Chapter 3.
Ancillary Services Markets

3.1 Introduction

3.1.1 Chapter Overview

This chapter reviews the performance of the ISO's ancillary service markets during the first year of operation. Section 3.1 provides a brief description of the ancillary service markets. Section 3.2 summarizes key market performance features and ongoing issues in these markets. Section 3.3 describes the demand for ancillary services over the first year and the factors affecting demand. Then Section 3.4 focuses on the market for Regulation Reserve, which has accounted for about 70 percent of ancillary service costs over the first year. Section 3.5 covers the performance of the ISO's three other ancillary service markets, Spinning, Non-spinning and Replacement Reserves. Section 3.6 describes the A/S market redesign effort that is currently underway, and Section 3.7 offers some conclusions. Additional discussion and analysis of the relationships between the A/S markets and the forward energy and real-time markets are provided in Chapter 6.

3.1.2 Market Description

The California ISO ancillary services (A/S) market is the first market in the world to procure A/S through a competitive bidding process. The A/S procured competitively in the California markets are Regulating Reserves or Regulation, Spinning Reserves, Non-spinning Reserves, and Replacement Reserves, which are defined as follows:

- **Regulation:** Generation that is already up and running, and synchronized with the ISO controlled grid so that the megawatts generated can be increased (incremented) or decreased (decremented) instantly through automatic generation control (AGC). Regulation is used to maintain real-time balance on the system.

- **Spinning Reserves:** Generation that is already up and running, or "spinning," with additional capacity that is capable of ramping over a specified range within 10 minutes and running for at least two hours.

- **Non-spinning Reserves:** Generation that is available but not running, that is capable of being synchronized and ramping to a specified level within 10 minutes, and then capable of running for at least two hours.

- **Replacement Reserves:** Generation that is capable of starting up if not already operating, synchronizing with the ISO controlled grid and ramping to a specified load within one hour, and running for at least two hours.

The first three A/S correspond to services defined in FERC Order 888 as *regulating*, *spinning*, and *supplemental reserves*. The ISO's fourth A/S, *replacement reserve*, is not explicitly defined or required under FERC Order 888 service, but was defined to satisfy WSCC requirements.

The four services defined above are collectively referred to as "reserve" A/S. The ISO market participants (the Scheduling Coordinators) can self-provide any or all of these A/S, bid them into the ISO markets, or purchase them from the ISO. Two other A/S, *voltage support* and *black start*, are procured on a long-term basis by the ISO, primarily through the Reliability Must Run (RMR) contracts. *In the rest of this report, the term "ancillary services" will refer only to the four "reserve" services, i.e., Regulation, Spinning, Non-spinning, and Replacement Reserves.*

Bids to supply any or all four reserve A/S are submitted simultaneously, after the corresponding PX forward energy market (day-ahead or hour-ahead) is cleared and unit level energy schedules are known. All A/S bids must contain a capacity component and an energy component. The A/S markets are then cleared sequentially, based on the capacity bid component only, from the "higher quality" to the "lower quality" services, i.e., first Regulation, then Spinning, then Non-spinning, and finally Replacement Reserves. If a unit is awarded capacity in one market, any bids from the unit to supply A/S in subsequent markets are adjusted to account for the capacity awarded to the unit in a previous market.

Whenever the forward market energy schedules (day-ahead or hour-ahead) can be accommodated without the need for inter-zonal congestion management and rescheduling, the ISO procures the four A/S through a system-wide auction. Suppliers of each service are all paid the system-wide market-clearing capacity price (MCP) for that service. If congestion exists, the requirements for each service are established on a zonal basis, and the procurement is carried out separately in each zone, resulting in different zonal market clearing prices. The A/S procurement protocols are currently being revised to recognize and take advantage of situations where A/S procured on a system-wide basis could create counter-flows to relieve inter-zonal congestion.

The present protocols are also undergoing changes to enable the ISO to procure lower-priced, higher-quality services to substitute for higher-priced, lower-quality services, while still meeting its total reliability requirements. These changes will allow the ISO to avoid paying irrationally high prices resulting from temporal exercise of market power, and thus lower its procurement costs. This reform of A/S procurement practices, referred to as the "Rational Buyer" protocol, is described more fully in Section 3.2.5.

3.2 Summary of Market Issues and Performance

Over the first year of operation, the performance of the ancillary service (A/S) markets was mixed. Although these markets functioned in a highly efficient, competitive manner for the vast majority of hours during the year, they were plagued by price volatility and spikes. Unlike the price volatility and spikes experienced in the energy markets, such performance in the A/S markets cannot simply be attributed to tight supply and high system load conditions.

A variety of additional factors contributed to A/S price volatility. Certain features of the A/S market design, operating protocols, software restrictions and regulatory conditions created market inefficiencies and distortions which resulted in higher and more volatile prices in these markets. When combined with the basic forces of supply and demand, particularly over the summer months, flaws in the overall design of the A/S markets created unexpectedly high and volatile prices. These problems and their effects on A/S market performance are discussed below.

3.2.1 Bid Sufficiency

A key indicator of supply adequacy in the ISO's A/S markets is *bid sufficiency*, defined as the quantity of bids submitted as a percentage of the total capacity demanded. For instance, bid sufficiency of 200-percent indicates that for each MW of capacity the ISO needed to purchase, bids for 2 MW were submitted. If the amount of capacity bid into the market is less than the ISO's market requirements, then bid sufficiency will be less than 100 percent and *bid insufficiency* will exist. In these situations, the ISO must rely on other sources of supply, such as Reliability Must Run (RMR) units, to meet its A/S needs. When bid insufficiency exists, or even when bid sufficiency is above 100 percent but relatively low, individual market participants have market power and can set the market clearing price at very high levels. In the A/S markets over the past year, market clearing prices frequently reached the price cap of $250 when bid insufficiency occurred. In these instances, any single bidder submitting a small amount of capacity at the price cap was able to set the market clearing price. Bid sufficiency for specific A/S markets is discussed more fully in subsequent sections of this chapter.

3.2.2 Procurement of Ancillary Services by Zone

During the month of July, the ISO frequently procured A/S zonally, by running separate markets for the two active zones, northern California (NP15) and southern California (SP15). This was done because of congestion on Path 26, a major intra-zonal interface south of Path 15. Procuring reserves separately for each zone improves the ISO's ability to deal with contingencies on either side of congested intra-zonal interfaces such as Path 26. At the same time, this practice tends to exacerbate bid insufficiency in the A/S markets.

3.2.3 Short-term Market Design Changes

As discussed in Sections 2.8 and 3.6, various measures were implemented over the past year as short-term fixes for specific problems in the A/S markets. Some of the most significant of these measures were the following:

- Lifting of cost-based price caps on A/S capacity (see Sections 2.8.4 and 2.8.13). In the early months of market operations, the investor-owned utilities (IOUs) could earn market prices for supplying energy, but were restricted to embedded-cost-based rates for A/S. When energy prices were high, this penalized IOUs that participated in the A/S markets, producing frequent shortfalls in A/S supply and contributing to spikes in A/S capacity prices. The ISO joined the IOUs and others in filings with FERC to extend market-based rate authority to all participants in the A/S markets. This authority was granted by FERC in its Order of October 28, 1998.

- Damage-control A/S price caps (see Section 2.8.6).

- Measures to facilitate out-of-state supply of A/S (see Section 2.8.9 and Section 3.2.4 below).

- Use of ISO load forecast rather than scheduled loads as the basis for determining A/S requirements (see Section 2.8.10).

In addition, certain measures were enacted specifically for the Regulation market. As noted above, the differential regulatory treatment of the A/S and energy markets caused early problems in the Regulation market. The ISO took three actions quickly to ensure that sufficient Regulation capacity would be available. These actions, which are discussed in more detail in Section 3.3, were:

- Implementation of the Regulation Energy Payment Adjustment (REPA), which effectively tied the payments for Regulation capacity to real-time energy prices (see Section 2.8.3).
- Relaxation of the ramping requirement for Regulation, to allow generators to offer capacity that could be converted to energy within 30 minutes of the AGC signal, rather than the 10-minute capability required by the original design.
- Separate procurement of upward and downward Regulation, to allow the ISO to meet its need for Regulation in one direction without having to over-procure capacity in the other direction (see Section 2.8.12).

3.2.4 Ancillary Services Market Redesign

Several of the measures discussed in the previous section were recognized at the time to be imperfect or incomplete. They were employed primarily to help mitigate immediate problems while the ISO addressed A/S market redesign in a more systematic manner and developed long-term solutions. In July 1998 the ISO embarked on a comprehensive market redesign process, which culminated in filings to FERC in March and April of 1999. In the course this process, the ISO developed a number of market redesign elements which, when implemented during the summer of 1999, will result in fundamental improvements in the functioning of the A/S markets. The major elements of A/S redesign are:

- Charging SCs for A/S based on metered demand, rather than on scheduled loads. In the original market design, the ISO charged SCs for A/S based on the volume of their scheduled loads. As the markets began operating, significant under-scheduling of loads became a common occurrence. Under-scheduling is inefficient for several reasons, and the practice of charging for A/S based on schedules was seen to be a significant incentive to under schedule. Moreover, in the presence of inaccurate scheduling, the practice could result in significant cost shifting among SCs. Charging for A/S based on metered rather than scheduled demand will become operational in summer 1999.
- Elimination of payments for A/S capacity and energy when the capacity sold to provide reserves would be unable to respond to ISO dispatch instructions
- Implementation of procedures to facilitate inter-SC trades of A/S. These procedures will become operational in August 1999.
- Separate clearing of the upward and downward Regulation markets, to allow different market clearing prices in each, rather than paying a common price to the bids selected for both upward and downward Regulation. The ISO will begin paying different prices for upward

and downward Regulation in July 1999. In the long run, redesign of the A/S and imbalance energy markets may permit the ISO to return to the original market design, of combined procurement of upward and downward Regulation. Changes to the real-time imbalance-energy market, which may reduce the ISO's demand for Regulation, are discussed in Chapter 4.

- Restructuring of charges for Replacement Reserves to discourage uninstructed deviations. One factor affecting A/S market performance is that the ISO's demand for A/S is determined, in part, by the performance of the real-time imbalance energy market. In particular, A/S procurement becomes more costly the more market participants meet their energy needs through uninstructed deviations, rather than through a combination of forward energy schedules and supplemental energy bids to the real-time market.[1] To discourage the use of uninstructed deviations, the ISO has proposed to increase its procurement of Replacement Reserves, with Replacement Reserve charges assessed to participants on the volume of their unscheduled and uninstructed over-consumption and under-generation. These changes will become operational in July 1999.

- The Rational Buyer procedure (see Sections 3.2.5, 3.4 and 3.8).

3.2.5 Opening of A/S Markets to Imports

During the first months of ISO operation, the ISO software could not validate A/S capacity bids from outside the control area. This was a significant deficiency. The northwest has major hydroelectric facilities, whose high ramping capability but limited extended energy-production capacity make them well-suited to provide operating reserves. In the south, the Los Angeles Department of Water and Power (LADWP) has substantial hydro and pumping facilities which could provide Spinning, Non-spinning and Replacement Reserves for the ISO's control area.

In August, 1998, the ISO started importing Operating and Replacement Reserves, and, as will be discussed below, these imports have often made important contributions to the functioning of the A/S markets. To increase the supply into the A/S markets, the ISO plans to increase its limit on the import of Operating Reserves to 50 percent in near future, through a three-party arrangement with the SCs and the neighboring control areas. The control areas that are party to the agreement will reserve adequate transmission capacity, and will respond to ISO's intra-hour 10-minute interchange schedule change requests under normal or emergency conditions. Testing of this procedure is planned for the first week of June 1999. For the longer term, the ISO will be further revising its import policy to allow imports of Regulation and to allow A/S imports to compete for intertie capacity on an equal basis with energy imports.

3.2.6 Sequential Auction Design and the Replacement Reserve Market

A feature of the original market design was a strict sequencing of California's markets, with the four A/S day-ahead auctions clearing after the close of the day-ahead PX energy and ISO congestion markets, and the discretion of bidders to bid into all or only some markets. The clearing sequence of the A/S auctions reflects a *quality ranking* of the four services, in which capacity that can meet the requirements of the later-clearing markets may not necessarily meet

[1] See Section 2.5 for an explanation of these terms.

the requirements of the earlier-clearing markets. This ranking was clearest in the original design, in which Regulation and Operating (Spinning and Non-spinning) Reserves were 10-minute products, and Replacement Reserves was a 60-minute product. Under that design, any capacity that met the requirements for Regulation could meet the requirements of all other A/S. Similarly, capacity that met the requirements for Spinning Reserves could also meet the requirements for Non-Spinning and Replacement Reserves, and capacity that could provide Non-spinning Reserves could also provide Replacement Reserves.

In using this quality ranking to establish the clearing sequence of the markets, while allowing discretion to bidders to bid into some but not all markets, some problems emerged. In particular, the early-clearing markets often cleared at relatively low prices due to large amounts of capacity being available at the beginning of the sequence. Later in the sequence the amount of available capacity would decline, causing the market clearing price to rise, particularly in the Replacement Reserves market. As a result the markets suffered repeated episodes of very high capacity prices for lower-quality reserve services, even though substantial lower-price capacity of adequate quality had been offered in the earlier markets.

To correct this perverse situation the ISO developed the *Rational Buyer* procedure. Under the Rational Buyer procedure, the ISO may increase its purchases of one service, and reduce its purchases of another service, provided that the additional capacity for the first service meets the technical requirements of the second service. For example, in accordance with the quality ranking of the services, the ISO could buy more Spinning Reserve and less Non-spinning or Replacement Reserves, or more Non-spinning and less Replacement Reserves, as a way to reduce total A/S procurement costs. The ISO could also buy more 10-minute Regulation to substitute for Operating and Replacement Reserves, or more 30-minute Regulation and less Replacement. Rational Buyer thus allows the ISO to depart from predetermined, inelastic requirements for each service, and instead utilize the clearing sequence of markets and the quality ranking of services in a flexible way to minimize its total cost of procuring A/S. Rational Buyer will be one of the A/S redesign elements implemented in July 1999.

3.2.7 Stage 2 Alerts and Operating Reserve Shortfalls

During the 1998 summer, the electrical loads in California reached their highest levels ever. Although the new market responded to this challenge successfully and avoided any significant outages, there were a number of alerts declared, and the ISO was later cited for allowing operating reserves to drop below the levels required by the relevant reliability criteria. These episodes were important events in the development of the ISO's A/S markets, as they focused needed attention on how the operating reserves (O/R) are used and, therefore, bid. See Chapter 4 for further discussion.

O/R capacity bids include associated energy bids which are included in the BEEP stack, as discussed further in Chapter 4. During normal operations, the ISO dispatches energy from the BEEP stack without differentiating whether the energy bid is associated with an O/R bid. Thus, a participant in the O/R auction can bid its marginal cost of producing energy, and need not recognize an opportunity cost associated with providing O/R. During high-load periods, however, when the ISO anticipates inadequate BEEP resources, it skips over the O/R-associated energy bids. Thus, in precisely those periods when energy prices are highest, O/R capacity suffers an economic cost by not participating in the real-time energy market. This cost is likely to be reflected in the bids for O/R capacity, and may thus drive up the ISO's cost of procuring O/R.

In addition, this practice by the ISO makes the definition of O/R somewhat ambiguous, so that suppliers cannot accurately evaluate the likelihood of receiving an energy dispatch instruction.

The management of O/R remains an outstanding issue for the continuing improvement of the ISO's A/S markets and is included in the ISO's long-term redesign program.

3.2.8 Market Operations Software

Many of the problems that occurred over the past year resulted from unforeseen market impacts of specific details of ISO's market rules and protocols, and in particular of the necessary staging of certain functionalities. These impacts only became apparent as markets commenced operation. In most cases, the problems were quickly identified, and options for remedying the design flaws were developed and assessed. Other problems resulted from flaws, or merely unforeseen consequences, of the new, complex software systems that had to be built from the ground up to implement the unique design of the California market. In many cases, the complexity and uniqueness of the software systems, and of the interfaces between the ISO and the SCs, also prevented solutions from being implemented quickly, and required the ISO to make needed changes incrementally. Given the complex interrelationships among the different markets, the ISO has had to carefully assess potential indirect impacts of changes in market protocols and design before implementing them, further slowing the solution of market problems.

3.3 Demand for Ancillary Services

As the institution responsible for the reliable operation of California's bulk-power grid, the ISO must determine and procure the quantities of A/S it needs to fulfill this responsibility. This role is spelled out in the Ancillary Services Requirements Protocol (ASRP) of the ISO Tariff. The ASRP also spells out the responsibility of Scheduling Coordinators (SCs) to either self-provide their A/S requirement, or to pay for their share of the A/S capacity purchased by the ISO. In the original market design, which was in effect through the first year of operation, these charges were distributed in proportion to the balanced schedules submitted by the various SCs. The design has now been changed, and beginning in July 1999 the ISO will assess A/S charges based on metered demands.

3.3.1 Overall Demand for Ancillary Services

The ISO uses different procedures to calculate its requirements for the four services purchased in the A/S markets. Fundamentally, the demand for A/S is primarily a function of total system loads. Figures 3-1 and 3-2 show the ISO's average hourly market requirements for each of the A/S for the month of August 1998, both in terms of MW and as a percentage of total ISO system load. As shown in Figure 3-2, the combined demand for A/S in the peak summer months averaged about 4,000 MW per hour, or at least 13 percent of total system loads.

Figures 3-3 and 3-4 show these hourly averages for the month of February 1999. In these figures, requirements for upward and downward Regulation are shown separately, reflecting the fact that starting in September 1998, the ISO began specifying separate requirements for these two types of Regulation. It should be noted that unlike the other A/S, downward Regulation does not represent a capacity requirement that precludes use of this capacity in the energy markets. As shown in Figure 3-4, the ISO's total requirements for all ancillary services other than downward Regulation represent about 10 percent of total system loads, even in the winter months. Figure 3-3 also illustrates that the ISO procured 500 MW per hour of Replacement Reserves during the peak hours (hours ending 7 through 22), with no procurements at night.

A more detailed description of factors affecting the amount of each A/S purchased by the ISO is provided in the following sections.

Figure 3-1. Average Hourly Ancillary Service Requirements (Aug. 1998)

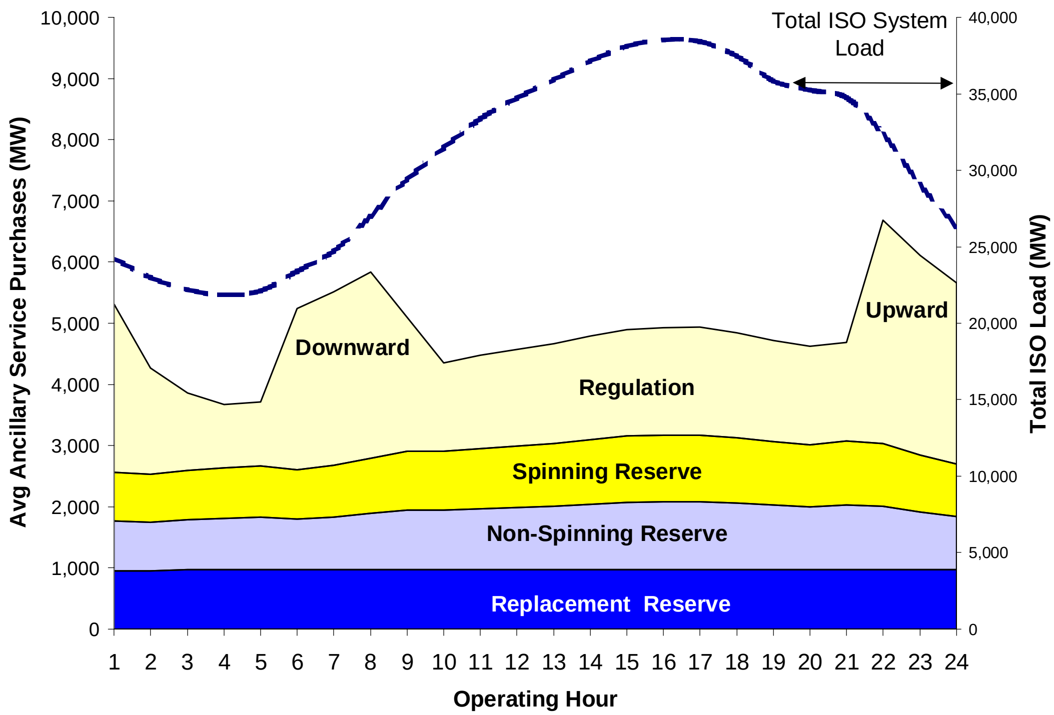


Figure 3-2. Average Hourly Ancillary Service Requirements as Percent of Total ISO System Loads (Aug. 1998)

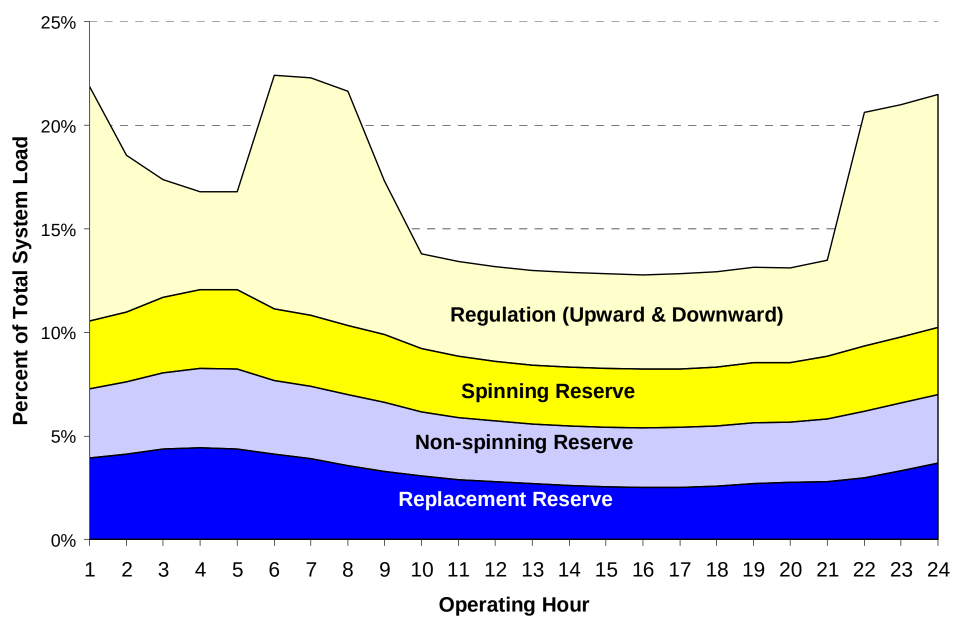


Figure 3-3. Average Hourly Ancillary Service Requirements (Feb. 1998)

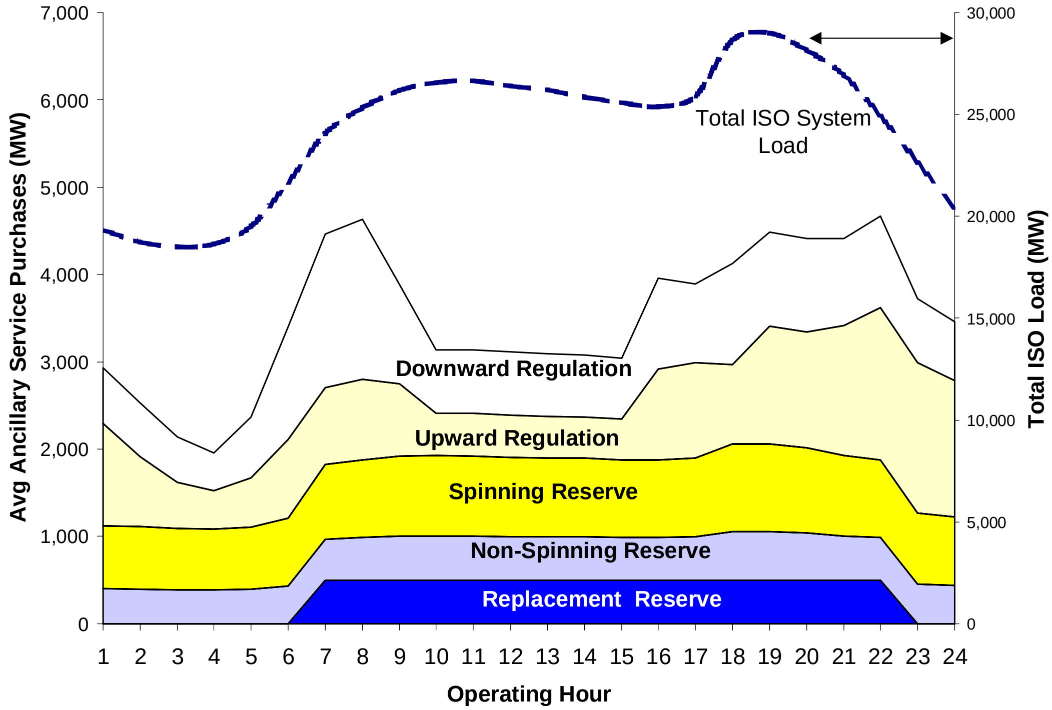
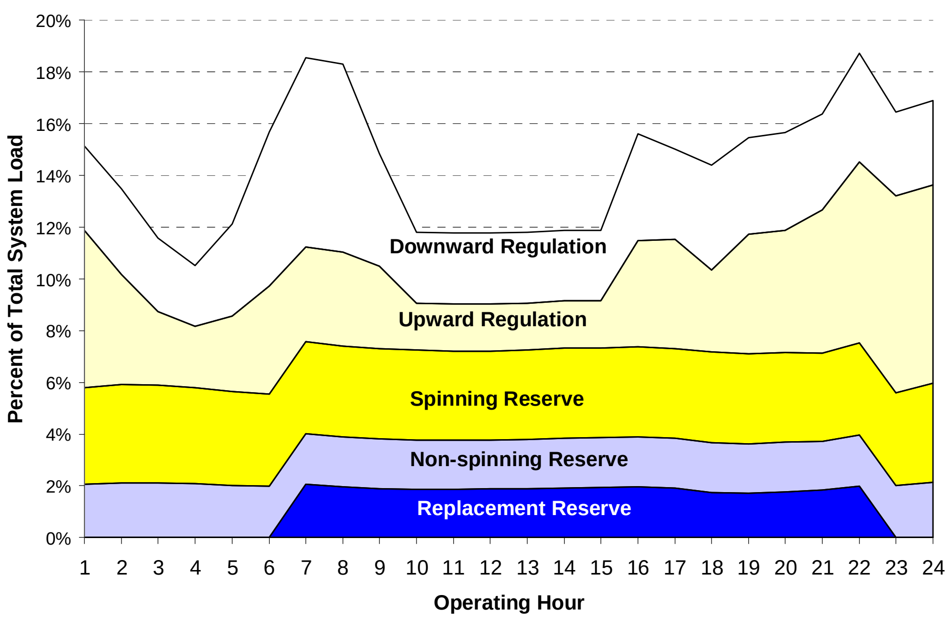


Figure 3-4. Average Hourly Ancillary Service Requirements as Percent of Total ISO System Loads (Feb. 1998)



3.3.2 Regulation Reserves

There is no established *ex-ante* formula for the ISO's requirements for Regulation. The Ancillary Services Requirements Protocol (ASRP) states that sufficient Regulation will be procured "to allow the ISO Control Area to meet the WSCC and NERC control performance criteria by continuously balancing Generation to meet deviations between actual and scheduled Demand and to meet interchange schedules." (ASRP 4.1.1) During the first months of the ISO's operations, until about June 15, 1998, the ISO needed on average 1,350 MW per hour of Regulation. During the summer peak, through the first week of September, Regulation requirements were substantially higher, averaging 2,020 MW per hour. ISO Regulation requirements then moderated, but have remained at an average of 1,850 MW per hour during the remainder of 1998 and the first quarter of 1999.

In general, the needs for Regulation relate to the size of the load, since load is subject to random variations to which Regulation responds. It is clear from Figure 3.1, however, that the ISO's Regulation requirement is not determined strictly by loads. Four other factors influenced the ISO's demand for Regulation during the 1998-99 operating year:

1. If there are large changes in loads during the day, there are periods during the "shoulders" of the peak period when many units are ramping up or down rapidly, and when flows across the interties between the ISO and neighboring control areas are changing rapidly and steadily. Because the ISO's schedules are balanced on an hourly basis, there will be large variations between the beginning and the end of each hour, which the ISO accommodates primarily with Regulation due to lack of adequate load following capability. The ISO's Regulation requirement thus tends to be highest not when loads are highest, but when loads are changing most rapidly, during the morning and evening ramps. Regulation demand is as much as 11-12 percent of load during shoulder hours, versus as low as 2-3 percent of load when load is more level during peak or off-peak hours.

2. The PX clears its forward energy market with no requirement or authority to enforce unit commitment constraints (start-up time, shut-down time, minimum up time, minimum down time, and ramp rate). When the PX participants commit their resources to meet the energy portfolio awarded, their schedules may not be achievable given their unit commitment constraints. They could fall short on some of these constraints and rely on the real-time market to make up the difference. This exacerbates the ISO's load following requirement which at present is served to a large extent by Regulation.

3. Faced with a shortfall of Regulation bids last June, the ISO expanded the acceptable capacity for Regulation to include that which could be converted to energy within 30 minutes of an AGC signal, rather than requiring10-minute response. The intent of this change was to increase the supplies of capacity that could be offered in the ISO auctions. A side effect was that the ISO needed to buy a larger quantity of capacity to maintain reliability. The latter effect explains at least in part why the ISO's Regulation requirements were substantially higher in late March 1999 than they were in early April 1998.

4. Beginning September 28, 1999, the ISO began procuring upward and downward Regulation separately, which allowed the ISO to more precisely match its service requirements to its actual needs, and should have reduced its total requirement. Since the ISO began doing this, market requirements for upward Regulation have averaged about 3 percent of total load

during most hours, but exceeded 7 percent during the late evening hours when load declines. Market requirements for downward Regulation have averaged about 2 percent of total load during most hours, but reach about 8 percent during the morning hours when system load increases.

3.3.3 Operating Reserves

The ISO's requirement for Operating Reserves (Spinning and Non-spinning) is the greater of (a) the largest single contingency, i.e., a single event involving the loss of a generation or transmission facility, or (b) 5 percent of the load served by hydroelectric resources plus 7 percent of the load served by other within-control-area resources. Loads served by firm imports do not contribute to the O/R requirements, whereas interruptible imports and on-call exports must be supported by 100 percent O/R, which must be self-provided by the SC scheduling the non-firm import or offering the export call.

In the original market design, the ISO O/R requirements were met with a 50-50 split of Spinning and Non-spinning reserves. Following CPS2 violations during the summer of 1998, however, the ISO was required to increase the Spin share of its O/R to 65 percent, so that Non-spinning Reserves accounted for 35 percent of O/R. This requirement extended through operating day May 5, 1999, after which the Spin share of O/R returned to 50 percent.

It is important to note that from the system reliability perspective, additional quantities of a "superior" A/S can substitute for an "inferior" A/S. Thus additional Spinning Reserve could be substituted for Non-spinning Reserve, and additional Non-spinning reserve could substitute for a comparable amount of Replacement reserve. This substitutability underlies the modifications to the ISO's sequential A/S auction process being implemented as part of the Rational Buyer procedure. Once the Rational Buyer procedure is implemented, the 50 percent Spin share will be a *minimum*, and the ISO will be able to buy a greater percentage of its O/R as Spinning Reserves, if that reduces the total cost of procuring A/S. The Rational Buyer protocols being implemented by the ISO are discussed in more detail in Section 3.8.

3.3.4 Replacement Reserves

The ASRP states that "the ISO needs sufficient Replacement Reserve to be available to allow restoration of Dispatched Operating Reserve within sixty minutes to its scheduled set point" (ASRP 6.1.1). In the original design, the ISO would forecast the likely dispatch of O/R, taking into account a variety of factors including anticipated shortfalls between scheduled demands and the ISO's load forecast, and patterns of generation and transmission outages. However, following high levels of Replacement Reserve purchases during the first two weeks of operation, the ISO established a pattern of constant day-to-day purchases of Replacement Reserves. Immediately following the price spikes of mid-July, the ISO first stopped purchasing Replacement Reserves, then resumed purchasing at lower levels. Since late September, the ISO has procured 500 MW per hour during the peak hours (hours ending 7 through 22), with no procurements at night.

Changes to the procedures for purchasing and charging for Replacement Reserves are an important part of the A/S market redesign, for implementation during the summer of 1999. These are summarized in Section 3.6.

3.4 Regulating Reserve

Of the four A/S procured by the ISO through day-ahead and hour ahead markets, Regulation capacity is the most scarce in terms of the number of units capable of providing the service. Demand for Regulation is also highest of all A/S, as discussed in the previous section.

During the first year of market operation, Regulation has also been the most costly A/S, in terms of both total costs and cost per MW of capacity. Regulation has also been, in many respects, the most problematic, with severe shortages of market supply during many hours in the early weeks of operation. These shortages led to the creation of an additional payment mechanism (REPA) and reliance on Reliability Must Run (RMR) units to ensure adequate supply.

3.4.1 Supply of Regulation Services

During the first two months of market operation, there was very little capacity bid into the Regulation market, and bid quantities were often substantially less than the requirements. This deficiency was primarily attributed to the fact that market participants were limited to FERC cost-based price caps for Regulation capacity, which ranged from $7.22/MW to $9.50/MW. Units subject to these caps were paid "as bid" for any capacity won in the Regulation market.[2]

A further disincentive to bidding into the Regulation market was that market participants did not expect to earn significant additional energy payments from Regulation. As explained in Chapter 2, units providing A/S may receive two payments, a payment to reserve the capacity and a payment for the amount of energy actually used in real time. Unlike other A/S, however, Regulation is designed to be a *zero energy service*, meaning that on average the net energy provided by Regulation capacity is zero. Although units providing upward Regulation were receiving the real-time imbalance energy price for any energy they generated for Regulation, real-time prices during these spring months were very low.

For hydro units with water storage capacity, the fact that the ISO has tended to rely on upward Regulation to meet load imbalances may represent a disincentive to participate in the Regulation market. For these units, the ability to provide upward and downward Regulation services in future hours may be decreased if they are frequently utilized in this way, rather than as a *zero energy service*. Hydro units in California are a key source of Regulation, although they account for only about 20 percent of the installed AGC capacity.

To compensate for the deficient market supplies of Regulation capacity, the ISO has called on generating units having Reliability Must Run Contracts (i.e., RMR Units).

3.4.2 Bid Sufficiency

A key indicator of the adequacy of supply in the ISO's A/S markets is *bid sufficiency*, or the amount of supply bids submitted as a percentage of the total quantity demanded. Virtually all price spikes in the ISO's A/S markets have occurred when bid sufficiency dropped below 200 percent. As bid sufficiency drops below 150 percent, the incidence of dramatic price spikes – which typically reach the ISO's $250 price cap – has increased exponentially.

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[2] A more appropriate payment for cost-based units would have been the minimum of the market clearing price and their cost based cap. This was not possible, however, due to limitations in the ISO's settlement software.

Figures 3-5 and 3-6 provide an overview of bid sufficiency in the Regulation market over the first 12 months of operation. For each month, these figures show the percentage of total peak and off-peak hours during which bid sufficiency levels reached the low levels at which most price spikes have occurred (less than 100 -percent, 100-150 percent, and 150-200 percent). Average bid sufficiencies are also shown, although it should be noted that at levels above 200 percent, the relationship between price and bid sufficiency diminishes significantly.

Figures 3-5 and 3-6 show that during April and May, there was a severe shortage of available bids for Regulation, with bid insufficiency occurring in over 80 percent of peak hours and 90 percent of off-peak hours, when demand for Regulation is highest.

In late May 1998 the ISO developed the Regulation Energy Payment Adjustment (REPA) to create a greater incentive for participation in the Regulation market. Under REPA, participants received the maximum of $20/MW or the ISO Hourly Ex-Post (real time) energy price for each MW of regulation capacity they provided, *in addition to* the capacity and energy payments they were receiving prior to REPA. REPA had an immediate and significant impact on the capacity bid into the Regulation auctions.[3] Figures 3-5 and 3-6 show how bid sufficiencies increased significantly from June to September as REPA was implemented and real time energy prices rose, thereby increasing the payment received by suppliers through REPA.

[3] At the same time, the ISO increased the required ramp time for Regulation from 10 minutes to 30 minutes. Some of the increase in bid quantities is therefore due to the fact that a number of units were now able to bid more capacity into the Regulation market.

Figure 3-5. Regulation Bid Sufficiency (Peak Hours)

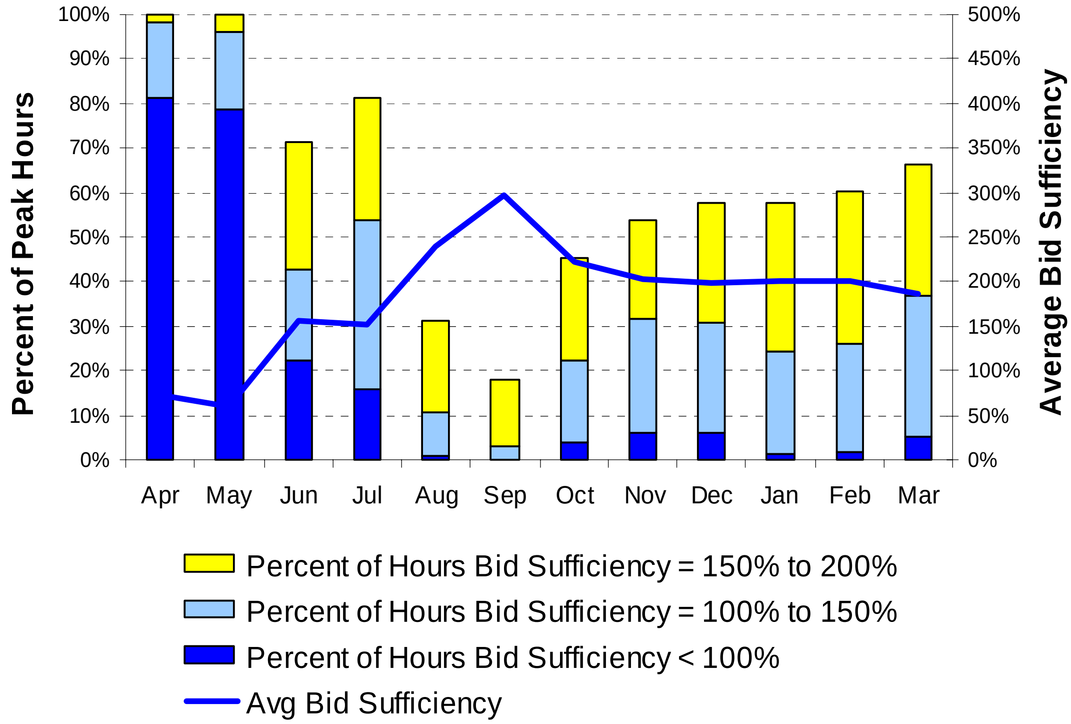
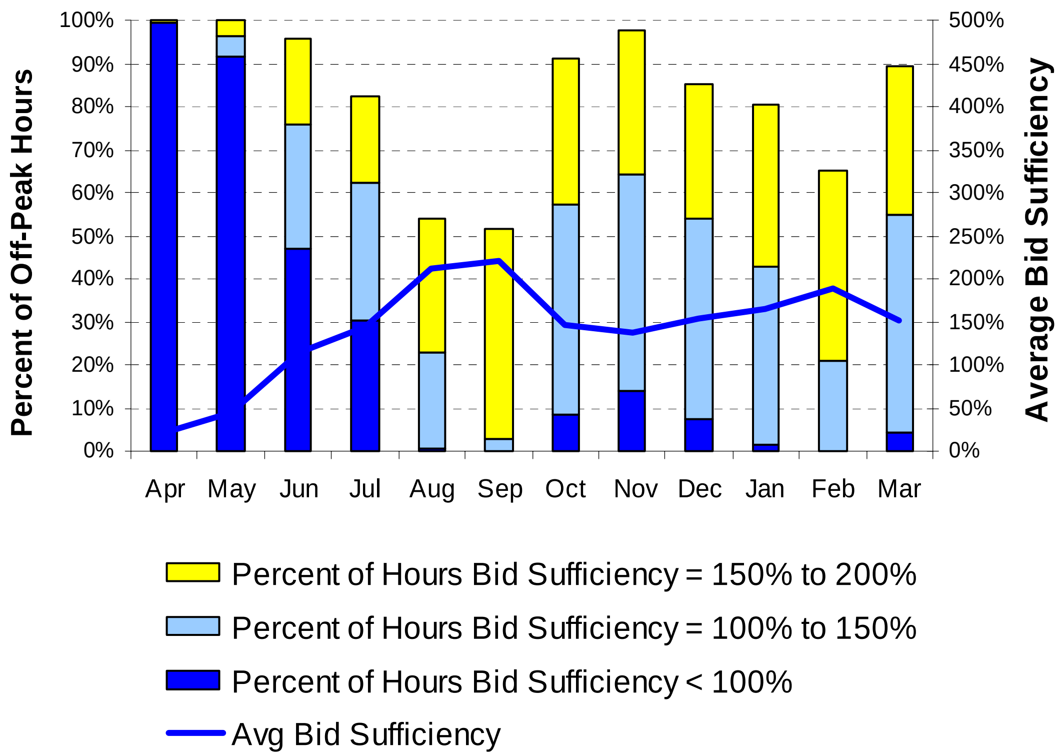


Figure 3-6. Regulation Bid Sufficiency (Off-Peak Hours)



3.4.2.1 Separate Procurement of Upward and Downwar d Regulation

The manner in which the ISO was initially procuring upward and downward Regulation had a significant impact on all A/S markets. Although the bids indicated the amount of upward and downward Regulation capacity the units could provide, the ISO's initial operating protocols and software did not establish separate requirements for upward and downward Regulation. Instead, the ISO determined an overall Regulation requirement for each hour, and then met this requirement by selecting Regulation bids based only on price, without regard to the mix of upward or downward regulation offered by each unit. In the end, however, the mix of upward and downward Regulation actually procured by the ISO would depend on the mix offered by the units accepted in the auction.

For example, under this procurement procedure, a capacity bid of –50 MW to +50 MW (representing 50 MW of downward and 50 MW) of upward Regulation), and a bid of –25 MW to +75 MW (25 MW downward and 75 upward) would both be considered as bids of 100 MW of Regulation. As a consequence, the ISO often found itself in situations where it had procured too little or too much Regulation in a particular direction.

This procurement approach also created problems in subsequent A/S markets, due to the sequential procedure for clearing these markets. The A/S markets are cleared sequentially, beginning with Regulation, followed by Spin, then Non-spin, and, finally Replacement. Any capacity a unit wins in one market is subtracted from that unit's capacity bids into subsequent markets. Thus all of the Regulation capacity awarded to a generation unit was subtracted from capacity bids for that same unit in subsequent A/S markets, without regard to the mix of *upward* and *downward* regulation in the accepted bid. In fact, the actual available capacity for other A/S from a unit providing Regulation is reduced only by the amount of *upward* regulation won.

A software change implemented on September 28, 1999 partially corrects both of these closely related Regulation problems. With the new software, separate requirements are set for upward and downward Regulation, and these requirements are procured separately. In addition, the new software only subtracts the accepted quantity of upward Regulation from the bids submitted in subsequent A/S markets. Unfortunately, protocol limitations precluded the possibility of setting separate market clearing prices (MCPs) for upward and downward Regulation. Instead, all Regulation capacity is still settled at a single price, which equals maximum of the MCP for downward Regulation and the MCP for upward Regulation. This problem will be corrected with the FERC approval of Amendment 14 to the ISO's Tariff and implementation of the summer 1999 A/S market redesign elements.

3.4.2.2 Supply and Demand for Upward and Downward Regulation

As shown in Figures 3-1 through 3-4, the demand for upward Regulation increases significantly in hours 19-24, while demand for downward Regulation is extremely high during hours 6-9. These demand patterns reflect the ISO's use of Regulation capacity as a *load following* product. In order to meet the peak morning loads, imports on the interties and in-state generation begin ramping up several hours in advance, in the early morning hours. This causes an over-generation condition, which the ISO mitigates by backing down those units that provide downward Regulation. Similarly, in the evening hours generation and imports on the interties start ramping down several hours prior to the sharp drop in load that occurs in the last few hours of the day.

For these hours, an under-generation condition exists which the ISO mitigates by ramping up the units that provide upward Regulation.

It is important to note that the load patterns which create high demand for upward and downward Regulation during certain hours, also tend to limit the amount of these services bid into the market at those times. For example, at times when generating units are ramping up to be ready to meet anticipated loads, they do not want to be directed to back down. Figures 3-7 and 3-8 show average hourly bid sufficiencies for upward and downward Regulation, for the months of October 1998 through March 1999, which corresponds to the period over which the ISO has specified separate requirements for these two services.

Figure 3-7 shows that the supply of upward Regulation has been below 150 percent over 30 percent of the time during the hours of 19-22, when demand for upward Regulation is highest and supply the lowest. Bid sufficiency for downward Regulation continues to be low during the early morning hours, as shown in Figure 3-8. Insufficient supply of downward Regulation has occurred nearly 20 percent of the time during operating hours of 6 to 8. This pattern is due to the fact that most generation that is on-line during the early morning hours is operating at a very low level, and therefore is not capable of providing much downward Regulation. As these units ramp up to meet morning loads, more downward regulation gradually becomes available. As a result of these patterns, price spikes in Regulation tend to occur almost exclusively during these two sets of hours. A more detailed discussion of trends and spikes in Regulation prices is provided in the next section.

Figure 3-7. Bid Sufficiency in Upward Regulation Market (Oct. 1998-Mar. 1999)

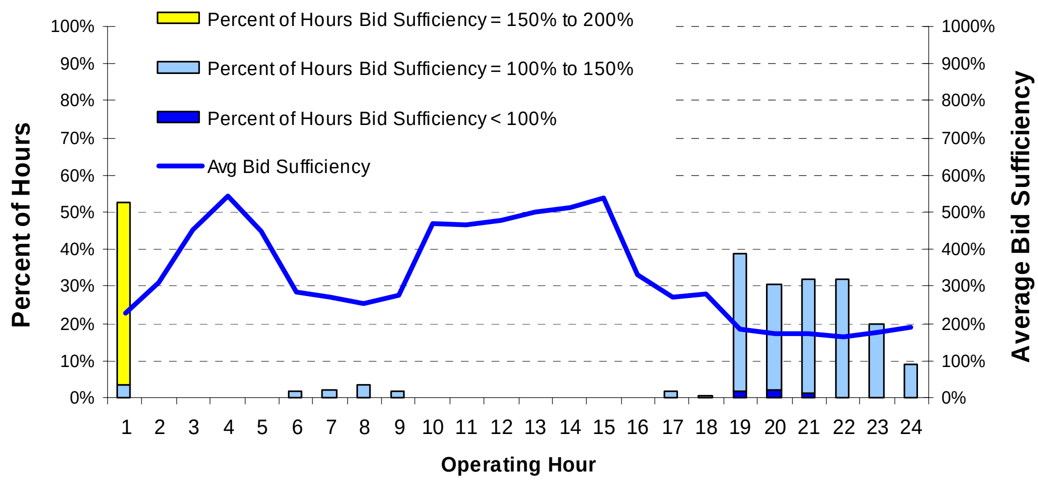
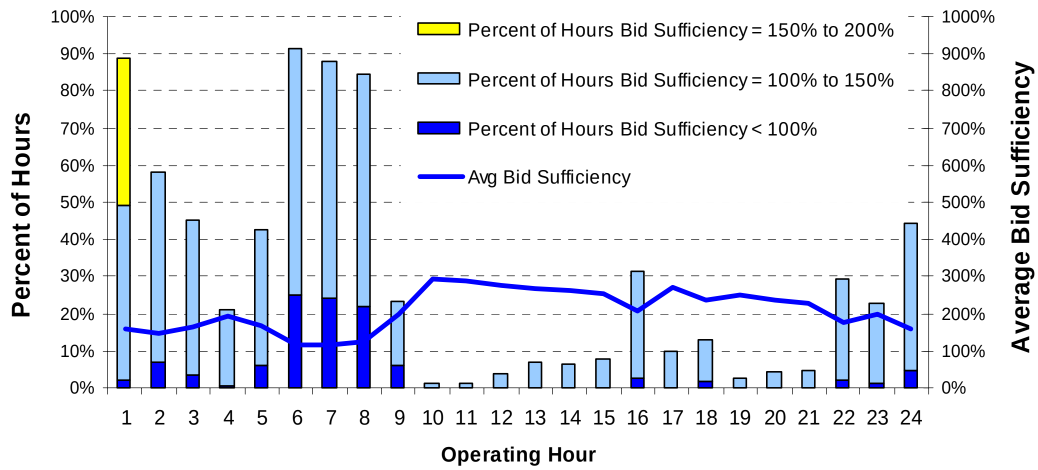


Figure 3-8. Bid Sufficiency in Downward Regulation Market (Oct. 1998-Mar. 1999)



3.4.3 Regulation Prices

Figure 3-9 shows the market clearing prices for the day-ahead Regulation market for the first three months of operation. From April 1 to June 10, Regulation prices averaged about $10/MW, as most participants were constrained to bidding cost-based caps which were under $10/MW. On June 10, 1998, FERC authorized new cost-based caps of $244/MW for one unit recently purchased by a new generator owner. This unit frequently set the MCP for regulation during the last few weeks of June and the first part of July.

FERC authorized A/S market based rate authority for AES on June 30, 1998, and for Houston Industries and Dynegy on July 10, 1998. In the same orders FERC also declared that Replacement Reserve was not an A/S and thus not subject to cost-based caps. This meant that all market participants could bid into the Replacement market at any price, and they did. Dramatic price spikes occurred in the Replacement Reserve markets on July 9 and July 13, which caused the ISO to impose a $500/MW A/S price cap effective July 14. The cap was later changed to $250/MW, to be consistent with the existing $250 price cap on the real time energy market. As shown in Figure 3-9, these price caps were hit frequently in the Regulation market during July and August.

During the month of September, however, competition to earn REPA payments intensified and caused Regulation capacity prices to be driven to zero for most hours. Regulation prices remained at zero for most hours during October and the first week of November. There were occasional price spikes, however, particularly during the middle part of October. As discussed earlier, the ISO started procuring upward and downward Regulation separately beginning on September 28. This new procedure tended to exacerbate bid insufficiency and was the main cause of the October price spikes.

Competition for REPA payments was very intense during the months of October and November. During October, some participants discovered that the ISO's market software would accept negative bids for A/S capacity. Generators who submitted negative bids were able to get all of their capacity accepted, whereas those submitting zero bids often had only a portion of their bids accepted. On November 5, the ISO reminded market participants that they could bid negative prices for A/S, and by November 8 the ISO began to see negative prices for Regulation capacity. Also, in October FERC issued an order granting all market participants market based rate authority for A/S capacity, effective November 3. With this ruling, coupled with the negative prices for regulation, the ISO and its Governing Board eliminated REPA payments as of November 28, 1999.[4] The effect on market clearing prices of eliminating REPA can be seen in Figure 3-10. For the month of December, Regulation market clearing prices averaged approximately $27/MW for SP15 and $24/MW for NP15.

[4] The ISO Board retains the authority the re-instate or set a new REPA payment under its tariff.

Figure 3-9. Regulation Market Clearing Prices

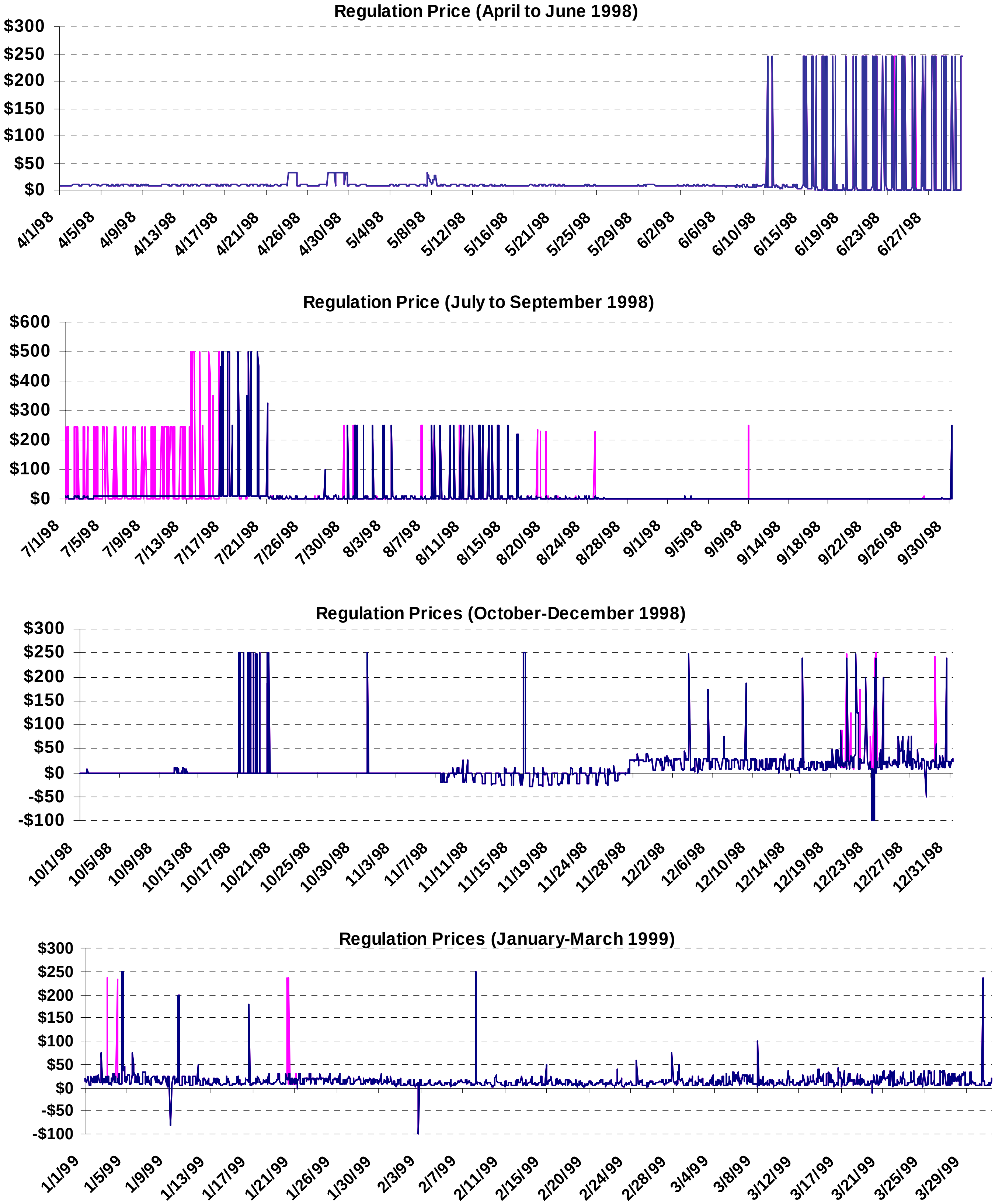


Figure 3-10. Effect of Eliminating REPA on Regulation Prices

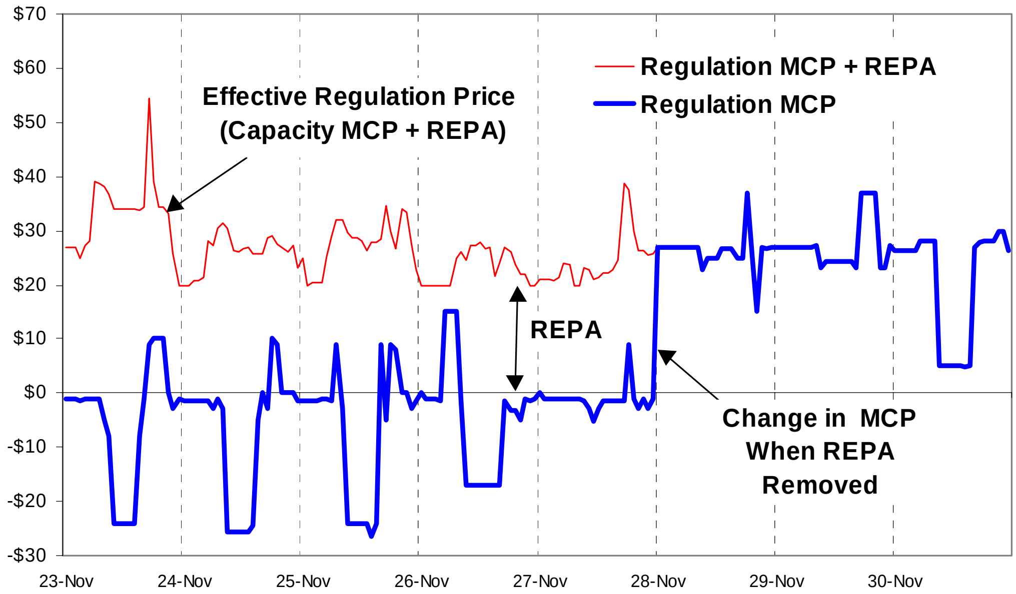
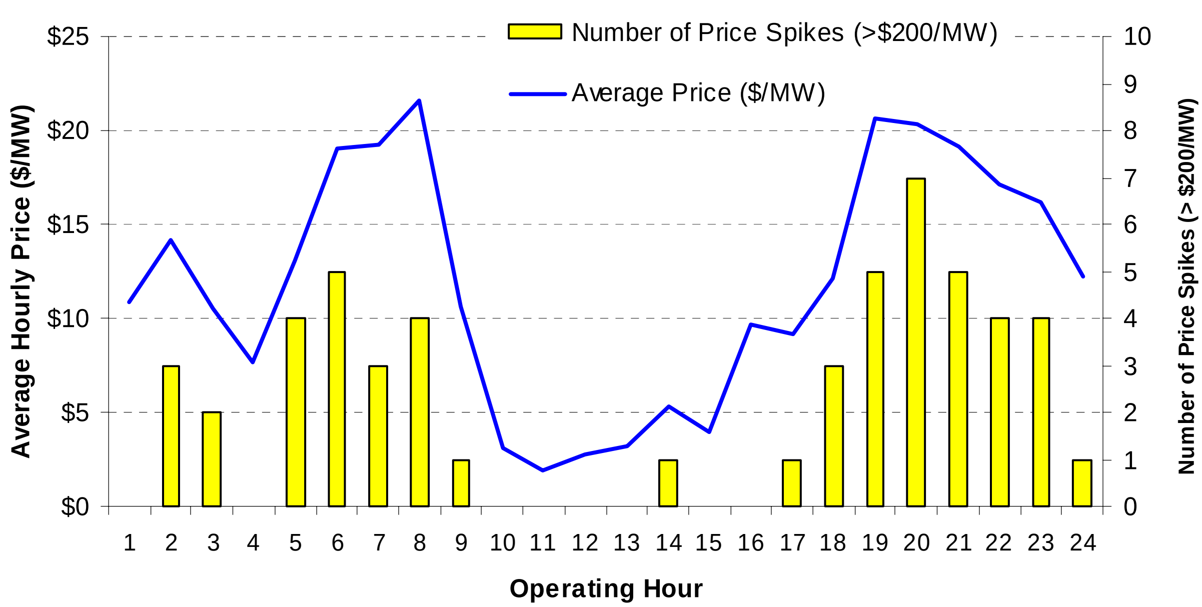


Figure 3-11. Average Prices and Price Spikes in Regulation Market

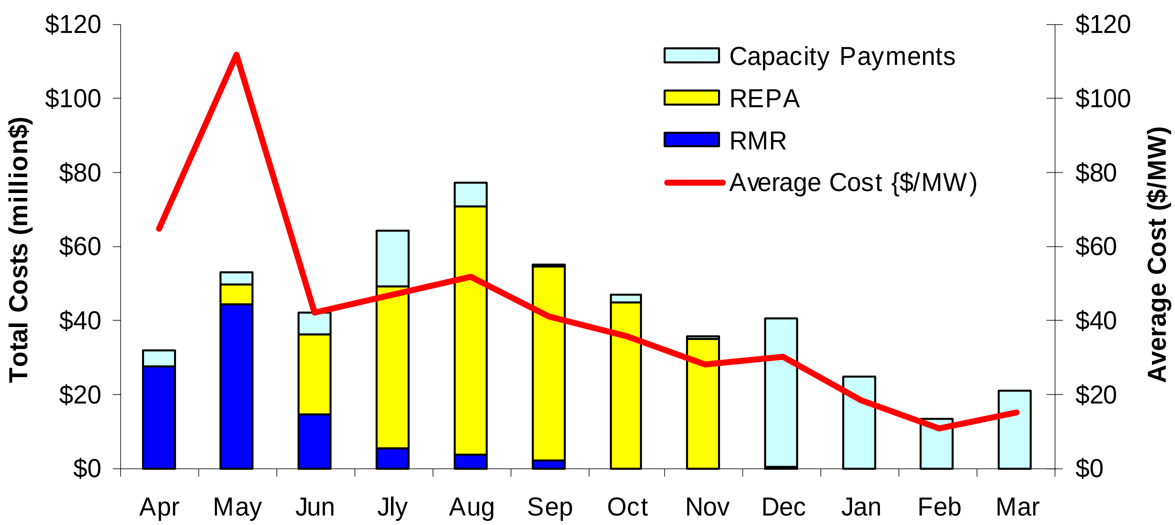


3.4.4 Regulation Costs

Over the first year of operation, the ISO spend approximately $500 million dollars on Regulation capacity, which represented about 70 percent of total A/S expenditures. Figure 3-12 shows the breakdown of monthly Regulation costs into three components: Regulation capacity procured in the day ahead market, REPA, and the cost of utilizing RMR units used to provide Regulation. During the first two months, RMR calls constituted most of the supply and hence the cost of Regulation. Once REPA was implemented, RMR costs declined dramatically as the market provided almost all of the needed capacity. During summer and early fall, competition for high REPA payments caused the capacity price of regulation to decline, and REPA made up almost all of the cost Over the year, the cost of regulation averaged about $34/MW.[5]

Figure 3-12 also demonstrates the average revenues earned by suppliers of Regulation. During the first two months, average revenues for Regulation capacity were approximately $8/MW. During the period REPA was in effect, average revenues increased to roughly $37/MW. Given this dramatic increase in revenues, it is not surprising that supplies to the Regulation market increased so significantly once REPA was implemented. After REPA was eliminated on November 28, 1998, average revenues fell to approximately $19/MW of capacity.

Figure 3-12. Total Monthly Cost of Regulation



[5] Average cost based on total costs (regulation from RMR units, capacity purchased through the market, and REPA payments) divided by total capacity purchased in the day-ahead market and capacity dispatched under RMR contracts.

3.5 Spinning, Non-Spinning and Replacement Reserve

3.5.1 Reserve Supplies

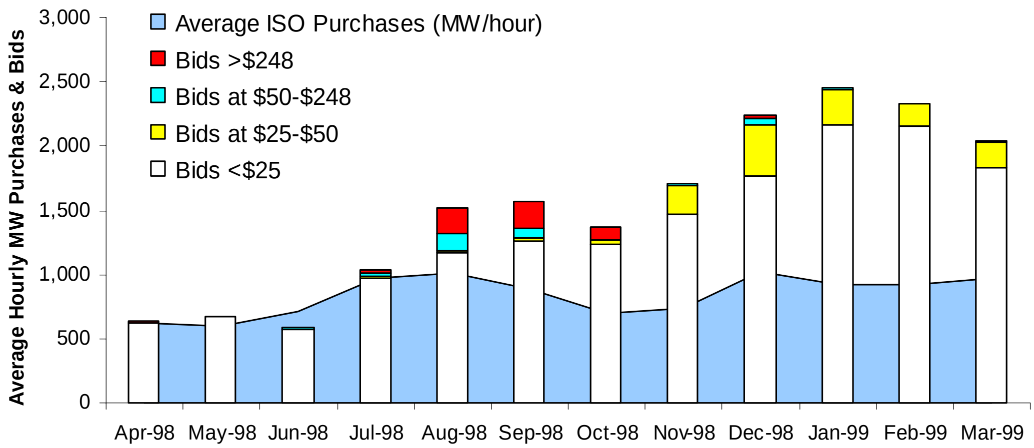
Figures 3-13 through 3-15 show the average hourly capacity bids (quantities offered in various price intervals) for the three reserve services which contribute bids to the supplemental-energy market, as well as the average quantities the ISO purchased. These figures suggest that overall supply conditions have improved significantly over the first year of operations, in terms of both the total supplies available and the prices at which those supplies were bid. At the same time, the display of average supplies hides a significant number of episodes when capacity was in much tighter supply, episodes during which many suppliers may have recognized and exercised the ability to set high market prices.

On average, there has been plenty of capacity available at relatively low prices (i.e., below $25/MW), particularly since September, 1998. Both total supplies, and the capacity bid at or below $25/MW, increased throughout the fourth quarter of 1998, during both peak and off-peak hours.

During the first quarter of operations, almost no reserve capacity was offered at prices above $25/MW. Although there was, on average, sufficient bid capacity in Non-Spinning and Replacement Reserves, the supplies offered in the Spinning Reserve auctions where often near or below the ISO’s total requirements, particularly during the peak hours. In July 1998, significant supply capacity received the right to bid and receive market-based rates for A/S capacity. With total bid capacity not substantially above the ISO’s requirements, on average, a number of these suppliers set bid prices at high levels, a practice that persisted through October. For the remainder of the first operating year, almost no capacity has been bid at prices above $50/MW in the Spinning Reserves auctions, and very little in the Non-spinning and Replacement Reserve auctions.

The fact that some capacity is bid at high prices in all of the markets suggests that suppliers believe there is a significant chance of such bids being accepted and a high price established for all accepted capacity. As will be seen below, however, during January 1999, when there was measurable capacity bid at or near the $250/MW cap in the Non-spinning and Replacement auctions, there were very substantial supplies available at low prices, so that market-clearing prices remained well below $5/MW.

Figure 3-13. Average Bid Quantities and Prices – Spinning Reserves, Peak Hours



Average Bid Quantities and Prices – Spinning Reserves, Off-Peak Hours

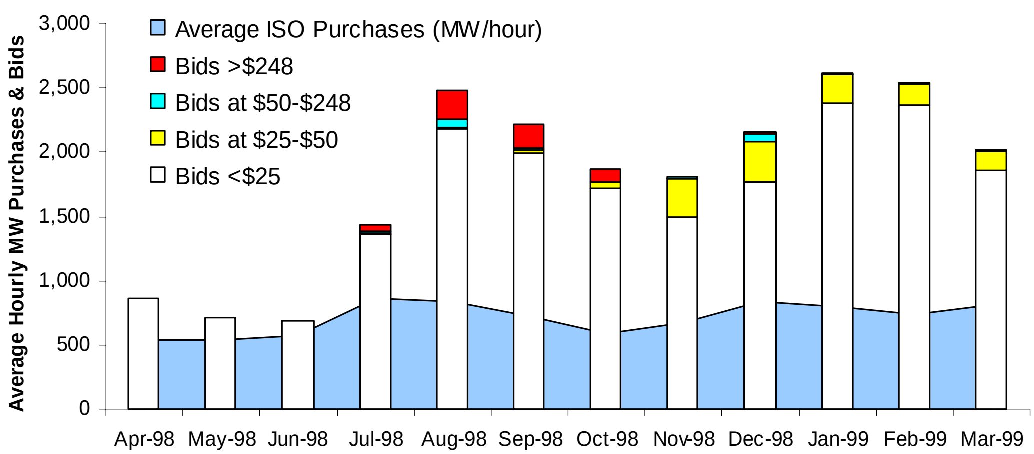
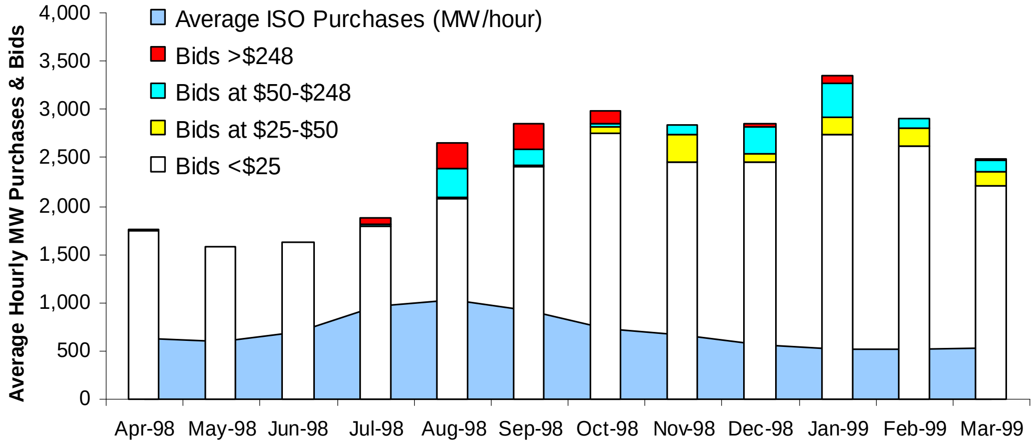


Figure 3-14. Average Bid Quantities and Prices – Non-spinning Reserves, Peak Hours



Average Bid Quantities and Prices – Non-spinning Reserves, Off-Peak Hours

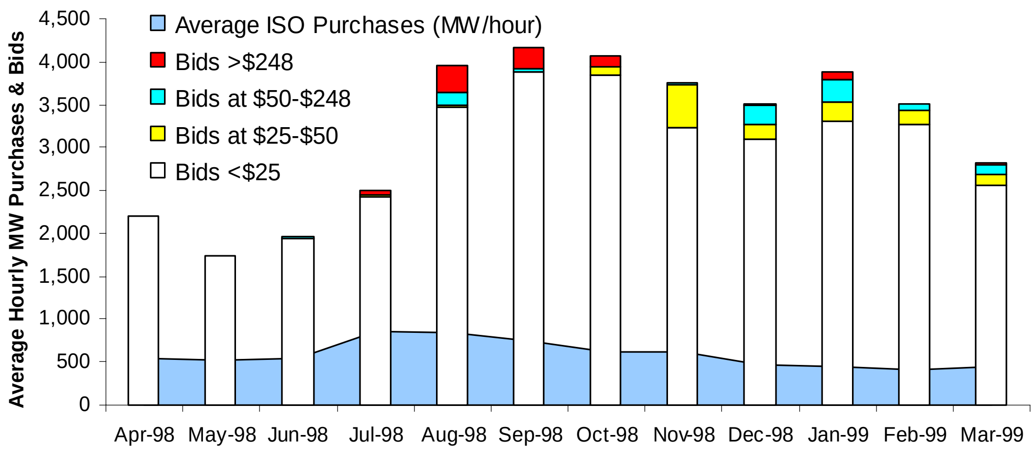
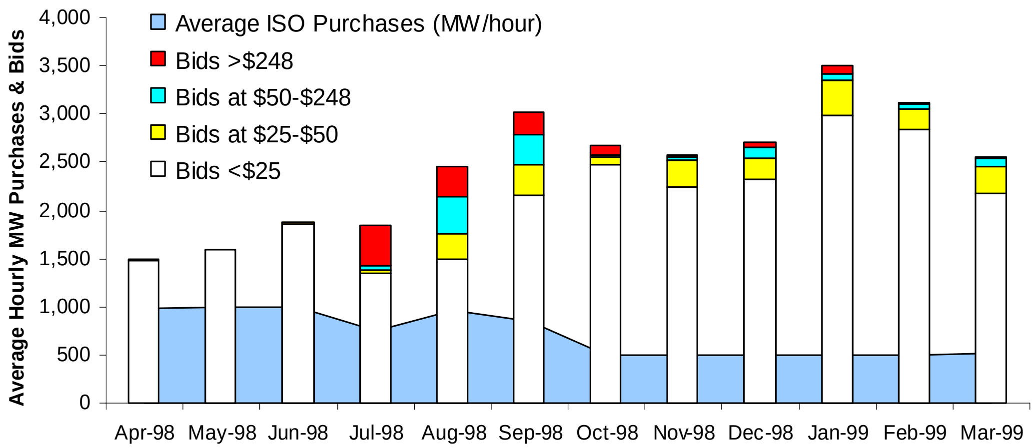
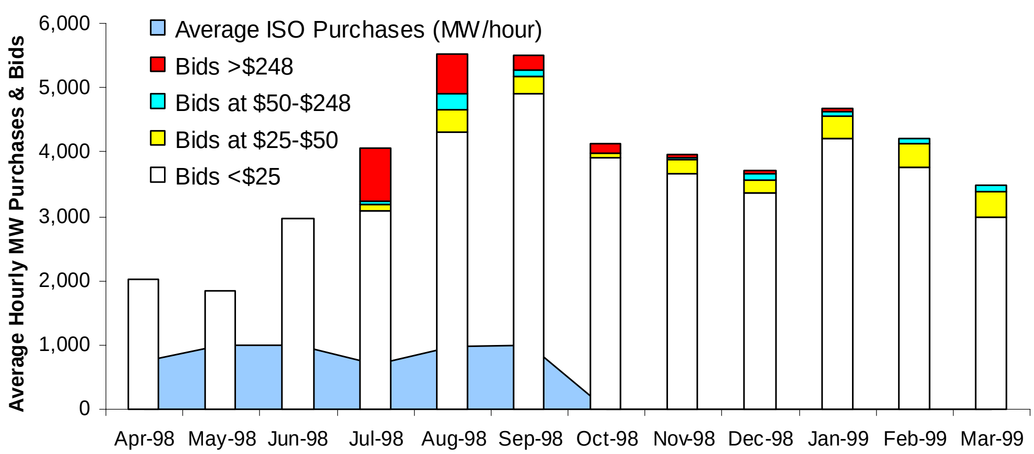


Figure 3-15. Average Bid Quantities and Prices – Replacement Reserves, Peak Hours



Average Bid Quantities and Prices – Replacement Reserves, Off-Peak Hours



3.5.2 Bid Sufficiency

Although average quantities of bid capacity were generally large relative to the ISO's capacity requirements, there were numerous time periods when supplies were not sufficient either to meet the ISO's requirements or to encourage competitive bidding. These time periods may be identified through *bid sufficiency ratios,* or the fraction of market requirements that are met by bid capacities.

Bid sufficiency ratios help to identify instances when a single supplier could be *pivotal*, i.e., able to drive prices to high levels by bidding capacity at extremely high prices, which are not based on either the direct or indirect opportunity cost of providing ancillary services. In such instances, the ISO's price caps may be the only limit on market clearing price. During hours when the bid sufficiency ratio is less than 100 percent, sufficient capacity is not offered in the market at any price, and all bidders in the market are pivotal; indeed, all bidders can set a high price without reducing their own supplies at all. If the bid sufficiency ratio is greater than 200 percent, then it is unlikely (but not impossible) that a single supplier would be pivotal. Even if a single supplier were to withhold all of its capacity from the market, the capacity offered by the other suppliers would generally still be adequate to result in a competitive price. For bid sufficiency ratios between 100 percent and 200 percent, some bidders could often be pivotal.

The solid lines in Figures 3-16 to 3-18 show the average levels of bid sufficiency. During the first spring and summer of operations, supplies were often inadequate to permit the operation of functional markets for any of these ancillary services, particularly during peak hours. Average bid sufficiency in the Spinning Reserve market (Figure 3-16) was below 150 percent through July. During 30 percent of the peak hours in July, bid sufficiency in the Spinning Reserve market was below 100 percent, so that any supplier could have set an arbitrarily high price (subject to the ISO's price cap).

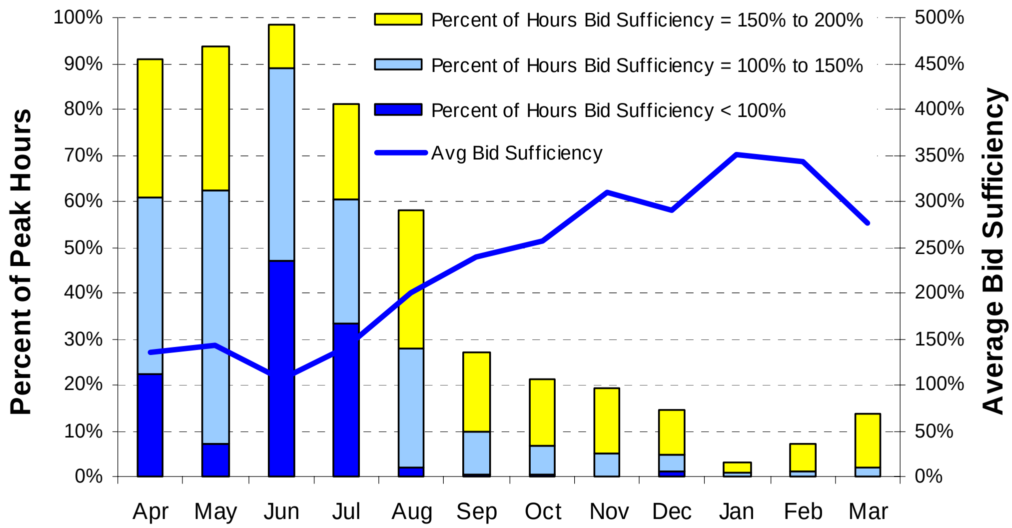
While bid sufficiency was higher in the remaining A/S markets, there was significant incidence of potentially non-functional markets. During July, bid sufficiency in the Non-spinning Reserve market was below 150 percent more than 30 percent of the peak hours, and below 200 percent in over half of the peak hours (Figure 3-17).

In the Replacement Reserve market, average levels of bid sufficiency were generally higher, exceeding 200 percent in all months. Nevertheless, in July there was absolute bid insufficiency (ratios below 100 percent) in over 15 percent of the peak hours. During these hours, prices in that market in particular were set at very high levels, as discussed in more detail below.

Since the end of the summer peak, bid sufficiencies in all markets have been generally high. There have, however, been a few hours in all markets in which bid sufficiencies have dropped below 200 percent, and there have been occasions of absolute bid insufficiency which have contributed to a few short-lived price spikes, particularly during the winter peak in late December.

The relationship between bid sufficiency, bidding behavior, and price outcomes is closely related to the analysis of market power discussed further in Chapter 7.

Figure 3-16. Bid Sufficiency Levels – Spinning Reserves, Peak Hours (7-22)



Bid Sufficiency Levels – Spinning Reserves, Off-Peak Hours (1-6, 23-24)

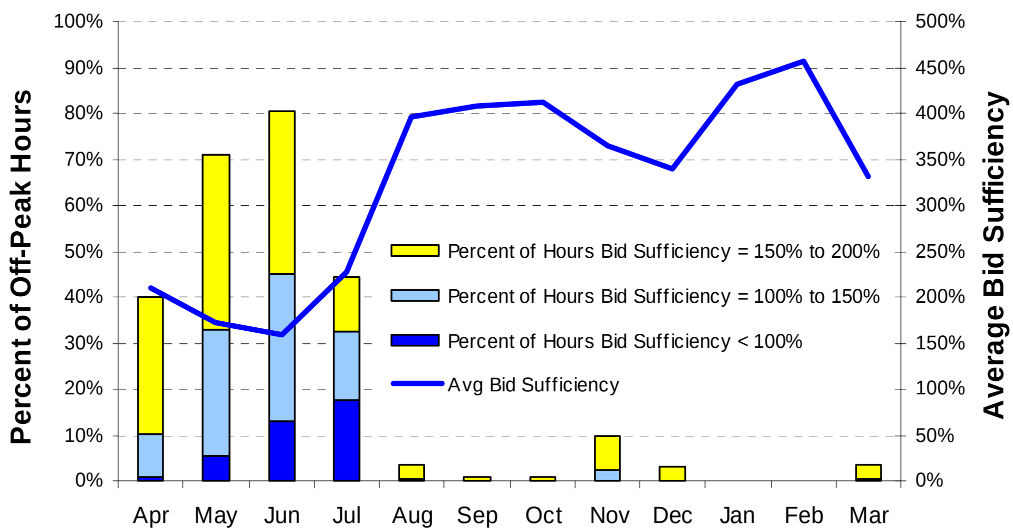
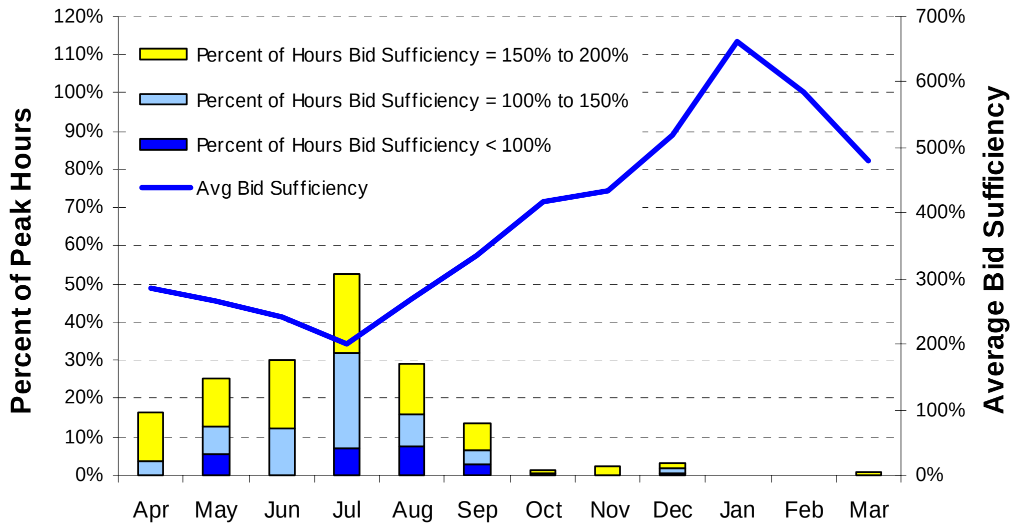


Figure 3-17. Bid Sufficiency Levels – Non-spinning Reserves, Peak Hours (7-22)



Bid Sufficiency Levels – Non-spinning Reserves, Off-Peak Hours (1-6, 23-24)

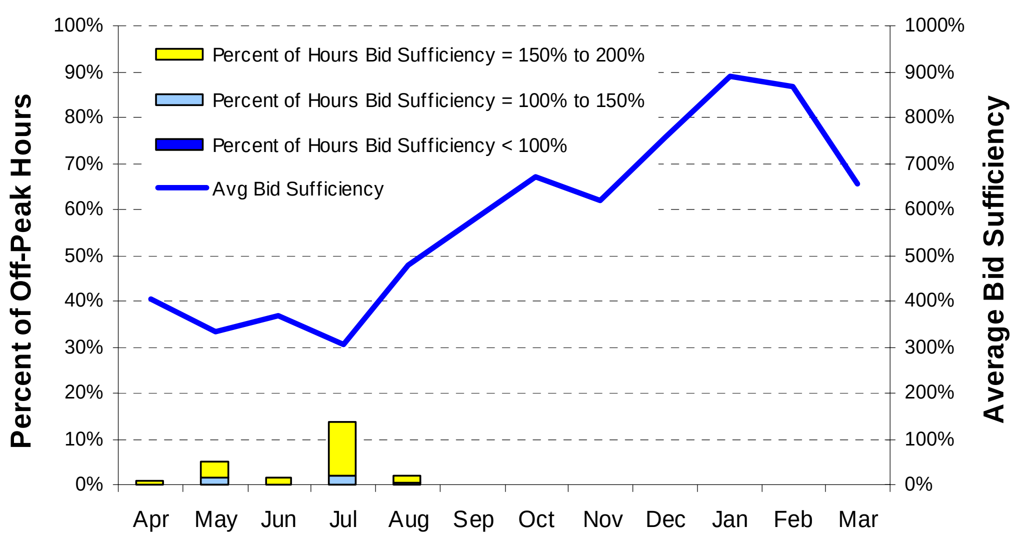
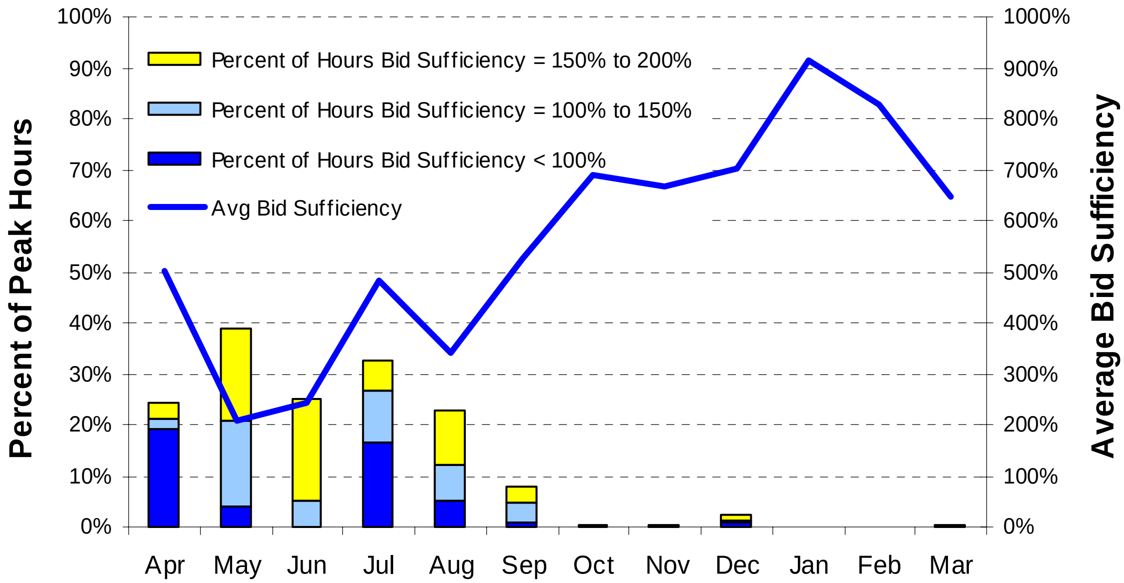
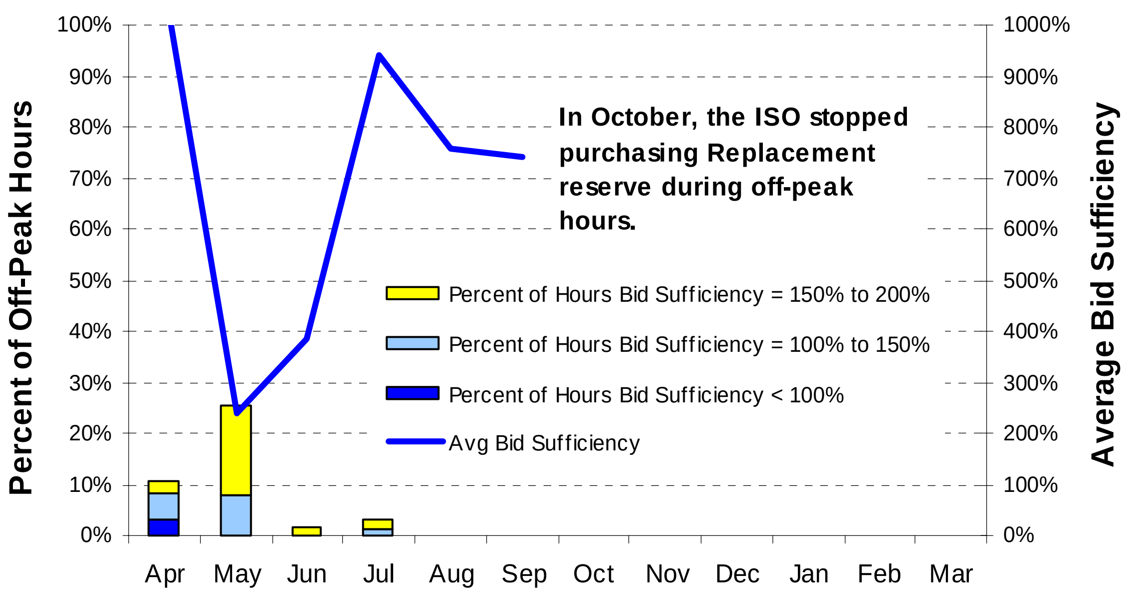


Figure 3-18. Bid Sufficiency Levels – Replacement Reserves, Peak Hours (7-22)



Bid Sufficiency Levels – Replacement Reserves, Off-Peak Hours (1-6, 23-24)



3.5.3 Ancillary Service Imports

Due to software limitations, during the first five months of operation the ISO was unable to accept bids for Spinning, Non-spinning and Replacement Reserves from outside its control area. Resources outside the ISO control area are a potentially important source of both real-time energy and A/S capacity. Imports of Operating Reserves (O/R, which include Spinning and Non-spinning Reserves) and Replacement Reserves began on August 6, 1998. Regulation cannot yet be imported. Importing of Regulation requires dynamic scheduling and control, and is included in ISO's longer term A/S redesign and implementation program.

Figures 3-19 to 3-21 show the average daily profiles of bid volumes, domestic and imports, submitted into the ISO A/S markets for Spinning, Non-spinning, and Replacement Reserves, respectively, from August 1998 through March 1999, along with the daily profiles of A/S procurement requirements. The A/S capacity bid by importers has tended to increase, so that by the first quarter of 1999 a good portion of the requirements could have been met by imports. The ISO is currently limiting its imports of O/R to 25 percent of its total requirement, however. This limitation is due in part to a reliability risk, which stems from the present inability to guarantee adequate available transmission capacity for imports during contingencies, which in turn could prevent imported reserves from being available within 10 minutes of a contingency.

Figure 3-22 shows a duration curve of O/R imports as a percentage of the ISO's total O/R requirements for all hours from August 1998 to March 1999. During this period, the ISO's 25% limit on imports of O/R was binding during about 4% of the time, representing a total of 290 hours. During about 60% of these 290 hours, virtually all O/R imports were from the Pacific Northwest. However, during about 40% of these hours, O/R imports were dispersed across three very different exporting regions:

- The Pacific Northwest (through the California-Oregon Intertie and the Pacific DC Intertie);
- The Southwest (through the Palo Verde substation in Arizona and through substations in the Las Vegas area); and
- Los Angeles (through Los Angeles Department of Water and Power, which is outside the ISO control area and is therefore treated as an importer of A/S).

Figure 2-23 summarizes share of O/R from each of these regions during the 290 hours in September and October when O/R imports were limited by the 25% constraint on O/R imports.

The ISO has recently changed its policy to allow imports of up to 50 percent of its O/R requirement. However, it should be noted that immediate impact of this change in the ISO's O/R import policy may be relatively small, since the 25% limit on imports of A/S has only been binding primarily during fall months and off-peak hours when A/S prices have been relatively low.

A more substantial obstacle to greater imports of O/R (and of Replacement Reserves) is the inability of sellers to secure unloaded intertie capacity for use only in the event of a dispatch from the ISO. Under current intertie management policy, unused capacity is released for use by energy, so that in the presence of congestion, reserve services cannot be imported. In a fully integrated market design, A/S would be permitted to compete with energy for access to transmission capacity.

Figure 3-19. Import and Domestic Capacity Bids for Spinning Reserves

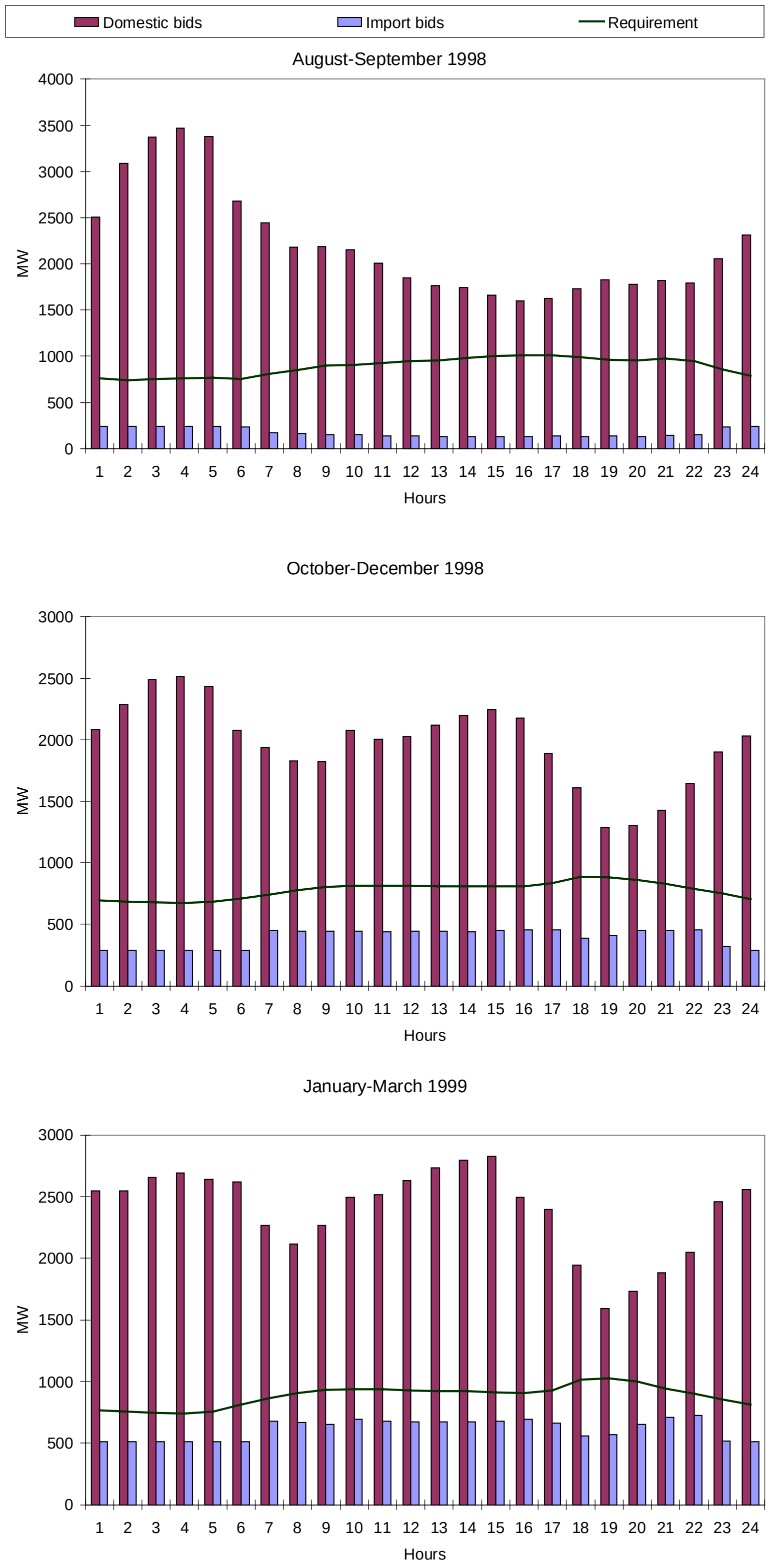


Figure 3-20. Import and Domestic Capacity Bids for Non-Spinning Reserves

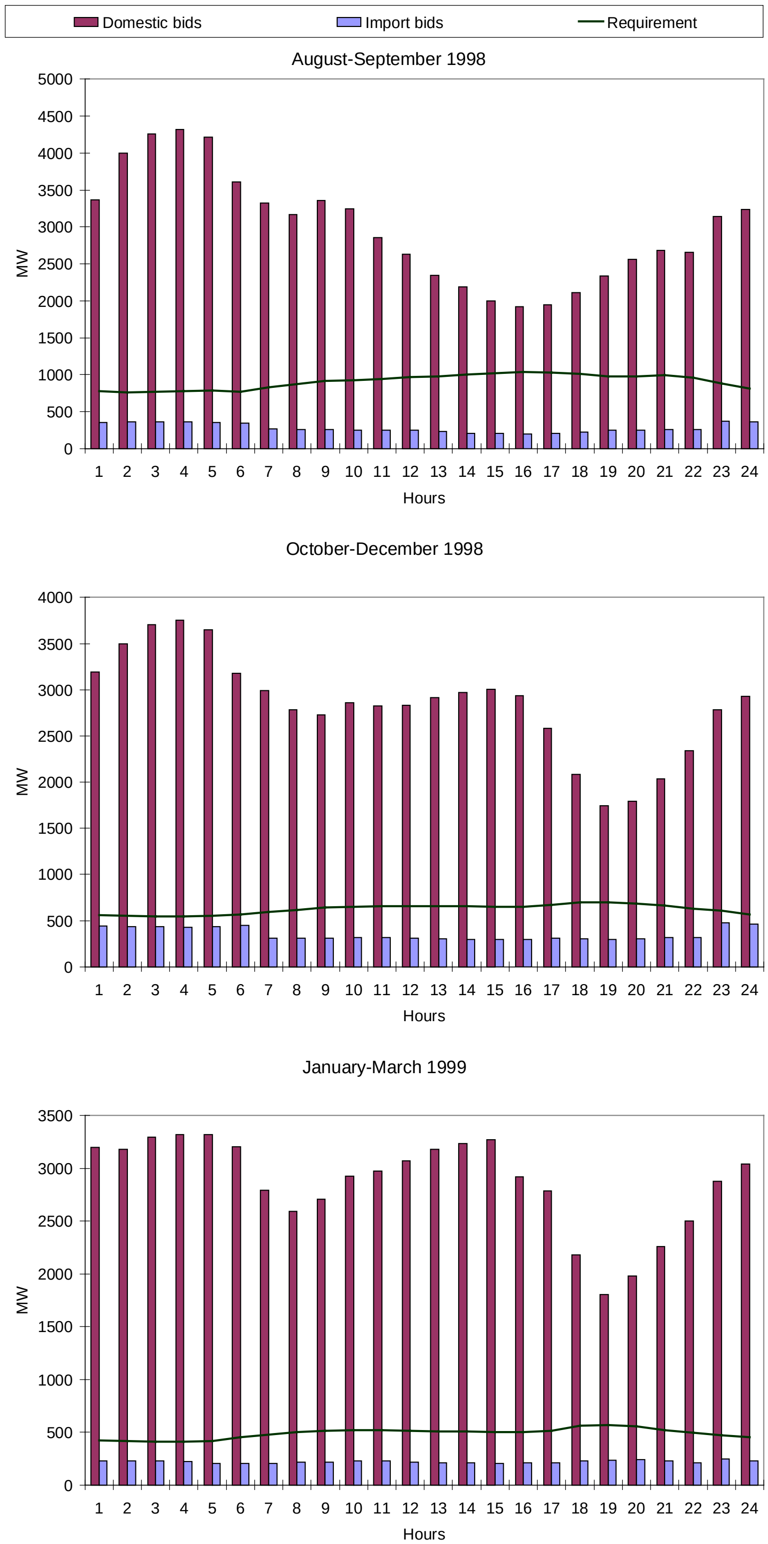


Figure 3-21. Import and Domestic Capacity Bids for Replacement Reserves

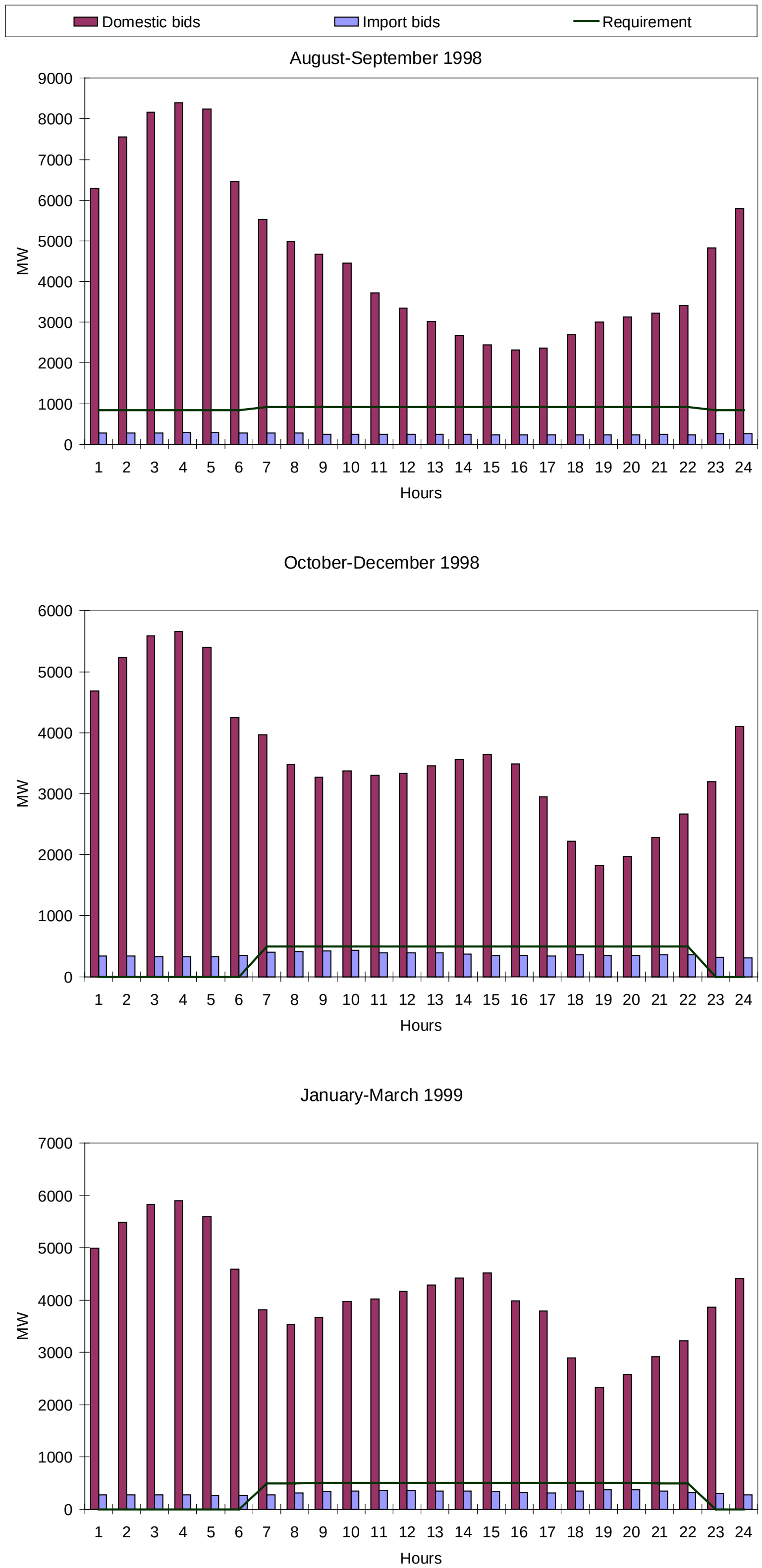


Figure 3-22. Operating Reserve Imports as a Percent of Total Requirements (Aug. 1998 – March 1999)

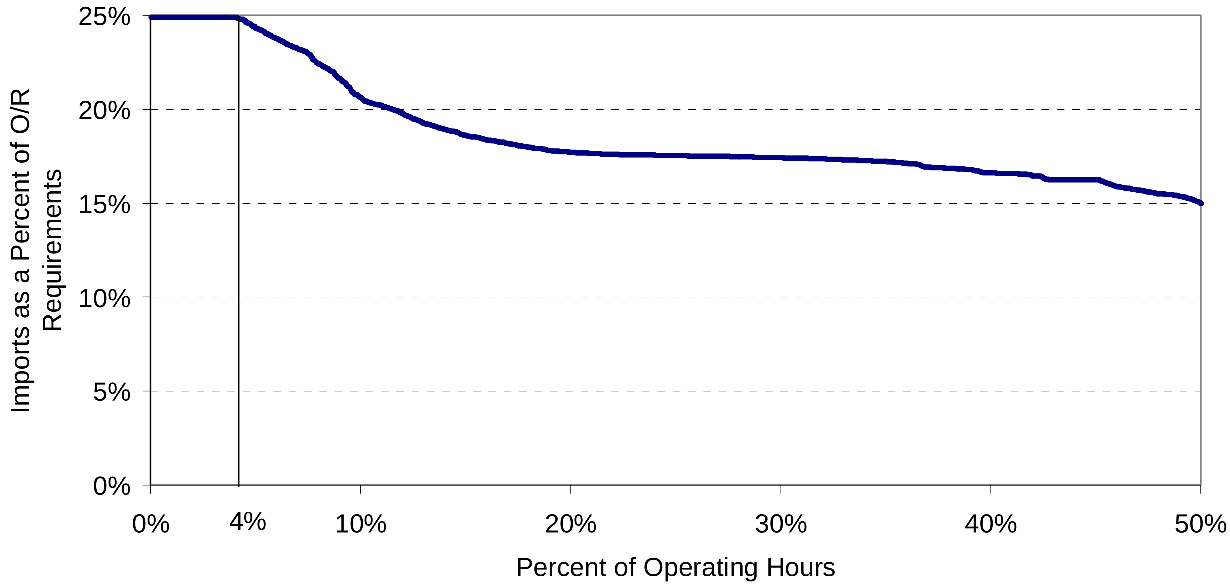
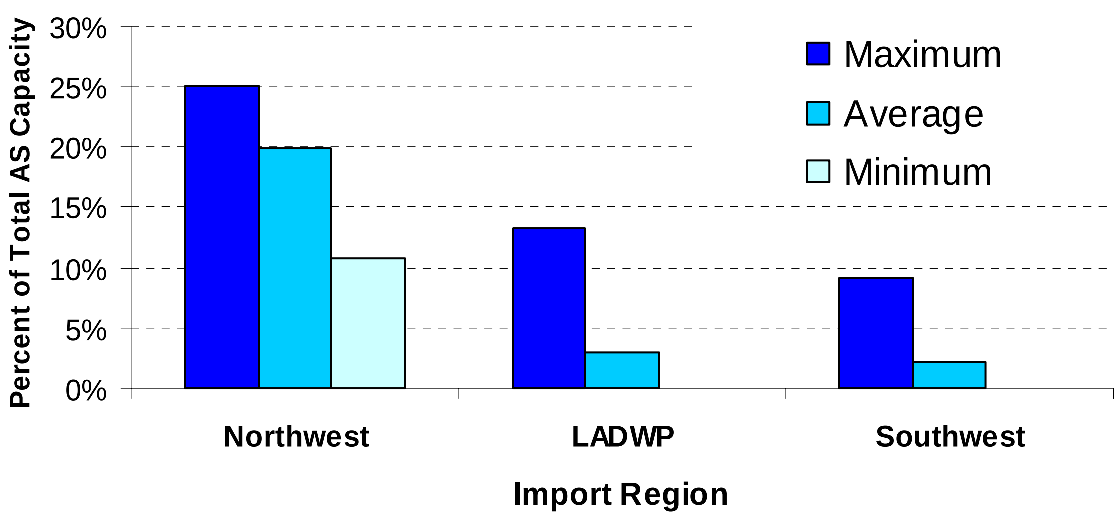


Figure 3-23. Shares of Operating Reserve Imports by Import Region During Hours when 25% Limit on Imports Was Binding



3.5.4 Spinning, Non-Spinning and Replacement Reserve Prices

Figures 3-24 to 3-26 show market-clearing capacity prices in the three dispatchable reserve services, broken down by quarter. In all three, capacity prices were low in the first months of operation, had frequent episodes of high prices during peak periods of the summer, tended to be quite low through the autumn, experienced a brief period of high prices at the winter peak in late December, and were low through the first quarter of 1999.

Spinning Reserve capacity prices remained low into the middle of June, 1998, never reaching above $9.50/MW. During this period, very little capacity suitable for Spinning Reserves had market-based rate authority, so the market-clearing prices reflected the old embedded-cost-based rates. At the same time, bid sufficiency was very low, averaging below 30 percent through June in peak hours, and only slightly higher in off-peak hours. It is, indeed, misleading to refer to these prices as “market clearing,” since in many hours the bulk of the ISO’s Spinning Reserves were provided under the terms of the RMR contracts.

In mid-June, the first divested generators began participating in the Spinning Reserve auction, leading to prices of $33.20/MW during the afternoons of June 13 and 14. During hour 9 on June 15, the price rose sharply to $244.60/MW, a price based on the conditional approval of market-based rates for a new generation owner, with a cap based on the RMR Reliability Payment Rate of the unit. For the next month, through July 13, prices fluctuated wildly between high levels, which were set by divested units at levels between $200/MW and $244.60/MW, and low levels set by units operating under embedded-cost-based rates. Between July 14 and 26, Spinning Reserve capacity prices stayed at the low levels, resuming the erratic behavior in late July and continuing into the middle of September. Since the summer peak passed, Spinning Reserve prices have been low, except for the brief winter peak in late December and a few isolated hours.

Prices in the Non-spinning and Replacement Reserve markets have followed a roughly similar pattern to that of the Spinning Reserve prices (see Figures 3-25 and 3-26). There are some significant differences. One is the dramatic price spikes of $5,000/MW and $9,999/MW in the Replacement market on July 9 and July 13, respectively. These spikes are not observable in the graph since prices above $250/MW are truncated. The other differences are evident in the visual patterns of the graphs. Price spikes generally appeared later in the year in Non-spin and Replacement than in the Spin market, the “bar-code” appearance of the Non-spinning price series is less dense than that of Spinning Reserve, and the Replacement Reserve bar-code is less dense than either of the others. These observations are consistent with the somewhat thicker supply in the Non-spin and Replacement markets. On average, these two markets performed less erratically than the Spinning Reserve market.

Overall, both during the summer peak and afterwards, supplies were greater and prices lower in the Replacement Reserve market than in the O/R markets. This is to be expected, because considerable capacity which is eligible to provide Replacement Reserves meets neither the requirements of Non-spinning Reserves (because of slow ramping) nor of Spinning Reserves (because of the requirement that the unit be on-line). However, when the markets for reserves as a whole ran short, so that a single supplier could set the price at arbitrarily high levels, this often manifested itself in the Replacement Reserve market, which was cleared after the other two markets. The result is that the highest prices have been set in the last market in the clearing sequence. During the hours when the Replacement Reserve price was $9,999/MW, the capacity prices in the earlier markets remained below $10/MW.

Figure 3-24. Spinning Reserve Market Clearing Prices

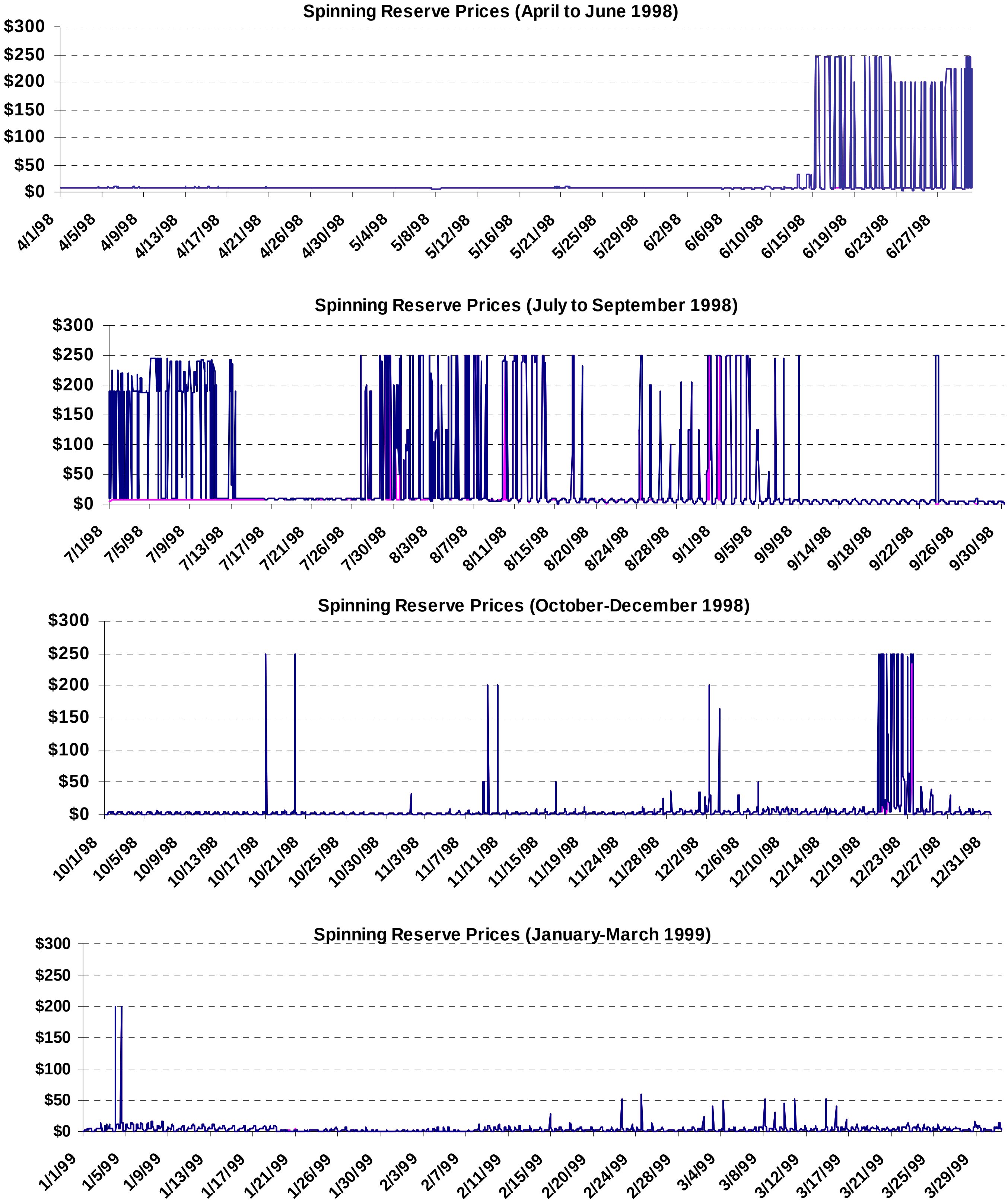


Figure 3-25.Non-Spinning Reserve Market Clearing Prices

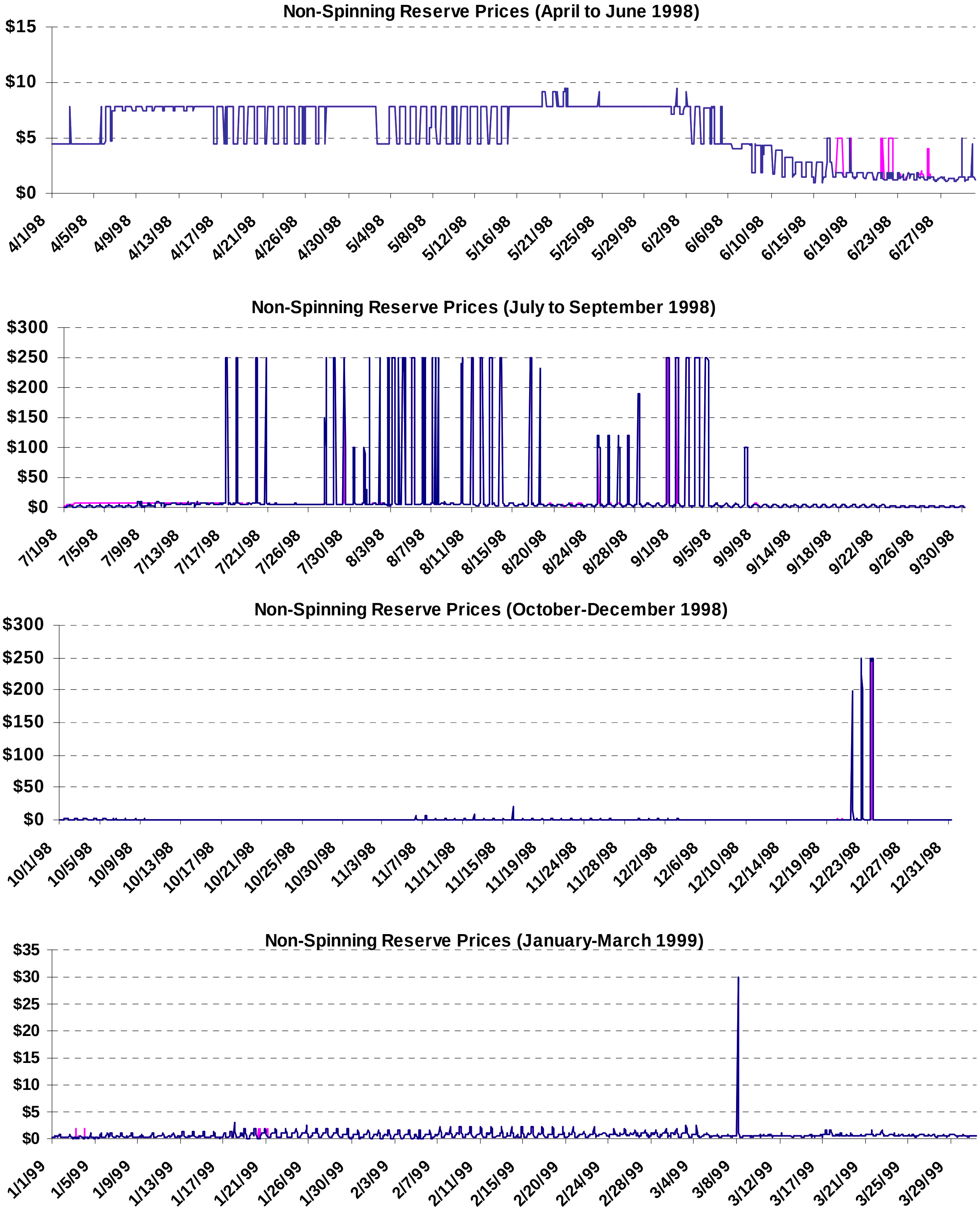
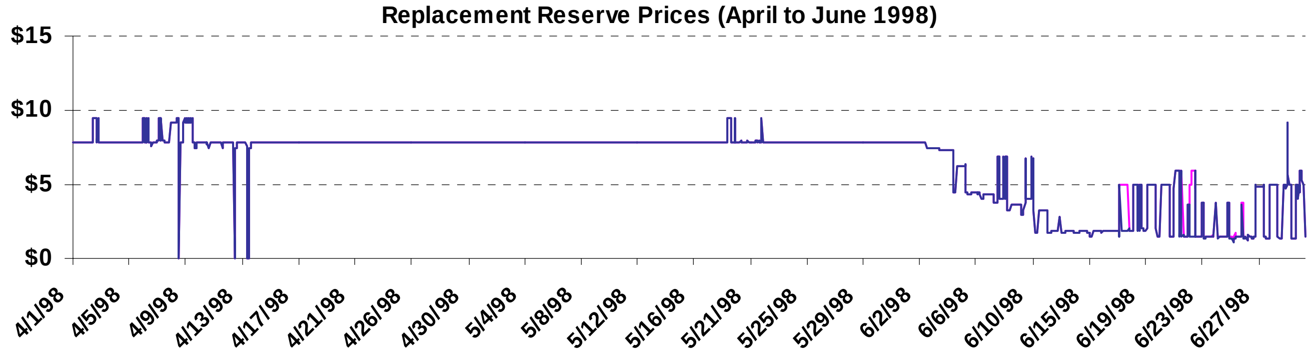
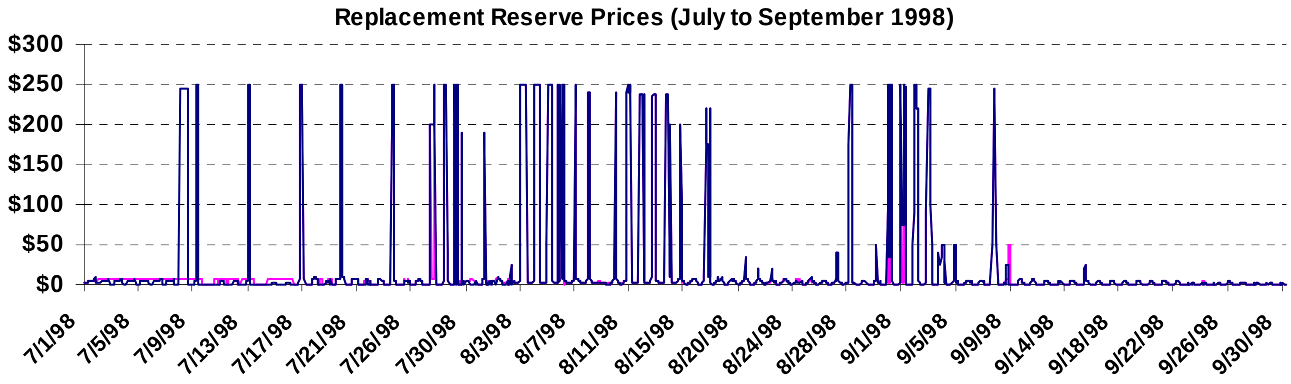
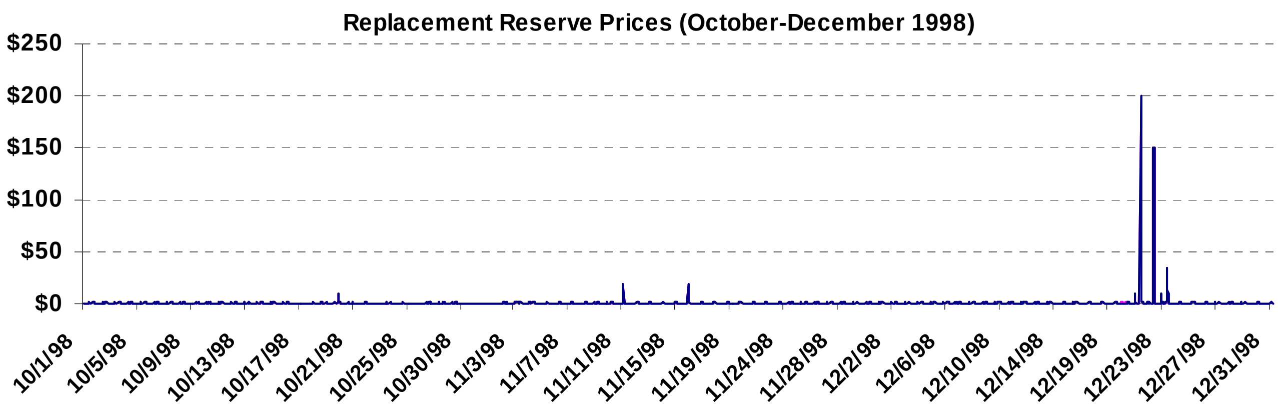
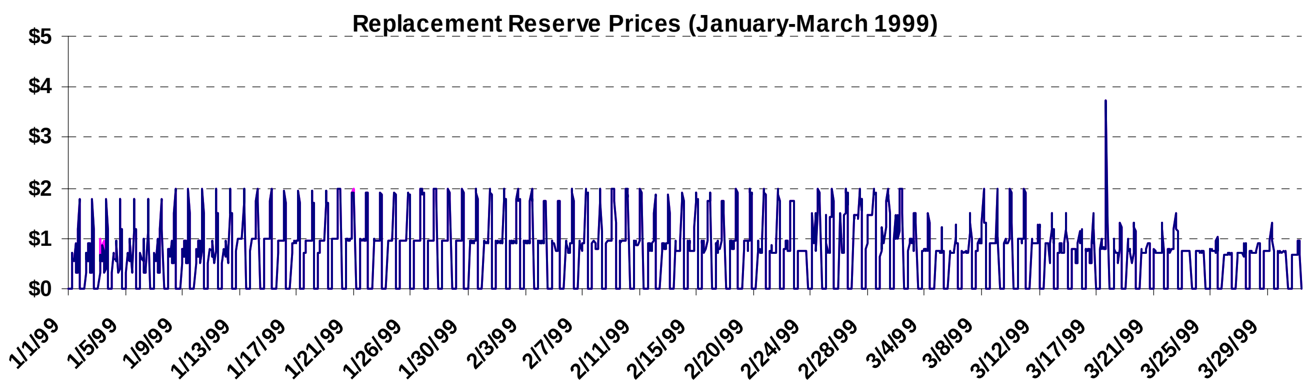


Figure 3-26.Replacement Reserve Market Clearing Prices









3.6 Ancillary Services Market Re-design

The first summer of operations was marked by the maintenance of caps on the prices for real-time imbalance energy (the BEEP cap) and A/S capacity. For the present and for the near-term, the two price caps are specifically inter-related. The original flaws in the BEEP software were repaired, but raising the BEEP cap while flaws and price caps remain in the A/S markets would lead to shortages of capacity in the A/S markets, as generators pursued the uncapped energy prices. The ISO now expects to raise both caps substantially and simultaneously, as soon as a number of market design improvements currently in progress are in place. The two markets – real-time energy and A/S – are closely related, and their relationship requires the ISO to improve the design and function of both markets in a coordinated fashion.

Specific elements of the ISO’s Ancillary Service Redesign program include:

1. ***Charging for A/S capacity based on metered demand, rather than on scheduled load.*** Charging based on schedules encouraged under-scheduling, leading to excessive reliance on the imbalance energy market and excessive demand for A/S, particularly Regulation. Moreover, when the ISO was faced with shortfalls between its load forecast and the scheduled load that exceeded the resources expected in the BEEP stack, the ISO made frequent out-of-market purchases of energy, often in blocks extending over several hours, and at prices which were extremely attractive to generators. This behavior may have discouraged participation in the real-time imbalance energy market, as well as in the forward energy markets. By charging A/S capacity costs to actual loads, rather than to scheduled, the ISO will eliminate disincentives to schedule loads forward.

2. ***Eliminating capacity and energy payments to sellers of A/S capacity who generate without instruction out of that capacity***. Uninstructed generation from A/S capacity led to a loss of quality of the ISO's reserves, and thereby required the ISO to increase its purchases in order to maintain system reliability. It also diminished the ISO’s confidence in the BEEP stack, and thus contributed to the need to make out-of-market block purchases, with consequent harm to the formal markets. Finally, uninstructed generation out of O/R capacity contributed directly to the losses of O/R, which that led to the ISO’s violations of the CPS2 standards.

3. ***Introducing a Rational Buyer procedure to allow the ISO to set increased purchases of higher-quality services (e.g., Spinning Reserves) against its requirements for lower-quality services (e.g., Replacement Reserves) when doing so reduces total A/S procurement costs.*** This procedure introduces some demand elasticity into the markets for the lower-quality services, and should encourage much more competitive bidding by suppliers. The principal result of this change should be to reduce the total cost of procuring A/S. In addition, if it drives market participants towards opportunity-cost bidding of A/S capacity, it should contribute to more efficient price discovery and revelation of marginal costs, leading in the long run towards market-driven economic dispatch of generation to provide both energy and A/S. The settlement for Rational Buyer will charge the same prices to the users as it pays to the suppliers. See Section 3.8 at the end of this chapter for further details.

4. ***Purchasing Replacement Reserves to cover the difference between scheduled and forecast load, and charging the Replacement capacity costs to under-scheduled load and over-scheduled generation.*** This will ensure sufficient resources in the real-time market to meet

demands, eliminate costly out-of-market calls, and reduce the use of Regulation to meet predictable fluctuations in load (i.e., load following). The procedure will discourage generators from generating with neither schedules nor dispatch instructions, since any real-time energy revenues they earn in this manner would be reduced by the Replacement charges. Instead, the generators would have the more attractive alternative of bidding into Replacement Reserve and earning the capacity price plus the real-time energy price.

5. ***Correction of a settlement procedure that encouraged participants in the real-time market to ignore dispatch instructions, leading to excessive demand for Regulation and other ancillary services.*** During the ISO's first year of operations, a recurrent problem was the treatment by some market participants of real-time dispatch instructions as a financial commitment with negligible, or even negative, penalties for non-performance. A number of proposals have been discussed for bringing the actual costs of non-performance to bear on the appropriate market participants. Faced with substantial resistance from some market participants, the ISO is, as a first step, eliminating any possibility of benefiting from the failure to follow a dispatch instruction. Under the "Effective Price" procedure, an SC whose generators fail to follow dispatch instructions entirely will be charged the average price paid to that generator during the hour for energy dispatch. This will eliminate the possibility of earning higher ten-minute interval prices and paying a lower Hourly Ex-Post Price for under-generation.

6. ***Automation of real-time dispatch, to allow more effective use of the supplemental-energy market and reduce use of Regulation for load following***. New BEEP software will dispatch an entire nomination list of energy increments simultaneously and electronically, with positive or negative acknowledgement required within one minute. This will allow much faster response of the real-time energy market, thereby allowing Regulating units to return more rapidly to their set points. In addition, the procedure will give the ISO a more accurate real-time accounting of the BEEP stack, particularly O/R, and may help avoid future CPS2 violations without requiring increases in O/R procurement.

7. ***Continuing changes to the Regulation auction, to manage the problems associated with the use of Regulation as a non-zero-energy product.*** During much of the first year of operations, the ISO procured upward and downward Regulation separately, but paid both sub-services the same market clearing price, chosen as the higher of the prices that cleared each sub-market. The separate procurement practice has allowed the ISO to avoid purchasing excess amounts of one sub-service to ensure adequate resources of the other. It has also, however, often led to confused bidding behavior. For example, if a generator believes that Regulation Up will set the market-clearing price at a level that will profit its delivery of Regulation Down, it may bid its Regulation Down capacity at a low price to ensure its acceptance at the high price set in the Regulation Up auction. In many hours, then, the price used to clear one of the sub-markets has been low, often less than zero. Negative bids under these circumstances have no relationship to the cost of providing services, and there is no presumption that the resulting procurement pattern is least-cost in any meaningful sense. Rather, capacity is bid at negative prices based on bidders' beliefs that the price will be set at a profitable level in the other sub-service. When these beliefs are uniformly strong, the market clearing price may be very low indeed. In a few cases, these beliefs have proved to be sufficiently diverse that the market clearing prices in both sub-service auctions, and hence the single price paid for both sub-services, were all negative. In these cases the "winning"

generators have paid the ISO to place their units under the ISO's AGC. Paying a single price for the two separately procured Regulation sub-services is a clear flaw in the current market design. This flaw will be corrected as a part of the A/S market redesign program that was filed with FERC on March 1, 1999.

8. ***Facilitation of non-ISO markets for A/S***. Under the original market design, Scheduling Coordinators could either self-provide A/S or be charged by the ISO for A/S procured on their behalf. There was, however, no mechanism for one SC to sell A/S directly to another SC. It could bid its surplus A/S capacity into the ISO's auctions at a low price, and execute an associated contract for differences with the A/S-deficient counterparty at an agreed-to price, thereby creating the financial equivalent of an A/S trade between the two SC's, but there was no way for one SC to directly provide A/S to meet another SC's requirements. In response to market participants' wishes for a direct A/S trading mechanism, motivated in part by some participants' legal inability to trade financial derivatives, the ISO will allow an SC to declare responsibility for another SC's A/S requirement. This mechanism will allow full inter-SC trading of A/S, without recourse to contracts for differences or similar financial instruments.

3.7 Conclusion

There are no sharp boundaries between the A/S markets and either the forward energy markets or the real-time imbalance energy markets. The performance of each market depends closely on the performance of the others, and actions in one market have direct and immediate consequences in the other markets. For example, Regulation Reserves are bought precisely to take up the slack between the random or predictable imbalances in the system and the lagged responsiveness of the formal real-time imbalance energy market. If the imbalance energy market were faster and more effective, the requirement for Regulation would be less. Similarly, O/R and Replacement Reserves are equally close to the imbalance energy market, since they comprise a significant portion of the energy resources on the supply side of the imbalance energy market. These reserves are, indeed, nothing more than a promise to appear in the spot market, with, in the latest version of the ISO markets, significant penalties for failures to appear, especially if the forfeited capacity payments are high.

3.8 Appendix – the Rational Buyer Algorithm

In its Order of May 26, 1999 on Amendment 14, FERC stated some questions and concerns regarding the Rational Buyer procedure. This Appendix addressed some of these concerns.

1. A/S Price-Quality Ordering and Variation

FERC's Order observes that the Rational Buyer method may not always result in the "rational" or quality-based ordering of A/S prices, i.e., Regulation Price ≥ Spin Price ≥ Non-spin Price ≥ Replacement Price. We agree that Rational Buyer prices can and often will vary from the strict, rational quality-price ordering. The ISO designed Rational Buyer in full recognition of this feature. Indeed, Rational Buyer was motivated largely by the frequent occurrence of "irrational" quality-price outcomes in the A/S markets. Here we further explain the rationale for the design of Rational Buyer.

The objective of Rational Buyer is to minimize the total purchase cost of A/S given market supply conditions. If this objective is achieved in a way that varies from the proper quality-price ordering, that should be considered rational on the part of the buyer. For example, suppose the requirements are 100MW Regulation and 100MW Spin, the bids in Regulation are 150MW at $5/MW and 50MW at $250/MW, and the only Spin bid is 150 MW at $10 MW. Then Rational Buyer will buy 150 MW of Regulation at a MCP of $5 and 50 MW of Spin at a MCP of $10. This outcome represents the least-cost purchase and is fully rational on that basis.

At the same time, we expect that irrational quality-price orderings will occur less frequently under Rational Buyer than they have using the present sequential market-clearing method. We also note that with any other method presently used or contemplated by other ISOs (including simultaneous optimization of energy and ancillary service) one could construct an example with irrational bids that would result in some lower quality service being priced higher than a higher quality service. Our analysis of actual bid data in the A/S markets has shown that the slope of the supply curve for the higher quality lower priced service, where substitution would take place, is often initially (i.e., at the pre-substitution quantity) much smaller than the slope of the lower quality higher priced service that is substituted. As a result, in the actual cases analyzed, the Rational Buyer solution almost always lines up quality with price in the expected rational order.

2. Market Efficiency

FERC has stated concerns regarding potential market inefficiency as a result of the Rational Buyer procedure:

> "*The ISO and PX energy auctions are operated so as to maximize the difference between buyers' aggregate bid value and sellers' aggregate bid requirements (subject to certain constraints). By contrast, the ISO auction proposed here would maximize the difference between buyers' aggregate bid value and buyers' procurement costs. One major difference in these two approaches is that the proposed A/S auctions would consider the effect of price changes on the buyers' costs of procuring inframarginal capacity, while the energy auctions do not consider this effect. Changing the mix of A/S may change the buyers' procurement costs of inframarginal capacity, but not the sellers' costs (and the social costs) of providing this capacity.*"

Some aspects of this statement deserve clarification:

(a) In any bid-based market it is important to make a distinction between a generator’s true willingness to supply a given unit to the market (its cost of supply) and the price bid for the unit. Similarly, there is a difference between the amount a given load is willing to pay to purchase from the market and the price it bids into the market to purchase this quantity. Any assessment of the social costs and benefits of a market-clearing rule can therefore not be made based on bids submitted by demanders and suppliers without knowledge of the actual costs and willingness to pay of all market participants. Unfortunately, these costs and willingness to pay are unobservable, and the error in assessing social costs and benefits of a price-setter rule based on demand and supply bids can be very large.

(b) Another important issue that has been ignored in this statement is that there is no “buyers’ aggregate bid curve” in the California ISO A/S markets, since the ISO can only announce fixed demand for each ancillary service with no purchase price elasticity. The Sequential Rational Buyer procedure counts on substitutable bids submitted in different A/S markets to introduce some degree of demand price responsiveness among the A/S markets (with no change in the total physical quantity (MW/h) procured). This is not the case in the PX market where price sensitive demand participation is permitted. Therefore, the concerns stated are not valid for the Sequential Rational Buyer algorithm. If the supply side bids rationally, valuing the higher quality services higher than lower quality services, no substitution will take place by the Sequential Rational Buyer, and the issue is moot.

(c) Rational buyer method can be analyzed from a perspective of substituting across A/S services or increasing trade across A/S markets. From both views, trade always improves system efficiency. To illustrate the point, assume there are two markets: Regulation and Reserve. The demand in each market is 1000 MW. If the initial market clearing prices are $10 and $20 respectively, the rational buyer method will be applied. Assume the rational buyer outcome is the final purchase of 1500 MW of Regulation at $12 /MW and 500 MW of Reserve at $12/MW.

    The impact on consumer surplus and producer surplus is the following. First, consumer surplus increased by $6000 (= $8*1000 - $2*1000). Second, assuming linear supply curve for simplicity, the producers’ surplus decreased by $3500. Therefore the overall surplus increased by $2500. Examining the Regulation and Reserve markets separately, in the Regulation market the producers gained $2500 while the consumers lost $2000. In the Reserve market the producers lost $6000 while the consumers gained $8000. Thus in our example, the buyer of Regulation is worse off and the producer of Reserve is worse off.

    In general, we can view rational buyer as a trade of higher cost lower quality product for a lower cost higher quality product. Standard trade theory shows that the new equilibrium with trade is most efficient and will result in maximum combined producer surplus and consumer surplus, although certain groups of consumers or producers may be worse off after the trade. In our example the Regulation market is the exporting market and the Reserve market is the importing market. Consumers’ gain in the importing market is greater than producers’ loss. Producers’ gain in the exporting market is greater than the loss of consumers. There is a net gain in each market, and the entire market ’ is better off with trade.

After reviewing a variety of approaches, we feel the Rational Buyer algorithm fits the market design philosophy developed in California of letting markets achieve efficiency rather than trying to mandate it. This means that some form of demand elasticity is crucial for the operation of an efficient market, whether that market is run sequentially or in a simultaneous fashion.

3. Rational Buyer Settlement

FERC has requested a clarification of the settlement procedure. We would like to clarify the distinction between three proposals, namely an earlier (original) ISO proposal, the MSC's proposal, and the Compromise proposal adopted by the ISO Governing Board that forms the basis of Amendment 14 to the ISO Tariff.

The original ISO proposal was based on the premise that the users would not be charged more than they would have paid under the existing (irrational) scheme. In order to achieve this objective the algorithm charged the users a different price than it paid the suppliers. The MSC stated that different purchase and sale prices would lead to perverse incentives and market inefficiency. The MSC proposal paid and charged both the Rational Buyer price and the Rational Buyer quantity. The ISO Board considered this to be inequitable and chose a compromise that charged the same prices to buyers and sellers, but did not change the original quantity obligations for each ancillary service.

The Compromise proposal, which is the basis of the Tariff language filed, uses the same price for suppliers and users. The suppliers are paid based on the purchased (Rational Buyer) prices and quantities. The users are charged based on the Rational Buyer prices, but for the "Original" requirements (net of self-provision) in each service. This does not guarantee that no user would be worse off compared to what they would have paid under the present (irrational) scheme. The irrational price should not be used as a reference for determining equitable treatment of users, since these prices were distorted to begin with. In this respect the compromise solution addresses the MSC's concern (shared by FERC) that the price charged for a service should be the same as the price paid to purchase the service. However, the compromise proposal keeps the user responsible for the original quantity of each service that they did not self provide (before substitution took place). In some cases this may lead to lack of revenue neutrality for the ISO. In such cases, the difference between total purchase costs and total user charges is allocated pro rata as a percentage of users' A/S bills.

The following example illustrates the three methods. To demonstrate revenue non-neutrality of the compromise proposal, the Rational Buyer prices in this example are slightly different from those in Appendix C of the FERC order.

Example

The following table shows the original (irrational) and the Rational Buyer (RB) quantities and prices.

	Original MW	Original Price	RB MW	RB Price
Regulation	1,500	$10/MW	3,000	$20/MW
Spin	1,000	$20/MW	500	$18/MW
Non-Spin	1,000	$40/MW	500	$18/MW
Replacement	1,000	$80/MW	500	$18/MW
Purchase Cost ($)	$155,000		$87,000	

The following table shows the quantities and prices charged to the users under each proposal:

Load Obligation and Cost Allocation

	Original ISO Proposal			MSC Proposal			ISO Board's Compromise Proposal		
	MW	Cost	$/MW	MW	Cost	$/MW	MW	Cost	$/MW
Reg	1,500	$15,000	10	3,000	$60,000	20	1,500	$30,000	20
Spin	1,000	$10,286	10.29	500	$9,000	18	1,000	$18,000	18
Nspin	1,000	$20,571	20.57	500	$9,000	18	1,000	$18,000	18
Repl.	1,000	$41,143	41.14	500	$9,000	18	1,000	$18,000	18
Total	$87,000			$87,000			$84,000		

As can be seen, purchase price used in the RB, and the price charged in the MSC and Compromise Proposal all utilize the same prices. Under the compromise proposal, ISO runs short by $87,000 - $84,000 = $3,000, which is charged to the users pro rata (ratio of 3,000/84,000), and yields $1,071 for Regulation and $643 for each of the other three services. This results in the total charge of $31,071 for Regulation and $18,643 for each of Spin, Non-spin, and Replacement.