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Ancillary Services Markets in California

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Acronyms and Abbreviations

ACE	Area Control Error
AGC	Automatic Generation Control
APX	Automated Power Exchange
AS	Ancillary Service
BEEP	Balancing Energy and Ex-Post Pricing System
CAISO	California Independent System Operator
CEC	California Energy Commission
CPS	Control Performance Standard
DCS	Disturbance Control Standard
FERC	Federal Energy Regulatory Commission
ICF	ICF Resources, Inc.
IOU	Investor-owned Utilities
MCP	Market-clearing Price
MORC	Minimum Operating Reliability Criteria
MW	Megawatt
NAERO	North American Electric Reliability Organization
NERC	North American Electric Reliability Council
PG&E	Pacific Gas and Electric Company
PX	Power Exchange
REPA	Regulation Energy Payment Adjustment
RMR	Reliability Must-run Contract
RRC	Regional Reliability Council
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric Company
WSCC	Western System Coordinating Council

Glossary

Key ancillary services and their definitions[2].

Service	**Description**
System control	The control-area operator functions that schedule generation and transactions before the fact and that control some generation in real time to maintain generation/load balance; Interconnected Operations Services Working Group definition more restricted, with a focus on reliability, not commercial, activities, including generation/load balance, transmission security, and emergency preparedness.
Reactive supply and voltage control from generation	The injection or absorption of reactive power from generators to maintain transmission-system voltages within required ranges.
Regulation	The use of generation equipped with governors and automatic-generation control to maintain minute-to-minute generation/load balance within the control area to meet NERC control-performance standards.
Operating reserve - spinning	The provision of generating capacity (usually with governors and automatic-generation control) that is synchronized to the grid and is unloaded that can respond immediately to correct for generation/load imbalances caused by generation and transmission outages and that is fully available within 10 minutes.
Operating reserve -supplemental	The provision of generating capacity and curtailable load used to correct for generation/load imbalances caused by generation and transmission outages and that is fully available within 10 minutes.
Energy imbalance	The use of generation to correct for hourly mismatches between actual and scheduled transactions between supplier and customers.
Load following	The use of generation to meet the hour-to-hour and daily variations in system load.
Backup supply	Generating capacity that can be made fully available within one hour; used to back up operating reserves and for commercial purposes.
Real-power-loss replacement	The use of generation to compensate for the transmission-system losses from generators to loads.
Dynamic scheduling	Real-time metering, telemetering, and computer software and hardware to electronically transfer some or all of a generator's output or a customer's load from one control area to another.
System black-start capability	The ability of a generating unit to go from a shutdown condition to an operating condition without assistance from the electrical grid and to then energize the grid to help other units start after a blackout occurs.
Network-stability services	Maintenance and use of special equipment (e.g., power-system stabilizers and dynamic-braking resistors) to maintain a secure transmission system.

[2] Source: Hirst and Kirby, 1997

Abstract

implemented open markets in which an Independent System Operator (CAISO) purchases much of its ancillary service requirements. Ancillary services (AS) are

maintain reliable operation within an interconnected system. California has AS requirements related to operating reserves and frequency control that are not self-

rules and self-provision was initially expected to be a major source of AS to CAISO. These services are procured by CAISO in day-ahead and hour-ahead auctions. Since the

been characterized by serious deficiencies, especially during the summer of 1998. The problems included extreme price volatility, market prices not reflective of underlying

improvements that will be in place during the summer 1999 season in order to overcome some of the most serious observed drawbacks. After an overview of the

markets managed by CAISO: regulation, spinning, non-spinning, and replacement reserves. This report also analyzes the evolution of market prices and some of the

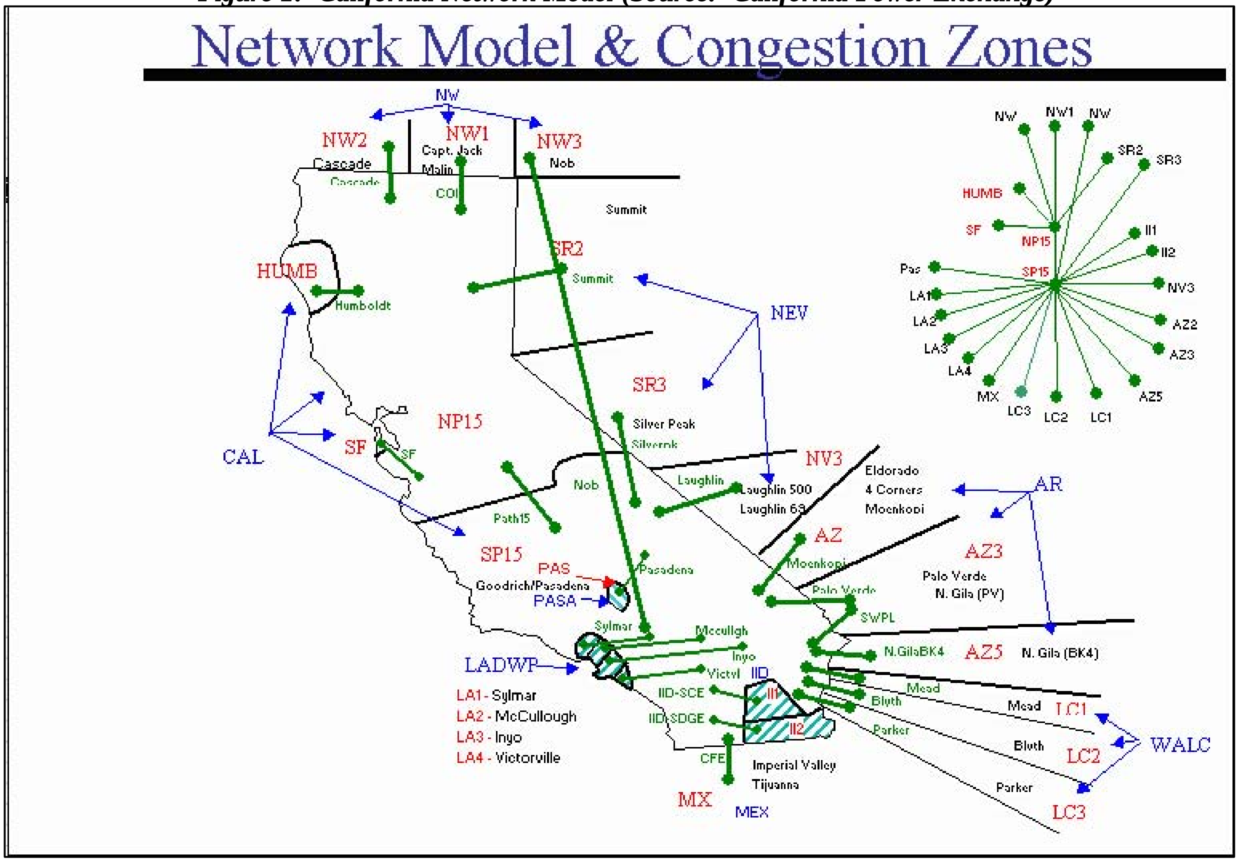
improvements proposed by CAISO are discussed.

1. California Restructured Electricity System Overview

Within California, more than 1300 generators produce electricity using a sum of approximately 54 GW of capacity, and total 1997 electricity consumption was 254 TWh (including self-generation). California is also a major electricity importer and has numerous transmission interconnections with adjacent states as shown in Figure 1. Of the 20% of electricity use that the state imported in 1997, 48% came from the Northwest and 52% from Southwest interconnections (CEC 1998).

In late 1996, the California state legislature approved legislation that, beginning 31 March 1998, fundamentally reorganized the state's electricity industry and introduced retail competition for the electricity consumers of the three major prior utilities. These three large private, investor-owned utilities (IOUs), Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric Company (SDG&E) were, historically, responsible for matching their own load and resources to maintain frequency and to match scheduled and actual flows at interconnection points. Therefore, each utility acted as a *control area* managing the coordinated operation of its own entire generation, transmission, and distribution systems as well as some of the assets of publicly owned utilities. The IOUs were responsible for all economic and technical functions, such as security analysis, economic dispatch, unit commitment, etc. The system was also characterized by significant assets owned and operated by publicly owned utilities, notably the significant transmission capacity of Los Angeles Department of Water and Power and the Sacramento Municipal Utility District, significant non-utility generating capacity, and numerous distribution networks.

Figure 1. California Network Model (Source: California Power Exchange)



Bold black lines identify Zone boundaries
Green lines identify transmission paths between zones (may include one or more lines)
Red letters denote Zone names
Black letters denote "abbreviated" scheduling point names
Green letters denote Path names
Blue letters denote abbreviated "geographic" location names

Zone Abbreviation Legend

AZ2		AZ3		AZ5		HUMB	
II1	SCE	II2	SDG&E	LA1	Sylnar	LA2	McCullough
LA3	Inyo	LA4	Victorville	LC1	Mead	LC2	Blyth
LC3	Parker	MX	CFE	NP15	North Path 15	NV3	Laughlin
NW1	Captain Jack	NW2	Cascade	NW3	NOB	Pas	Goodrich/Pasadena
SF	San Francisco	SP15	South Path 15	SR2	Summit	SR3	Silver Peak

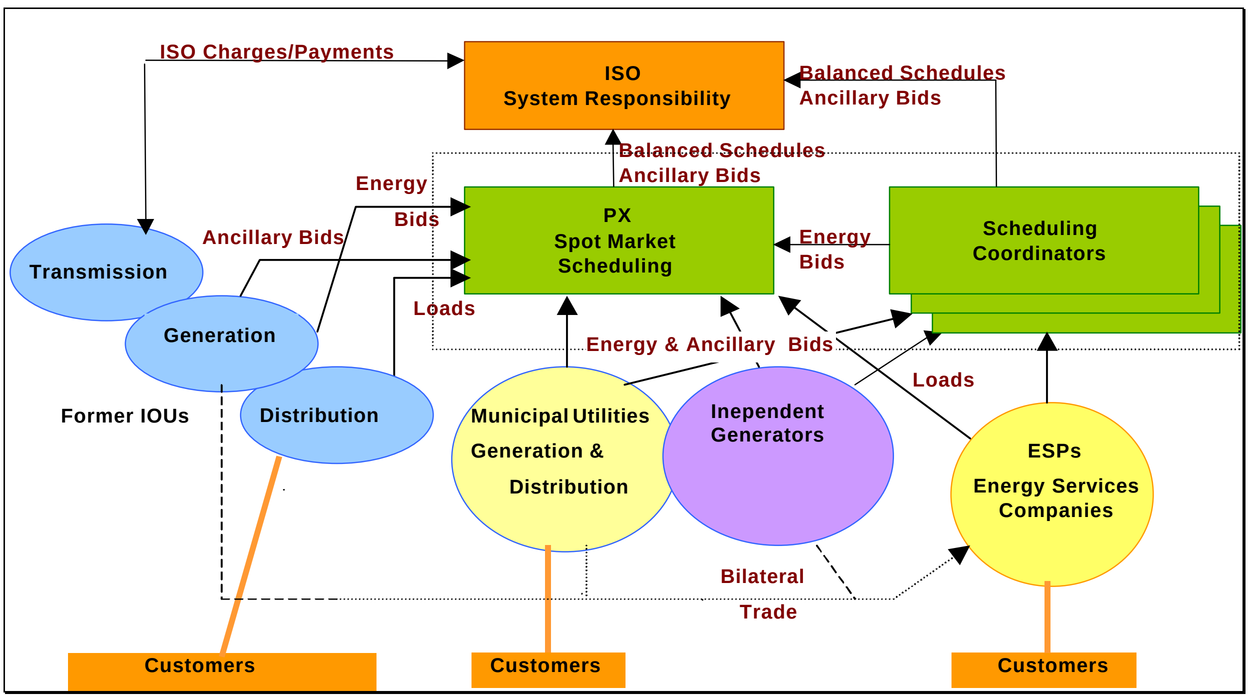
In August 1996, the passage of Assembly Bill 1890 provided the legal basis for competition among electric service providers in California. In brief, AB 1890:

- calls for the establishment of the Power Exchange (PX) and the Independent System Operator (CAISO) as independent, public benefit, non-profit market institutions to be overseen by a five-member Electricity Oversight Board, as well as by Federal regulation through the Federal Energy Regulatory Commission (FERC);

- requires California's utilities (both IOUs and publicly owned) to commit control of their transmission facilities to CAISO, that is, owners of transmission assets maintain ownership of them, but CAISO now operates them as part of the overall the state system;
- allows for direct, bilateral electricity trading;
- calls for a transition to retail competition beginning 1 January 1998 and will be completed no later than 31 March 2002;
- calls for additional requirements concerning stranded cost recovery, rate reduction, divestiture of generation assets, etc.

The roles and relationship between the market participants on both the wholesale and retail sides of the new California electricity market are illustrated in Figure 2.

Figure 2. California Market Structure



The primary purpose of the California PX is to provide an efficient, short-term, competitive wholesale spot energy market. The PX is one of a potentially unlimited number of Scheduling Coordinators (SC) authorized to communicate balanced schedules and other information to CAISO, which conducts the real-time dispatch. PG&E, SCE, and SDG&E, which together distribute 80% of the electricity sold in California, must buy and sell electricity through the PX during a transitional period of stranded cost recovery. The PX determines the price of electricity on an hourly basis for the Day-Ahead and Hour-Ahead markets, according to the demand and supply bids submitted.

In the *Day-Ahead market*, for each hour of the 24-hour scheduling day, the PX constructs aggregate supply/demand curves from all bids to determine the market-clearing price (MCP) for each hour. Generator bids initially submitted into the day-ahead market auction need not be attributed to any particular unit or physical scheduling plant, which is referred to as a *portfolio bid*. In the *Hour-Ahead market*, bids are submitted to the PX at least 2 hours before the hour of operation. In contrast, these are *unit specific bids*, portfolio bids are not allowed. The purpose of the Hour-Ahead market is to give participants an opportunity to make adjustments based on their Day-Ahead schedules, thereby minimizing real-time imbalances. The MCP is determined in the same way as in the Day-Ahead market (California PX 1998). Due to the lack of activity in the Hour-Ahead market, in December 1998, the PX introduced the Day-Of market. It consists of an on-peak auction (hours ending 11:00 to 16:00) with energy bids submitted by 6 a.m., a noon auction (hours ending 17:00 to 24:00) with energy bids submitted by 12 p.m., and an off-peak auction (hours ending 1:00-10:00) with bids submitted by 4 p.m[3]. The Day-Of market began on 17 January 1999.

Wholesale electricity trading can be conducted either in the PX or as bilateral agreements passed through other SCs. In either case, however, trades must be scheduled with CAISO. As such, the chief difference between bilateral and PX trading, as far as CAISO is concerned, lies only in which SC provides the required scheduling information. As with the PX, independent SCs facilitating bilateral trades must provide CAISO with balanced schedules and settlement ready meter data. Independent SCs may broker trades and aggregate supply and demand bids. These agreements can also be made in open markets that compete with the PX, and one has already emerged, the Automated Power Exchange (APX). In addition, as in other wholesale electricity markets, buyers and sellers have the option of engaging in financial rather than, or in addition to, physical trades.

CAISO is charged with ensuring open access and maintaining the reliability of the transmission grid. CAISO (1) coordinates day-ahead and hour-ahead schedules from all SCs, (2) buys and provides AS as required, (3) controls the dispatch of generation accepted to procure AS, and (4) performs real-time balancing of load and generation in the Imbalance Energy Market (More and Anderson 1997).

CAISO scheduling functions, together with transmission congestion management protocols for the transmission grid in the day-ahead and hour-ahead markets, consist basically of the following steps:

- After a market clearing price has been established, portfolio bids that have been received into the day-ahead market are broken down into generation-unit schedules. Then, these schedules are submitted to CAISO along with *adjustment bids* that reflect the willingness of generators to adjust their schedules to alleviate potential congestion problems in the transmission grid.

[3] In contrast, the Block Forward market consists of standardized contracts that are available for 16 hours of on-peak energy during a weekday for a specified month.

- CAISO determines, based on all unit-specific supply bids and location-specific demand bids, whether transmission congestion exists. If there is inter-zonal congestion, CAISO uses the adjustment bids to adjust the submitted schedules. The adjusted schedule is then returned to the PX or whatever SC submitted it.
- These adjusted schedules, together with transmission usage charges determined by CAISO according to an established congestion management procedure, become the foundation for zonal Market Clearing Prices and SCs can, one time only, submit revised schedules to CAISO.
- Schedules comprise forecast loads and any sources of supply, imports, exports, transfers, or generation. Generators' schedules are modified to compensate for transmission losses.
- CAISO announces final schedules and congestion charges.
- In the hour-ahead market, CAISO scheduling function is similar to the one presented but Scheduling Coordinators do not have the opportunity to resubmit revised schedules in case of congestion.

For a more detailed description of CAISO scheduling functions and congestion management procedures, see Papalexopoulos (1998).

CAISO directly acquires AS and imbalance energy needed to rectify submitted schedule inaccuracies using quite different procedures. Regulation service, spinning reserve, non-spinning reserve, and replacement reserve are procured daily, based on competitive mechanisms. Suppliers' bid prices and quantities for each type of service are made in Day-Ahead and Hour-Ahead markets. Two other vital AS, reactive power supplied locally for voltage support and black-start generation capability, are acquired by specific contracts.

Real-time imbalances result when there are differences between scheduled and metered values for demand and supply. In order to adjust power generation so that actual generation and load match in real time, CAISO utilizes the Real-Time Energy Market. This process is conducted based on *supplemental energy bids* from the supply side only and on incremental energy bids from units already scheduled to provide capacity reserve in the AS market. CAISO separately sorts incremental and decremental energy bids in two price merit order lists and calls upon the bids when it is necessary to adjust the balance between generation and load. The last unit called upon in this way in each ten-minute interval, sets the real-time market price. Participants are charged (or paid) this price for any discrepancies between their actual and scheduled supply and load based on an hourly average of the ten-minute prices, which is known as the real-time spot price.

2. Reliability Criteria

Traditionally, vertically integrated utilities have been responsible for ensuring reliability in their service territories. The *control areas*[4] had the primary responsibility for ensuring bulk power system reliably. In California, each of the three major utilities operated its own control area. Resource planning and transmission adequacy studies were also systematically conducted by utilities based on the *obligation to supply at minimum cost*.

A wholly voluntary utility organization, the North American Electric Reliability Council (NERC) has been in the forefront of establishing reliability policy, standards, and guidelines. The primary members of NERC also belong to Regional Reliability Councils (RRCs), each formed by the utilities operating within a region. Currently, there are ten RRCs, and California is a part of the vast Western System Coordinating Council (WSCC).

With the segregation of generation and transmission, Independent System Operators are entirely new entities emerging from reorganization, that operate regional transmission systems irrespective of ownership, and take responsibility for grid reliability. In the case of California, CAISO ensures open access to market participants and maintains reliability. CAISO is the *security coordinator*[5] for the grid, and former control areas have delegated their responsibilities to CAISO, which, in general, is required to continue complying with NERC Operating Policies (ICF 1997).

Under the competitive framework, voluntary responsibility for ensuring reliability is no longer practical. Consequently, NERC is likely to be transformed into a new entity, the North American Electric Reliability Organization (NAERO), which will require more precise, measurable, and mandatory reliability standards. NERC Operating Policies and Planning Standards (NERC 1998; NERC 1997), now voluntarily adopted by utilities, would become mandatory.

Prior to restructuring, each vertically integrated utility provided AS to meet NERC and its own RRC reliability criteria. Separation of different services and their associated costs was not necessary. These services were bundled with the primary function of energy supply, and their costs were recovered through energy rates. Under the new market structure, clear specification of each service is needed, costs and prices for each service arise unbundled from energy prices, and suppliers compete in price assuming specific technical requirements are met.

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[4] *control area* is an electrical region that is operated under centralized control to achieve a balance between its generation and load, and to control the interchange with other control areas to which it is electrically connected.

[5] *security coordinator* is the entity with responsibility and authority for directing the implementation of operating actions as part of the process of maintaining bulk transmission security for a control area, group of control areas, subregion, etc.

CAISO, to procure AS under the new competitive markets, follows NERC and WSCC reliability criteria. In Sections 2.1 and 2.2, NERC Operating Policy 1 on Generation control and performance is summarized. This operating policy sets definitions and reliability criteria for procurement of operating reserves and generation control services (NERC 1998).

2.1. *Operating Reserves*

Under the new structure, NERC establishes *operating reserve requirements*[6] that are followed by control areas or security coordinators. The operating reserve consists of the regulating reserve and the contingency reserve. The *regulating reserve* is the amount of spinning reserve needed to provide a safe regulating margin. Automatic Generation Control (AGC) controls spinning reserve. The *contingency reserve* is an additional amount of operating reserve sufficient to reduce the Area Control Error (ACE)[7] so that after the most severe single contingency, it meets the Disturbance Control Standard (see Section 2.2). The contingency reserve consists of spinning and non-spinning reserves. At least 50% of the contingency operating reserve (i.e., *spinning reserve*) will automatically respond to frequency deviations.

This percentage may be reduced if it still complies with the Performance Standards. *Interruptible load* may be included in the non-spinning reserve, provided that it can be interrupted within ten minutes. *Reestablishing (replacement) operational reserve,* an additional amount of operating reserve, aids in reestablishing the minimum specified reserve after such reserve has been used. In addition to the previous NERC criteria, Minimum Operating Reliability Criteria (MORC)[8] requires *restoration of operating reserves* within 60 minutes after an event begins.

WSCC criteria establish an absolute minimum operating reserve level equal to zero as the minimum level allowed before the initiation of preventive remedial actions, including the shedding of firm load. However, the California ISO requires a minimum operating reserve margin equal to 1.5%. In order to maintain that level, involuntary reduction of firm native demand when necessary would be required by CAISO.

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[6] *requirements* – obligations that control areas and other entities must follow.

[7] Area Control Error is the instantaneous difference between net actual and scheduled area interchange, taking into account the effects of frequency bias. The equation for ACE is: $ACE = (NIA - NIS) - 10\beta (FA - FS)$. In this equation, NIA accounts for all actual meter points that define the boundary of the control area and is the algebraic sum of flows on all tie lines. Likewise, NIS accounts for all scheduled tie flows of the control area. The combination of the two (NIA-NIS) represents the ACE associated with meeting schedules. The second part of the equation, $10\beta(FA-FS)$, is a function of frequency. The 10β represents a control area's frequency bias (β is negative) where β is the actual frequency bias setting (MW/0.1Hz) used by the control area and 10 converts the frequency setting to MW/Hz. FA is the actual frequency, and FS is the scheduled frequency. FS is normally 60 Hz but may be offset to effect manual time error corrections.

[8] MORC sections correspond to NERC operational policies and require that the more stringent or specific of the NERC or MORC criteria should be followed.

2.2. *Automatic Generation Control*

NERC establishes AGC requirements that must be followed by each control area or security coordinator. Each control area should maintain regulatory ability with electric generation so that it is synchronized to the interconnection. The AGC will be able to increase and decrease in order to provide for adequate system regulation, which is in compliance with the Control Performance Standard (see below).

The NERC *tie-line bias standard*[9] requires that each control area should set its frequency bias (expressed in MW/0.1 Hz) as close as practical to the control area frequency response characteristic.[10]

The NERC *governor guide*[11] recommends that generating units 10 MW or greater be equipped with governors for frequency response. Governors should provide a 5% droop characteristic[12] and be fully responsive to frequency deviations exceeding ± 0.036 Hz.

The NERC performance standards require that control areas meet the following criteria: (1) *Control Performance Standards (CPS1 & CPS2)* require that the average ACE over a one-year period and also in ten-minute periods must be within specific limits; and (2) the *Disturbance Control Standard (DCS)* requires that the ACE must return either to zero or to its pre-disturbance level within ten minutes following the start of a disturbance.

[9] *standards* – requirements that are measurable and which can be audited.
[10] An area's frequency response characteristic depends on the combined effect of all droop characteristics of generator speed governors and the frequency characteristic of all loads.
[11] *guides* – operating practices that may be considered but are not required to be followed.
[12] The governor droop characteristic of a generation unit is given by the ratio of frequency deviation (% with respect to nominal frequency) needed to change generation power output (% with respect to nominal output) multiplied by 100. For example, a 5% droop means that a 5% frequency deviation causes 100% change in power output.

3. Design of the California ISO Ancillary Services Markets

CAISO is responsible for ensuring that sufficient AS are available to maintain the reliability of CAISO-controlled grid, consistent with WSCC, MORC, and NERC criteria. AS requirements established by CAISO may be self-provided by each Scheduling Coordinator (SC). Those AS that are required but not self-provided must be competitively procured by calls on longer-term contracts or by CAISO in the day-ahead market, the hour-ahead market, or in real time. CAISO manages all AS, both CAISO-procured and self-provided, in the real- time dispatch. CAISO manages the following AS:

- regulation service,
- spinning reserve,
- non-spinning reserve,
- replacement reserve,
- reactive power support, and
- black-start generation capability.

In the following sections, AS refers to the first four services that are procured through daily markets. Reactive power support and black-start generation are acquired separately through contracts. For more details on the contents of this section, see CAISO (1998).

3.1. Requirements

To ensure compliance with NERC and WSCC reliability criteria, CAISO establishes AS requirements.

Regulation Service. When AGC calls for more generating units, the regulation service provides it. The required amount of regulation service is determined as a percentage of the aggregate scheduled demand. Under traditional regulation, utilities are assigned a 3% requirement for regulation capacity. In the original AS market design, this percentage was constrained between a minimum of 1% to a maximum of 5%. However, in August 1998, CAISO filed for a modification, which FERC approved, giving CAISO total flexibility to specify the required percentage of regulation capacity needed to meet applicable reliability criteria.

Spinning and Non-spinning Reserves. The required amount of minimum contingency operating reserve made up of spinning and non-spinning reserve is determined as:

- 5% of the demand to be met by hydro generation plus 7% of the demand to be met by generation from other resources (demand covered by firm purchases from outside CAISO control area is not included), or
- the single largest contingency, if this is greater, or

- more stringent criteria required by CAISO.

Spinning reserve formed by unloaded synchronized generation ready to increase output shall be no less than one-half the total amount of operating reserve.

Non-spinning reserve may be provided by, among others, the following resources:

- demand which can be reduced by dispatch;
- interruptible exports; and
- off-line qualified generating units.

Each generating unit scheduled to provide spinning or non-spinning reserve must be capable of converting the full capacity reserve to energy production within ten minutes after the issue of CAISO dispatch instruction, and of maintaining that output for at least two hours.

In addition to the above requirements, an operating reserve equal to the total amount of non-firm imports scheduled by SCs must be self-provided by responsible SCs and may consist entirely of non-spinning reserve.

*Replacement Reserve***.** The required quantity of replacement reserve is determined by CAISO based on:

- historical analysis of the deviation between actual and day-ahead forecast demand,
- historical patterns of unplanned generating unit outages,
- historical patterns of shortfalls between final day-ahead schedules and actual generation,
- historical patterns of unexpected transmission outages, and
- other factors affecting CAISO's ability to maintain system reliability.

Replacement reserve may be supplied from resources already providing another AS, such as spinning reserve, but only to the extent that the ability to provide the other AS does not restrict in any way the provision of replacement reserve. The sum of AS capacities supplied by the same resource cannot exceed the total capacity of that resource. In Section 5.5, one exception to this rule is presented that has been introduced by CAISO regarding downward regulation capacity.

3.2. Obligations for and Self-provision

Each Scheduling Coordinator is assigned a share of the total AS requirement. This obligation is determined *pro rata*, based on the contribution of its metered demand to the total requirement of each particular. The obligation was originally based on scheduled demand (see Section 5.1 for details). For instance, each SC must provide the percentage of its metered demand that will be used for regulation service, where

CAISO determines the percentage. Each SC may choose to self-provide all, or a portion of its obligation in each zone. To the extent that a SC self-provides, CAISO correspondingly reduces the quantity of AS it procures.

3.3. Competitive Procurement and Market Auctions

CAISO operates competitive Day-Ahead and Hour-Ahead markets to procure regulation, spinning reserve, non-spinning reserve, and replacement reserve services not self-provided. Any SC representing generating units or loads may bid into these markets.

Bids for the Day-Ahead market are sent to CAISO the day prior to trading day. The bids include information for each of the 24 hours of the trading day. Bids for the Hour-Ahead market must be received at least two hours prior to the trading hour. SCs may buy back in the Hour-Ahead market capacity already sold to CAISO in the Day-Ahead market by submitting a revised bid. In addition, if SC's non-self-provided obligation in the Hour-Ahead market is less than its non-self-provided obligation in the Day-Ahead market, SC must sell back the excess to CAISO in the Hour-Ahead market.

When SCs bid into AS markets, they may bid the same capacity into as many of these markets as desired. CAISO evaluates bids in AS markets sequentially and separately in the following order: regulation, spinning reserve, non-spinning reserve, and replacement reserve. Any capacity accepted by CAISO in one of these markets is not passed onto the following markets; any losing bids in one market may be passed onto the following markets if the SC so specifies. SCs can also specify different capacity prices and different energy prices for each market.

Bid information, bid evaluation, and price determination rules used in the day-ahead regulation auction are presented. In this case, each SC, j, submits the following information for each generating unit, i, for each hour of the trading day t:

(a) maximum operating level (MW);
(b) minimum operating level (MW);
(c) ramp rate (MW/Min) $Ramp_{ijt}$;
(d) the upward and downward range of generating capacity over which generating unit i is willing to provide regulation ($Cap_{ijt}max$ in MW), where $Cap_{ijt}max \geq 30^* Ramp_{ijt}$. (Originally it was considered 10 instead of 30; in Section 5.5, the reasons that motivated this change are explained). Additionally, under the initial market design, the same auction took bids for upward and downward range for regulation and just one single market-clearing price was determined. In Section 5.5, and ISO proposal to conduct two separate auctions is described, one for downward and another for upward regulation, providing two different regulation prices; and
(e) the bid price of the capacity reservation $CapRes_{ijt}$ (\$/MW).

(f) the bid capacity Cap_{ijt}(MW).

CAISO selects generating units based on quantity and location of system requirements. One of CAISO's objective in accepting bids is to minimize the sum of total bids selected, but is subject to two constraints:

(a) the sum of selected bid capacities must be greater than or equal to required regulation capacity; and

(b) each generating unit's bid capacity must be less than or equal to that generating unit's ramp rate times 30 minutes (see Section 5.5).

The total bid for each generating unit is calculated by multiplying its capacity reservation bid price by its bid capacity.

Thus, subject to requirements by location, CAISO will accept winning regulation bids for hour t in accordance with the following criteria:

$$Min \sum_i \sum_j TotalBid_{ijt}$$

Subject to

$$\sum_i \sum_j Cap_{ijt} \geq Requirement_t$$

$$Cap_{ijt} \leq Cap_{ijt} \max \forall i, j$$

where,

$$TotalBid_{ijt} = CapRes_{ijt} \times Cap_{ijt}$$

$Requirement_t$ = Amount of upward and downward movement capacity required in hour t

Regulation capacity can be made available for upward and downward movement. For each generating unit concerned, the price payable to SCs is the zonal market clearing price (MCP_{xt}) equal to the highest-priced winning regulation capacity bid in zone x; i.e.,

$MCP_{xt} = Max\ (CapRes_{ijt})$ in zone x for settlement hour t

CAISO's auction does not compensate the SC for the minimum energy output of generating units bidding to provide regulation capacity. Therefore, disposition of any minimum energy associated with regulation or other reserve services selected in CAISO's AS markets is the responsibility of the SC selling those services.

The spinning reserve auction procedure is similar to the one described for regulation capacity. $Cap_{ijt}max$ (MW) is the additional capability synchronized to the system, which is immediately responsive to system frequency and available within 10 minutes. In the case of the non-spinning reserve auction, $Cap_{ijt}max$ (MW) is the capability available within 10 minutes. Loads can also bid for this service. $Cap_{ijt}max$ (MW) is the demand reduction available within 10 minutes. Finally, in the case of the replacement reserve auction, SCs can submit MW available within 60 minutes of dispatch, by generation units and loads. Zonal market-clearing prices are determined for each market.

In addition to capacity bids, resources bidding reserve services can bid a price for the energy output from reserved capacity $EnBid_{ijt}$ (\$/MWh). CAISO uses these bids along with supplemental energy bids to match generation and demand imbalances in the real-time energy market, as explained in the next section.

In the hour-ahead AS markets, similar rules as the ones presented for the day-ahead AS auctions are applied. When an SC wants to reduce the day-ahead self-provision, it may do so by buying back the reduced amount at the hour-ahead price.

3.4. Real-Time Dispatch of AS Resources and Supplemental Energy Bids

In real time, CAISO dispatches generating units, loads, and system resources to procure imbalance energy. In addition to the resources which have been scheduled to provide AS in the day-ahead and hour-ahead markets, CAISO may dispatch resources for which SCs have submitted supplemental energy bids. Supplemental energy bids must be submitted to CAISO no later than 30 minutes prior to the operating hour. Bids may be submitted at any time after the day-ahead market closes and cannot be withdrawn after 30 minutes prior to the operating hour. CAISO may dispatch the associated resource at any time during the operating hour. Supplemental energy bids must include the bid price of incremental and decremental changes in energy (up to 11 ordered quantity/price pairs representing up to 10 steps). All the quantity blocks received from supplemental energy bids and from energy bids of resources scheduled to provide AS are ordered in a merit order stack of ascending incremental and descending decremental price bids, known as Balancing Energy and Ex-post Pricing (BEEP) stack.

CAISO's real-time dispatch is based on the following principles:

(a) Generating units providing regulation service are automatically dispatched by AGC to meet NERC and WSCC Area Control Error performance requirements.
(b) Once the ACE has returned to zero, CAISO determines whether the regulation generating units are operating at a point away from their set point. CAISO then adjusts the output of generating units or resources available (either providing spinning, non-spinning, or replacement reserve, or offering supplemental energy) in order to return the regulation units to their set points so that the full regulating margin is restored.
(c) Generating units, loads and system resources are dispatched based on the merit concerned to respond to the fluctuation in demand or generation. CAISO can do one of two things to minimize the cost of providing imbalance energy. First, if additional energy output or demand reduction is needed, CAISO dispatches

resources in ascending order of order of energy bid prices and the effectiveness (location and ramp rate) of the resource incremental energy bid prices. Second, when required to reduce energy output, CAISO dispatches resources in descending order of decremental energy bid prices.

(d) Dispatch is conducted only to meet imbalance energy requirements. CAISO should not dispatch resources in real time for economic trades either between SCs or within a SC portfolio.

Once a decremental bid has been used by CAISO, it is included in the incremental part of the stack with an incremental bid equal to its decremental price bid. Once an incremental bid has been used by CAISO, it is included in the decremental part of the database with a decremental bid equal to its incremental bid price.

If pre-arranged operating reserve units are used to meet imbalance energy requirements, CAISO may replace such operating reserve by dispatching available supplemental energy bids. Operating reserve procured from replacement reserve shall not require replacement of utilized replacement reserve. In addition, CAISO may also need to purchase additional AS if the services arranged in advance are used to provide imbalance energy and such depletion needs to be recovered to meet reliability contingency requirements.

If a generating unit, load, or system resource fails to respond to a dispatch instruction, the responsible SC shall pay CAISO the difference between the resource's instructed and actual output at the hourly ex-post price. This applies whether the AS concerned is contracted or self-provided. Additional penalties or sanctions can be imposed by CAISO. Section 5.4 describes a proposed market design modification that would remove gaming opportunities related to this issue.

3.5. Imbalance Energy Prices and Charges

Imbalance energy is calculated in ten-minute time intervals using the ten-minute ex-post price, but only the energy weighted average of these prices is reported as the hourly ex-post price, and all energy delivered in the hour received this average price. In order to reduce demand or to change energy output in each ten-minute period, the ten-minute ex-post price equals the bid price of the marginal resource dispatched by CAISO. As a result, the imbalance energy price (or, the real-time energy price) can be interpreted as the spot price of energy, since it represents the instantaneous cost of acquiring electrical energy. In other words, unscheduled energy delivered to CAISO receives this price, and vice-versa for unscheduled demand.

The marginal resource dispatched in the ten-minute period is determined by the following:

(a) if generation output is increased or demand reduced, the generating unit, load, or system resource with the highest energy bid that is accepted by CAISO for incremental generation, or demand reduction; or

(b) if generation output is decreased, the generating unit or system resource with the lowest energy bid that is accepted by CAISO for decremental generation.

If the net quantity of imbalance energy in the ten-minute period, *t*, is positive, then

$$P10Min_{xt} = Max(EnBid_i)_{xt}$$

If the net quantity of imbalance energy in the ten-minute period, *t*, is negative, then

$$P10Min_{xt} = Min(EnBid_i)_{xt}$$

where $P10Min_{xt}$ is the ten-minute ex-post price in zone *x* during period *t* and $(EnBid_i)_{xt}$ is the energy bid price for resources providing AS and the supplemental energy bids for other resources dispatched by CAISO during the ten-minute period *t* in zone *x*.

The hourly ex-post price in each zone is equal to the energy-weighted average of six ten-minute ex-post prices in each zone *x*, which is calculated as follows:

$$PHourExPost_x = \frac{\sum_{t=1}^{6}(P10Min_{xt} \times SysDev_t)}{\sum_{t=1}^{6} SysDev_t}$$

where $SysDev_t$ is the absolute difference (whether positive or negative) between the deviation between scheduled and metered demand, and the deviation between scheduled and metered generation in ten-minute period *t*.

If CAISO declares a system emergency (e.g., during times of supply scarcity) and involuntary load shedding is mandated during the real-time dispatch, CAISO will set the hourly ex-post price at an administrative price.

SCs face an imbalance energy charge, which is allocated by adding the cost of imbalance energy, unaccounted energy, and any errors in the forecasted transmission losses. Each SC pays for deviations between its scheduled and actual generation, load, imports, and exports at the hourly ex-post price.

3.6. Settlement for AS Suppliers

CAISO performs a daily settlement function with scheduling coordinators. CAISO calculates imbalances between scheduled, instructed, and actual quantities of energy provided by using meter data. In the following, the formulas used to settle AS payments in the day-ahead markets are presented. SCs for resources that provide AS capacity through CAISO auctions will receive the following payment for AS capacity sold (regulation, spinning reserve, non-spinning reserve, and replacement reserve):

$$CAPPay_{xt} = CAPQDA_{xt} * CAPCDA_{xt} - Penalty$$

where,

$CAPPay_{xt}$: SC's total payment received for AS capacity in zone x sold through CAISO auction, for settlement period t

$CAPQDA_{xt}$: SC's total quantity of AS capacity in zone x sold through CAISO auction, for settlement period t

Penalty: penalty for failure to pass the availability test

$CAPCDA_{xt}$: the AS market clearing price, in zone x and in the Day-Ahead market for settlement period t.

The settlements for the hour-ahead markets are calculated by substituting hour-ahead prices in the relevant formulas and then deducting any amount SCs must pay to CAISO for buying back in the hour-ahead market capacity sold in the day-ahead market.

SCs that bid resources providing instructed energy deviations in real time will receive the following payments:

$$(EnBid_i)_{xt} = EnQInst_{xt} * P10Min_{xt}$$

where,

$(EnBid_i)_{xt}$ = payment for instructed energy deviations in zone x with real-time dispatch for the ten-minute period t

$EnQInst_{xt}$ = instructed energy increase or decrease in zone x with real-time dispatch for the 10-minute period t.

On 21 May 1998, CAISO, concerned about the insufficient number of regulation bids, instituted an additional payment for suppliers of regulation energy. The Regulation Energy Payment Adjustment (REPA) is an amount per MW of regulation capacity that was set according to an estimate of the energy provided. It was priced as the greater of either $20/MWh or the hourly ex-post price. REPA significantly improved the sufficiency of bids. After FERC authorized market-based rates for all AS bidders on October 28th and after a period of zero and even negative regulation prices, CAISO suspended REPA in November 1998. REPA was unnecessary because regulation capacity bids could now internalize the estimated costs of energy production.

3.7. *Settlement for AS Users*

CAISO determines a separate hourly user rate for each settlement period purchased in both the day-ahead and hour-ahead markets. Each rate is charged on a volumetric basis. This rate is applied to each non-self-provided obligation. The total capacity payments to service suppliers divided by the total requirement that has not been self-provided equals the user rate per unit. Each SC pays this user rate multiplied by its non-self-provided obligation.

The dispatched replacement reserve capacity cost is allocated to SCs in proportion to their contribution to imbalance energy requirements. The user rate is calculated as the net cost of purchasing undispatched replacement reserve (obtained as the total cost of replacement reserve) less the cost for replacement reserve dispatched and divided by CAISO's total replacement reserve requirement not self-provided by SCs.

4. Operation of Ancillary Services Markets

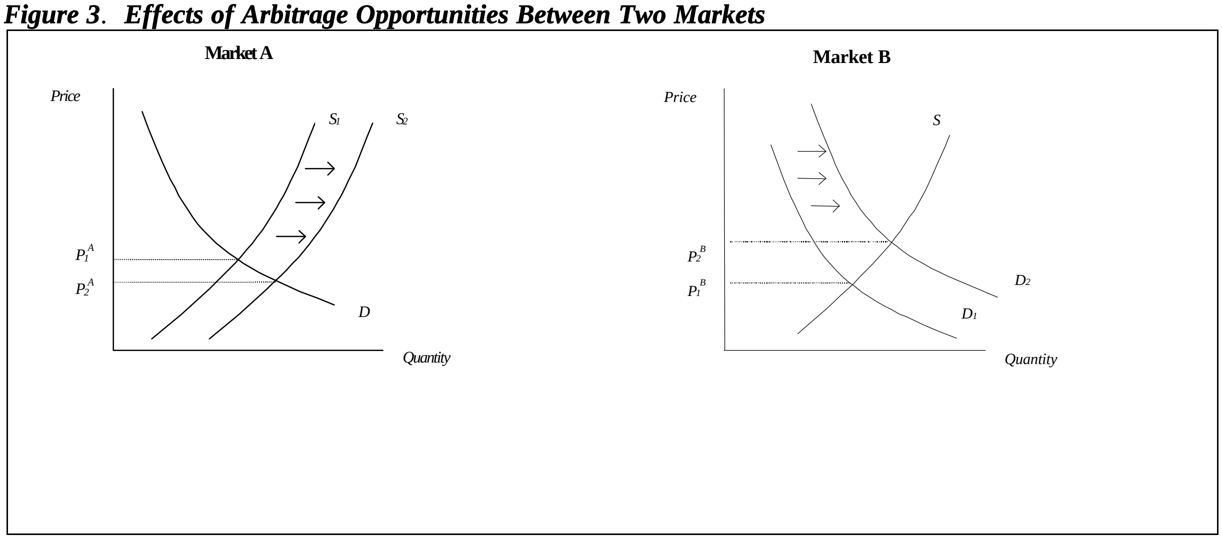
Under ideal competitive conditions (i.e., no market participant has market power) and assuming sufficient supply resources, the following conditions should hold:

- Prices in all AS markets should equilibrate so that suppliers would expect to earn almost the same variable profits (market revenues less variable costs) regardless of the market they choose to bid their generating capacity.

The fact that the prices in all of the AS markets should equilibrate in this manner can be explained by the principle of arbitrage. Simply put, arbitrage opportunities for a commodity exist if it is possible to make more variable profit in some market A than in some other market B; viz., an arbitrageur can buy the commodity in market B at a low price and sell it in market A at a high price. Assuming that transaction and transportation costs are negligible, the arbitrageur is, thus, able to earn revenue costlessly, i.e., the arbitrageur finds "free money." As other arbitrageurs learn of this opportunity to make "free money," they rush in to buy from market B and sell in market A. In terms of economic theory, there will be an exogenous *increase in the demand* for the commodity in market B, thereby putting *upward pressure on the price* there (p^B). At the same time, there will be a corresponding exogenous *increase in the supply* of the commodity in market A, which will lead to *downward pressure on the price* there (p^A). These pressures will continue until the two prices equal and any opportunities for arbitrage are eliminated (see Figure 3 for an illustration).

- Prices in regulation and spinning reserve markets should be related to day-ahead and real-time energy prices.

***Figure 3**. Effects of Arbitrage Opportunities Between Two Markets*



In a perfectly competitive market, the unit price of a good is equal to the cost of supplying an additional unit, (i.e., the marginal cost). Since bidders in the regulation and spinning reserve markets use similar underlying technology as bidders in the day-ahead and real-time energy markets, their marginal costs are related. In fact, they differ by an amount close to the incremental fuel costs and other variable costs incurred by generating rather than standing by. Hence, prices in these markets should also be correlated. Moreover, the actual cost of providing capacity from a generating unit should be less than the cost of providing energy from the same unit because of avoided fuel and other costs. However, providing capacity reserves involves opportunity costs. Opportunity costs, for instance, arise from units that have energy variable costs below the energy market price. The opportunity cost is equal to the energy market price less the unit's variable cost when operating reserves are provided by reserving capacity instead of generating energy. Units generating energy during off-peak hours, for instance, incur actual costs. This is done in order to provide downward regulation reserve when their variable costs are higher than the energy market price. Those units would recover these costs through the regulation capacity payment, and each unit in its regulation bid price would internalize energy costs. If that unit is a hydro resource with limited energy storage capability, then the regulation bid price would include the opportunity cost to sell that energy at the market price in peak hours instead of producing it in off-peak hours. For more details in actual and opportunity costs incurred by units providing AS, see Singh (1998) and De la Fuente (1999).

- Prices in the non-spin and replacement reserve markets should be lower than the prices of regulation and spin reserve markets because the former services do not require the generator to be running during the hour for which capacity is made available.

Furthermore, the structure of the California electricity market is such that suppliers who commit capacity through the ancillary services markets receive *both* the imbalance energy payment and the respective ancillary service capacity payment, whereas those who bid through the supplemental energy market receive only the imbalance energy payment. Therefore, a generator can make more profit by bidding into the replacement reserve market rather than the supplemental energy market. As in the aforementioned arbitrage example, suppliers would continue to bid into the replacement reserve market, increasing the supply until the payment they receive there is equal to what they would receive in the supplemental energy market. In essence, this implies that the replacement reserve price will be driven to zero and any opportunities for arbitrage will be eliminated. Hence, the prices in the non-spin and replacement reserve markets should be very close to zero due to the principle of arbitrage (Wolak 1998).

The following sections describe our analysis of energy and AS market price evolutions from April 1998 to March 1999. This analysis will verify the performance of California AS markets and test some previous hypotheses.

4.1. On-Peak Prices

In Table 1, some summary statistics about PX day-ahead energy market, CAISO real-time energy market, and AS average weekly prices in terms of $ per MWh from April 1998 to March 1999 are presented.

The *mean* represents the central tendency of the average prices, while the *standard deviation* measures the volatility, or dispersion, of average prices. In order to have a basis for a meaningful comparison of the average price's volatility, the *normalized standard deviation* (or the *standard deviation to mean* ratio) is also presented. This provides a standardized measure of price volatility.

Table 1. Average Energy and AS Prices Summary Statistics (April 1998 to March 1999)

	Mean ($/MWh)	Standard Deviation ($/MWh)	Normalized Standard Deviation
PX Peak	28.18	13.05	0.46
Real Time Peak	27.97	16.42	0.59
Regulation Peak	11.36	10.80	0.95
Spinning Reserve Peak	16.09	24.77	1.54
Non-Spin Reserve Peak	9.81	18.40	1.88
Replacement Reserve Peak	10.56	20.11	1.90
PX Off-Peak	16.72	7.49	0.45
Real Time Off-Peak	15.24	7.51	0.49
Regulation Off-Peak	16.97	21.57	1.27
Spinning Reserve Off-Peak	5.30	7.70	1.45
Non-Spin Reserve Off-Peak	2.29	2.62	1.14
Replacement Reserve Off-Peak	2.12	3.01	1.42

In Table 2, the *correlation coefficients* for the on-peak energy and AS prices are presented. The correlation coefficient between two attributes *x* and *y* measures the degree to which the two are related. The range of the *correlation coefficient* is [-1, 1], where a value of -1 means that the two attributes have a perfectly negative relationship, while a value of 1 means that the two have a perfectly positive relationship.

Table 2. Correlation Coefficients for On-peak Average Energy and AS Prices (April 1998 to March 1999)

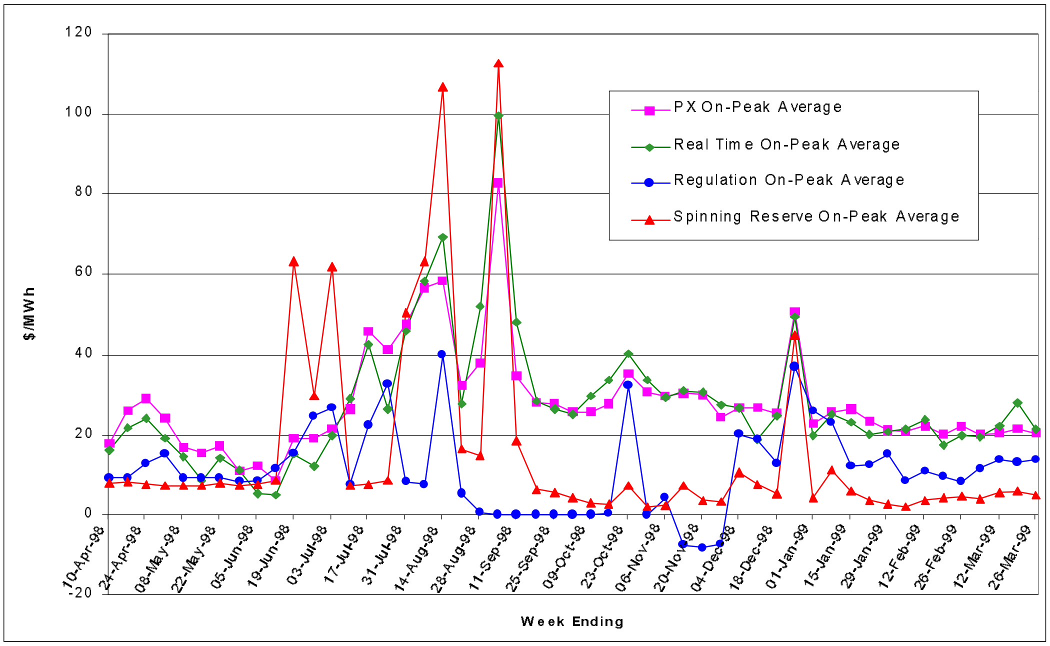
	PX	Real Time	Regulation	Spinning Reserve	Non-Spin Reserve	Replacement Reserve
PX	1.00	0.95	0.12	0.70	0.83	0.77
Real Time	0.95	1.00	0.00	0.68	0.76	0.70
Regulation	0.12	0.00	1.00	0.29	0.19	0.21
Spinning Reserve	0.70	0.68	0.29	1.00	0.78	0.75
Non-Spin Reserve	0.83	0.76	0.19	0.78	1.00	0.97
Replacement Reserve	0.77	0.70	0.21	0.75	0.97	1.00

In Figure 4, on-peak (hours from 7:00 through 22:00) weekly average price values are compared for the PX day-ahead energy market, CAISO real-time energy market, and the day-ahead regulation and spinning reserve markets.

In Table 2, a high correlation, i.e., 0.95, between average prices in the PX day-ahead energy market and in CAISO real-time energy market (hourly ex-post prices) exists and is also evident from Figure 4. During the summer period starting mid-July and ending mid-September, average prices were above $40/MWh, and real-time prices were higher than day-ahead prices, reaching a maximum value of $100/MWh. After the summer, energy prices were between $20/MWh and $40/MWh. In general and during the week of Christmas, real-time prices were slightly higher than day-ahead prices.

Regulation average prices were below energy prices but did not correlate with them (with correlation coefficients of 0.12 for PX day-ahead prices and 0.001 for real-time prices). Thus, it appears that the trajectory of these prices does not reflect actual or opportunity generation costs. In addition, important price fluctuations from one week to another are observed without any clear explanation. The existence of a long period with almost zero and negative prices is explained by REPA payments, discussed above (see CAISO 1998b). After the suspension of REPA, regulation capacity prices have adopted a pattern more closely correlated to energy prices.

Figure 4. Comparison of Energy Prices and Regulation and Spinning Reserve Prices (on-peak)



Contrary to what is expected under ideal conditions, spinning reserve prices were higher than regulation prices for most of the period examined. Beginning January 1999, the ratio between both prices has made more economic sense since spinning reserve services have fewer “stand-by” generation requirements than the regulation service and are, thus, expected to be lower. Spinning reserve average prices were extra high, exceeding even energy prices and reaching a maximum of $107/MW, for most of the summer period (mid-June to mid-September). The greater correlation of spinning prices to energy prices than to regulation prices, displays a deficient market performance because of high values observed during the summer period.

On the another hand, Figures 5 and 6 show the high volatility that characterized prices in the regulation and spinning reserve markets. Indeed, both the average regulation and spinning reserve prices have *normalized standard deviations* of over 1 (see Table 1). In each week, CAISO compares the hourly highest, the hourly lowest, and the weekly average prices during on-peak hours.

Figure 5. High, Weekly Average, and Low Prices in the Regulation Market (on-peak)

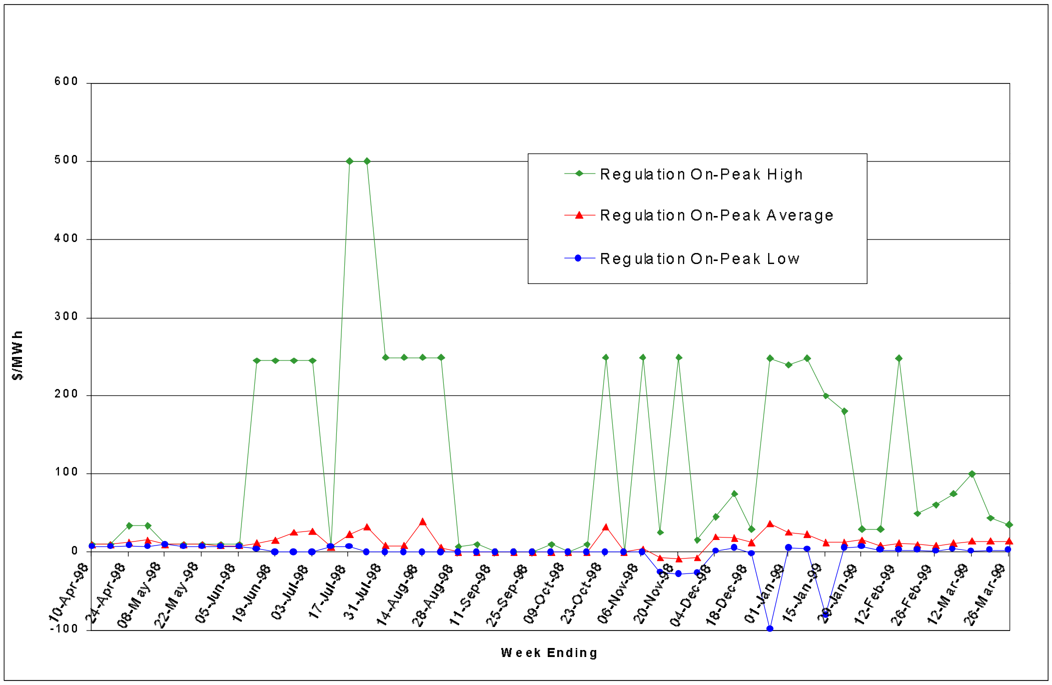


Figure 6. High, Weekly Average, and Low Prices in the Spinning Reserve Market (on-peak)

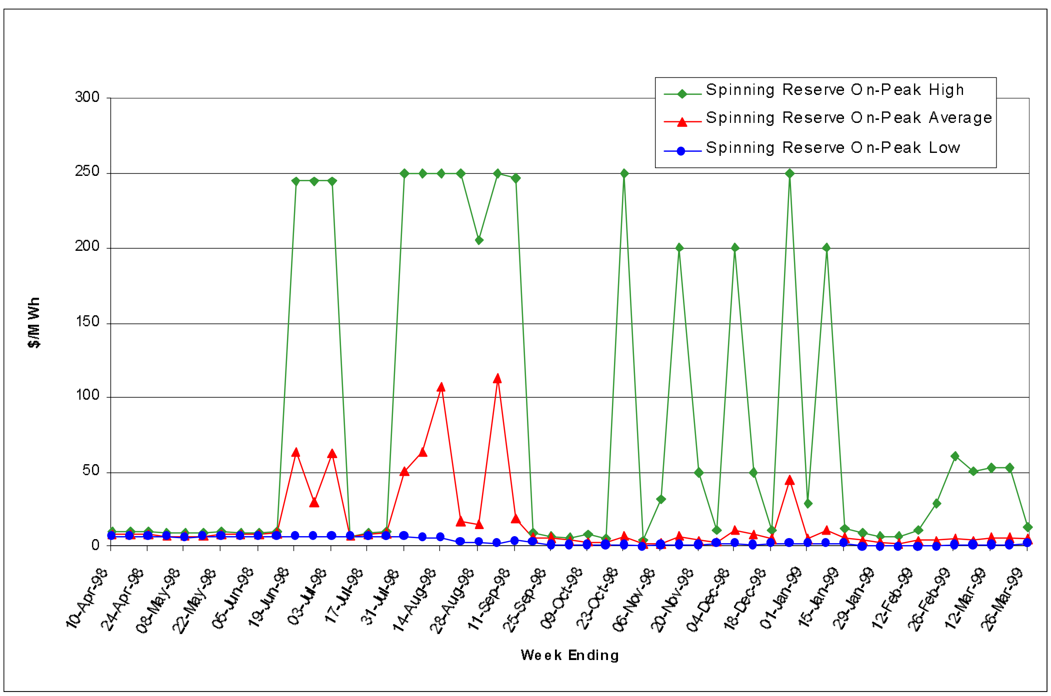


Figure 7. Comparison of Regulation, Operating, and Replacement Reserve Prices (on-peak)

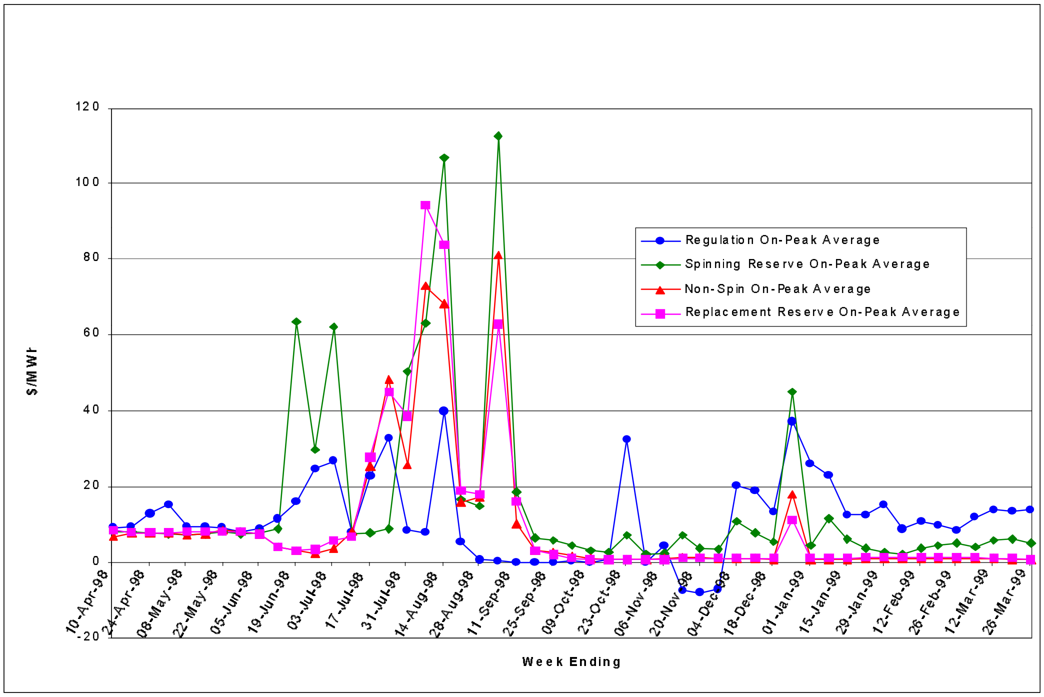


Figure 7 shows the evolution of regulation and spinning reserve prices along with two other AS on-peak weekly average prices. Non-spinning and replacement reserve price evolutions are highly correlated with each other and also with spinning reserve prices (refer to Table 2 for the *correlation coefficients*). Usually replacement average prices are almost equal to non-spinning prices and lower than spinning prices. Exceptions to that pattern were prevalent during the high price summer period when replacement prices exceeded non-spinning prices, and also both exceeded spinning prices in some weeks. After the summer period, by mid September, both average prices, non-spin and replacement, keep a lower value of approximately $1/MWh, which was exceeded only during the Christmas week.

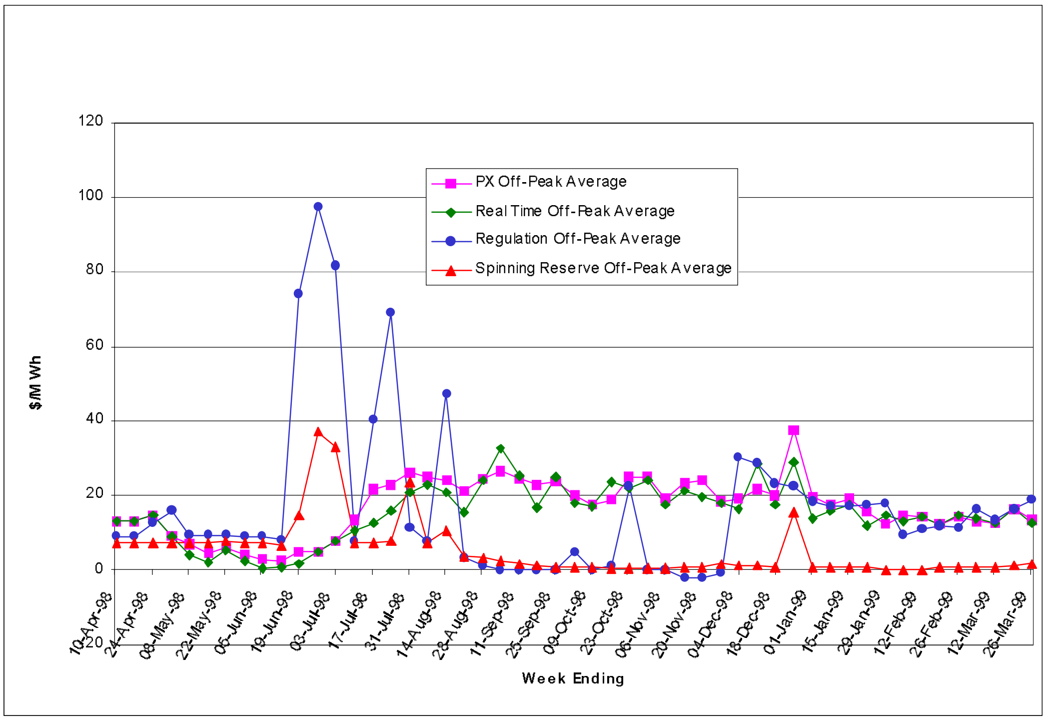
4.2. Off-Peak Prices

In Table 3, correlation coefficients are given for the off-peak (23:00 to 6:00) weekly average prices.

Table 3. Correlation Coefficients for Off-peak Average Energy and AS Prices (April 1998 to March 1999)

	PX	Real Time	Regulation	Spinning Reserve	Non-Spin Reserve	Replacement Reserve
PX	1.00	0.92	-0.23	-0.25	-0.38	-0.51
Real Time	0.92	1.00	-0.30	-0.32	-0.46	-0.54
Regulation	-0.23	-0.30	1.00	0.71	0.07	0.00
Spinning Reserve	-0.25	-0.32	0.71	1.00	0.34	0.37
Non-Spin Reserve	-0.38	-0.46	0.07	0.34	1.00	0.93
Replacement Reserve	-0.51	-0.54	0.00	0.37	0.93	1.00

Figure 8. Comparison of Energy Prices, and Regulation and Spinning Reserve Prices (off-peak)



In Figure 8, off-peak weekly average price values are compared for the PX day-ahead energy market, CAISO real-time energy market, and the day-ahead regulation and spinning reserve markets

Starting in mid-July, average energy prices in off-peak hours are nearly \$20/MWh. Day-ahead and real-time prices remain strongly correlated (a correlation coefficient of 0.92). It can be observed that off-peak energy prices have a lower seasonal fluctuation pattern than on-peak prices (see the normalized standard deviation in Table 1).

Regulation prices in off-peak hours behave differently throughout the year. During the summer period up to mid-August, regulation prices frequently exceeded energy prices, reaching a maximum weekly average value of \$100/MW. This pattern reveals that high fluctuations are not highly correlated with energy prices. During the second period up to the end of November, regulation prices were low remaining near zero and negative prices. From the beginning of December to the present, off-peak regulation average prices are almost equal to average energy prices. The most recent pattern of behavior follows economic expectations, even though regulation prices still appear high.

Spinning reserve prices in off-peak hours had a different behavior before and after the summer. Before summer, especially from mid-June until mid-July, they were higher than energy prices. Since mid-August, spinning prices in off-peak hours were near or below $1/MW, except during the week of Christmas.

Non-spinning and replacement reserves prices in off-peak hours are not represented in Figure 8. These prices have been kept at low values even during the summer when they reached a maximum weekly average value of $8/MW. Since the end of August, the non-spinning average value has been kept at approximately $0.5/MW, and the replacement reserve price is almost zero with very little fluctuation.

4.3. Analysis of the Summer Period

The CAISO Market Surveillance Committee examined the performance of AS markets during the first summer months, June and July (Wolak 1998). Some of the findings of that report have characterized the performance of these markets for most of the period of operation, as commented in previous sections. Some of the most important observed deficiencies were the following:

- AS market prices did not reflect changes in the underlying marginal costs of supplying the services;
- high price volatility even during periods when the demand of service was unchanged;
- prices for lower quality services, such as replacement reserve, exceeded prices for higher quality services, such as regulation
- AS prices often exceeded day-ahead or real-time energy prices at the same hour.

Some of the factors identified in the Committee's report (Wolak 1998) that may have contributed to this low performance were:

- Generators belonging to public utilities under the FPA were subject to cost-based price caps. They submitted bids capped at FERC authorized cost-based rates and were not paid above their cost-based bid. Through the first three months of operation, all market participants were cost-based capped. On June 30 and July 10, some market participants were allowed to bid and earn market-based rates. FERC determined the market-based rates for all participants in the replacement reserve market, which contributed to the dramatic price spikes on July. CAISO responded by imposing an initial cap of $500/MW, and subsequently lowered it to $250/MW. After the summer period, on 28 October 1998 FERC granted market-based rates for all market participants.

- CAISO requirements for regulation and operating reserves during the summer months were higher than the values recommended by NERC and WSCC criteria (presented in section 3.1).
- When purchasing AS, CAISO follows a rigid standard that does not allow substitution between services. CAISO would not purchase a lower quality service at a given price if a higher quality price were available at a lower price, that is the aim of the rational buyer proposal presented in the next section.
- Reliability Must Run (RMR) contracts are awarded to some generation units in order to provide reliability services when called upon by CAISO. These contracts provided few incentives to bid into the AS markets because RMR contracts provide more revenues. This problem decreased bid sufficiency and increased the likelihood of gaining market power by some participants.
- The lack of bid sufficiency forced CAISO to procure AS purchases out of the market increasing the overall cost of these services.
- The dispatch practices for the provision of imbalance energy followed by CAISO had not been transparent to market participants. CAISO sometimes did not dispatch some units providing operating reserves, even though they were the lowest available energy bids. CAISO has also indicated that some units receiving payments for reserves have increased their output to receive also the imbalance energy payments even though they were non-instructed by CAISO.
- AS costs were allocated pro-rata among Scheduling Coordinators according to their day-ahead schedules, instead of the actual loads. This provided incentives to under-schedule; consequently the hour-ahead schedules always exceeded the day-ahead schedules, and the amount for replacement reserve required by CAISO was higher. As it is presented in the next section, CAISO has proposed some market modifications to overcome this problem.
- Until 6 August 1998, CAISO could not accept ancillary services bids from any supplier outside CAISO control area because of limitations in software. By comparison, CAISO energy imports sometimes reached up to 20%.

After CAISO Market Surveillance Committee report, CAISO has initiated a process where several AS market design improvements have been identified in agreement with market participants.

5. AS Markets Redesign

CAISO is currently in the process of filing with FERC the corresponding Tariff Amendments to implement market improvements before summer 1999 (CAISO 1999). This section presents the main proposed design changes.

5.1. Billing AS Costs Based on Metered Demand

Each SC has to pay CAISO for the portion of AS costs not self-provided. For settlement purposes, it is proposed that the SC's obligation be calculated as a function of the SC's actual metered demand instead of the scheduled load as in the original design. By doing so, SCs must pay the additional AS needs required as a consequence of demand deviations, removing the clear incentive to under schedule.

5.2. No AS Capacity or Uninstructed Deviation Payment

Either uninstructed deviations using capacity committed for AS provision or failure to meet a dispatch instruction degrades CAISO's ability to control the system reliably. If a committed resource was incapable of delivering AS in accordance with its bid, then the payment for the uninstructed energy and AS capacity will be eliminated to the extent of the deficiency. In addition, if a resource fails in following the dispatch instructions ordered by CAISO, payments for AS capacity will be rescinded between the committed and the generated quantities.

5.3. CAISO as Rational Buyer of AS Requirements

Under the proposal of rational buyer, CAISO would buy AS requirements from sequential AS markets with flexibility in order to produce the lowest total cost of procuring them while satisfying reliability requirements. CAISO would adopt the common sense rule of applying for a higher quality service bid rather than a lower quality service when doing so reduces purchase costs. For instance, CAISO can substitute extra regulation capacity for spin capacity if this unused regulation capacity was bid in at lower prices than the spin capacity. This proposal is based on two basic principles:

- for each generating unit, the total capacity bid cannot decrease as the quality of the AS product decreases, and
- for each generating unit, the bid prices associated with AS products must not increase as the quality of the AS product decreases.

To evaluate sequential auctions, a CAISO matching algorithm would search the set of feasible bid prices (i.e., a subset of the bid prices offered in the four AS auctions) and would find the associated cost to meet the AS requirements for each feasible set of prices. The algorithm would select the minimum-cost set after an exhaustive search of possible outcomes. In the case of multiple optima, the algorithm would select the set that minimizes the use of regulation as reserves, spinning reserve as non-spinning or replacement reserve, and non-spinning reserve as replacement reserve.

In practice, regulation bids would be matched first to meet the specific regulation requirement. Then, additional regulation capacity (not matched) can be used to satisfy any type of reserve requirements; spinning requirements must be satisfied by the combination of regulation and spinning reserve bids. A similar procedure is applied to procure the requirements of non-spinning and replacement reserves. The total MW purchased must be equal to the total requirements of AS.

As an example, consider the following AS requirements: 1,500 MW of regulation, and 1,000 MW each of spinning, non-spinning, and replacement reserves. Under the existing procedure, market-clearing prices (MCP) presented in Table 4 are obtained. If the rational buyer procedure is applied, then the MW purchased and the resulting prices change according to the right side of Table 4.

Table 4. Example of Rational Buyer Procedure

Service	Existing Procedure		Rational Buyer	
	Requirement (MW)	MCP($/MW)	Purchase (MW)	MCP($/MW)
Regulation	1,500	10	2,500	20
Spin	1,000	20	1,000	20
Non-spin	1,000	40	500	20
Replacement	1,000	80	500	30
Total Cost ($)	155,000		95,000	

The settlement of these markets after the application of the rational buyer procedure would be implemented as follows. Accepted AS bids will be paid the MCP for each service based on the final results of the Rational Buyer procedure. That is, 2,500 MW of regulation would be paid at $20/MW, and so on. The total payments to AS providers would be $95,000 (see Table 4). AS buyers settlement would be based on the preliminary AS requirements (before the Rational Buyer procedure) and the final MCPs. That is, the original requirement of 1,500 MW regulation would be charged at $20/MW and allocated to metered demand that is not covered by regulation self-provision, and so on. Table 5 presents these costs for each service. Observe that there is a surplus coming from the charges to AS buyers ($100,000) less the payments to AS providers ($95,000). This difference is added to a balancing account. This account will be cleared at regular intervals with a new charge to SCs, where the cost or benefit will be allocated pro rata to the respective SC as a total AS bill for the same interval.

Table 5. Cost Allocation According to the Rational Buyer Proposal

Service	Existing Procedure Cost Allocation ($)	Rational Buyer Cost Allocation ($)
Regulation	15,000	30,000
Spin	20,000	20,000
Non-spin	40,000	20,000
Replacement	80,000	30,000
Total Cost ($)	155,000	100,000

5.4. Settlement of Uninstructed Deviations and Replacement Reserve Allocation

Uninstructed deviations occur because of two different reasons: (1) when resources committed to provide energy imbalances do not respond to CAISO dispatch instructions, and (2) when forward market schedules deviate without notifying CAISO. The asymmetry in prices at which instructed deviations are paid (10-minute ex-post price) and uninstructed deviations are charged (the hourly ex-post price) can create incentives for uninstructed over-generation during high-priced 10-minute periods and uninstructed under-generation during low-priced 10-minute periods. For instance, if a generator who offered to provide imbalance energy receives a dispatch instruction for incremental energy in a 10-minute interval with an estimated price of $30/MWh but the estimated hourly ex-post price is $25/MWh, that generator can choose not to respond. CAISO would pay it at $30/MWh, but only charge $25/MWh for uninstructed imbalance energy, which results in a net gain of $5/MWh for doing nothing.

Uninstructed deviations lead to excessive regulation requirements, the need for more supplemental energy bids, non-compliance with NERC disturbance control standard that requires a return to 60 Hz within 10 minutes after disturbance, high volatility in the imbalance energy price, and other operational problems.

The Min-Max proposal was developed to solve some of these problems. According to the Min-Max proposal, uninstructed deviations supplying energy to CAISO would be paid at the lowest 10-minute price within the hour. Uninstructed deviations taking energy from CAISO would be charged at the highest 10-minute price within the hour. CAISO would over-collect, and the surplus would be distributed among SCs in proportion to their metered demands. The Min-Max proposal has not been implemented yet to allow stakeholder input, although CAISO has proposed a compromise. In addition to the market design changes described in Sections 5.1 and 5.2, CAISO will consider the use of "effective price" for settlement of uninstructed deviations by units that fail to respond to dispatch instructions and will modify CAISO's procurement of replacement reserves.

The result of implementing the "effective price" proposal is equivalent to no payments or charges for committed resources that fail to follow the decremental or incremental dispatch instructions. Therefore, the proposal eliminates the incentive of gaming from ignoring a dispatch instruction.

CAISO will procure additional ("deviation") replacement reserve when SC scheduled loads fall short of CAISO forecasted load. The extra costs will be allocated based on the obligation they cause from under-scheduling load or over-scheduling generation. This modification will reduce the number of emergency situations when CAISO has to purchase out-of-area reserves, several of which were required in 1998. For instance, in the day-ahead market, CAISO will procure a percentage of the best estimation of the difference between CAISO load forecast and the sum of energy schedules in the day-ahead market, plus an estimate of schedules in the hour-ahead market, plus an estimate of supplemental energy bids. CAISO would assign one MW of replacement reserve obligation to each MW of the difference between final hour-ahead load schedule and metered demand. CAISO would also assign one MW obligation to each MWh of net undelivered scheduled generation. If the cumulative under-scheduled load and over-scheduled generation is greater than the total additional replacement reserve requirement, each SC will receive a pro-rata allocation of its obligation. Otherwise, the excess of obligation will be assigned to all SCs in proportion to their metered demand.

5.5. Regulation Procurement and Separate Pricing of Regulation "Up" and

In August 1998, CAISO filed some market modifications with FERC regarding the procurement of regulation service. According to the original AS market design, any capacity accepted in one of these AS markets shall not be passed to another market of lower quality. Therefore, both the upward and downward accepted regulation capacities were not allowed to participate in any of the latter reserve markets. FERC accepted CAISO's proposal to allow the provision of operating reserves by the downward part of regulation capacity. Thus, the particular unit would provide two different services:

1. Reduce output in response to AGC signals.
2. Increase output when CAISO needs to call upon the unit for reserves.

The unit could be directed to provide distinct services during different portions of a single hour. On the other hand, FERC also accepted CAISO's proposal that CAISO would specify with advance notice to SCs, a time within 10 to 30 minutes for calculation of the maximum capacity a generator may bid in the regulation market. The original design allowed a maximum limit of only 10 minutes (i.e., if the ramp rate was 5 MW per minute, the unit could only bid 50 MW as regulation capacity). The resulting CAISO modification stems from the fact that, during some hours, the regulation capacity will be sufficiently responsive if the generator can modify its output during the hour. Therefore, the time limit was expanded from 10 to 30 minutes.

Finally, it has been proposed that “regulation-up” and “regulation-down” will be procured and priced separately as two different services.

5.6. *Lifting of Current Price Caps*

As a consequence of the high prices registered during the last summer period (some hours reached $9,999/MW), CAISO imposed a cap for AS market prices at $500/MW. By 24 July 1998, CAISO revised that cap to $250/MW, which applies in both the real-time energy market and in the AS markets. Currently, CAISO is reviewing the conditions that must be met to lift the cap to a higher value. It seems that the cap will remain at least during the summer of 1999. A market surveillance committee has undertaken a plan that will identify crises based on price pattern observations and detect supply insufficiency. This information will enable further recommendations on price caps.

5.7. *Other Issues*

CAISO and market participants have pointed out several critical issues that may arise in the future. Some of them are:

- Interactions between RMR contracts and AS market bids. These two ways to provide reliability services need a more coherent design.
- Transactions of AS obligations between scheduling coordinators. CAISO AS management procedures should take into account that SCs will be able to sell or buy AS obligations from other SCs.
- Increment of activity in AS hour-ahead markets. To facilitate the solution of scheduling problems derived from the day-ahead markets, these markets need liquidity.
- Definition and specification of the market for new products, such as load-following and ramping, that are currently bundled with regulation and the spinning reserve services.
- Increment of the frequency of settlements at least every ten minutes. Doing so would facilitate the solution of problems associated with the settlement of instructed and uninstructed deviations.
- Integration of transmission congestion management procedures and AS zonal market clearing prices.
- Release of market data and its level of confidentiality.

6. Conclusions

California has been one of the pioneering restructured electricity markets introducing competition in the procurement of ancillary services. CAISO's responsibilities include establishing the total requirement for each service and procuring requirements that have not been self-provided by scheduling coordinators, based on competitive daily auctions. Complicated design and other particular characteristics of market participants have affected supply sufficiency and bid prices. Different factors associated with this setup have been responsible for the market's erratic performance. High price volatility, no correlation between prices and costs, and average AS prices higher than energy prices during some weeks characterize these markets. CAISO, along with market participants, is attempting to identify some of the critical issues affecting these markets. As a result, CAISO has filed several market design improvements with FERC. However, from past experience, uncertainty still exists concerning how these markets will perform next summer when reliability services are expected to be critical in avoiding emergency situations and generalized outages.

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