Chapter 2. Introduction to the ISO Markets

2.1 Chapter Overview

The purpose of this Chapter is to provide background for the more detailed discussions in subsequent chapters. Section 2.2 introduces the basic elements of electric industry restructuring, and describes the structure of California's newly deregulated electricity markets and the California ISO's role in the overall design and operation of those markets. Section 2.3 provides an overview of the markets operated by the ISO, namely, ancillary services (A/S), real-time imbalance energy, and transmission congestion. Sections 2.4 to 2.6 review the performance of each of these three markets and introduce the key issues, to provide background for the full discussions in Chapters 3 to 5. Finally, Section 2.7 provides a chronological description of problems encountered, key developments, and changes in the design and performance of these markets during the ISO's first year of operation.

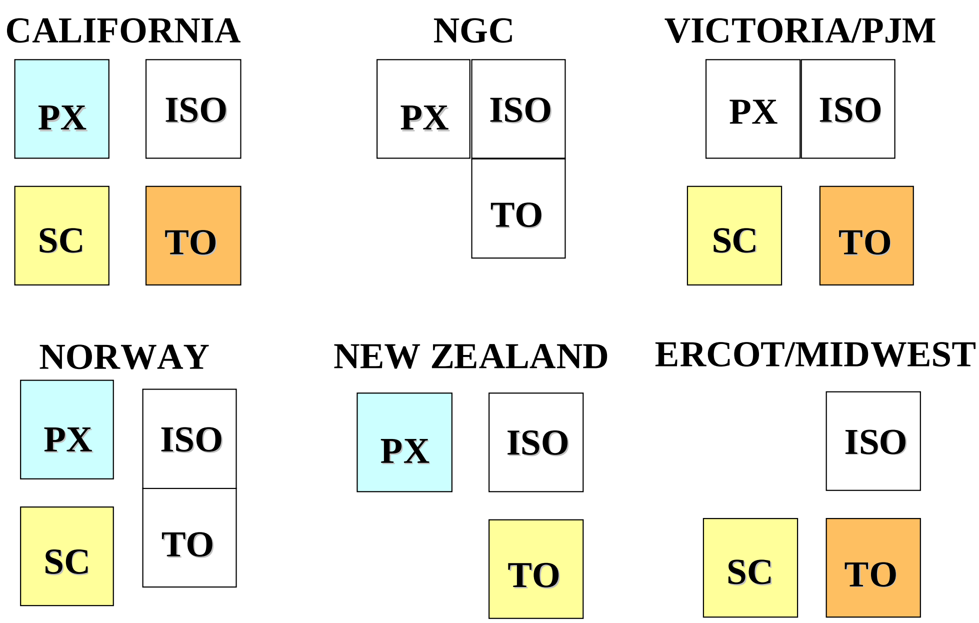
2.2 Restructuring of the Electric Utility Industry

The electric industry is undergoing sweeping restructuring around the globe. A variety of structural models are being proposed, considered, and experimented with in different countries. A fundamental feature of most restructuring models is the unbundling of the traditional integrated utility structure into separate functional components. Under these new models, generation and retail services are unbundled from transmission and distribution, with generation and retail services becoming competitive, while transmission and distribution remain regulated, natural monopolies which provide essential transport services for the competitive service providers. Under the new models, each of these functions may be provided by a distinct business entity.

The main entities involved in the provision of transmission services are the Independent System Operator (ISO) and the Transmission Owners (TOs). The main users of transmission services are, ultimately, generators and loads. However, most restructuring models feature some types of business intermediaries who deal directly with transmission service providers on behalf of generators and loads. Such intermediaries include centralized, wholesale power pools or Power Exchanges (PX), as well as aggregators of bilateral energy service contracts, generically referred to here as Scheduling Coordinators (SCs). Not all of these entities need to be present in any specific restructuring model. In some cases the centralized energy market (PX) does not exist, and in other cases it is merged with the ISO. The bilateral market represented by the SCs may or may not be provided for, depending on the structure adopted.

Examples of some existing and emerging structures are given in Figure 2-1. Adjoining boundaries indicate that the services are provided by a single entity.

Figure 2-1. Examples of Existing or Emerging Market Structures



The market structure adopted in each case is, to a large extent, characterized by the scope of activities and authority delegated to the entity responsible for day-to-day operation of the transmission system, i.e., the system operator. These features vary widely among the different ISOs existing or emerging in the U.S. and other countries. To facilitate the comparison of market structures, it is helpful to consider the ISO's role and responsibilities in each of the following areas:

- Operations Planning and Scheduling
- Dispatching of Generation Resources
- Real-time Transmission System Control and Monitoring
- On-line Network Security Analysis
- Market Operations and Settlements
- Transmission Planning, Ownership and Maintenance

The minimum or core responsibility of all existing and emerging ISOs is the coordination of operations planning within the ISO's area of jurisdiction. A "minimalist ISO" would intervene in operations planning and scheduling only in case the schedules developed by the participants (control areas, PX, SCs, etc.) are likely to result in transmission congestion. The ISO would then coordinate measures to alleviate the congestion. The minimalist ISO would not usually perform real-time control through automatic generation control (AGC). It may, however, monitor the operation of the power system to ensure adequacy of available reserves and other pertinent ancillary services. Examples of a minimalist ISO are ERCOT, and the structure being contemplated for MAPP.

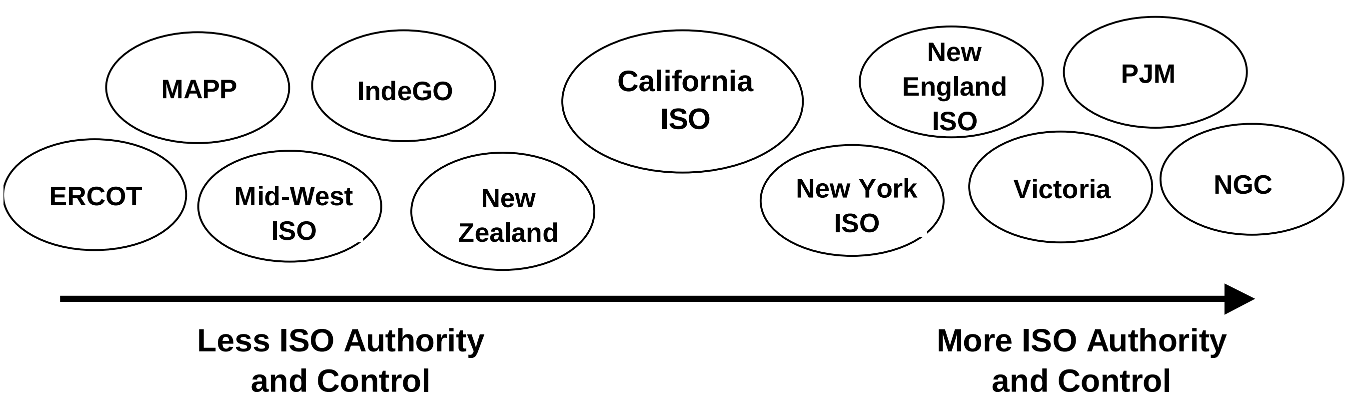
At the other end of the spectrum, some existing or emerging ISOs have a wide range of authority and enjoy extensive centralized control. In addition to the basic functions of a minimalist ISO, a "maximalist ISO" would:

- Perform generation scheduling (possibly including unit commitment), and scheduling of ancillary services
- Dispatch generation for energy imbalance and ancillary services, as well as congestion management
- Perform real-time control of generation, transmission, and ancillary resources
- Facilitate a forward (day-ahead and/or hour-ahead) energy market
- Plan and execute transmission system expansion (although it may or may not own the transmission assets).

The PJM ISO is an example of a maximalist ISO. The National Grid Company (NGC) in the U.K. is another example, in which the ISO assumes ownership of transmission assets.

The California ISO falls somewhere in the middle of the spectrum. The California ISO has no jurisdiction over the forward energy markets, and has very limited control over actual unit level generation scheduling and unit commitment. The following figure shows schematically how the California ISO compares with other planned or operating ISOs, based on the scope and extent of its authority and control. In this figure, the degree of ISO authority and control increases from left to right: to the left are those ISOs with minimal authority and control; to the right are those ISOs with maximal authority and centralized control.

Figure 2-2. Comparison of ISO Models



2.3 Overview of the California ISO Markets

The California ISO is a not-for-profit California corporation established on May 5, 1997. Its headquarters and main control center are in Folsom, near Sacramento, in northern California, and its backup facility is in Alhambra, near Los Angeles, in southern California.

The California ISO is responsible for reliable operation of the high voltage grid in California. The three Investor Owned Utilities (the IOUs, Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric Company (SDG&E)) retain ownership of the high voltage grid, and are responsible for its maintenance and actual switching operations. The California ISO operates a hierarchical control system for real-time power system control, with the control center in Folsom at the highest level of the hierarchy. The second level of the hierarchy includes the three IOU system control centers, whose operation was transferred to the California ISO on March 31, 1998. The California ISO does not perform direct control of field devices, but coordinates their operation. It does, however, perform automatic generation control (AGC). The California ISO does not perform centralized optimization for dispatching energy resources. Except in limited circumstances, to avoid system emergencies, it may only dispatch the resources, or parts thereof, which are bid into the markets it operates, plus certain reliability must-run generators under option contracts.

The motto of California's restructured energy industry in general, and the California ISO in particular, is "Reliability through Markets." The California ISO manages the California markets in three major areas:

- Ancillary services (A/S)
- Real-time imbalance energy
- Transmission congestion management.

More detailed descriptions of these markets are provided in Sections 2.4 to 2.6 below.

The California ISO also manages long-term Reliability Must Run (RMR) contracts and the dispatching of the RMR units. RMR units are generation units that have been designated as essential to the ISO controlled grid based on their location, as determined by local reliability needs in accordance with regional (i.e., western states) reliability criteria. The California ISO does not conduct the forward (day-ahead and hour-ahead) energy markets. Forward energy markets are conducted by the California Power Exchange (California PX).

The California ISO's market participants are the scheduling coordinators (SCs). The SCs are certified by the ISO, and act as the intermediaries between the ISO and the generators, retailers and consumers. The California ISO has so far certified 42 SCs, 27 of which have been actively participating in its markets. The California PX, in addition to conducting the forward energy markets, is also an SC.

The California PX and the other SCs submit balanced, forward energy schedules to the California ISO on a day-ahead and hour-ahead basis. *Balanced* means that generation plus imports must equal loads plus exports plus losses. At the same time as it accepts the energy schedules, the California ISO also accepts bids in the three major market areas identified above which it operates. Based on the energy schedules, the California ISO determines what it will need to purchase through these markets.

The schedules and bids accepted by the ISO in the day-ahead markets establish financial commitments, which are settled separately for each market for each operating hour, based on the day-ahead market clearing prices. Changes from day-ahead schedules, which are submitted to the California ISO's hour-ahead markets, are settled at the hour-ahead market clearing prices.

Changes from the final forward market schedules (as accepted by the California ISO at the close of the hour-ahead markets) are settled at the real-time market prices.

To help the reader understand how the various ISO and PX markets in the California system function in relation to one another, Figure 2-3 below provides a time sequence of activities in all these markets.

Figure 2-3. Time Sequence of Key Activities in ISO and PX Market Operations

Day Ahead	California ISO	California PX
2 days ahead – by 6 PM	Evaluate & publish public market information.	
Day ahead – 6:00 to 6:30 AM	Receive SC load forecasts; aggregate DAC loads; send aggregated DAC loads to UDCs.	
By 7:00 AM		Receive participants' portfolio energy supply & demand bids for each hour.
By 7:15 AM		Conduct energy auction & notify successful bidders of hourly MCPs & quantities.
By 9:10 AM		Receive participants' Initial Preferred Schedules, identifying specific generating units & loads that fulfill aggregate awards in the energy auction; receive adjustment bids for inter-zonal congestion management.
By 9:30 AM		Receive A/S bids.
By 10:00 AM	Receive & validate preferred energy & self-provided A/S schedules & bids from all SCs.	Submit to ISO preferred energy schedules, A/S & adjustment bids.
10:00 to 11:00 AM	Perform A/S auction & inter-zonal congestion management; develop & publish adjusted energy schedules, A/S schedules & MCPs, & estimated congestion charges. NOTE: energy & A/S schedules will be Final if there is no inter-zonal congestion.	
By 12:00 noon	If 10 AM schedules had inter-zonal congestion, receive & validate revised preferred energy & self-provided A/S schedules & bids.	Submit to ISO revised schedules. PX always submits same energy schedules as 10 AM, but may have revised A/S bids.
12:00 noon to 1:00 PM	Perform A/S auction & inter-zonal congestion management; develop & publish Final energy schedules, A/S schedules & MCPs, & congestion charges.	
By 1:15 PM		Send to participants Final energy & A/S schedules & congestion charges; calculate zonal MCPs.
By 1:30 PM approx.	Determine any deficiencies in A/S markets; evaluate RMR requirements relative to Final schedules.	
By 5:00 PM approx.	Publish any changes to Final schedules due to A/S shortfall & RMR requirements.	

Hour Ahead	California ISO	California PX
By 3 hours ahead		Receive participants' energy supply & demand bids, relative to Final DA schedules.
By 2 hrs 50 min ahead		Calculate MCPs & quantities, determine preferred schedules.
By 2 hours ahead	Receive & validate energy schedules, & self-provided A/S schedules & bids.	Receive participants' adjustment & A/S bids; include with preferred schedules submitted to ISO.
2 hrs to 1 hr ahead	Perform A/S auction & congestion management; develop & publish Final energy schedules, A/S schedules & MCPs, congestion charges, & GMMs.	
By 1 hour ahead		Transmit ISO Final schedules to participants.
Prior to operating hour		Calculate & publish zonal MCPs.
Real-time – Prior to Operating Hour	**California ISO**	**California PX**
By 1 hour ahead		Receive participants' supplemental energy bids.
By 45 min ahead of operating hour	Receive supplemental energy bids for real-time market.	
By 20 min ahead	Accept ETC schedules not already scheduled in DA or HA markets.	
Real-time – Within Operating Hour	**California ISO**	**California PX**
By 10 minutes ahead of operating instant	Receive actual system load & MW generation on AGC (from PMS).	
10 min. ahead to operating instant	Determine energy imbalances & dispatch winning supplemental bids via PMS.	

2.4 Ancillary Services Markets

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 (Regulation), Spinning Reserves, Non-Spinning Reserves, and Replacement Reserves. 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.

These four services are collectively referred to as "reserve" A/S. Also, the term "Operating Reserves" (O/S) is commonly used to refer collectively to Spinning and Non-spinning Reserves. The California 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 currently 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. The 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 California 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 the 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 Chapter 3.

2.5 Real-time Imbalance Energy Market

Deviations from forward market schedules (day-ahead and hour-ahead) are inevitable in real-time, particularly for the scheduled load. The ISO's automatic generation control (AGC) process uses the Regulation A/S to mitigate random fluctuations in system frequency, which result from instantaneous generation-load and net interchange imbalances. To supply the more systematic and predictable departures of load and interchange from the forward schedules (e.g., the morning and evening ramps), the California ISO utilizes the energy bids from the other A/S markets, as well as "supplemental energy" bids which are submitted specifically for this purpose. These bids collectively constitute the real-time imbalance energy market. In utilizing these resources the ISO selects them in increasing order of their bid prices.

The Balancing Energy and Ex-post Pricing (BEEP) system helps the ISO control room to manage the ISO's real-time imbalance energy market. The BEEP system uses the real-time energy bid stack to determine which units to dispatch (increment or decrement) every 10 minutes to correct measured real-time energy imbalances, predicted changes in load, and the technical characteristics of the resources in the BEEP stack (time delay, ramp rate, etc.).

The BEEP stack is computed and processed for each hour using the bids for that hour. The BEEP system establishes the real-time dispatch price every 10 minutes based on the real-time energy bid of the marginal unit- dispatched in that interval. The 10-minute prices are paid or charged for the dispatched increments or decrements, respectively. These dispatched quantities are called "instructed deviations," and are dispatched by the ISO to meet the systematic and predictable variations from schedule mentioned above. In addition, a quantity-weighted average of the 10-minute prices is computed as the hourly real-time *ex post* energy price. All random fluctuations or "uninstructed deviations" from schedules, by loads or generators, are settled at the hourly *ex post* price. The hourly *ex post* price is also used to settle with the AGC units for any net Regulation energy during the hour.

In practice, the ISO has occasionally had to rely on Regulation energy and the AGC process not only for random fluctuations, but also for a share of the more systematic and predictable imbalances. In the traditional utility this function is known as "load following." The need for the ISO to use Regulation energy for load following has arisen due to deficiencies in the BEEP software, inadequate communication to the field, and flaws in the market design which limit the ISO's ability to ensure execution of its real-time dispatch instructions. The market redesign and software improvement programs currently underway are aimed to alleviate these problems and enable the ISO to manage real-time imbalances more effectively.

For example, in order to discourage gaming, individual "effective prices" will be computed for settling with those dispatched resources that do not follow the dispatch instructions. This is more fully described in Section 3.6, which discusses the ISO's market redesign program.

In the absence of real-time inter-zonal congestion, the *ex post* BEEP price applies to all real-time imbalance energy system-wide. When real-time inter-zonal congestion occurs, the BEEP energy stack is constructed and used separately for each congestion zone. Thus the *ex post* prices may be different in different congestion zones.

The real-time energy stack may also be called upon in case of real-time intra-zonal congestion. In such cases it is used in conjunction with the adjustment bids and possibly the Reliability Must Run (RMR) units. When energy bids are used from the BEEP stack to mitigate real-time intra-zonal congestion, they typically are taken out of sequence. They are paid (or charged) according to their bids, but these bids do not establish a market-clearing price.

2.6 Congestion Management Markets

Congestion occurs when the forward schedules submitted by the SCs to the California ISO cannot all be dispatched as they stand, because to do so would overload one or more transmission pathways. When this occurs, the complete set of submitted schedules for the given hour is called "infeasible." In these cases the ISO must manage the congestion by adjusting the submitted schedules so as to keep the flows over all transmission pathways within acceptable limits, and thereby to make the complete set of submitted schedules "feasible."

The California ISO performs congestion management in the forward markets by utilizing the so called "adjustment bids" which are submitted along with the day-ahead and hour-ahead energy schedules. Upward and downward adjustment bids indicate the economic value of incremental changes to a resource schedule as perceived by the bidder. In a workably competitive market, adjustment bids should reflect the incremental cost of each resource. In the case of bilateral trades, adjustment bids may also reflect contractual penalties for non-delivery.

A primary distinction is made between inter-zonal and intra-zonal congestion, and the mitigation procedures are different although both use the adjustment bids. This distinction is based on the notion of "congestion zones," which are described in the next section.

Some parties may hold physical transmission rights (called Existing Transmission Contracts or ETCs) or financial transmission rights which mitigate their risk of being adversely affected by inter-zonal congestion along specific pathways. Such parties may have no incentive to submit adjustment bids. Some parties who do not possess such rights may also decide not to submit adjustment bids. When a resource schedule is submitted with no adjustment bids and no physical or financial transmission rights, the ISO treats it as a price taker in the congestion management markets.

2.6.1 Congestion Zones

Congestion zones are defined as areas within which congestion is infrequent, possibly difficult to predict, and has relatively small impacts. Transmission rights within a zone would therefore be difficult to auction and to resell in a secondary market. In contrast, congestion between zones is defined to be predictably frequent and to have large impacts. The terms "inter-zonal" and "intra-zonal" are used to refer to congestion and congestion management between and within congestion zones, respectively. Inter-zonal congestion typically occurs over a major transmission pathway, although the entire transmission connection between zones may not be just a single transmission line or group of transmission lines in a single corridor.

Presently, the California ISO Tariff defines four congestion zones: North of Path 15 (NP15), South of Path 15 (SP15), Humboldt, and San Francisco. Due to lack of adequate competition in the Humboldt and San Francisco zones, they have been designated "inactive zones" and are treated collectively as a single congestion zone included in NP15. Thus in practice there are actually only two active congestion zones in the ISO system.

The marginal cost of using a congested *inter-zonal* interface is defined as the *incremental value* of that interface to the marginal user, and is determined from the adjustment bids. This marginal cost then becomes the "usage charge" (in $/MWh), and is paid by all SCs who intend to use that inter-zonal interface, based on their final schedules as accepted by the ISO. The inter-zonal charges collected by the ISO are paid to those transmission owners who own the relevant inter-zonal interface and the holders of financial rights for that interface.

The intra-zonal congestion market sets the congestion price per unit of energy at the level of the average cost of relieving all congestion within the zone, again determined from the adjustment bids. It is paid by all SCs within the zone in proportion to their scheduled load within and net export out of that zone. No payment is made to the transmission owners for intra-zonal congestion mitigation. The SCs whose schedules are incremented (decremented) to alleviate intra-zonal congestion are paid (pay) their adjustment bids.

New zones may be defined if intra-zonal congestion becomes frequent and is determined to be inefficiently priced at average cost. Likewise, zones will be combined if inter-zonal congestion becomes infrequent and is determined to be inefficiently priced at marginal cost. Section 7.2.7 of the ISO Tariff includes provisions for creation, modification, and elimination of zones. The two main criteria stated in the Tariff for creation of a new zone are:

1. Cost of intra-zonal congestion mitigation. If, over a 12-month period, the cost to alleviate the congestion on a path within a zone is equivalent to at least 5 percent of the product of the rated capacity of the path and the weighted average Access Charge of the participating TOs, the ISO may create a new zone. In making this calculation, the ISO will only consider periods of normal operation.

2. Existence of workably competitive generation markets in each of the new zones. Any new zones so created must have a workably competitive generation market on both sides of the relevant inter-zonal interface for a substantial period of the year.

Inter-zonal and intra-zonal congestion management have different objectives, network topology, operational impacts and price impacts, as described briefly in the next two sections.

2.6.2 Inter-zonal Congestion

Inter-zonal congestion is managed using adjustment bids to adjust the forward schedules and thus mitigate the congestion, while minimizing the bid cost of these schedule adjustments and keeping all SCs' schedules in balance. The requirement to keep all SCs' schedules in balance for inter-zonal congestion mitigation is referred to as the *market separation constraint*. The SCs are not paid for such balanced incremental changes in their schedules, although this may involve increasing the scheduled delivery from a higher priced resource and decreasing the scheduled delivery from a lower priced resource. Through its adjustment bid, the SC is bidding to buy (or sell) transmission capacity in the inter-zonal congestion management market. The ISO does not buy energy from or sell energy to the SCs to mitigate inter-zonal congestion. Rather, the ISO buys and sells inter-zonal transmission capacity. Consequently, the ISO will only charge and pay the SCs according to their inter-zonal transmission use and the market participants' determination of the cost of usage for inter-zonal transmission.

The bid cost minimization objective combined with the market separation constraint guarantees that inter-zonal transmission is allocated to those SCs who value it most, as reflected in their adjustment bids. As stated above, the marginal SC establishes the usage charge for the inter-zonal interface, and all SCs pay this charge based on their accepted, scheduled flows on the interface. It should also be noted that a counter-flow schedule (i.e., a schedule in the opposite direction of inter-zonal congestion) would be paid at the usage charge rate even if it has no associated adjustment bids. The net amount collected by the ISO is paid to the transmission owners (TOs) and, once financial rights are in place, will be paid to both financial rights holders and TOs.

The network topology for inter-zonal congestion is predominantly radial, to make it easy to define transmission rights between adjacent zones in terms of rights to use specific transmission corridors. This approach is different from that adopted in the Eastern Interconnection ISOs, where nodal pricing is used and transmission rights are based on nodal points of delivery and receipt, using centralized dispatch.

2.6.3 Intra-zonal Congestion

In mitigating intra-zonal congestion the California ISO has two objectives: 1) to alleviate the congestion at the lowest cost, and 2) to minimize the changes to the preferred schedules of the SCs. To achieve these objectives, the ISO reschedules the resources within the zone using the adjustment bids. The SCs are paid for increments to their schedules and are charged for decrements, based on their incremental and decremental adjustment bids. The net cost of the congestion (i.e., the overall net payment to the SCs for these schedule changes) is recovered from all SCs. It is assessed on the basis of their scheduled loads within the zone plus their scheduled net exports out of the zone, without regard to the location of their load or export nodes with respect to the congested intra-zonal interface.

For intra-zonal congestion there is no market separation constraint, which means that some SC schedules may not be balanced after the intra-zonal congestion mitigation adjustments. Because of the localized nature of intra-zonal congestion, some SCs may not have sufficiently diverse portfolios to enable the ISO to keep each SC's portfolio in balance as it reschedules to alleviate the congestion. The ISO does, however, use an intra-zonal congestion management algorithm which minimizes the impacts on the individual SCs' forward energy schedules. The network topology for intra-zonal congestion mitigation is generally a meshed network type.

2.7 Reliability Must-Run Generation

The ISO manages long-term Reliability Must Run (RMR) contracts and the dispatching of the RMR units. The units under RMR contracts are those that enjoy locational market power since the ISO needs a portion of their generation for reliable operation of the ISO control area regardless of their price. Accordingly, these are cost-based regulated contracts. The RMR units can in general participate in the competitive markets, and earn market profits for the portion of their capacity not dispatched under RMR.

Reliability Must-Run (RMR) generation is defined in the ISO Tariff as generation that the ISO determines is required to be on line to meet Applicable Reliability Criteria requirements. This includes:

i) Generation constrained on line to meet North American Electric Reliability Council (NERC) and Western Systems Coordinating Council (WSCC) reliability criteria for interconnected systems operation;

ii) Generation needed to meet Load demand in constrained areas (i.e., under conditions of intra-zonal congestion); and

iii) Generation needed to be operated to provide voltage or security support of the ISO or a local area.

In order to maintain the reliability of the ISO Controlled Grid, the ISO currently procures service from one hundred and seventeen (117) Reliability Must-Run units. During the first year of ISO operation, RMR units were classified in three categories called Contracts A, B, and C. When an RMR unit under Contract Type A was dispatched by the ISO, it was paid the startup cost (if it was not already scheduled to be on), variable cost per MWh of RMR energy, and a pro rata share of annual fixed cost (Reliability Payment) per MWh of RMR energy. Under Contract A, the owner kept any market revenues for energy or A/S resulting from the participation of the unit in the market. Under RMR Contract B, a pro rata share of fixed costs was paid up front (called the Availability Payment), but only the operating costs (start-up cost and variable cost) were paid per MWh of RMR energy. Under Contract B, however, the unit owner kept only 10 percent of its market profits for the non-RMR energy or capacity it sold from the unit in the market. The RMR units under Contract C received their full annual fixed cost, and were under direct control of the ISO. They were paid their operating costs (start-up and variable costs), but could not earn market revenues.

Because of flaws in the design of the RMR Contracts, their structure has been modified. During the first year of operation, it was observed that units under RMR Contract Type A that were dispatched under RMR frequently, had an incentive to withhold from the forward energy markets, even if the market clearing price (MCP) was higher than their operating cost, unless the MCP was high enough to cover the Reliability Payment as well. By withholding, such units could also potentially raise the forward market price for the rest of the units in the owner's portfolio. With RMR Contract B, where a large portion of market profits would have to be reimbursed, by withholding, the unit owner could advantage the other units in its portfolio, for which it would keep 100 percent of the market profits.

The ISO suggested two basic reforms in these contracts to eliminate these perverse incentives. The first modification was up front payment of a portion of fixed costs with no requirement to pay back any portion of the market profits. This would eliminate Contract A, and reduce the up front payment for contact B, thus substantially reducing withholding incentives. The second reform was to treat the minimum energy needed for system reliability as *must-run*, i.e., subject to pre-dispatch before the day-ahead market and netting it out by a matching load (or bid as a price taker in the PX market) in the day-ahead schedule. All parties to the Settlement of the RMR contracts have accepted the first modification. The second modification, pre-dispatch and netting out, is under dispute.

The ISO is currently involved in a process to develop a single *pro forma* Reliability Must-Run Agreement with terms and conditions of service and a standard rate methodology that can be uniformly applied to all RMR units. The ISO has currently identified ten local areas within the ISO Controlled Grid requiring RMR mitigation measures. Four of the ten local areas contain sub-areas that exhibit their own unique RMR criteria violations based on the location of generating units and geography.

2.8 Major Issues Encountered in the First Year of Operation

The California ISO markets started operation on March 31, 1998, with day-ahead schedules submitted for Operating Day April 1, 1998.

2.8.1 Real-time Energy Price Cap

Just before start-up, a deficiency was identified in the ISO's real-time Balancing Energy and Ex-post Pricing BEEP) software and its communication of instructions to settlements, making it evident that real-time prices could be set by the software at levels higher than those corresponding to actual dispatch. This deficiency could provide an opportunity for gaming and exercise of market power in ISO's real-time market, where no cost-based rates were in effect. Finding a solution to the problem was a pre-requisite for the transfer of control from the three California IOUs to the ISO. A bid price cap of $125/MWh was adopted as a temporary solution to allow the market to start up. The cap was subsequently raised to $250/MWh late in May 1998, bringing it in line with an administrative cap of $250/MWh on the adjustment bids in the ISO's congestion management markets.

2.8.2 Insufficient Bids for Ancillary Services and Cost-based Price Caps

During the first few weeks of operation, bid insufficiency in the A/S markets was the ISO's main problem. All A/S suppliers were subject to cost-based rate caps, while energy prices were not similarly regulated. As a result, suppliers could earn substantially more in the uncapped PX forward market than they could in the A/S markets[1] The ISO compensated for the deficiency in the A/S markets by calling upon the RMR units for A/S capacity. This was costly because: (1) of the pricing structures of RMR contracts, (2) most of the RMR units were under Contract A, which required the ISO to pay a *pro rata* share of their annual fixed and capital recovery costs in addition to their start-up and variable operating costs, and (3) due to the slow ramp rates of the Regulation capacity, much more capacity for Regulation had to be dispatched out of RMR.

2.8.3 Regulation Energy Payment Adjustment (REPA)

Bid insufficiency was particularly severe in the Regulation capacity market. In response to persistent bid shortages in this market, the ISO devised and adopted the Regulation Energy Payment Adjustment (REPA), which went into effect as of May 21, 1998, while waiting for FERC approval. The REPA paid all suppliers of Regulation capacity an energy adder, per MW of Regulation capacity, per hour, at the higher of $20/MW or the hourly real-time energy price. REPA was approved by FERC on June 24, 1998, effective retroactively to May 21.

REPA was effective but costly, making up more than half of the cost of A/S in the seven months it was in effect. It attracted sufficient Regulation capacity into the market and displaced the RMR calls for Regulation, although RMR calls were still being made to offset deficiencies in other A/S markets for some time. The RMR calls for A/S diminished gradually as FERC granted market-based rates for A/S to some generators starting in June 1998. The REPA payment was stopped altogether in November, following FERC's approval in late October of market-based rates for all A/S.

2.8.4 Lifting of Cost-based Caps for New Generation Owners (NGOs)

On June 30, 1998 FERC issued an Order granting AES market-based rates for A/S. In the same ruling, FERC also stated that Replacement Reserve was not a FERC Order 888 service, and therefore not subject to cost-based rate caps. At the same time, many suppliers of the other A/S (Regulation, Spin, and Non-spin) remained under cost-based rates. The uneven treatment of these markets led to defensive bidding by some of the IOUs, who were still under cost-based caps and were also *net buyers* of such services. Because Replacement Reserves is the last market

[1] The BEEP price cap did act as a *de facto* price cap for the PX forward markets, as the demand could shift from the PX markets to the real-time market. However, the BEEP cap was much higher than the A/S capacity cost-based rate caps, which were typically in the range of $5 to $12 per MW per hour.

to clear in the sequential market clearing process for A/S, this defensive strategy led to potential bid insufficiency in the Replacement Reserve market despite its prevailing market based rates.

2.8.5 July Price Spikes

As loads increased during Summer 1998's first major heat wave, just when the ISO was celebrating its first 100 days of successful and smooth operation, and with the news media on hand, the uncapped Replacement Reserves market hit the price of $5,000/MW/h on July 9. The Replacement Reserves price hit $9,999/MW/h on July 13, and stopped at that level only because the participants had assumed the ISO software would accept only up to four digits, when in fact it could have accepted up to 17 digits.

2.8.6 Damage Control Ancillary Service Price Caps

In response to the July 1998 spikes, the ISO made an emergency filing with FERC and set a cap of $500/MW on all A/S markets starting July 14. The cap was lowered by action of the ISO Governing Board on July 24 to $250/MW, in line with the caps on ISO's real-time energy and congestion management markets. At that point the ISO embarked on an ambitious market redesign program. On July 17, FERC responded to the ISO's emergency filing and granted the ISO the authority to set a maximum price at which it would purchase A/S. At the same time FERC ordered the ISO Market Surveillance Committee (MSC) and the PX Market Monitoring Committee (MMC) to prepare independent reports on the operation of the ISO's A/S markets. The MSC report of August 19, 1999 was adopted as the reference framework for ISO's market redesign program, as discussed in Section 3.6.

2.8.7 Record Loads and Emergency Conditions

Despite flaws in the market design, shortcomings in the software, and record loads, the ISO kept the lights on. Emergency conditions were encountered on a few occasions during peak summer days, with record temperatures and new system peaks. The ISO declared emergency conditions and asked industrial and commercial loads with load curtailment agreements to curtail load on four days as follows:

- July 27, from 2:52 p.m. to 5:00 p.m.
- August 4, from 4:00 p.m. to 5:30 p.m.
- August 31, from 3:05 p.m. to 7:00 p.m.
- September 1, from 12:30 p.m. to 6:00 p.m.

2.8.8 Out-of-Market Purchases

To avoid system emergencies, the ISO occasionally may make out-of-market arrangements with neighboring control areas. During the wet spring season, the ISO paid neighboring control areas to take its surplus power. But during the peak summer days, the ISO bought blocks of energy for its real-time market from neighboring control areas, to make up for deficiencies it expected to occur in its own markets. The following table shows the costs incurred by the ISO for out-of-market transactions with neighboring control areas during the months of spring (when over-generation was sold at negative prices) and summer (when block energy was purchased out-of-market).

Figure 2-4. Payments by ISO to Other Control Areas

Payments to other control areas to accept ISO's over-generation energy		Payments to other control areas for out-of-market procurement of supplemental block energy	
Date	**Amount**	**Date**	**Amount**
5/31/98	$10,741	8/3/98	$1,455,000
6/1/98	$434	8/4/98	$3,415,875
6/2/98	$16,013	8/5/98	$2,625,250
6/3/98	$4,164	8/10/98	$600,636
6/4/98	$10,714	8/12/98	$2,193,096
6/6/98	$174	8/13/98	$3,525,317
6/7/98	$40,904	8/14/98	$658,464
6/8/98	$14,641	8/20/98	$30,000
6/11/98	$4,207	8/22/98	$2,320
6/12/98	$1,095	8/24/98	$336,306
6/14/98	$1,575	8/31/98	$3,901,562
6/30/98	$1,735	9/1/98	$7,567,650
		9/2/98	$2,595,325
		9/3/98	$2,957,945
		9/4/98	$475,000
		12/20/98	$83,750
		12/21/98	$1,545,516
		3/14/99	$92,250
Total	**$106,398**	**Total**	**$34,061,261**

2.8.9 Market Design Modifications

In order to limit further the need for out-of-market transactions to avoid system emergencies, the ISO has adopted several measures in its market redesign program.

- The ISO Tariff now permits negative pricing of real-time energy (supplemental energy bids and the energy bids in the A/S capacity markets).
- The procurement and cost allocation of Replacement Reserve has been modified to augment the liquidity of the real-time energy market.
- Staged software development was completed, allowing the ISO to accept out-of-state bids into its reserve A/S markets (Spinning, Non-spinning, and Replacement reserves) beginning on August 6, 1998, with a limit of 25 percent of requirement on the import of Operating Reserves. This limit is being raised to 50 percent as of June 1999.

2.8.10 Changes in Criteria for Determining A/S Purchase Requirements

Starting on August 9, 1998 the ISO changed its operating procedure for determining its A/S requirements in the day-ahead and the hour-ahead markets. Instead of procuring A/S capacity based on scheduled load and generation, the ISO's load forecast was adopted as the basis for procuring these services. This step was taken after it became apparent that load was often significantly under-scheduled, particularly during peak days. Thus the ISO load forecast became the most reliable indicator of actual loads and of the amount of A/S needed to ensure system reliability.

In addition, the ISO had flexibility to slightly reduce its A/S procurement in the day-ahead market and make it up in the hour-ahead market, if this could substantially reduce the price it paid. With the lack of adequate liquidity in the hour-ahead A/S markets, however, ISO's ability to exercise such discretion was limited. This deficiency is now being gradually rectified with measures that systematically defer part of the A/S procurement to the hour-ahead market.

2.8.11 Uninstructed Deviations

To facilitate the response of market participants to real-time price signals, the ISO started publishing 10-minute real-time prices as of September 4. This measure was adopted after it became apparent that the delays associated with conveying hourly prices to the market were resulting in speculative *uninstructed deviations* from final hour ahead energy schedules by generation units, which in turn exacerbated the fluctuations in the real-time imbalance energy market. Publication of 10-minute prices was intended to encourage generators to engage in uninstructed deviations that would *reduce*, rather than exacerbate, system imbalances. It should be noted, however, that the ISO's current market redesign program includes several measures to discourage uninstructed deviations in general, and to encourage systematic participation through market bids.

2.8.12 Separate Procurement of Upward and Downward Regulation

Although the ISO needs different amounts of *upward* and *downward* Regulation, the ISO's initial market protocols procured a total amount of Regulation, without directly considering which direction the bidder offered. Starting on September 28, the ISO began selecting Regulation bids based on separate purchase requirements for *upward* and *downward* Regulation. Under these revised protocols, upward and downward Regulation requirements are established and procured separately, but pending software upgrades all Regulation bids accepted by the ISO are paid a single market clearing price, which is the higher of either the highest accepted upward Regulation bid or the highest accepted downward Regulation bid. In practice, upward regulation tends to be priced higher during hours when system load is declining, such as the late evening hours, when the demand for Regulation up is highest and the available supply is lowest. During morning hours when system loads are increasing, the price tends to be set by downward Regulation, since demand for this service is high and supply tends to be low during these hours.

The fact that both upward and downward Regulation are priced the same has given rise to aggressive and risky bidding behavior in the form of large negative bids to gain market share. A bidder can bid a highly negative price and offer disproportionate quantities in the two directions, hoping that someone else will be a positive price setter with quantities bid in the opposite direction. The Regulation market has occasionally cleared at negative prices, reaching -$99 /MW/hr on December 23, 1998, -$100 on February 3, 1999, and -$3,350 on May 16, 1999. Negative bids as aggressive as -$100,000 /MW/hr have been observed. This deficiency is being rectified during summer of 1999.

2.8.13 Removal of All Cost-based Price Caps

On October 28, 1998 FERC removed the cost-based rates on the A/S markets. This long-awaited decision allowed the ISO to do away with some of the special measures (such as REPA), which had been taken to ensure adequate supply in the A/S markets. On November 5, awaiting an ISO Board meeting, the ISO reminded market participants that nothing in the ISO Tariff prevents negative price bids in A/S capacity markets. The immediate result of this was that, with the cost-based caps lifted, *negative* market clearing prices for Regulation capacity ensued, which counter-balanced the REPA payment made in addition to the market capacity price. On November 27, 1998, REPA was reduced to zero based on an ISO Board decision, resulting in positive market clearing prices for Regulation.

2.8.14 Negative Energy Bids and Over-generation

The ISO started accepting negative price bids for supplemental energy (and energy out of A/S capacity) on March 17, 1999. The real-time market cleared at a negative price (-$3.5 /MWh) for three hours on March 28, 1999.

Figure 2-5. Chronology of Key Events in California Electricity Markets

Date	Action	Market Conditions and Impact
Mar.31, 1998	PX and ISO day-ahead markets opened. Real-time energy cap of $125, PX cap of $2500, cost-based caps on A/S capacity.	Insufficient A/S bids, especially for Regulation.
May 21*	ISO implemented REPA. Units providing Regulation receive MCP of capacity plus REPA payment equal to maximum of $20/MWh or real-time energy price.	Supply bids nearly doubled on average in first week compared to prior week, and bid sufficiency increased thereafter.
May 27	Real-time cap raised to $250.	
June 10	FERC approved $244/MWh cap for El Segundo LLP, based on the A/S cost-based rates in its RMR contract, subject to refund, and set the matter for rehearing.	Prices for Regulation and Spinning Reserve were often at or close to $244 cap for some hours of following days.
June 24	FERC approved REPA.	Regulation supply bids increased slightly in first week compared to prior week.
June 30	FERC approved market-based rate authority for AES.	No Regulation or Spin prices went above $244; Non-spin remained low in period until damage caps imposed.
June 30	FERC declared that Replacement Reserves were not an A/S (in AES case), so not subject to cost-based cap.	Replacement reserve bid sufficiencies improved dramatically, but prices spiked up to $9999 in following days.
July 1*	ISO began procuring A/S by zone when possibility of congestion on Path 15.	A/S price spikes in SP15 due to low bid sufficiency and market power of NGK's . A/S supply bids from NP15 not utilized to meet demand in SP15, even though this would often create counter flow from direction of congestion (south to north).
July 10	FERC approved market-based rate authority for Destec and Houston Industries.	ISO did not buy any Replacement Reserves July 10. The following days had widely varying demands by hour.
July 13	ISO imposed $500/MWh damage control caps on A/S prices effective trading day 7/14.	

July 14	ISO stopped procuring A/S by zone, except for hours when day-ahead congestion on Path 15 is forecasted (effective trading day 7/15).	
July 26*	ISO reduced A/S damage control caps from $500 to $250/MWh.	
Aug. 8	ISO implemented software to allow out-of-control-area imports of A/S, except for Regulation.	Improved bid sufficiency during peak hours.
Aug. 9*	ISO began procuring A/S based on load forecast rather than schedules.	
Sept. 28*	ISO began procuring Regulation up and down separately, while paying the higher of the two marginal bids.	ISO only transfers the excess RegUp to the Spin market now, instead of the incorrect excess total Reg supply.
Oct. 28	FERC authorized market-based rates for all sellers of A/S and Replacement Reserves. To take effect November 3.	
Nov. 6	ISO reminded market participants of their ability to submit negative bids.	Negative Regulation prices resulted on next trading day.
Nov. 28*	ISO terminated REPA payments.	Regulation prices immediately rose.
Mar.17, 1999*	ISO allowed negative bids for Spin, Non-spin, Replacement, and Supplemental Energy.	

* indicates Trading Day change was effective.