpine	48.70	22-Mar-03
Colton Landfill Project *	NM Colton Genco, LLC	1.20	14-Apr-03
High Desert Power Project	Constellation Power	850.00	21-Apr-03
Mid Valley	NM Mid Valley Genco, LLC	2.40	21-Apr-03
Riverview Energy Center (GP Antioch)	Calpine	48.70	2-May-03
Tracy Peaker Plant Unit 1	GWF	85.00	30-May-03
Tracy Peaker Plant Unit 2	GWF	85.00	30-May-03
Sunrise Power Project, Phase II, Unit 3	Edison Mission Energy	251.00	1-Jun-03
Agua Mansa Power Project *	City of Colton	43.00	27-Jun-03
San Diego State University GT #1 *	San Diego State University	5.30	10-Jul-03
San Diego State University GT #2 *	San Diego State University	5.30	10-Jul-03
San Diego State University SGT *	San Diego State University	4.00	10-Jul-03

Generating Unit	***Owner or QF ID***	***Net Dependable Capacity (MW)***	***Commercial Operation Date***
Milliken Landfill Project	NM Milliken Genco, LLC	4.80	17-Jul-03
Ciclo Combindado Mexicali	Intergen	170.00	20-Jul-03
Central La Rosita II Combined Cycle	Energia de Baja California	310.00	22-Jul-03
Elk Hills Generating Project	Elk Hills Power	549.00	24-Jul-03
Termoelectrica De Mexicali	Termoelectric De Mexicali	600.00	30-Jul-03
Highwinds Project	Highwinds, LLC	145.80	1-Aug-03
Woodland Combined Cycle Plant **	Modesto Irrigation District	83.00	1-Aug-03
Huntington Beach Unit 4	AES	227.43	7-Aug-03
Mountain View III	PPM Energy	22.40	15-Dec-03
Highwinds Project Phase 2	Highwinds, LLC	16.20	29-Dec-03
Wintec V Facility	Wintec Energy, Ltd.	1.30	30-Dec-03
Total Commercial for 2003		4,876.66	

* Units are Non-Participating Generators.
** Unit is owned by a municipal utility.

Source: California ISO 2003-2004 Winter Assessment; California ISO Operations Engineering Department

In its 2002-2003 Winter Assessment, the CAISO projected that 2,082 MW of new generation commencing commercial operation in 2003 would be available by May 2003. Those projections were revised to 908 MW constructed as of March 1, 2003, and an additional 4,058 MW projected through the end of 2003.

1.2.2 Retired Generation

Approximately 2,152 MW of generation capacity was removed from service in 2003. Over 50 percent of that was located in the SP-15 congestion zone. Table 1.3 lists the generation facilities that were retired in 2003.

Table 1.3 Retired Generation Facilities in 2003

Generating Unit	*Capacity (MW)*
Jefferson Smurfit Corporation	28.5
Sunlaw Energy - Federal	28
Sunlaw Energy - Growers	28
Wheelabrator Martel Inc.	13
Alamitos Unit 7	134
Pittsburg Unit 1	167
Pittsburg Unit 2	154
Pittsburg Unit 3	154
Pittsburg Unit 4	150
Morro Bay Unit 1	171
Morro Bay Unit 2	171
Ellwood Generating Station	56.1
Etiwanda 3	320
Etiwanda 4	320
Mandalay 3 GT	120
So. California Sunbelt Developers, Inc. (Mojave)	16.6
Wind Farm Management, Inc.	0.4
Dept. of Parks & Recreation	0.01
Lichter Sigmund	0.05
Etiwanda GT Unit 5	120
Total Retirements for 2003	2151.66

Reliant Resources held an auction for the generating capacity from Etiwanda 3 and 4, Mandalay 3, and Ellwood Generating Station from April 1, 2004 to March 31, 2005, as agreed to in the Stipulation and Consent Agreement in the Western Markets Investigation (EL03-95-000 *et al.*). Not receiving bids for that capacity, Reliant mothballed these facilities.

Generation in the CAISO Control Area changed by the following net amounts:

Congestion Zone	*Generation Additions (MW)*	*Generation Reductions (MW)*	*Net Change*
NP-15	853.5	-638	215.5
SP-15	2247.13	-1171.66	1075.47
ZP-26	1729.03	-342	1387.03
ISO Control Area	4829.66	-2151.66	2678

1.3 Transmission System

Since the CAISO began operations in the spring of 1998 through 2003, the CAISO controlled transmission system has been expanded by the completion of 273 transmission projects at an estimated cost of $2.36 billion. However, both the installation of new generation across the Western Interconnection and the retirement of generation in California have placed additional stress on the transmission controlled by the CAISO. Transmission in Southern California in particular suffers from a great deal of congestion primarily due to new generation additions in northern Mexico near Imperial Valley and in Arizona near Palo Verde. This congestion exists not only in California but also across the entire southwest area, which is composed of Arizona, Southern Nevada, Southern California, and Northern Mexico. To develop transmission additions to mitigate this congestion, a broad sub regional planning group called Southwest Transmission Expansion Plan (STEP) was formed. STEP has developed an overall transmission plan for the area and is currently in the process of implementing a variety of projects.

To assist in overcoming this congestion, San Diego Gas and Electric added a second 500/230 kV transformer at the Imperial Valley substation in mid 2003. While this relieved the congestion at Imperial Valley, the congestion was simply shifted to other areas of the grid. To reduce this congestion the following CAISO approved additions are currently either nearly through permitting or under construction:

- The addition of a second 500/230 kV transformer and a 500-kV bus at Miguel Substation. This $16.7-million upgrade is scheduled to be operational by December 2004.
- Upgrading the current carrying capability of the Series Capacitors in the Imperial Valley-Miguel 500-kV line. This $3.9-million project is necessary to take advantage of the transformer addition at Miguel. It will be operational by December 2004.
- Reconductoring the 2.6-mile Proctor Valley-Telegraph Canyon 138-kV line. This is necessary to eliminate potential overloading on the underlying system as Miguel import capability is increased. It will be completed by June 2004.
- Installation of a second 230 kV circuit between the Miguel and Mission substations. This project is waiting final approval from the CPUC. If approved this spring as expected, construction will be initiated immediately and the project is planned to be in-service in June 2006.

Even after these additions are completed, a substantial amount of Intrazonal and Interzonal congestion will continue to exist in this area of the grid. As a result, it will continue to be necessary to mitigate the congestion with the applicable CAISO congestion management protocols.

Additional upgrades have been planned in STEP to further mitigate this congestion. These upgrades include several series capacitor upgrades on the lines from Arizona to Southern California and on the lines from Arizona to Nevada. In addition, a second 500/230 kV transformer is planned for the Devers Substation. These upgrades may be in-service as soon as 2006. For the longer-term, large scale projects, like the addition of a second Palo Verde-Devers 500 kV line, are currently in the planning stage. A second Palo Verde-Devers 500 kV line could be in-service as soon as 2008.

On January 1, the CAISO assumed control of transmission from the cities of Anaheim, Azusa, Banning, and Riverside. To facilitate scheduling and congestion management for this additional transmission, the CAISO created five new external congestion zones and associated branch groups. Table 1.4 below shows the percentage of hours in 2003 when congestion was present in the Day-Ahead or Hour-Ahead Markets.

Table 1.4 Percentage of Hours Where South West Muni Transmission was Congested

Branch Group	*Day-Ahead Congestion Present*	*Hour-Ahead Congestion Present*
LUGOGONDR_BG	0.00%	0.00%
LUGOIPPDC_BG	0.51%	0.51%
LUGOMKTPC_BG	0.02%	0.00%
LUGOTMONA_BG	3.57%	0.16%
LUGOWSTWG_BG	0.46%	0.17%

1.4 Long-term Contracts

1.4.1 Contract Renegotiations

Authority for the California Energy Resource Scheduling (CERS) division of the California Department of Water Resources to purchase and schedule energy for the investor-owned utilities expired on December 31, 2002. The California Public Utilities Commission (CPUC) ordered Pacific Gas and Electric and Southern California Edison to assume scheduling and collateral responsibilities for covering their residual net short by January 1, 2003.[2] As a result, CERS has ceased active participation in the CAISO markets, although it retains title to the power purchase agreements it negotiated on behalf of the utilities. CERS also remains an active participant in the CAISO's market redesign process.

[2] D.02-10-062, at Ordering Paragraph 16.

In 2002, the CPUC authorized the investor-owned utilities to negotiate multi-year long-term contracts for their residual net short, in conjunction with CERS as a financial backer for the contracts.[3] Requirements for disclosing contract information to the CAISO's Department of Market Analysis under the Market Monitoring and Information Protocol are unclear; negotiations for information regarding utility procurement costs and transactions are ongoing. As a result, once the utilities assumed scheduling responsibilities in January 2003 for contracts backed by CERS, the CAISO has received little information regarding the amount of energy and associated cost provided by long-term contracts to serve utility load.

Renegotiation efforts continue, in conjunction with the ongoing litigation in the long-term contract docket at FERC described below. By the end of 2003, two suppliers, Allegheny Energy Supply Corporation and Morgan Stanley Capital Group had renegotiated the terms of their agreements with CERS and were removed from the FERC litigation.

Additionally, in September, Allegheny sold their contract to J. Aron and Company, a subsidiary of Goldman Sachs Group.

The renegotiations in 2003 did not substantially change the contract quantities for 2003 and 2004, as the number of contracts renegotiated was quite small. However, they did result in about 200 MW per hour less supplied after January 2005. Figures 1.1 through 1.5 compare the average contract capacities after renegotiation to the average actual residual net short in 2003. The capacities are shown for summer and non-summer and weekend and weekday periods.

[3] D.02-08-071.

Figure 1.1 2003 Summer Weekday Capacities

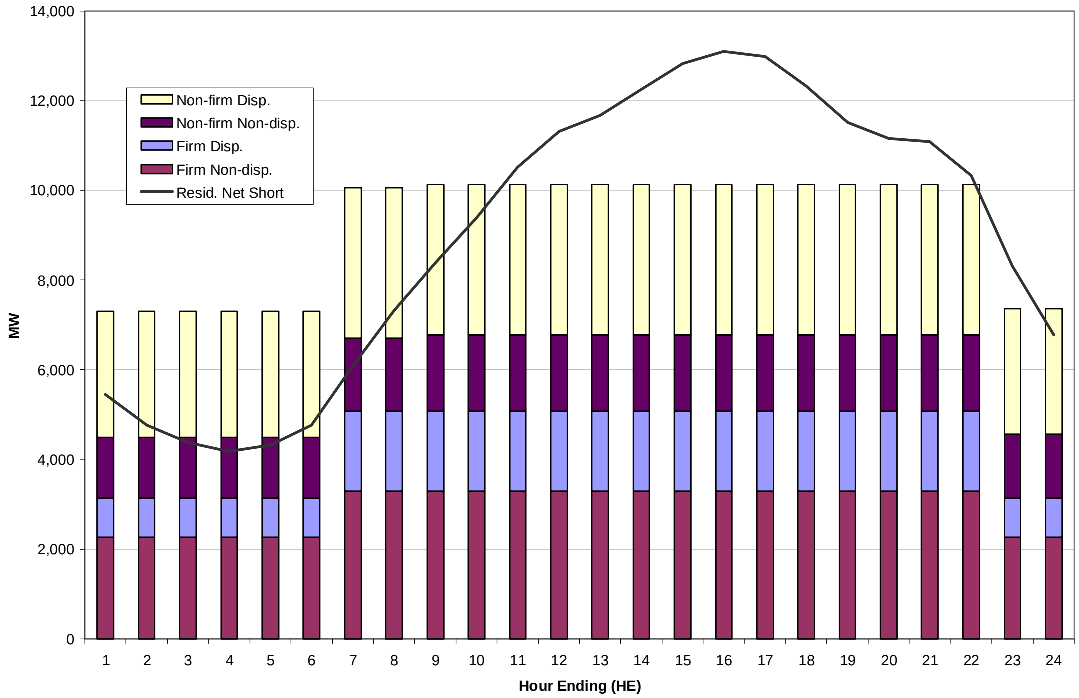


Figure 1.2 2003 Summer Weekend Capacities

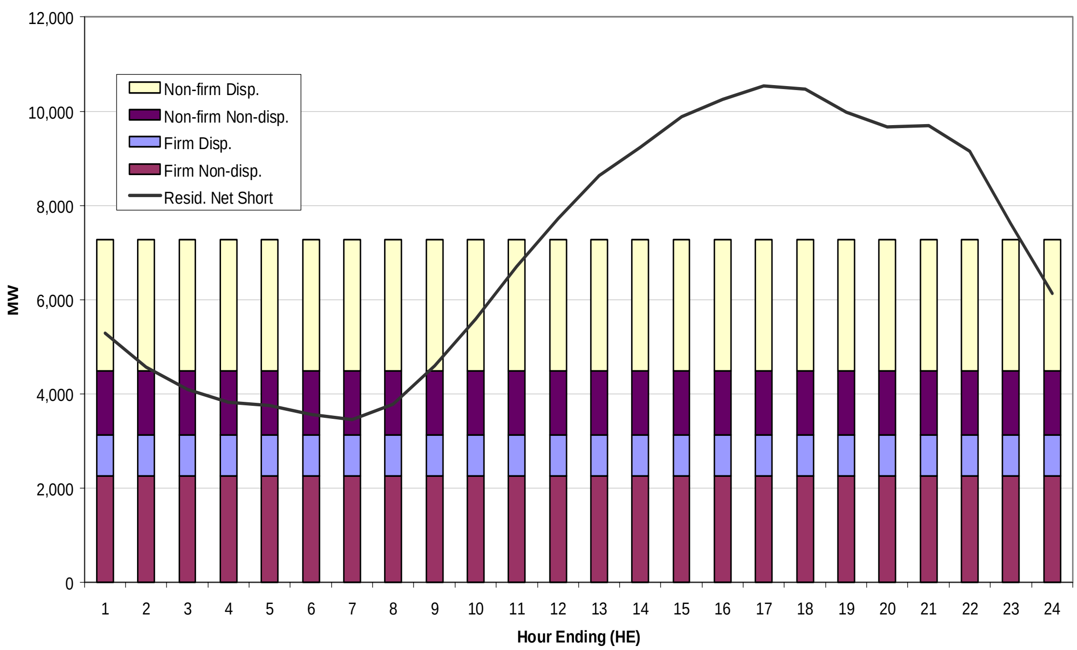


Figure 1.3 2003 Non-Summer Weekday Capacities

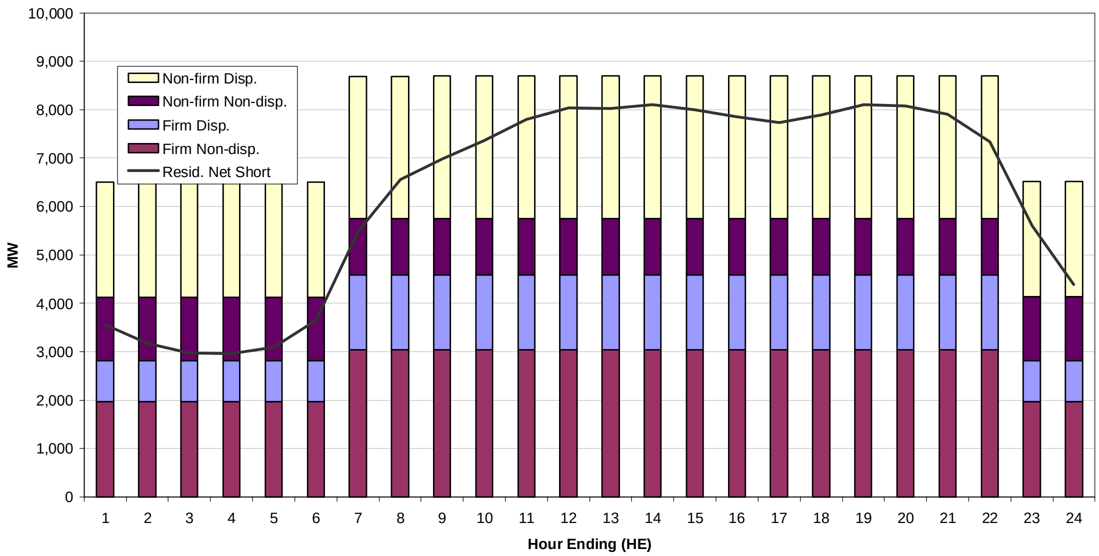
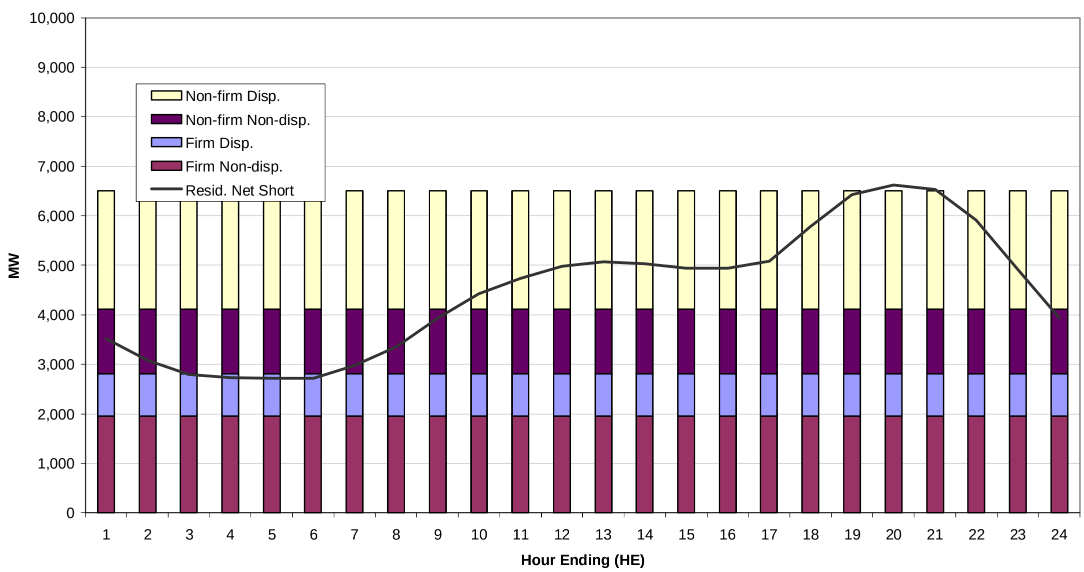
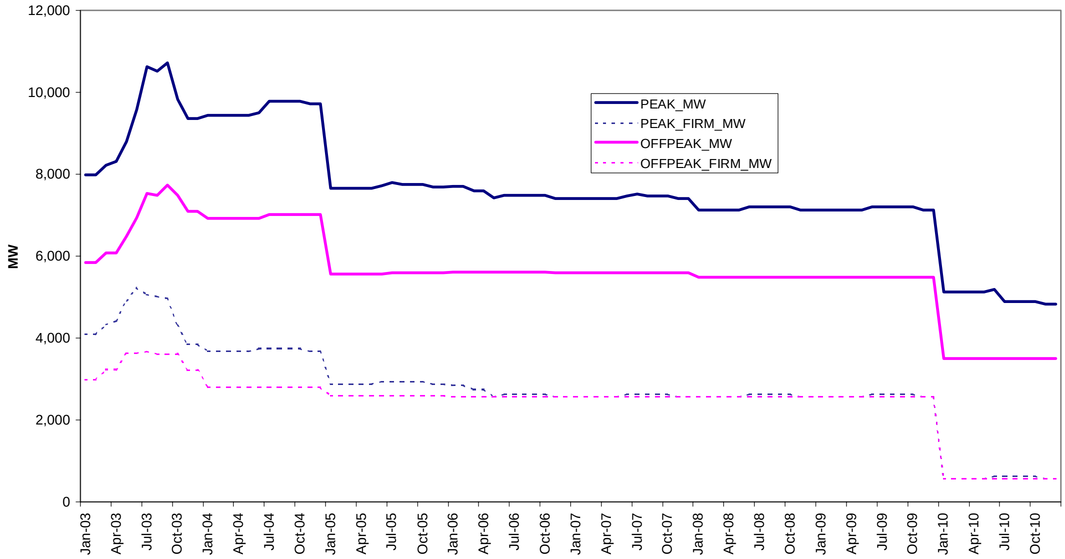


Figure 1.4 2003 Non-Summer Weekend Capacities



Figures 1.5 Monthly Capacities, January 2003 to December 2010



FERC Long-Term Contract Litigation

FERC held hearings on the long-term contracts case the California Electricity Oversight Board and CPUC filed against suppliers[4]. The hearings were to determine the appropriate burden of proof standard for contracts lacking explicit language establishing a "public interest" burden of proof standard. FERC issued a Partial Initial Decision on January 16, wherein they found that the *Mobile-Sierra* standard applied to the Dynegy, El Paso, Morgan Stanley and Sempra Energy contracts.[5] FERC issued a subsequent Order on July 26 affirming the Partial Initial Decision and denying the complaints remaining after the settlements from renegotiation[6]. The Commission also denied subsequent requests for rehearing.[7]

On November 13, the CPUC voted to file an appeal to FERC's orders denying the complaints against suppliers.

Sempra Energy Resources Contract Litigation

The State of California filed a complaint against Sempra Energy Resources in San Diego County Superior Court alleging breach of contract and requesting that the ten-year power purchase agreement with Sempra be voided in July 2002. On May 20, 2003, a ruling from the Superior Court was returned upholding the contract with Sempra.

[4] EL02-60-000 *et al.*, EL02-62-000 *et al.*
[5] 102 FERC 63,013 at ¶53.
[6] 103 FERC 61,354.
[7] 105 FERC 61,182.