Report on Redesign of California Real-Time Energy and Ancillary Services Markets

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Summary

This report reviews the performance of the California ISO's real-time energy and ancillary services markets over the past 18 months, with particular emphasis on the relative performance of these markets during the summer of 1999 versus the summer of 1998. We offer recommendations for correcting some of the remaining market design flaws identified in previous MSC reports. We also identify several flaws in the market design that have revealed themselves since our March 1999 report was submitted. Recommendations for correcting these market design flaws are provided. Finally, we describe several long-term changes in market design that we believe should be implemented to facilitate the transparency of hourly wholesale market prices to retail electricity customers.

The performance of the ISO's ancillary services markets during the summer of 1999 appears to be significantly improved relative to the same month during the summer of 1998, based on market prices, market requirements, and bid sufficiency frequencies. However, a substantial proportion of this improvement in market performance can be attributed to lower average hourly total system loads during the summer of 1999 relative to the summer of 1998.

We find that significant market power remains in California's wholesale energy market during periods of high total system load, which primarily occur during the summer months. We find that for the majority of summer months in 1999, for the same level of total system load, real-time energy prices were higher in 1999 than in 1998. Nevertheless, the total amount of market power exercised during the summer month of 1999 that we have data for appears to be significantly less than that exercised during that same month in 1998. We also present evidence that suggests that the opportunities for the exercise of market power in the ISO's ancillary services markets are greater when these markets are cleared on a zonal versus statewide basis.

The outstanding market design flaws identified in previous MSC reports are: (1) rules for dispatching Reliability Must-Run (RMR) contract generation units, (2) the lack of a price-responsive hourly wholesale electricity demand, and (3) the inability of utility distribution company loads to forward contract for their energy and ancillary services demands outside of the PX markets.

Market design flaws identified since the April 1999 MSC report are: (1) the incentives for generation unit owners to create and profit from resolving intra-zonal congestion, (2) non-compliance of generation unit owners with ISO technical standards for providing energy and ancillary services capacity, and (3) the lack of incentives for price-responsive retail demand caused by the current California "stranded asset" recovery mechanism.

Long-term market redesign issues analyzed are: (1) ISO policy for new zone creation, (2) ISO policy for new generation interconnection, (3) retail competition policies when any one of the three investor-owned utilities ends its stranded asset

recovery period, and (4) mechanisms for selling Pacific Gas and Electric's hydroelectric facilities to enhance the competitiveness of the California wholesale electricity market.

This report provides recommendations for addressing each issue. We continue to advocate pre-dispatch and mandatory day-ahead scheduling of RMR capacity as market-efficiency enhancing, consistent with the market design principles of the California market, and necessary for a workably competitive wholesale electricity market.

Because of remaining market power in the California wholesale electricity market and the lack of incentives for a price-responsive hourly retail demand created by the California market's stranded asset recovery mechanism, we continue to advocate that the ISO have the authority to impose a purchase price cap on its energy and ancillary services markets, at least until all remaining major market design flaws are eliminated. We advocate that the ISO maintain the current $750/MW price cap at least through the end of the summer of 2000. At this time, enough information on the performance of the ISO's markets under the new ancillary services market design and new RMR contracts (with the pre-dispatch and day-ahead scheduling reforms suggested above) will be available to evaluate whether removal or raising of this price cap is warranted.

We recommend revising the ISO's intra-zonal congestion management protocols to create strong incentives for market participants to eliminate rather than cause intra-zonal congestion. A framework for determining the advisability of creating new congestion zones from a market power perspective is given. Based on the market power analysis presented in this report and incentives for creating intra-zonal congestion under current ISO protocols, we believe that the ISO should exercise restraint in creating new congestion zones, unless it feels that system reliability will be significantly enhanced by creating a new congestion zone.

We also recommend that the ISO monitor the FTR market and establish position limits on the quantity of FTR capacity controlled by any single market participant (including affiliates) during the initial stages of the operation of this market. Because of the several features of the FTRs offered by the ISO, there may be opportunities for certain market participants purchasing a large fraction of the FTR capacity on certain transmission paths to profit from subsequently creating inter-zonal congestion in the day ahead energy market.

To provide incentives for retail competition that increases the responsiveness of hourly retail demand to hourly wholesale electricity and ancillary services prices, we recommend the adoption of a default provider retail rate in the post-rate-freeze period that reduces the original rate-freeze retail rate by some fraction of the previous year's annual average stranded asset recovery, rather than one that passes-through hourly wholesale energy and ancillary services costs according to a representative load profile.

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1. Introduction and Summary

This report analyzes the performance of the ISO's energy and ancillary services markets since the previous Market Surveillance Committee (MSC) report was submitted to the Federal Energy Regulatory Commission (FERC) on March 25, 1999. We offer recommendations for correcting some of the remaining market design flaws identified in previous MSC reports. We also identify several flaws in the market design that have revealed themselves since our March report was submitted. Recommendations for correcting these market design flaws are provided as well. Finally, this report describes several long-term changes in market design that we believe should be implemented to facilitate the transparency of hourly wholesale market prices to retail electricity customers. These changes should be implemented before the Competition Transition Charge (CTC) period, during which the original investor-owned utilities (IOUs) receive payment for their "stranded assets," ends.

A. Assessing the Performance of the ISO's Markets

1. Status of Redesign of Ancillary Services Markets

Since our last report, the ISO has implemented or will soon be implementing a number of ancillary service (A/S) market reforms. These reforms and their implementation dates are summarized below and many are described more fully in the body of this report.

Market Reform	Date Implemented
• Allocation of A/S cost based on metered demand	August 17, 1999
• Withholding payments when awarded A/S capacity is found to be unavailable in real-time.	February 2000
• Rational Buyer Protocol	August 17, 1999
• Additional Replacement Reserve procured to make up day-ahead under-scheduling of load and under-production of generation Requirement criteria Cost allocation	August 17, 1999
• Automated BEEP	February 2000
• Separate upward and downward regulation prices	August 17, 1999
• Improved facilitation of load participation in A/S markets	No definite date
• Inter-SC trades of A/S	September 13, 1999
• Improved ISO control of regulation units	December 31, 1999

2. Data Currently Available

Because many of the major ancillary services market redesign changes have only recently been implemented, the MSC has been unable to analyze comprehensively many of the issues FERC requested that the MSC address in this report. In particular, the vast majority of the design changes in the ISO's ancillary services markets were implemented on August 18, 1999, leaving the MSC with, at best, less than one-month's worth of data on market outcomes to use to determine the impact of these changes on market performance. Given the dramatically different load conditions between August and September 1999 and these same two months during 1998, these limited data are insufficient to provide any definitive assessment of the success of the ancillary services market re-design process. Several of the other ancillary services market re-design elements were implemented very recently, and others have yet to be implemented. Because of the comprehensive and interrelated nature of these market reforms, any assessment of their success given the data available at present would be premature.

The major Reliability-Must-Run (RMR) reforms were implemented effective June 1, 1999. A complete assessment of these reforms is also constrained by data availability. The ISO's settlement data on actual metered unit-level electricity production and take-out-point electricity consumption on an hourly basis is currently only available through July 26, 1999.[1] This information is an essential input to a full assessment of the performance of the California energy market. Nevertheless, we offer a detailed analysis of the performance of the California energy market up to this date.

Although our focus is on the ancillary services markets and real-time energy markets, because of the very strong interactions among these markets and the PX markets (as emphasized in the our previous reports), the ISO's markets cannot be understood in isolation from the PX day-ahead and hour-ahead markets.

Despite the fact that data constraints prevent us from assessing the impact of ISO's recent market design changes, we note number of outstanding design flaws, including several that have become more noticeable since the March 1999 report.

3. Performance of the ISO's Markets is Improving

From October 1998 to June 1999 market performance in the California energy market is what would be expected from a workably competitive market. We attribute this in no small part to the fact that this period was characterized by low levels of total ISO load relative those that occur during peak hours in the summer months. In addition, during many of these months, electricity from hydroelectric facilities was plentiful. The performance of the California energy market over this time period is encouraging. Given system and weather conditions over this time period, it is not surprising, and certainly does not imply that the ISO's markets will be workably competitive under more demanding load conditions.

[1] Some of our data is available more recently than July 1999. For example, we are able to track bids and market-clearing prices through August 31,1999. We also analyze selected data on market-clearing prices and quantities recently through October 1, 1999.

Our basis for concluding that the performance of the market has improved comes from analyzing many of the indices discussed in our previous reports. We find that the frequency of price spikes in the ancillary services markets that cannot be explained by high load conditions has been significantly reduced. Generally, the price caps have been hit in the energy and ancillary services markets during late 1998 and early 1999 when total ISO load has been fairly high. This observation tends to support the view that, at least most of the time, prices reflect underlying demand and supply conditions rather than the exercise of market power. We are also encouraged by the fact that total ancillary services costs as a fraction of total energy costs have continually fallen from late 1998 through August 1999.

There are several reasons for the apparent improvement in the performance of these markets. A number of market design changes have been implemented; these should improve the efficiency of the market. Furthermore, the ISO continues to learn and improve its operations. Specifically, we present evidence that the ISO has managed to use less of certain ancillary services to provide reserve capacity for the same level of total ISO load. In addition, the ISO has embarked on a comprehensive plan to improve the compliance of market participants with the technical standards associated with providing the various ancillary services. For example, when the ISO procures a 10-minute response-time service it can easily verify if that is what it is actually getting. This increased monitoring, combined with penalization for non-compliance, has improved the quality of ancillary services capacity submitted to the various ISO markets. These monitoring and enforcement activities also have increased the likelihood that, if called on to provide real-time energy, a unit owner can and will actually provide that energy under the terms at which the associated capacity was bid into the market.

The very mild weather conditions experienced in California during the summer of 1999 are probably the single most important factor behind the apparent improvements in market performance. The ability of firms to exercise market power requires sufficiently high load conditions, which is typically due to very hot weather. During these time periods, all generators know that they stand little likelihood of not being called to provide either energy or ancillary services, even if they bid significantly in excess of their production costs. However, when the weather is mild, the demand for electricity is significantly lower relative to available generation capacity. All generation unit owners know that under these load conditions they stand a significant likelihood of not being called to provide energy or ancillary services if they bid sufficiently in excess of their marginal cost of production. Consequently, a true test of the success of the ancillary services and other market reforms must await a time period when system load conditions are at or above those experienced during the summer of 1998, a period with very high system loads.

4. Market Power Persists

Despite these improvements, our analysis of the recent data from the summer of 1999 reveal that market power persists in the ISO's markets, particularly during periods of high system load. During these time periods, price movements across hours of the day are significantly in excess of the increased costs of supplying power during these hours.

During these time periods, even the highest-cost generation unit supplying energy is being paid according to a price significantly in excess of its marginal production cost in that hour. This is a direct indication of market power.

We have limited data from the summer of the 1999 with which to perform a definitive analysis of the exercise of market power during these months. However, for the one month we do have data, July 1999, we see evidence of continued exercise of market power. Specifically, we calculated market clearing prices assuming a “pure” competitive market benchmark, compared them to actual energy costs in those hours, and found the actual costs to be on average 20% above those predicted by this benchmark market outcome. Although below the value of this spread in July 1998 of 38%, the spread for July 1999 remains unacceptably high.[2] It is important to note that the existence of this amount of market power in the California wholesale electricity market does not imply that the annual total cost (including wholesale electricity and ancillary services costs) of delivering electricity to final consumers in California is higher than it would have been if the vertically-integrated monopoly regime had continued.

Our analysis of market conditions following the recent increase in the price cap in the ISO’s energy and ancillary services markets from $250/MW to $750/MW (on October 1, 1999) shows that under certain system conditions (which could occur with some frequency during the summer and early fall), prices in both the energy and ancillary services markets can rise to their maximum levels, well above marginal production costs. The evidence therefore supports the need for some level of price protection for buyers until we can review market performance next summer and confirm that the extent of the exercise of market power has substantially decreased.

5. Underlying Causes of Market Power

The underlying causes of market power in the ISO's markets are no different from those leading to market power in other markets. Buyers have a limited ability to substitute to other products (inelastic demand). Suppliers from outside the market have limited ability (usually due to transmission constraints) to offer their product for sale (inelastic supply). There is also concentration among sellers, and certain existing regulatory rules further reduce flexibility on the supply and demand side of the market.

Final hourly retail demand is virtually price inelastic with respect to the hourly wholesale price of electricity. This is due in large part due to California’s retail rate freeze that severs the link between hourly wholesale energy costs and retail prices paid for electricity consumed. The current combined retail rate freeze and stranded asset recovery mechanism eliminates any incentive retail customers have to install hourly meters and purchase their electricity according to rates that vary with hourly wholesale energy and ancillary service prices. This mechanism eliminates virtually any incentive energy services providers (ESPs) have to install real-time meters and bill their customers according to rates that vary with hourly wholesale energy and ancillary service prices.

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[2] This figure was computed using the methodology described in "Diagnosing Market Power in California's Restructured Wholesale Electricity Market," Severin Borenstein, James Bushnell, and Frank Wolak, University of California Energy Institute, July 1999. Available from http://www.ucei.berkeley.edu/ucei/.

Supply remains fairly concentrated, although the recent divestiture of much of Pacific Gas and Electric's fossil fuel capacity to Southern Company has reduced the concentration of generation ownership in the NP15 congestion zone. Still, particularly during hot weather days, demand conditions are such that certain suppliers are "pivotal" and their bids can have a large effect on the price of energy or any of the ancillary services during certain hours of the day.

Concerns about market power for a given ancillary service are exacerbated during periods of peak demand for that service and during periods of inter-zonal transmission constraint in the day-ahead energy market. Periods of peak demand for certain ancillary services need not coincide with periods of peak demand for electricity. For example, the ISO's peak demand for regulation typically arises during the shoulder periods on days when energy demand is peaking. Inter-zonal transmission constraints creates smaller geographic markets which can lead to greater opportunities for generation unit owners to exercise market power within each congestion zone.

Finally, it is important to emphasize that the California energy and ancillary services markets remain a work in progress. Key elements of this market are still not in place: complete reform of the RMR contracts, meaningful compliance (e.g., the ability of the ISO to verify that suppliers of ancillary services indeed stand ready to offer those services as promised), and various ISO operating practices, software upgrades, and the like.

B. Short-Term Recommendations

1. Complete the Design of California Markets

The ISO is still in the process of implementing various market designs that, hopefully, will improve the efficiency of the ISO's markets. Over the past year, this process has focused on the redesign of the ancillary services markets, although significant efforts are underway which are aimed at improving the responsiveness of the real-time energy BEEP stack.

A major outcome of the ancillary services re-design process is the implementation of the Rational Buyer protocols. The ISO has also adopted ancillary services procurement practices that have improved the liquidity of the hour-ahead ancillary services market, by delaying some of its ancillary services purchases from the day-ahead to the hour-ahead market. Finally, ISO has taken steps to reduce its role as the major purchaser of ancillary services by allowing Scheduling Coordinators more flexibility in self-providing their ancillary services requirement through inter-SC trades. A major component of the project to increase the responsiveness of the real-time BEEP stack is aimed at increasing the speed and accuracy with which dispatch instructions are sent to generators and responded to. The other component is concerned with *ex post* verification of actual compliance with ISO technical standards for providing each of the ancillary services, and confirmation that all ancillary services purchased are actually supplied.

2. Retain Price Caps for an Interim Period

Perhaps the single most important policy issue we address in this report is whether the FERC should continue to grant the ISO the authority to impose purchase price caps on its energy and ancillary services markets. Several outstanding design flaws identified in our previous reports have not yet been adequately addressed, so that the ISO's markets cannot yet be relied upon to be workably competitive. This is particularly true during hours of high ISO system load, which primarily occur in the months of July to September. Consequently, we strongly believe that the FERC should continue to grant the ISO the authority to impose purchase price caps. Indeed, under current market conditions, we believe that removing the ISO's authority to implement a purchase price cap would pose a significant risk in that very high prices for energy and ancillary services could prevail during hours with a high ISO system load and/or high demand for a specific ancillary service. We therefore urge the FERC to extend the ISO's authority to impose purchase price caps on all ISO markets until it is clear that significant market power cannot be exercised in the ISO's markets. The current $750 maximum price should be retained at least until RMR reform is completed. The price cap should remain at this level through the end of the summer of 2000.

3. Remove Regulatory Barriers to Demand Response

The current CTC recovery mechanism and the associated retail electricity price rate freeze is a major barrier to the development of the price-responsive hourly retail demand necessary for a price responsive hourly wholesale demand for energy and ancillary services. As discussed in previous MSC Reports, a price-responsive hourly wholesale demand is essential to limit the exercise of market power by generators during periods expected to have high system loads. During periods of low system loads, competition among suppliers is usually sufficient to discipline the exercise of market power because a significant fraction of available generation capacity is not needed to meet anticipated demand. Currently, during periods forecast to have high system loads, all generation unit owners know that a very large fraction of their capacity will be required to meet the ISO's energy and ancillary services needs, regardless of the bid price. With a credible price-responsive hourly wholesale demand (which is only possible with a price-responsive hourly retail demand), generators bidding high prices know that they stand a significant chance of not selling their capacity, even during periods predicted to have high system loads. For this reason, generation unit owners will bid prices closer to their marginal costs because they recognize that if prices are too high, the price-responsive wholesale demand will decide not to purchase.

We show that the current CTC recovery mechanism and associated retail rate freeze dulls the incentives ESPs have to install the hourly meters necessary to enable meaningful hourly pricing of retail electricity. This regulatory mechanism also eliminates virtually any financial incentive retail customers have to install their own hourly meters or purchase electricity according to retail rates which reward hourly price-responsiveness to wholesale electricity and ancillary services prices. The only market participants with financial incentives to reduce wholesale energy and ancillary services prices are the three utility distribution companies (UDCs), who currently have very little financial incentive to provide hourly metering technology to their retail customers. The three original IOUs also currently have significantly less ability to reduce wholesale energy and ancillary services prices relative to the summer of 1998 because of the sale of a significant amount of their in-state fossil fuel generating capacity since that time.

We also show that the requirement of the CTC recovery mechanism which prohibits forward contracting for energy and ancillary services by the utility distribution companies (UDCs) outside of PX reduces the opportunities for final demand in the California market to respond to high energy and ancillary services prices. Under this mechanism, the only market participants with a significant financial incentive to keep wholesale energy prices low currently have significantly less ability to do so. All other market participants are either indifferent to high wholesale energy and ancillary services prices (the ESPs and retail customers) or have a strong financial incentive to cause high prices (the new generation owners). Consequently, we believe that these incentives provided by CTC recovery mechanism make a very strong case for the FERC continuing to grant the ISO the authority to set a purchase price cap on its energy and ancillary services markets.

We also believe that all restrictions on IOUs entering into long-term forward financial contracts for energy and ancillary services outside of the PX should be removed. We would very much like to see the PX provide these products and we applaud the formation of the "block forwards" market for energy. We also hope that a similar market for ancillary services will be created very soon. To provide additional incentives for market participants to offer the full range of forward financial instruments that loads desire, the UDCs should be permitted to enter into these forward financial contracts with whomever they wish. We should emphasize that we are not advocating that UDCs no longer be required to use the PX as their Scheduling Coordinator for all of their generation and load for the rate freeze period. We believe that this requirement of the CTC recovery mechanism substantially improves the efficiency of the California electricity market during its initial stages of development by providing a transparent and robust market where generators and loads can hedge their day-ahead energy commitments and obligations. Because of the incentives caused by other requirements of the CTC mechanism described above, this role of the PX is even more valuable during the retail rate freeze period.

We also believe that the end of the CTC recovery mechanism for an UDC, such as San Diego Gas & Electric's announcement to end on July 1, 1999, presents a unique opportunity to develop the incentives for price-responsive retail demand necessary for a competitive wholesale energy and ancillary services market. A very important question that must be addressed at the end of the retail rate freeze is how to determine the default provider rate option for the UDC. To foster a price-responsive retail demand and encourage true value-added retail competition, the default provider retail rate should be set at the current rate freeze price less some fraction of the expected reduction in per MWh CTC payments by the UDC's customers as a result of ending the rate freeze. The default provider retail rate should not be set equal to the hourly wholesale price plus the per unit transmission and distribution charges and other per unit unavoidable charges unless the customer already has an hourly meter installed. Charging a customer with a conventional meter according to this rate requires the use of load-profiling, which destroys any incentive the customer has to reduce its hourly demand in response to high wholesale prices in that hour. For this reason, such a default provider rate locks-in a retail demand that does not respond to hourly wholesale price movements, while at the same time virtually eliminating any profit margin for ESPs to compete for by supplying electricity to retail customers. Under our suggested default provider scheme, one way these retail margins can be competed away is by ESPs and the UDCs paying for the installation of hourly-metering technology. Customers on hourly meters will increase the competitiveness of the wholesale electricity market, which should result in lower average wholesale electricity prices to all California consumers, whether or not they have an hourly meter.

4. *Improve FERC and CPUC Communication*

As noted in the previous section, a price-responsive hourly wholesale demand for electricity is not possible without a price-responsive hourly retail demand. This is perhaps the best, but by no means the only, illustration of how retail electricity market regulatory polices set by the California Public Utilities Commission (CPUC) have a direct impact on the efficiency of wholesale electricity markets. The CTC recovery mechanism described above is another important example. Wholesale markets in California and rest of the United States would greatly benefit from retail policies that improved rather than hindered the efficiency of wholesale electricity markets.

Another area of state-level regulatory policy that can exert a significant impact on the competitiveness of wholesale electricity markets is the process for expanding, siting and financing new transmission capacity. Given the increased opportunities for the exercise of market power during hours when there is congestion in the transmission grid, state policies that are consistent with increasing the efficiency of wholesale electricity markets are crucial to the success of wholesale electricity industry re-structuring efforts.

Consequently, we recommend that the FERC coordinate its policies to enhance the competitiveness and efficiency of wholesale electricity markets with CPUC policies for the design of state-level retail electricity market policies. The ultimate goal of electricity restructuring--lower delivered electricity prices for California consumers--can be best achieved with greater communication and coordination between the CPUC and FERC along this dimension. A useful step in direction would be to organize a conference on this topic between relevant FERC and CPUC staff and California market participants. This would be an ideal forum to discuss the major issues associated moving the California market from one with few incentives for market-efficiency-enhancing behavior, caused in part by the CTC recovery mechanism, to one which provides all market participants with the price signals necessary to market-efficiency-enhancing decisions.

5. *Implement Pre-Dispatch and Day-Ahead Scheduling of RMR Units*

Our previous reports provided detailed analyses of the Reliability-Must-Run units and the contacts under which those units operate. The new RMR contracts, which became effective June 1, 1999, represent a significant improvement over the original RMR contracts that they replaced. However, the issue of when to dispatch and schedule RMR units under these new contracts has been point of disagreement between the ISO and the owners of these units. As we explain in detail below, the efficiency of California's energy and ancillary services markets would be improved by dispatching RMR units *before* the start of the day-ahead energy market. Under this procedure, the pre-dispatched RMR capacity from each RMR unit would then be required to be part of a balanced day-ahead energy schedule submitted to ISO. This change should greatly reduce or eliminate the market inefficiencies caused by the attempts of RMR unit owners to use the local market power possessed by their unit during certain system load conditions to set high prices in the energy and ancillary services markets.

6. *Use PG&E Hydro Divestiture to Enhance Competition*

The sale of PG&E's hydro assets can hasten the end of its CTC recovery period, and thus potentially contribute to improved hourly price-responsiveness in the California market. However, there should be no rush to complete this divestiture unless it reduces concentration in the markets to provide ancillary services and energy. We recommend selling PG&E's hydro assets in watershed-size increments to entities not currently owning significant generation capacity in California. We much prefer a "structural" solution of this type, which genuinely reduces market power, rather than a "behavioral" solution consisting of various regulatory rules intended to limit the exercise of market power by new owner. Behavioral rules may be hard to monitor and enforce, and may enhance the ability of other firms, besides the one subject to the behavioral rules, to exercise market power. Therefore, these sorts of behavioral rules may increase market prices even though the firm subject to these rules never sets the market price.

7. *Modify the ISO's Congestion Management Procedures*

This report also analyses the impact of the ISO's current intra-zonal congestion management protocols on the performance of the real-time energy market. Since the March 1999 report, intra-zonal congestion costs have dramatically risen, and the number of intra-zonal interfaces experiencing noticeable congestion has also risen. We suggest several market rule changes that would significantly reduce the frequency of intra-zonal congestion and the mitigation costs when it does occur.

The ISO's current system for managing intra-zonal congestion provides no market participant with a financial incentive to reduce intra-zonal congestion costs. However, depending on load conditions and the production of nearby generation units, any generation unit owner can profit from causing intra-zonal congestion that it subsequently relieves. This occurs because the ISO's intra-zonal congestion management protocols allows generators located on a workably competitive side of an intra-zonal interface to be paid as bid to relieve the congestion. The California market rules allows unit owners to pursue their financial interests in the real-time market. Therefore, when these firms find that grid conditions are such that they can earn substantial profits from alleviating intra-zonal congestion along an intra-zonal path, this congestion tends to occur. Consequently, it appears that much of the current intra-zonal congestion in the California market is not caused by bidding behavior of price-taking generators, but it is instead the result of strategic actions of favorably located generators who understand the incentives created by the ISO's current intra-zonal congestion management protocols. We should emphasize that we are not saying that these generators are violating the ISO market rules by these actions. These generators are simply attempting to maximize their expected profits subject to the market rules they face.

Our solution to this market design flaw is to create a market participant with a strong financial incentive to keep intra-zonal congestion costs down. As we argue, there is no meaningful economic distinction between energy provided to relieve intra-zonal congestion from a local monopoly or duopoly supplier of this service and local grid reliability services provided by a local monopoly or duopoly supplier of this service. RMR units are designated to provide the latter but not the former service, although the ISO tariff allows these units to be used to provide this service as well. We classify both of these services under the general category of "market liquidity," because once a given quantity of market liquidity energy has been provided at certain points in the transmission grid, it is possible to run an unconstrained zonal energy market. These market liquidity providers have an incentive to alleviate intra-zonal congestion because under the terms of their RMR contract, they face the prospect of being called to relieve intra-zonal congestion with incremental or decremental energy at their RMR variable payment rate. During high load conditions, when the zonal energy price is expected to be very high, the prospect of foregoing the zonal-market clearing price and receiving the RMR variable payment rate to relieve intra-zonal congestion gives the RMR unit owner a strong incentive to generate from its RMR units and other units to prevent intra-zonal congestion. This will allow the firm to earn a high zonal price for all its capacity producing imbalance energy during that hour.

To give the Participating Transmission Owner (PTO) the incentive to upgrade the transmission grid on the paths where there is significant intra-zonal congestion, we recommend charging the PTO for the costs of all RMR calls to mitigate intra-zonal congestion. Currently, RMR energy used for local grid reliability services is charged to the PTO, so that by charging the PTO for the costs of relieving intra-zonal congestion by RMR units, we are explicitly recognizing the equivalence of these two actions by RMR units.

We also recommend that the ISO delay implementing any scheme for managing intra-zonal congestion in the forward market until it is convinced that the incentives to cause intra-zonal congestion in the real-time market have been significantly reduced. Otherwise it may simply end up paying twice to relieve the intra-zonal congestion along the same transmission path--once in the forward market and again in the real-time market. This outcome can occur because even though day-ahead energy schedules are required to be balanced and are made feasible by a forward market intra-zonal congestion measure, a generation unit is free to deviate from this schedule and cause intra-zonal congestion if this is profitable given system conditions in real-time.

8. Monitor Firm Transmission Rights (FTRs) Market

We remain unconvinced that Firm Transmission Rights (FTRs) sold by the ISO are a socially valuable "product." First, they are designed to be primarily used to hedge against congestion charges in the day-ahead energy market, where no energy is actually delivered, and not against congestion charges in the real-time market, where all energy is delivered. We also do not expect any market participant to pay more for an FTR than it can expect to earn in congestion revenues by owning this right. However, the ex post cost to another market participant besides the ISO of selling this hedge product is exactly equal to these congestion revenues. Consequently, one interpretation of the ISO's sales of FTRs is that it is selling a product at an expected loss (the price is less than the congestion revenues the FTR owner expects to receive) to hedge congestion charges in a market where no energy is actually delivered. The ISO's FTRs also provide scheduling priority in the event that there are insufficient adjustment bids to clear the market on either side of a transmission path. However, for a large enough default usage charge along a transmission path, we would expect Scheduling Coordinators to always find it in their financial interest to submit adjustment bids across the transmission path, so that the ISO's scheduling priority should rarely, if ever, come into play.

Because of the opportunities to earn profits from day-ahead inter-zonal price differences created by the existence of FTRs, one can understand why most market participants want the ISO to offer this product. However, it is unclear why requiring that ISO offer this product enhances the efficiency of the California electricity market. If the ISO did not offer FTRs, we would expect similar products to be offered if there were generators and loads willing to pay prices greater than or equal to the expected congestion revenues they avoid by the purchase of this product. This requirement on the relationship between the privately supplied FTR price and the expected congestion revenues avoided is necessary for the entity offering the product to expect to earn a profit. In addition, we would also expect these privately offered transmission congestion hedge contracts to be based on congestion in the real-time market, when generation unit owners are actually supplying energy to the grid, rather than congestion in the day-ahead market which leads to only forward financial commitments to produce electricity. As the incident involving Path SR3 on May 25, 1999 illustrates, a SC's day-ahead energy schedule along a transmission path can differ enormously from the capacity of the path[3]. This can then lead to significantly higher zonal or statewide day-ahead energy prices and a very high transmission charge across that path.

Because of the uncertain benefits to market efficiency from the ISO selling FTRs and the increased profit-making opportunities they allow market participants who are able to cause inter-zonal congestion, we strongly recommend that the ISO be able to monitor the operation of this market. We also continue to believe that if certain market participants are able to obtain a large fraction of the FTR capacity on a certain transmission path, they may be able to earn profits from setting extremely high

[3] On May 25, 1999 a day-ahead energy schedule was submitted across Path SR3, which has a capacity of 15MW, that was more than 100 times this value.

congestion prices along this path.[4] Therefore, if there are going to be FTRs, in order to monitor this market, we strongly recommend that market participants be required to report all secondary trades so that regulators (and the ISO) can track the ownership of these rights. We also believe that the ability of generators to set very high congestion prices will be greatly diminished if *position limits* are imposed on their ownership. These position limits would set a maximum on the fraction of available FTR capacity of a transmission path that a market participant can own. We recommend that any one entity (including affiliates) be limited to holding no more than 40% of the available FTRs on any given interface.

9. Exercise Restraint in Creating New Zones[5]

When a transmission path within a zone is regularly congested, there are good reasons to create a new zone. This transforms an intra-zonal interface into an inter-zonal interface: doing so allows congestion over this interface to be handled using market processes based on adjustment bids (as opposed to the ISO's procedures for handling intra-zonal congestion). However, creating a new zone can lead to highly concentrated ownership of generation units in the markets within each zone, which enhances the ability of generation unit owners to set high zonal prices. In the light of this tradeoff, it is not the case that creating more zones always or typically enhances the efficiency of the overall market. Recognizing this tradeoff, the ISO Tariff calls for the creation of new zones only if generation markets on both sides of the interface in question are "workably competitive."

Below we provide a framework for assessing whether electricity markets in general, and zonal generation markets in particular, are "workably competitive." We then apply this general framework and offer an empirical analysis of market outcomes during 1999, which demonstrates that zonal markets do indeed allow greater opportunities for the exercise of market power. We find that, controlling for the level of total system load, when the ancillary services markets in California were cleared on a zonal basis, day-ahead prices in the SP15 congestion zone were significantly higher than in comparable hours, in terms of total system load, when the markets were cleared on a statewide basis. In addition, we find that what we call the pivotal bidder frequency in the ancillary services markets is significantly higher when these markets are cleared on a zonal basis rather than statewide. We say that a bidder is pivotal in a market during a given hour if by removing its bids from the market there are insufficient remaining bids to meet market demand. This implies that at least for the amount of this bid shortfall, in the absence of a purchase price cap on that market, the pivotal bidder could name any bid price and that would set the market price.

In addition, in our analysis of the ISO's current intra-zonal congestion management protocols we show that there are no market participants with a significant

[4] In May of 1998, the MSC issued an opinion on the ISO's transmission rights proposals. At that time position limits were recommended. This opinion is included as Appendix A to this report.
[5] Rules regarding the creation of new zones is intimately linked with procedures by which intra-zonal congestion is managed and new generators can interconnect to the grid. We address both of these issues below in the section on long-term recommendations.

financial incentive to reduce the incidence of intra-zonal congestion, but many with strong financial incentives to cause intra-zonal congestion. Consequently, it is difficult to argue that the same frequency and geographic distribution of intra-zonal congestion would occur if the ISO's protocols made the existence of intra-zonal congestion costly to some or all market participants. We therefore provide recommendations for revising the ISO's intra-zonal congestion management protocols to create incentive for market participants to reduce the incidences of intra-zonal congestion.

Because of the increased opportunities to exercise market power during congested times in a market with more zones, we recommend that the ISO delay the formation of new congestion zones unless it needs to do so for system grid reliability reasons,. If the current location and frequency of intra-zonal congestion continues after the revised intra-zonal congestion management protocols have been implemented, then creating a new congestion may be the only solution. However, if these revised protocols significantly reduce the frequency of intra-zonal congestion in the California market, then the ISO has saved itself significant increased market power risk and improved market efficiency by avoiding the creation of a new congestion zone. It has also saved the significant software and administrative costs associated with creating a new congestion zone.

The current frequency and distribution of intra-zonal congestion illustrates another important implication of the fact that the California market design allows all generators substantial freedom to pursue their financial interest in the real-time market. It is extremely difficult, under the California market design, to disentangle system reliability issues from strategic issues associated with generators pursuing their economic interests. In the present context, the ISO's current intra-zonal congestion management protocols create financial incentives to create intra-zonal congestion, which can significantly compromise real-time system reliability. The ISO system operators must often increment and decrement significant amounts of generation capacity in real-time to manage a problem that is created in large part by the economic incentives that generators face under the current ISO protocols for managing intra-zonal congestion. Consequently, the success of the California market design requires aligning as closely as possible the generator's financial incentives for supplying energy in real-time with the ISO's desire to maintain system reliability at least cost.

C. Long-Term Recommendations

1. Complete the Market Design Process

The ISO is currently in the process of reviewing various proposed Market Redesign 2000 (MR2000) Projects. These projects will continue the current ancillary services and real-time energy market re-design processes. Several are particularly promising and should improve the efficiency of the ISO's markets. Our highest priority project proposes to provide greater integration of the ancillary services management (ASM) software and the inter-zonal congestion management (CONG) software. The basic aim of this re-design is to allow ancillary services capacity to compete for the use of transmission capacity, which should increase the depth of the ISO's inter-zonal congestion management markets. Allowing generators to have separate ramp rates for several operating levels for each ancillary service is another market change likely to increase market efficiency because it increases the match between the generator's financial commitments and the physical capabilities of the generating unit (under these financial commitments). The ability of a SC to bid and self-provide the same ancillary service from the same unit during the same hour should give market participants greater flexibility to enter into commitments to buy and sell ancillary services. All of these MR2000 projects should significantly improve the operation of the ISO's markets.

2. Develop Rules Governing Entry by New Generators

California market does not yet have clear policy for connecting new generation units to the ISO grid. On June 23, 1999, the ISO filed Amendment 19 to the ISO Tariff to implement a New Generation Connection Policy (NewGen) approved by the ISO Board of Governors. On September 15, 1999, the FERC rejected this new generation connection policy. As we discuss in Section 9 of this report, a major shortcoming of the ISO's NewGen policy given in Amendment 19 can be traced to the existing ISO protocols for managing intra-zonal congestion. We therefore recommend that any NewGen policy implemented include a revision of the ISO's intra-zonal congestion management policy to eliminate the incentive that generation owners have to cause intra-zonal congestion.

A major focus of the ISO's NewGen policy is how the incremental intra-zonal congestion caused by a new entrant will be determined and mitigated. The new entrant should only pay for the additional costs its presence in the grid imposes on other market participants, not for additional intra-zonal congestion costs that result from the incentives caused by the ISO's intra-zonal congestion management protocols. This NewGen policy should also compensate new entrants for any benefits their presence provides to other market participants by netting out from these incremental intra-zonal costs any system benefits it provides.

Besides our recommendations for revising the ISO's intra-zonal congestion management protocols, we also provide recommendations for the design of the ISO's NewGen policy. Many of the features of the ISO's current NewGen are consistent with these recommendations, but the missing ingredient that has not been explicitly spelled out is the ISO's revision to its intra-zonal congestion management policy. However, we should also note that the ISO has made significant progress over the past month in formulating revisions to its intra-zonal congestion management protocols which appear largely consistent with our recommended intra-zonal congestion management protocols.

3. Eliminate Price Caps

The MSC remains committed to the elimination price caps on all of the ISO's markets as soon as possible. If only to prevent market participants from testing the extremes of what is a tolerable maximum magnitude for a price spike, we believe that it would be prudent for the ISO management and Board to maintain an extremely high "damage control" price cap indefinitely. However, once the major design flaws in the

ISO markets have been corrected and the markets appear to be workably competitive, there is little economic rationale even for this damage control price cap.

4. Transmission Planning

The current California market design provides limited incentives for grid upgrades and expansions. In addition, the process by which transmission capacity expansion and siting decisions will occur is still the subject of some debate. This is an area where greater communication and coordination between the CPUC and the FERC could enhance the efficiency of the California market over the long-term.

Grid expansions and upgrades are highly beneficial to the competitiveness of the California electricity market. As our empirical evidence indicates, if the energy and ancillary services markets always cleared on a statewide basis, ancillary services prices would most likely be lower. However, the grid upgrades necessary for this to occur may not justify the wholesale energy price reductions that would result from completely eliminating congestion. Nevertheless, if the lessons from deregulation in the airline industry (which greatly expanded the complexity of its network following deregulation) are at all applicable to the electricity industry, a competitive market in generation may require a more extensive and higher-capacity network than the historical vertically integrated regulated utility regime. During this regime, the vertically integrated utility could substitute between additional transmission capacity and additional generation in ways that may not be possible under the new competitive regime. Consequently, there is good reason to believe that we are currently at a point where additional transmission upgrades at the appropriate points in the California network can significantly increase the competitiveness of the ISO's markets.

Another area for further CPUC and FERC coordination is in removing any regulatory barriers that prevent existing transmission capacity (ETC) owners in California from joining the ISO. For this reason, the ISO's MR2000 project proposal to provide non-firm transmission rights should be undertaken. It will allow ETC holders greater flexibility to participate in the ISO's markets and give the ISO market participants greater access to unused transmission capacity.

2. Market Performance During the First Year of the ISO's Operations

A. MSC Report on 1998 Market Performance

In its August 1998 report, the MSC conducted a review of the operation of the ISO's ancillary services markets and offered recommendations for improving the performance of these markets. The MSC recognized at the time that more definitive recommendations would have to await additional market experience and further data analysis.

The Committee found that the ISO's ancillary services markets were not yet operating in a manner consistent with workable competition. Prices in the ancillary services markets were not fluctuating in a manner that reflected changes in the underlying marginal costs of supplying these products. Ancillary services markets exhibited extreme price volatility, even during periods when demand was unchanged for long periods of time. In the Committee's opinion, the conditions were not yet in place to rely on these markets to set efficient, cost-reflective prices. Prices for lower quality services such as replacement reserve routinely exceeded the prices for higher quality services such as regulation. Often ancillary services capacity prices exceeded both the Power Exchange (PX) and real-time energy price for the same hour, despite the fact that no net energy need be produced to supply these ancillary services.[6] The Committee recommended that until workable competition was established, the ISO continue to utilize a price cap for ancillary services.

The Committee identified nine underlying factors that were then contributing to the inefficient operation of the ISO's ancillary services markets: (1) some firms were subject to cost-based price caps while others were allowed to earn market-based rates; (2) the demand for ancillary services was higher than anticipated; (3) the amount of each ancillary service demanded by the ISO did not depend on market prices and these demands were not procured in a rational manner; (4) perverse incentives for generator bidding and scheduling behavior were created by the RMR contracts; (5) the ISO often purchased ancillary services separately from small geographic areas, increasing the potential for the exercise of market power; (6) the ISO's dispatch practices were not transparent to market participants; (7) the allocation of ancillary services costs to scheduling coordinators was flawed; (8) suppliers of ancillary services from outside of the ISO control area were excluded from participation in these markets; and (9) the ISO's computer systems were still facing various software difficulties that were not yet fixed.

While the Committee was not able to measure precisely the relative significance of each of these problems, its analyses did provide some insights. The quantities of ancillary service purchased far exceeded the levels at which they had historically been acquired. High demand was not a direct cause of the market irregularities, but the substantial quantities acquired appears to have increased the impact of the other factors. Prices for 'inferior' ancillary services routinely exceeded those for 'superior' services. The ISO's inability to substitute among these services therefore appeared to have significantly impacted the cost of acquiring them. Lastly, it appeared from the MSC's preliminary analysis that RMR contracts were not doing a great deal to reduce market power problems. Instead, they were most likely contributing to such problems by providing incentives for owners of generators with RMR units to bid and schedule their units less aggressively, at higher prices than they would in the absence of these incentives.

In our March 1999 report, further review of the performance of the ISO's ancillary services markets bears out the observations made in our August report.

[6] Any allowable net energy supplied while providing these services is paid for at the real-time energy price.

- In the former vertically integrated regulated utility environment, the total cost of ancillary services was approximately 3-5% of the total energy cost. The ISO's experience so far is that ancillary services comprise approximately 15% of the monthly energy cost, although we noted that this comparison is biased in favor of finding higher costs in the competitive regime.
- August and September 1998 prices for ancillary services continued the pattern observed in the latter part of July with prices in all markets hitting the ISO's price cap of $250 on a frequent basis.
- Bid sufficiency analysis for July and August 1998 showed many periods of bid insufficiency—values of bid sufficiency less than 100%. This was particularly true during periods of peak ISO load. One striking feature of the graphs presented in the report is the tremendous *volatility* in bid sufficiency, even throughout the day.

B. August MSC Report Recommendations

The August 1998 MSC Report recommended to the ISO seven specific measures that would, in the Committee's judgement, enable the ISO's ancillary services markets to become workably competitive. Those recommendations are described below.

1. Adoption of "Rational Buyer" Protocols

The ISO should implement "rational" purchasing practices for ancillary services that allow the ISO to substitute cheaper superior services for more expensive inferior services in its procurement of ancillary services.

2. Reform of Reliability Must-Run (RMR) Contracts

The ISO should revise RMR protocols and contracts so that these contracts no longer provide incentives for generating units with RMR contracts to bid and schedule less aggressively (higher prices for the same bid quantity) into the day-ahead energy market and ancillary services markets. This could involve creating a new class of true option contracts to replace most of the RMR contracts.

3. Approval for Market-Based Rates

The FERC should grant market-based rates for all market participants, assuming the ISO retains the authority to impose a damage control price cap.

4. Retention of a "Damage Control" Price-Cap

The FERC should allow the ISO to retain a damage control price-cap on all ancillary services that can be raised or lowered at the ISO's discretion, regardless of what decision is made on granting all firms market-based rates for all ancillary services.

5. Use of a Statewide Auction for Ancillary Reserves

The ISO should run the auction for ancillary services on a statewide basis. If the statewide market-clearing prices left a shortfall of supply in a given zone, the Committee recommended using RMR contracts to make up the shortfall.

6. Reduce the Demand for Regulation

The ISO should revise its scheduling and/or energy imbalance protocols to help reduce its need for regulation capacity.

7. Ambiguous Dispatch Practices for the Provision of Imbalance Energy

The ISO should establish transparent protocols for dispatching supplement energy bids and energy bids associated with ancillary services capacity in the real-time energy market.

C. ISO Market Redesign Proposals

On March 1, 1999, pursuant to the Commission's direction in its October 28th Order, the ISO filed the first major set of its ancillary services market redesign proposals.[7] These proposals included:

1. Adoption of "Rational Buyer" Protocols

The ISO proposed to modify its ancillary service procurement process to enable the ISO to purchase additional quantities on one ancillary service that can substitute for another ancillary service, in order to reduce total ancillary services purchase costs.

2. Uninstructed Deviation and Replacement Reserve Allocation

The ISO proposed to adjust the amounts payable to the operators of resources that fail to comply with ISO dispatch instructions. The ISO also put forward a plan for it to purchase additional quantities of Replacement reserves to cover any forecast deficiencies in available energy, in order to reduce the ISO's reliance on out-of-market purchases for that purpose. The cost of this additional Replacement reserve capacity is allocated to loads in proportion to the extent that their hour-ahead energy schedules are below their real-time consumption, and to generation in proportion to the extent their real-time generation falls short of their hour-ahead energy schedule. In this sense loads, are deterred from scheduling less than their demands in the real-time market, and generators are deterred from under-producing energy relative to hour-ahead schedules.

A major way load protects itself from the attempts of generators to set high prices in the PX and ISO energy markets during peak ISO load periods, is by shifting demands between these markets and routinely scheduling significantly less energy on an hour-ahead basis than its expects to consume in the real time market. The MSC felt that this scheme would increase the cost of such defensive actions by demand, thereby making price spikes in PX and ISO energy markets more likely.

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[7] On December 11, 1998, the ISO filed two other tariff changes relevant to ancillary services market redesign: the allocation of responsibility for ancillary services based on metered demand, rather than scheduled demand, and the withholding of payment for uninstructed deviations from ancillary service capacity. The first of these changes, billing A/S based on metered demand was implemented on August 17, 1999. The second change, the so-called "no-pay" provision, will most likely be implemented in February 2000.

3. *Automation of Dispatch Instructions for Real-Time Energy*

The ISO described how it would automate the communication of dispatch instructions to resources supplying imbalance energy in order to allow the ISO to make better use of those resources, thereby reducing its requirements for regulation service. (No changes to the ISO's tariff or protocols were required for this element of the redesign package.)

4. *Separate Pricing of Regulation Up and Regulation Down*

The ISO proposed to introduce separate pricing for the upward and downward components of regulation service in attempt to increase the efficiency of the regulation market.

5. *Reduced Transaction Costs for Loads Participating in A/S Markets*

The ISO proposed to develop an agreement to facilitate the participation of dispatchable loads in ancillary service markets. The Participating Load Agreement (PLA) is the load counterpart of the Participating Generator Agreement (PGA). It is a pro forma contract to standardize load participation in the non-spin and replacement markets. (No changes to the ISO Tariff or Protocols or to ISO software were required for this element of the redesign package.)

6. *Trading of Ancillary Services*

The ISO proposed certain modifications to permit Scheduling Coordinators (SCs) to engage in trades of ancillary services, with the intention of providing alternative means for SCs to fulfill their ancillary-service obligations.[8]

In its May 26 Order, the Commission approved these six ISO's market redesign proposals.

D. *Status of August MSC Report Recommendations*

The Commission and the ISO have carried out, or are in the process of implementing in whole or part, most of the Committee's recommendations, as more fully described below. However, since most of these new market design features were not implemented until August 17, 1999, there is limited market experience with which to gauge the effectiveness of these changes. Given this limited experience, we feel it would be premature to try to assess the impact these reforms have had on the overall performance of the ISO markets.

8 The March 1 filing also included: (1) proposed modifications to the Ancillary Services Requirements Protocol ("ASRP") to reflect the ISO's new requirements concerning communications and direct control systems for units providing Regulation service; (2) a proposed modification to the ISO Tariff to provide for the payment of amounts due for Ancillary Service capacity dispatched under certain RMR contracts to the relevant Participating Transmission Owner; and (3) a change to the Market Monitoring Information Protocol to clarify the relationship between the ISO and the independent Market Surveillance Committee

1. *"Rational Buyer" Protocols*

The ISO's "Rational Buyer" Protocols (filed March 1, 1999 and implemented August 17, 1999) includes several features of the MSC's rational buyer recommendation. We believe that the ISO's implementation of "Rational Buyer" represent a significant and positive step towards improving the performance of the ISO's ancillary services markets. Fundamentally, improved flexibility in the ISO's procurement practices will tend to undermine any market power that suppliers of ancillary services might otherwise enjoy. As mentioned in our March 25th report, there are several important features of the MSC's recommendations that were not adopted.

The ISO's Rational Buyer Protocol employs different settlement procedures than were recommended by the MSC in our August 1998 report. Under the ISO's proposed protocol, although the ISO indeed purchases the Rational Buyer Quantities of each ancillary service, those ultimately paying for ancillary services, and those providing their own ancillary services, must only pay for or self-provide a quantity for each service equal to the ISO's *initial* ancillary services requirements (i.e., prior to any rational-buyer adjustments). For example, if the ISO's initial requirement for regulation reserve is 3% of the ISO's load, but the ISO's Rational Buyer Protocol results in purchasing regulation reserve amounting to 5% of the ISO's load, then both demanders and self-providers must purchase or provide regulation amounting to 3% of their load. This settlement procedure tends to create a subsidy to self-providers of ancillary services, because the total amount the ISO pays to providers of ancillary services under this scheme will generally be less than the total amount collected from purchasers of ancillary services. As a result, self-providers of ancillary services will have diminished incentives to make adjustments that would cause the rational-buyer prices to satisfy the inequalities that higher-quality ancillary services sell for higher prices, which was one of the major goals of adopting a rational buyer protocol to begin with.

As discussed in our March 25th report, we recognize that both equity and efficiency concerns are implicated in the settlements procedure that is adopted in conjunction with the ISO's Rational Buyer Protocol. We would prefer to see a settlement method that does not introduce subsidies into the system, and that conveys more accurate price signals to users and self-providers of ancillary services. As a general rule, the Committee is disinclined to give great weight to equity arguments based on so-called entitlements resulting from flaws in the market design that the ISO is in the process of fixing, especially if such equity considerations impede the efficient operation of the ISO's markets.

2. *RMR Contracts*

The Committee, and particularly its Chairman, Frank Wolak, have given significant attention to RMR issues since the August 1998 MSC Report.[9] The MSC

[9] In December of 1998, an analysis of the impact of RMR contracts on the California energy market was prepared by Frank Wolak and James Bushnell for the Market Surveillance Committee. An updated version of this analysis is entitled, "Regulation and the Leverage of Local Market Power in the California Electricity Market," University of California Energy Institute, POWER Working Paper, PWP-70, July 1999. This report also contained a detailed set of recommendations for revision of the RMR Contracts.

strongly recommended that the ISO revise RMR protocols and contracts so that these contracts no longer provide incentives for generating units with RMR contracts to bid and schedule less aggressively into the day-ahead energy market and ancillary services markets. The MSC believes that market incentives are much improved under the new RMR contract settlement, implemented June 1, 1999. However, one aspect of the RMR contract reforms recommended by the MSC in its March 25, 1999 report has yet to be implemented. This concerns the timing of RMR calls relative to the operation of the day-ahead energy market and the corresponding day-ahead scheduling requirements for units called to provide RMR energy.

Currently, RMR calls are made following the close of the day-ahead energy market. Under the scheme recommended by the MSC in its March report, RMR calls would be made before day-ahead energy schedules are submitted to the ISO. Generators receiving these RMR calls would have the option to elect to receive their RMR variable payment rate or a market determined price for supplying the RMR quantity of energy from that unit. Under this scheme, each RMR unit owner would know the amount of energy that must be provided from that unit during each hour of the following day for local grid reliability reasons before it bids into the PX day-ahead energy market or submits balanced day-ahead energy schedules to the ISO. Under the MSC's recommended scheme, after the ISO determines its RMR energy requirements, all generation owners with RMR units must submit a balanced day-ahead energy schedule to the ISO which has each RMR unit that it owns supplying at least the quantity of RMR energy the ISO requires from that unit.

Even though the major RMR reforms were implemented effective June 1, 1999, a complete assessment of these reforms is constrained by data availability. The ISO's settlement data on actual metered unit-level electricity production and take-out-point electricity consumption on an hourly basis is currently only available through the last week of July 1999. This information is an essential input to a formal assessment of the performance of the California energy market. Nevertheless, we perform analysis of the California energy market up through the date that we currently have data available.

3. Market-Based Rates.

The Commission has eliminated cost-based rates for ancillary services provided by all market participants, and authorized market-based rates for those services. This step is a prerequisite to workably competitive ancillary services markets. However, as the Committee noted in its August 1998 report, the ownership and control of the PG&E hydro units requires particular attention. The MSC recommends that the hydro systems be divested on a watershed-by-watershed basis to a buyer unaffiliated with PG&E or other major generation owners in Northern California.

4. Damage Control Price-Cap

The Commission on May 26, 1999 ordered to remove the ISO's authority to impose purchase price caps for ancillary services and imbalance energy as of November

15, 1999. Under it's existing authority, the ISO on October 1, 1999 increased the purchase price caps for ancillary services and imbalance energy from $250/MW to $750/MW. As discussed more fully below, the Committee strongly recommends that the ISO retain the authority to set and change these caps, that the $750 cap be retained through the summer of 2000, and that caps thereafter be raised to the $2,500 level as soon as market conditions permit.

5. *Statewide Auction for Ancillary Services*

The ISO has made a concerted effort over the past year to procure ancillary services on a Statewide basis whenever possible. Rather than automatically splitting the ancillary service market whenever there are significant south to north transmission constraints, the ISO also considers the locational distribution of ancillary service resources and will run a statewide auction if it results in a acceptable combination of northern and southern resources. During the spring and summer of 1999, there have only been a few occasions where the ISO has had to procure ancillary services separately for northern and southern California. However, during the fall season, limited ancillary service supplies (i.e. less hydro) and frequent south to north congestion within California often necessitate regional procurement. As was evident in northern California during the first week of October 1999, market power increases significantly when the market is split on a zonal basis.

6. *ISO Procurement Practices*

Two major issues that remain unresolved from the August 1998 MSC report are the ISO's procedures for procuring regulation reserve and the transparency of the ISO's process for dispatching reserve capacity from the real-time energy bid stack. The ISO has implemented several market design changes to address both of these issues. However, it appears that the philosophy underlying the California market design, which does not require generators to follow their net day-ahead and hour-ahead energy schedules in real time, makes it difficult fully to solve these problems. This additional freedom given to generators creates greater uncertainty for the ISO about how it will meet real-time demand with generation, relative to a system where energy schedules are firm physical commitments to supply energy and generators face strong financial penalties for deviations from these energy schedules. In addition, as discussed in our March 25th report, differences in how the ISO settles "instructed" versus "uninstructed" deviations from forward energy schedules has created some undesirable, from a market efficiency perspective, opportunities for generators. The ISO manages this increased uncertainty by purchasing more regulation capacity than was used in the pre-ISO regime. This increased regulation capacity allows the ISO to respond instantaneously to any local energy needs due to deviations by non-regulating generators from their net day-ahead and hour-ahead energy schedules. However, in recent months, the ISO has been able to significantly reduce regulation requirements by placing a greater reliance on the real-time energy bid stack for managing energy imbalances, particularly during critical ramping periods.

In an effort to create a financial penalty for schedule deviations, the ISO, as part of the ISO's Amendment 14 ancillary service market reforms, adopted a new procedure for determining replacement reserve requirements and for allocating the costs of replacement reserve to SCs. Under this new procedure, in addition to the replacement reserve procured for other reliability purposes, there are additional replacement reserves requirements that are based on the difference between the ISO's load forecast and total scheduled energy with some additional adjustments for expected supplemental energy bids and RMR dispatch. Replacement capacity is charged to both loads and generation in proportion to the amount that they under-schedule in the day-ahead and hour-ahead markets. It is worth noting that this proposal will increase the costs to loads and generators from shifting their demands and supplies between the day-ahead, hour-ahead and real-time markets. This scheme therefore increases the cost to loads of bidding a price-responsive demand into the PX and therefore substituting into the hour-ahead and real-time markets if generators bid too high in the PX. The result of this implicit tax on load shifting may be to increase prices in both the PX and real-time energy markets.

As discussed in our March 25th report, another remedy is to require that supplemental energy bids into the real-time energy market be submitted further in advance of the actual hour they may be asked to provide energy, and to impose penalties on generators who remove these bids in advance of the market (similar to those that are imposed on energy bids from winning ancillary services capacity). This remedy would allow the ISO to reduce its purchases of all ancillary services because the BEEP stack could then be treated in much the same way as reserve capacity coming through one of the ancillary services markets. Making real-time energy bids a genuine commitment for an extended period of time would also allow the ISO to end its current practice of skipping over the energy bids of units providing spin and non-spin reserve capacity.

Because the current market design often creates incentives for generators not to follow the sum of day-ahead and hour-ahead energy schedules or 10-minute instructed deviations, to some extent increased procurement of regulation may simply be one of the inevitable costs associated with the current market design. Because price signals are the only available tool to discipline deviations by generators, these signals must be particularly strong and accurate. It is impossible to use an hourly price to discipline deviations *within* the hour that are financially beneficial to the generator. Ideally, we would like prices and quantities to clear second-by-second and generators to pay for imbalances relative to schedules at this second-by-second price. Clearly, such a settlement scheme is beyond the range of technological feasibility. Consequently, over-procurement of regulation may be a necessary to correct this mismatch between the time intervals over which instructed deviations are paid versus uninstructed deviations.

3. Market Performance Since March 1999

A. Ancillary Service Costs

As can be seen in Figure 1 the total monthly cost of ancillary services has declined significantly during the ISO's second year of operation, particularly during the summer months. A number of factors contributed to this decline.

- During April through May of 1998, because most market participants were constrained by cost-based caps for ancillary services there was very little capacity bid into the ISO's ancillary service markets. This was particularly true for the regulation market which market participants perceived as a zero-net energy market, which meant that they did not expect to earn much in the way of net energy payments from providing regulation capacity. For all reserve services, if the capacity is called to provide energy it receives the real-time price for any net energy provided. Given the lack of regulation capacity being provided through the market, the ISO called on RMR units to provide additional regulation. Most of the costs shown for ancillary services during the ISO's first two months of operation are payments to RMR units. During the same two months in 1999, the ISO did not need to dispatch any RMR units to provide ancillary services.

- On May 21, 1998, in an effort to increase supply to the regulation market, the ISO implemented a Regulation Energy Payment Adjustment (REPA). Under REPA market participants received the greater of $20 or the ISO ex-post hourly imbalance energy price for each MW of regulation capacity awarded. For June, 1998, RMR and REPA payments constituted roughly 80% of the total monthly cost of ancillary services and for July through September 1998, REPA was so effective in attracting bids to the regulation market there was very little need to dispatch RMR for regulation. During July through September 1998, REPA constituted roughly 50% of the total monthly cost of ancillary services. On October 28, 1998, FERC approved market-based rates for all providers of A/S and the REPA payment was eliminated one month later. Though REPA was successful in attracting more regulation capacity to the market, in retrospect, it may have been an excessive enticement during the peak summer season when prices in the ISO's imbalance market were often quite high.

- During July through August 1998, because of transmission constraints between northern and southern California, the ISO frequently ran two separate markets for ancillary services, one for northern California and one for southern California. This practice generally resulted in higher prices in the southern region and a greater frequency of price spikes. During the same two months in 1999, the ISO rarely ran two separate markets.

- 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. This changed on August 6, 1998 when the ISO began accepting import bids for these three services but for reliability reasons, limited spinning and non-spinning imports to 25% of the ISO's total requirements for these services. On June 1, 1999, this limit was increased to 50%.

- Ancillary service requirements decreased significantly in 1999.

- Loads were lower during the summer of 1999 freeing up more capacity for the ancillary services markets.

In April 1999, in an effort to develop a more robust hour-ahead ancillary services market, the ISO began shifting day-ahead ancillary service requirements to the hour-ahead market. Initially, 3-5% of the day-ahead requirements were shifted to the hour-ahead market and by mid May, this was increased to about 10%. In addition to shifting a certain fixed percentage of the market requirements to the hour-ahead market, the ISO also shifted additional amounts to avoid large price spikes in the day-ahead market and bid insufficiency. This practice reduced the overall costs of ancillary services.

Figure 1

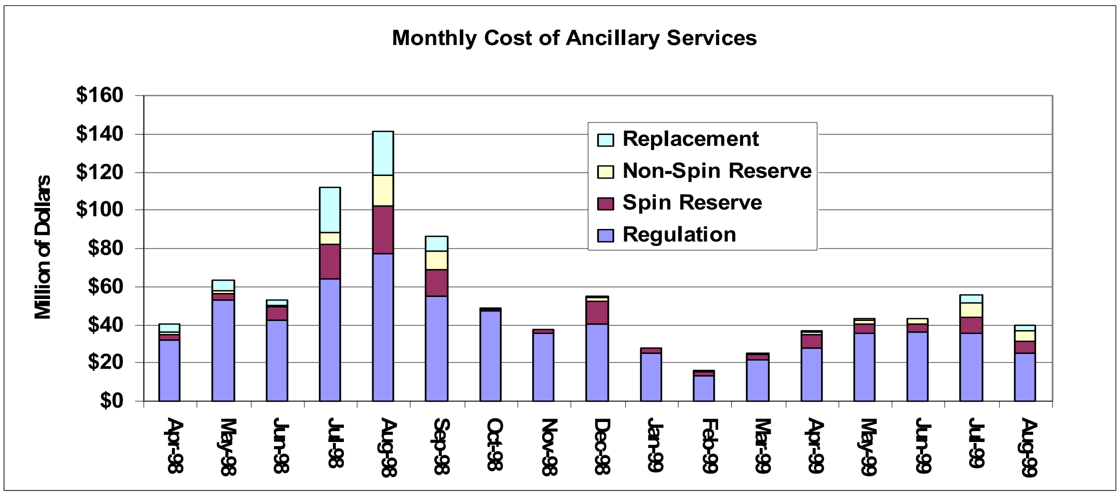


Figure 2

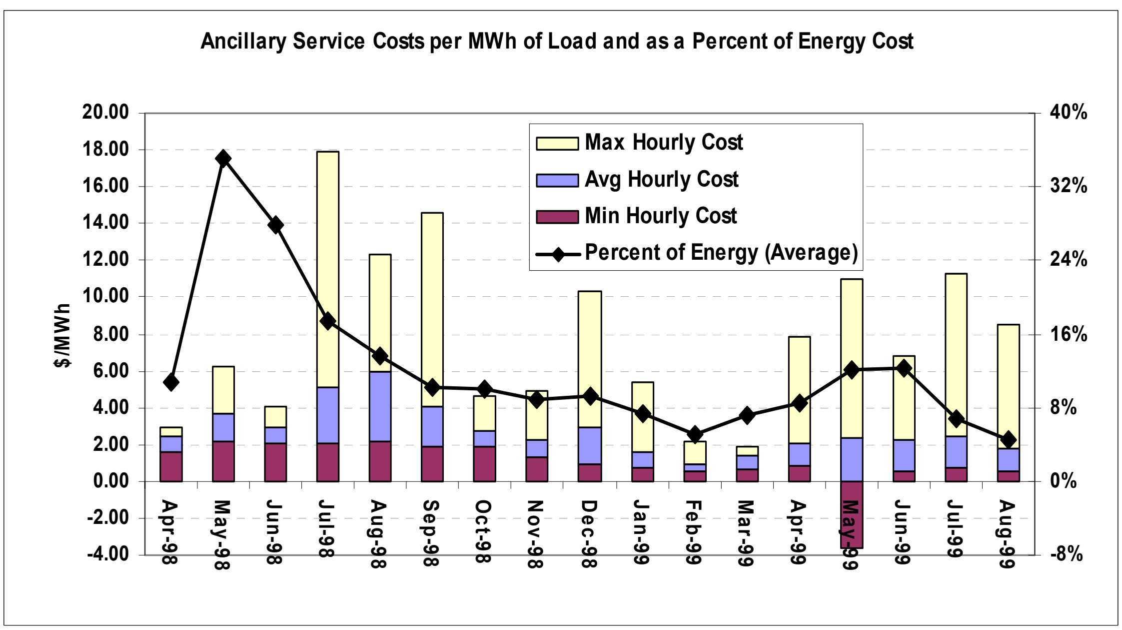
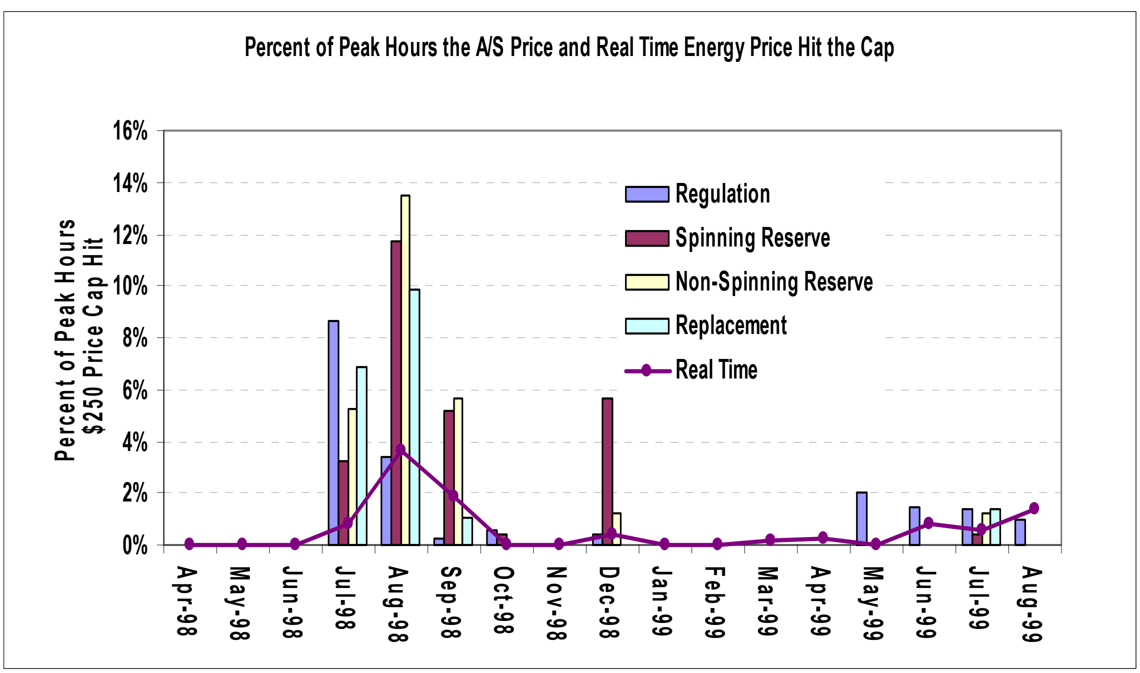


Figure 2 shows the minimum, maximum, and average hourly ancillary services cost expressed in dollars per MWh of ISO actual system loads for each month of ISO operation. In July of 1998, hourly ancillary services costs peaked at $18/MWh and averaged approximately $5/MWh. In contrast, for July of 1999, average hourly costs averaged approximately $2.40/MWh of system load and never exceeded $12/MWh of system load. August 1999 cost savings are even more dramatic. In August of 1998, the average hour cost of ancillary services was $6/MWh of system load compared to $2/MWh for August 1999. Figure 2 also shows average ancillary service costs expressed as a percentage of the estimated value of ISO actual system loads. ISO actual system loads were valued at the PX day-ahead unconstrained market-clearing price. In May 1998, ancillary service costs was equal to roughly 35% of the estimated value of ISO system loads, but these costs declined sharply in subsequent months. During July through August 1998, ancillary service costs were approximately 16% of total energy costs. During the same period for 1999, ancillary service costs were only 6% of total energy costs.

The negative minimum hourly cost shown for May 1999 was the result of several significant negative price spikes in the regulation market. On May 16, 1999 in hour 4 and 5, the market-clearing price for regulation was negative $3,350.28/MW. These negative spikes were caused by market participants submitting large negative bids for upward regulation with the apparent belief that other bids for downward regulation would set the market-clearing price during these hours. With this bidding strategy, market participants can gain large market shares for upward regulation while receiving a positive price set by high demands for downward regulation. In these particular hours, this strategy backfired as market participants collectively bid enough capacity at negative bid prices to cover demand for both upward and downward regulation. Effective August 18, 1999 the ISO set separate prices for Regulation Up and Regulation Down.

Figure 3



As mentioned above, during the summer months of 1998, price spikes occurred quite frequently in the A/S markets and were one of the main reasons for the high cost of ancillary services during this period. As can be seen in Figure 3, the $250/MW cap on ancillary service capacity was frequently hit in July through August of 1998. In August of 1998, the price cap was hit in more than 10% of the peak hours for spinning, non-spinning, and replacement reserve markets, whereas in August of 1999 the $250/MW cap was hit less than 2% of the time for these same markets.

B. Ancillary Service Quantities

One of the main factors contributing to lower ancillary service costs is that the ISO has made a concerted effort to lower overall requirements for ancillary services. Figures 4 and 5 show average hourly ancillary service requirements for August 1998 and August 1999, respectively. For August 1999, average hourly ancillary services requirements declined from 1998 levels. Requirements were particularly reduced during off-peak hours. The services having the greatest reduction in requirements were regulation and replacement reserve. Figures 4 and 5 also plot that average hourly system loads to illustrate the pattern of loads throughout the day that are associated with these ancillary services quantities.

Figure 4

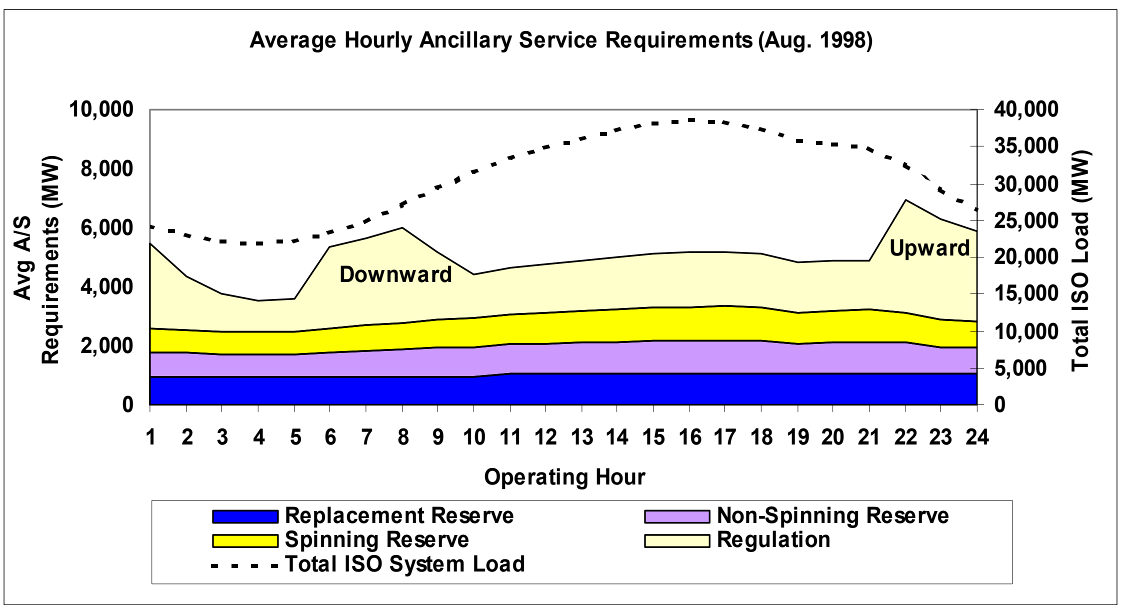
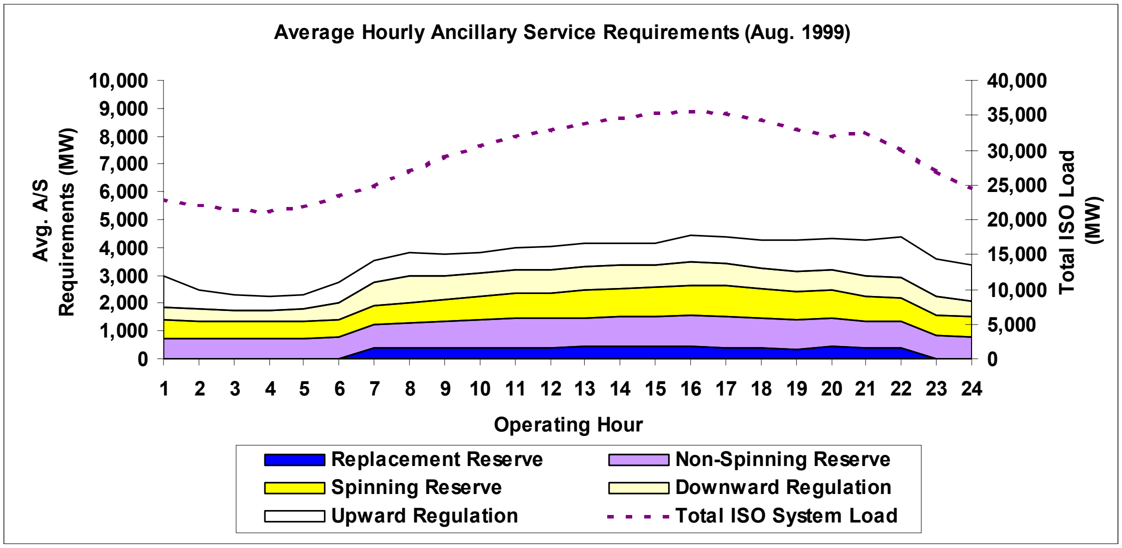


Figure 5



Part of the decline in ancillary service requirements can be attributed to the fact that system loads were significantly lower on average during most hours of the day during August 1999. However the reduction in average ancillary services requirements is proportionally greater than the reduction in average loads. While average hourly loads were about 5% lower in August 1999, the average reduction in ancillary service requirements was about 28%. Figures 6 and 7 express the ancillary service requirements for August 1998 and August 1999, respectively, as a percent of system loads. In August 1998, total ancillary service requirements averaged about 17% of system loads but declined to 13% in August 1999. Though not shown here, similar results were found for the month of July.

Figure 6

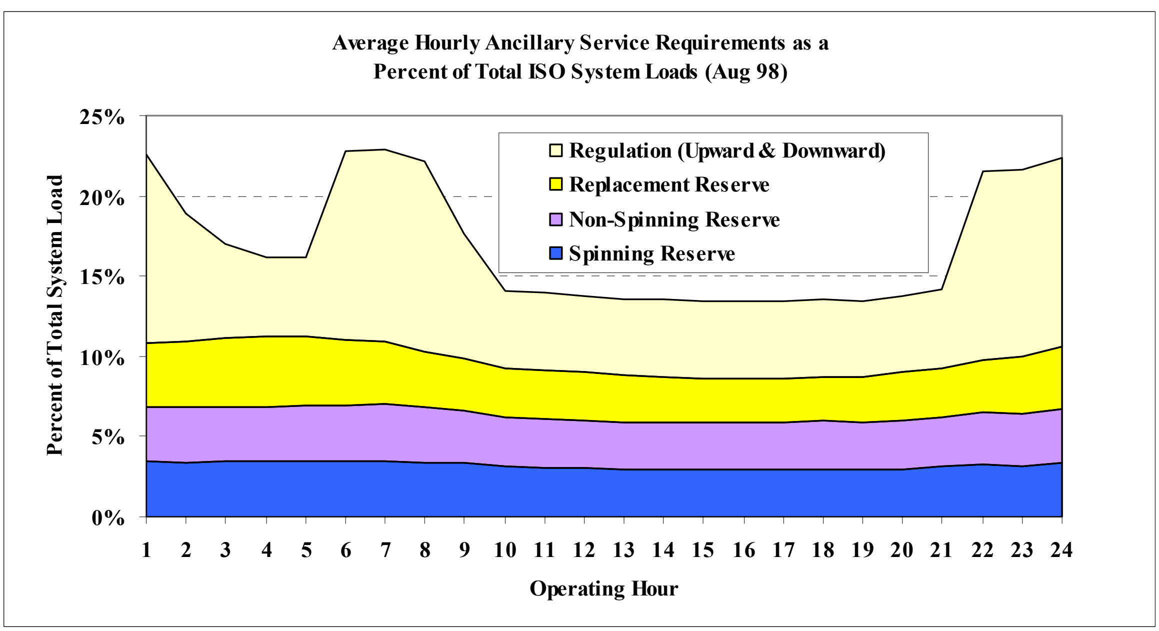
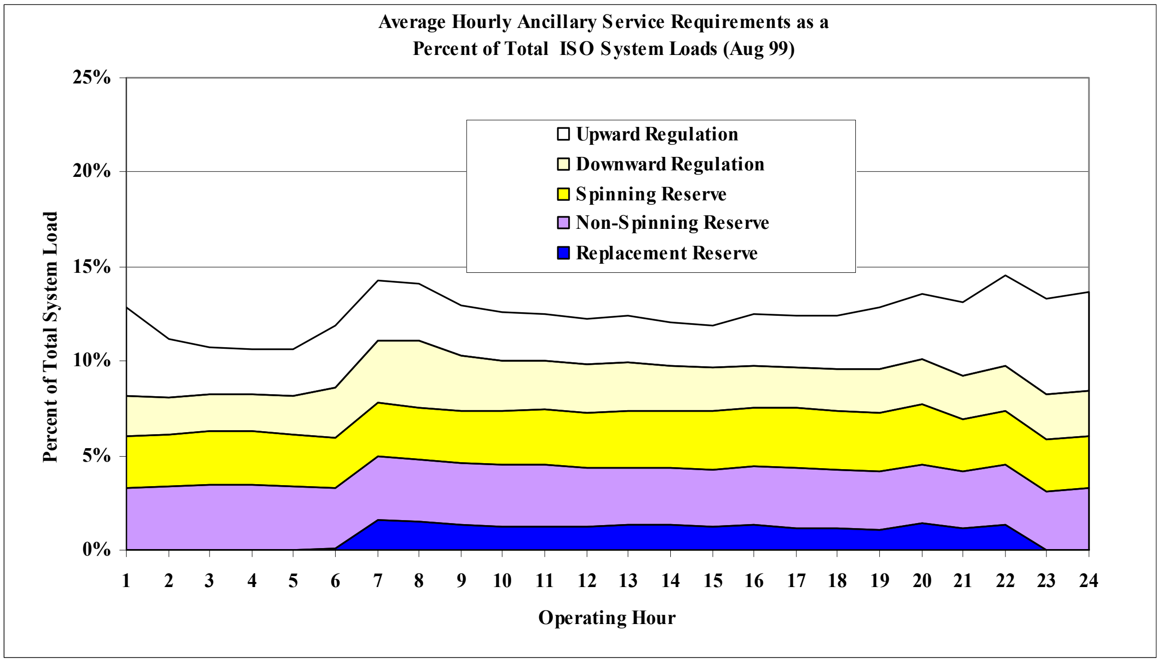


Figure 7



One question that immediately arises after viewing these figures is: To what extent is the reduction in ancillary services requirements in the summer 1999 versus the summer 1998 attributable to the lower average hourly ISO loads during the summer of 1999 versus the summer of 1998? Specifically, is the ISO getting by with less ancillary services during the summer of 1999 relative to the summer of 1999 only because of lower ISO load during the summer of 1999? To investigate this hypothesis more formally we employ linear regression techniques. This model relates the level of market-wide ancillary services requirements for each service as of the end of the hour-ahead market to the level of total ISO load as well as various dummy variables for each month from June 1998 to August 1999. Because of the changes in ancillary services procurement policies that resulted from the implementation of the Rational Buyer Protocol, we end our August sample at August 17, the day before Rational Buyer was implemented. This analysis will also allow us to separate the impacts of better procurement practices from the old ancillary services procurement protocols from the Rational Buyer procedure as more market data under the Rational Buyer protocol becomes available.

Define the following variables:

REQ(i,j) = Hour-ahead ancillary services requirement for service i in hour j

ISOLOAD(j) = Total ISO load in hour j

DAY(k,j) = An indicator variable that equals 1 if hour j is in day of week k=2,...,7

HOUR(h,j) = An indicator variable that equals 1 if hour j is the hour of the day h=2,...,24

MONTH(m,j) = An indicator variable that equals 1 if hour j is in month of year m = 2 ,...,12

JUNE99(j) = An indicator variable that equals 1 if hour j is in June of 1999

JULY99(j) = An indicator variable that equals 1 if hour j is in July of 1999

AUG99(j) = An indicator variable that equals 1 if hour j is in August of 1999

For all hours from June 1, 1998 to August 17, 1999 and for each ancillary service, i, we regress REQ(i,j) on a constant term, a sixth order polynomial in ISOLOAD(j) (to control for a potentially highly nonlinear impact of the total ISO load on the demand for that ancillary service), the complete set of DAY, HOUR, MONTH indicator variables given above and the three indicator variables, JUNE99, JULY99 and AUG99. The regression coefficient on JUNE99 gives the average difference in ancillary services requirements in June 1999 versus June 1998, controlling for differences in the level of total ISO load across hours in the two months. A similar interpretation holds for the coefficients on JULY99 and AUG99.

Table 1 gives the point estimates and standard errors for the coefficients associated with the indicator variables JUNE99, JULY99, and AUG99 for each of the ancillary services. This table provides strong evidence that the reduction in ancillary services requirements from the summer of 1998 to the summer of 1999 cannot be solely attributed to the lower average hourly ISO loads during the summer of 1999. Except for June 1999 for Non-Spinning and Spinning Reserve, controlling for differences in total ISO load across the two summers, average hourly ancillary services requirements in 1999 were significantly lower than during the same month of 1998. For Non-Spinning Reserve the average hourly load-adjusted ancillary services requirement was substantially higher in June 1999 versus June of 1998. For Spinning Reserve this increase was only approximately 40 MW.

Table 1: Load-Adjusted Year-to-Year Difference in Market Requirements

Month	**Load-Adjusted Difference in Average Hour-Ahead Ancillary Services Requirements Between Summer of 1999 and Summer of 1998**			
	Regulation	**Spin**	**Non-Spin**	**Replacement**
June	-150.17 (17.28)	40.36 (4.78)	156.33 (4.05)	-830.59 (10.76)
July	-577.20 (16.81)	-238.52 (4.65)	-150.87 (3.94)	-237.80 (10.47)
August	-485.64 (21.72)	-111.27 (6.01)	-66.23 (5.09)	-766.68 (13.52)
Standard Errors in Parentheses				

C. *Ancillary Service Prices*

Prices in the day-ahead ancillary service market were on average much lower compared to the same period last year and there were significantly fewer price spikes. Figures 8 and 9 show the total number of price spikes in excess of $200/MW and the average hourly price for day-ahead regulation capacity for August 1998 and August 1999, respectively. In August 1998, price spikes in the day-ahead regulation market were fairly prevalent during two distinct periods of the day, in the morning hours when demand for downward regulation was high relative to supply and in the late evening hours when demand for upward regulation was high relative to supply. These demand patterns reflect the ISO's use of regulation capacity to provide net energy counter to load growth during the hour. In order to meet the peak morning loads, imports on the interties and in-state generation begin ramping up several hours in advance. 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 providing upward regulation.

In August 1998, there were no separate requirements for upward and downward regulation. These two services were bought as a single product. REPA was also still in effect during this period. Average hourly regulation prices for this month are highly correlated with the frequency of price spikes and were highest during the evening ramp down hours averaging a high of $98.50/MW in hour 22. Regulation prices were much more moderate in August 1999 both in terms of the number of price spikes and the average hourly price.

There were a number of important changes in the regulation market during this month compared to last year:

- REPA was no longer in effect
- For the first part of August (August 1-17), upward and downward regulation were being procured separately but settled at a single price equal to the maximum of the upward and downward market clearing prices[10],
- During the last part of August (August 18-31) upward and downward regulation were settled at separate market clearing prices.
- The ISO adopted a new practice of shifting some day-ahead requirements to the hour-ahead market if doing so would avoid a significant price spike so long as the ISO was confident that ample supplies would be available in the hour-ahead market.
- The ISO implemented a new algorithm for determining regulation requirements that placed greater reliance on the imbalance market to follow load. This new

[10] At that time, software limitations prevented the ISO from settling upward and downward regulation using separate prices. New software was implemented on August 18, 1999 to correct this.

algorithm significantly reduced regulation requirements during the two critical ramping periods.

With the exception of the elimination of REPA, which put upward pressure on regulation prices, all the other changes put downward pressure on regulation resulting in average hourly prices for upward and downward regulation for August 1999 that were under $40/MW in all hours.

Figure 8

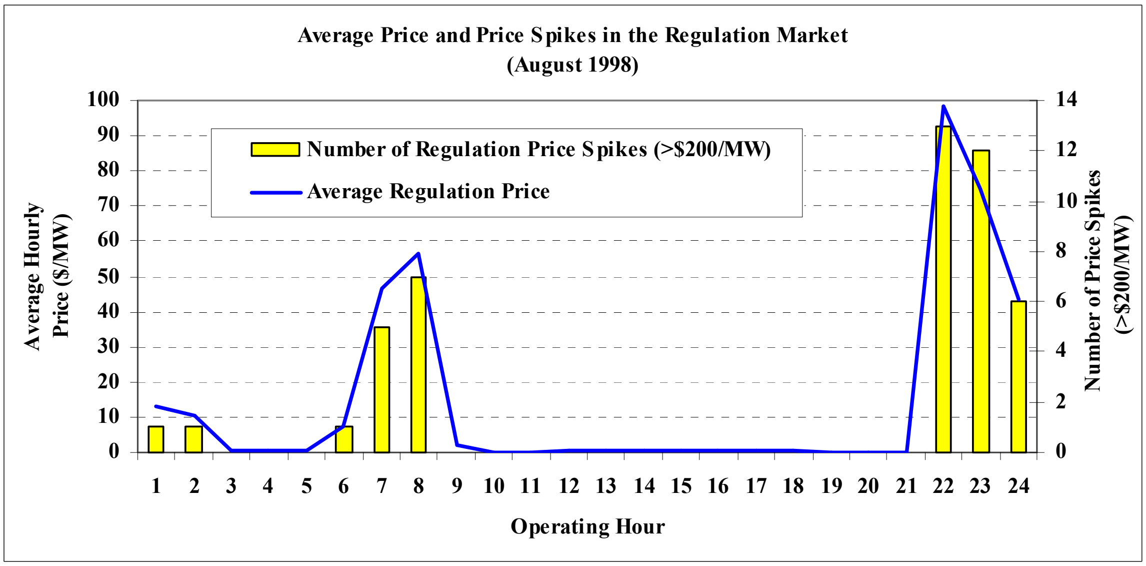
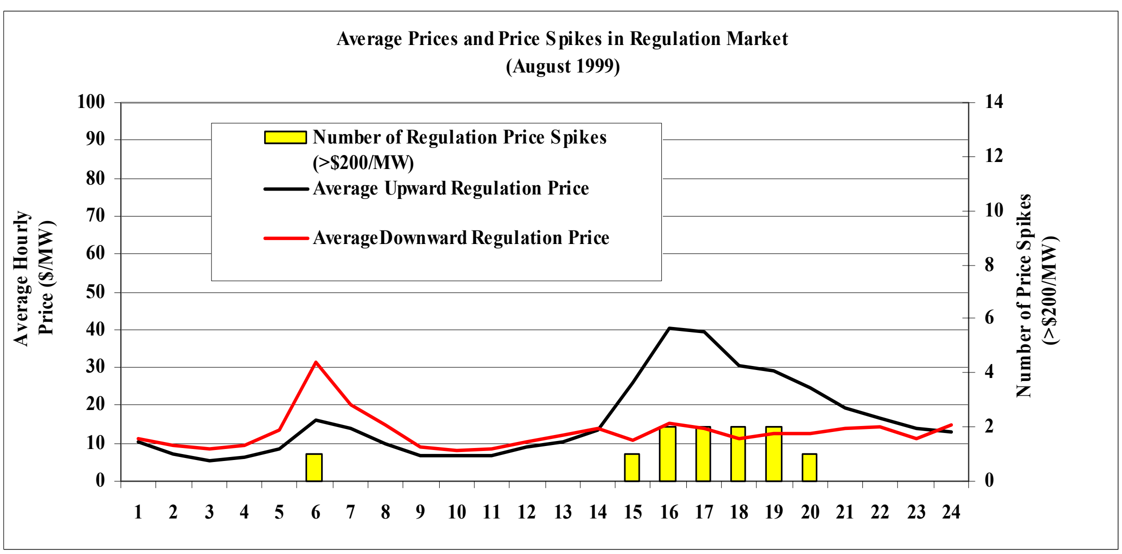


Figure 9



Market performance improved significantly in the Spinning, Non-spinning, and Replacement reserve markets. In all three of these markets, the frequency of price spikes dropped significantly as well the average hourly prices for these products (Figures 10-14). As with regulation, there were several important changes that brought about improved price performance for these services:

- ISO requirements were significantly lower, particularly for replacement reserve.
- On occasion some ancillary service requirements were shifted to the hour-ahead market to avoid price spikes in the day-ahead market.
- Imports limits for Spinning and Non-spinning reserve were increased to 50% of requirements.
- Rational Buyer was implemented in the day-ahead market on August 17, 1999 for Operating Day, August 18, 1999.

Although the first three changes mentioned would most likely cause ancillary service prices to decline, it is unclear how rational buyer would effect average prices.

Figure 10

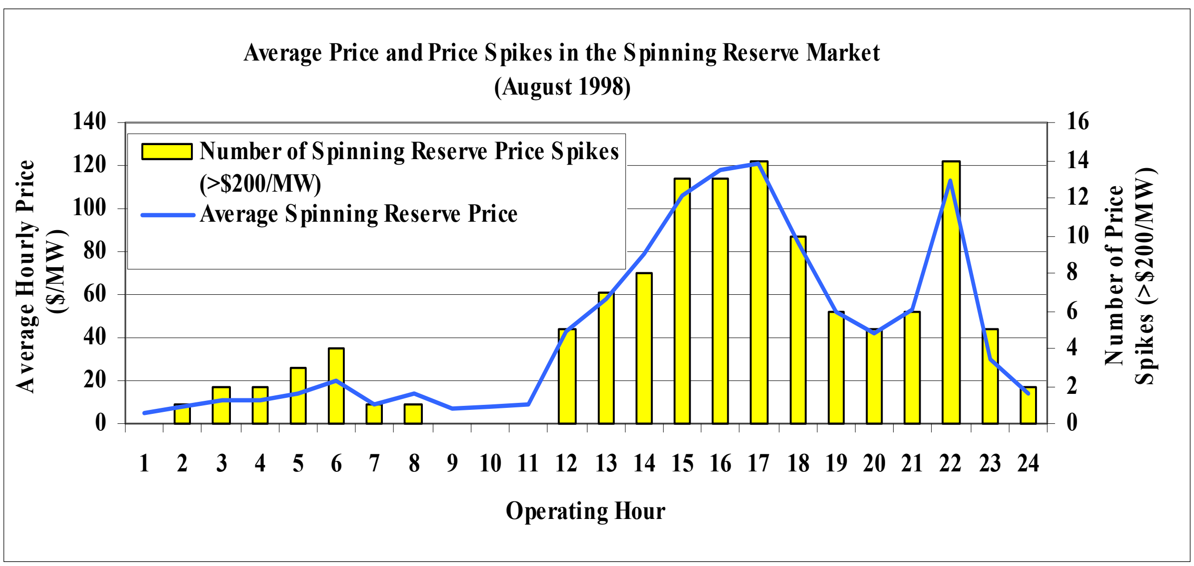


Figure 11

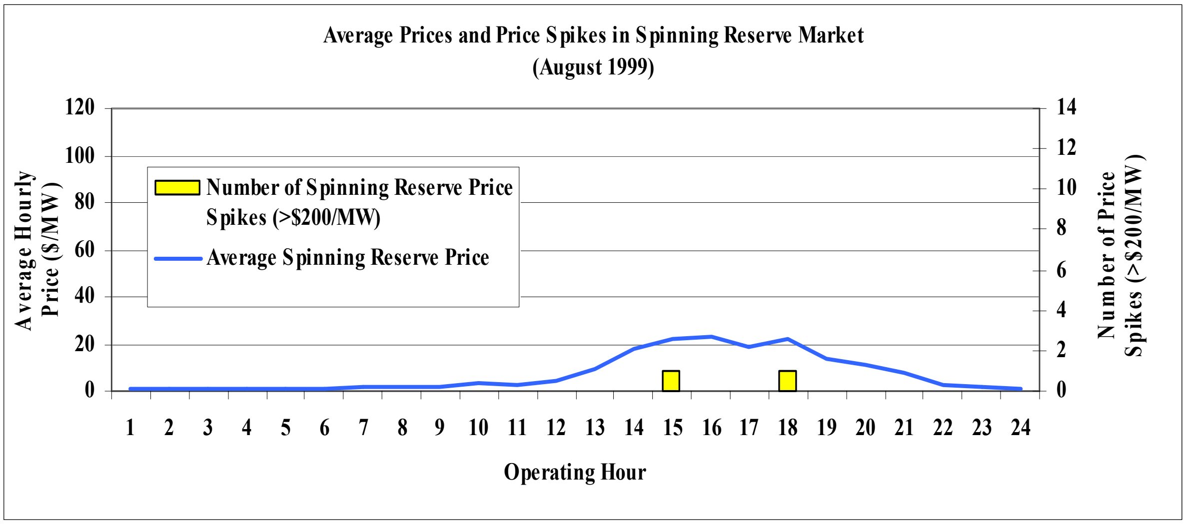


Figure 12

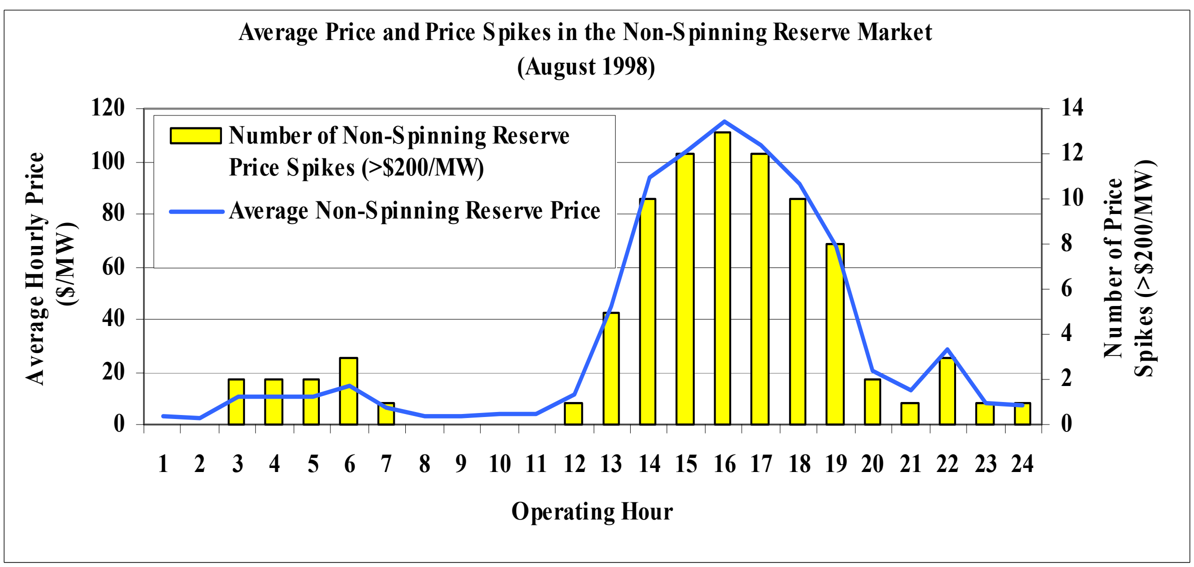


Figure 13

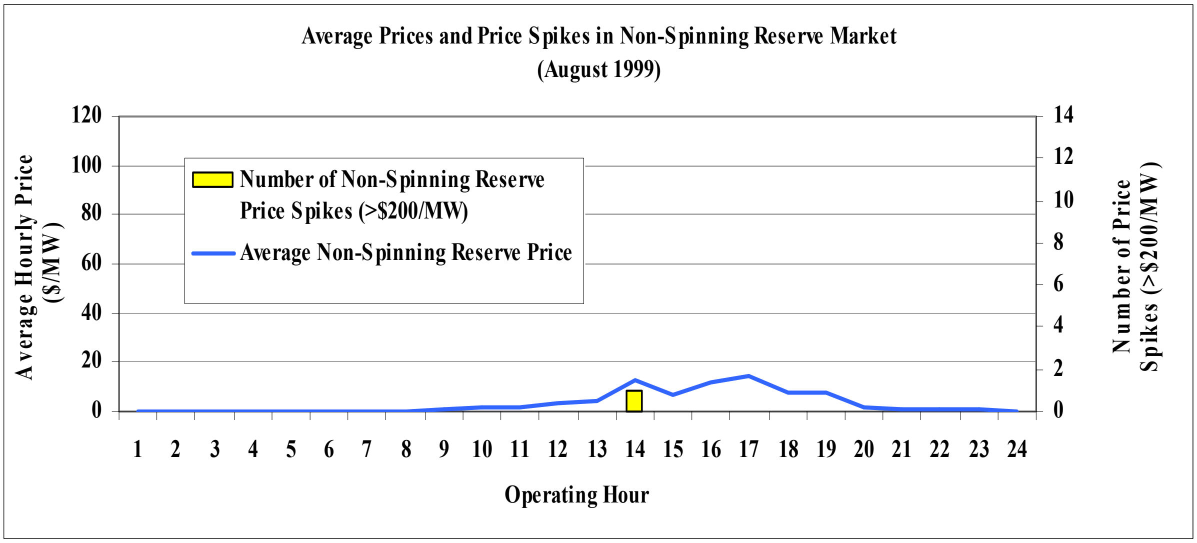


Figure 14

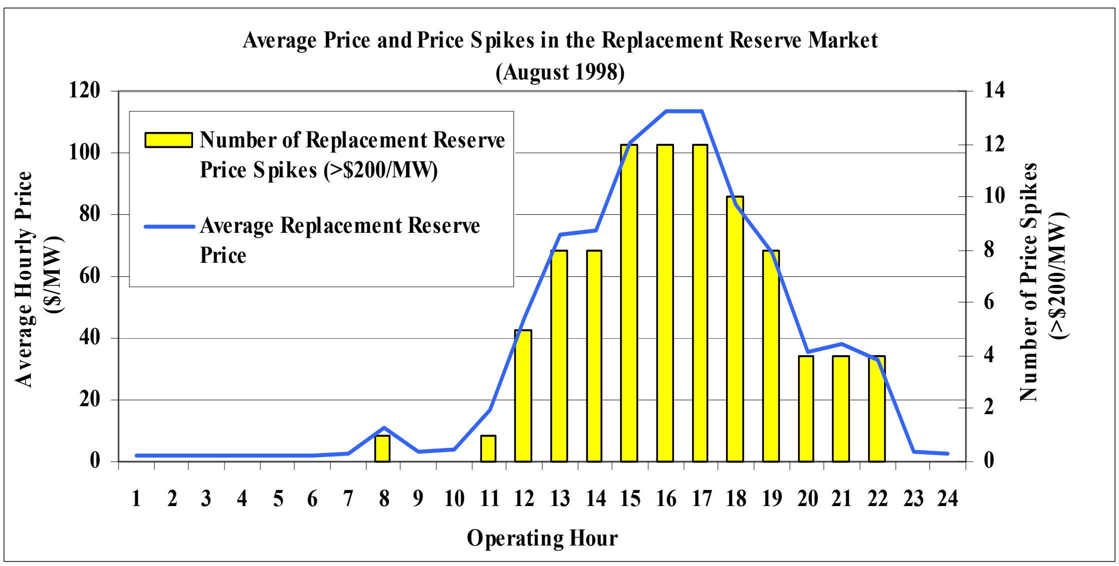
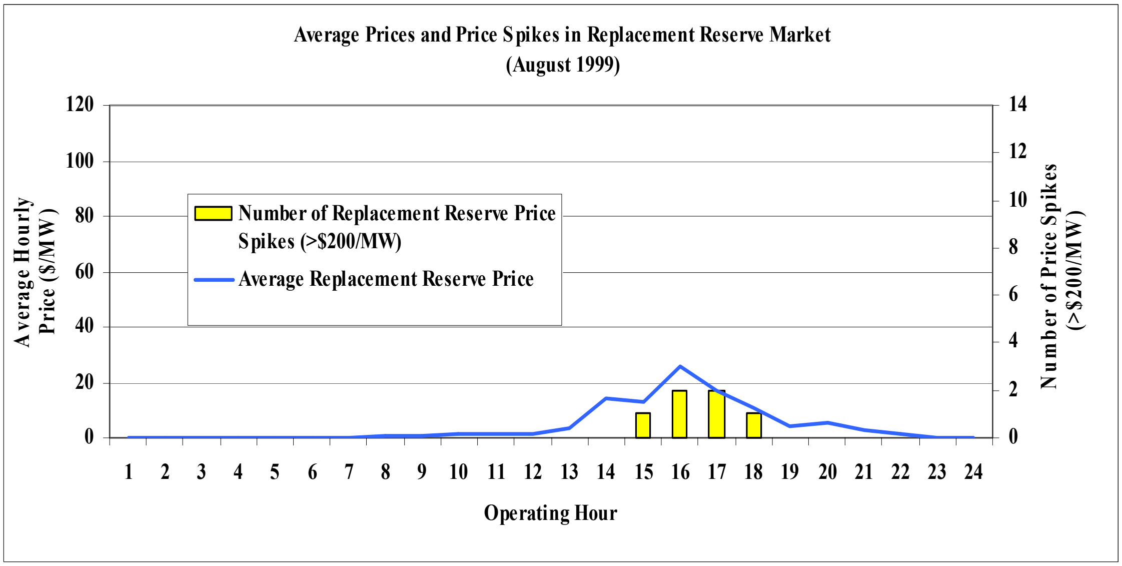


Figure 15



Although market price performance in the day-ahead ancillary service markets improved significantly in 1999, it is important to note that summer load conditions were unusually low in 1999. During July through August 1998, there were 154 hours when ISO actual system loads exceeded 38,000 MW versus 76 hours for July through August 1999. Figures 16 to 23 provide some insight into how the ancillary service markets performed under different load conditions and relative to the PX day-ahead and ISO real-time energy markets. These Figures show the average prices for day-ahead ancillary services, the average day-ahead unconstrained PX energy price, and the average ISO real-time energy price under different load conditions for two distinct periods July to August 1998 and July to August 1999. In a well-functioning ancillary services market, one would not expect the market price of ancillary service capacity to exceed the market price of energy. These Figures indicate that this expectation was often violated in 1998, under a variety of load conditions, but much less so in 1999 and generally only under high load conditions. These results are encouraging in that they demonstrate there is a stronger positive correlation between ancillary service prices, load conditions, and energy prices. However, the results also demonstrate that there still remains a tendency for prices in all markets to approach the price cap under high load conditions.

Figure 16 shows how regulation prices for July-August, 1998 compared to system loads and energy prices. Regulation prices for this month are heavily influenced by the Regulation Energy Payment Adjustment (REPA). Recall that during this period in addition to the regulation market-clearing price, participants in the regulation market also received a REPA payment equal to the greater of $20/MW or the ISO real-time price. This Figure demonstrates that in hours when loads were under 31,000 MW, the regulation price on average exceeded both the ISO real-time energy price and the PX day-ahead energy price. When one factors in REPA, the *effective regulation price* (Regulation MCP + REPA payment) exceeds energy prices in almost all hours except for those hours where loads exceeded 38,000 MW. During the hours when loads exceeded 38,000 MW, regulation prices were driven to zero making the *effective regulation price* equal to the ISO real time energy price.

Figure 16

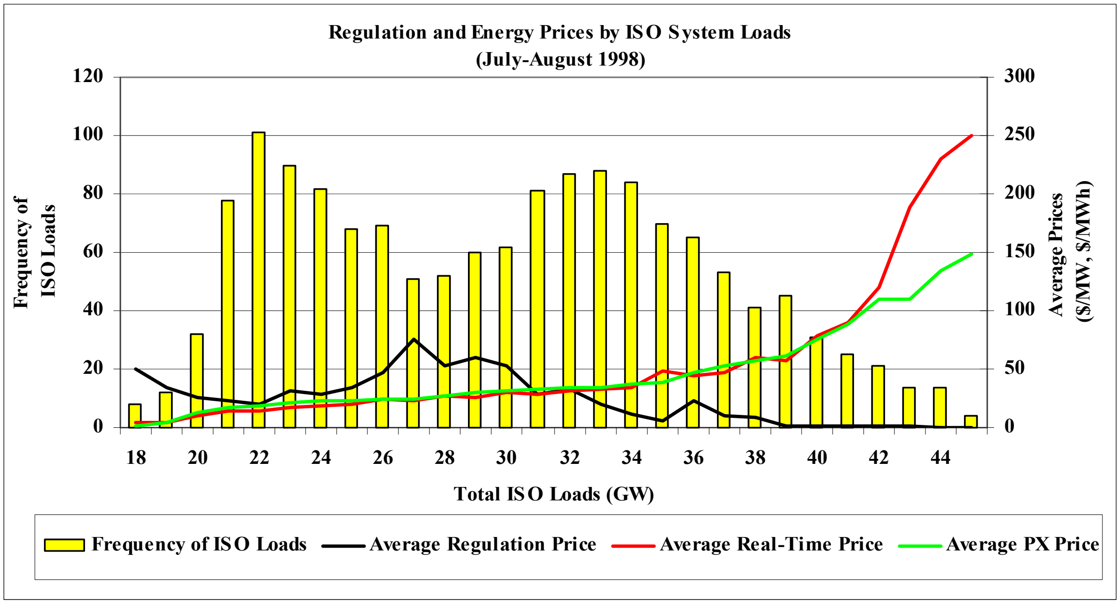


Figure 17 shows how prices for upward regulation compared to system loads and energy prices for July through August 1999. For this period, REPA was no longer in effect and for most of the month (August 1-17), a single price was paid for both upward and downward regulation. The ISO began paying separate prices for downward and upward regulation on August 18, 1999. For hours where loads were in the range of 18,000-27,000 MW, upward regulation prices were at or near the ISO and PX energy prices. For hours where loads ranged from 28,000 to 38,000 MW, upward regulation prices were generally lower than the ISO and PX energy prices. For hours were loads exceeded 38,000 MW average regulation prices were typically above the PX day-ahead energy price but generally lower than the ISO real-time price. One explanation for these results is that unit owners supplying regulation capacity must be compensated for the additional wear and tear on their units caused by responding to dispatch signals in real-time under automatic generation control (AGC). In addition, as noted above, the ISO uses regulation capacity to supply net energy counter to the direction of growth in system load during the hour. Units supplying upward regulation often must buy back energy in the real-time market at high prices, and those supplying downward regulation must often supply net energy during periods of very low prices.

Figure 17

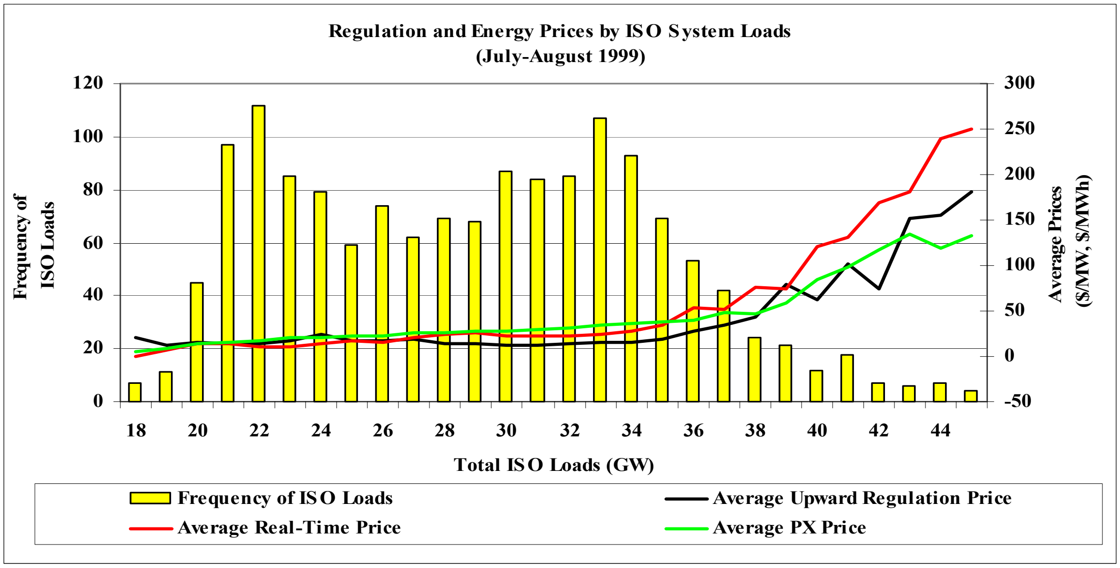


Figure 18

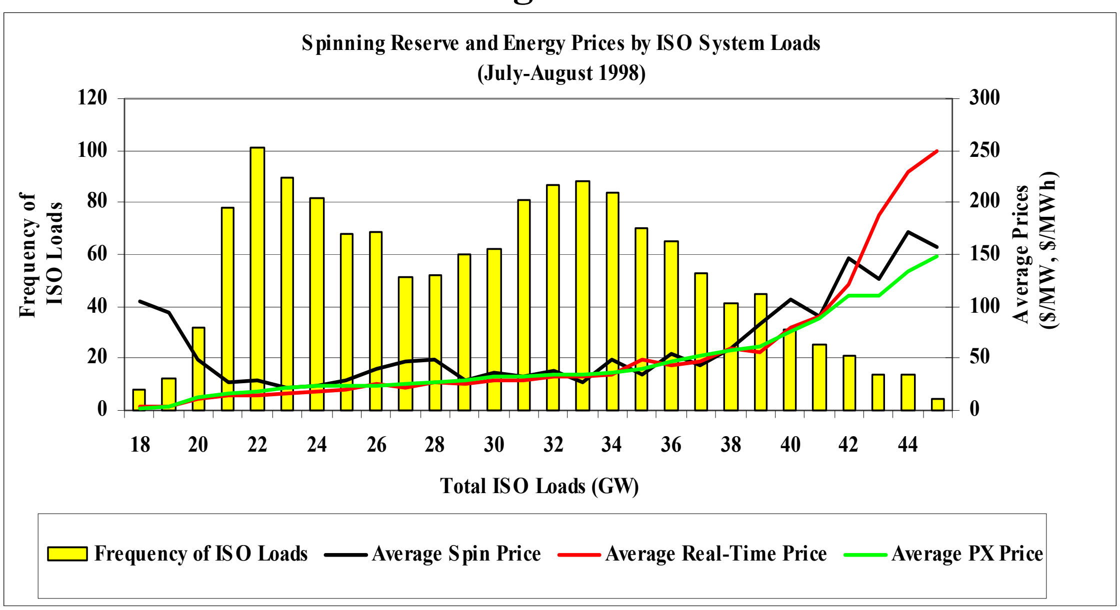
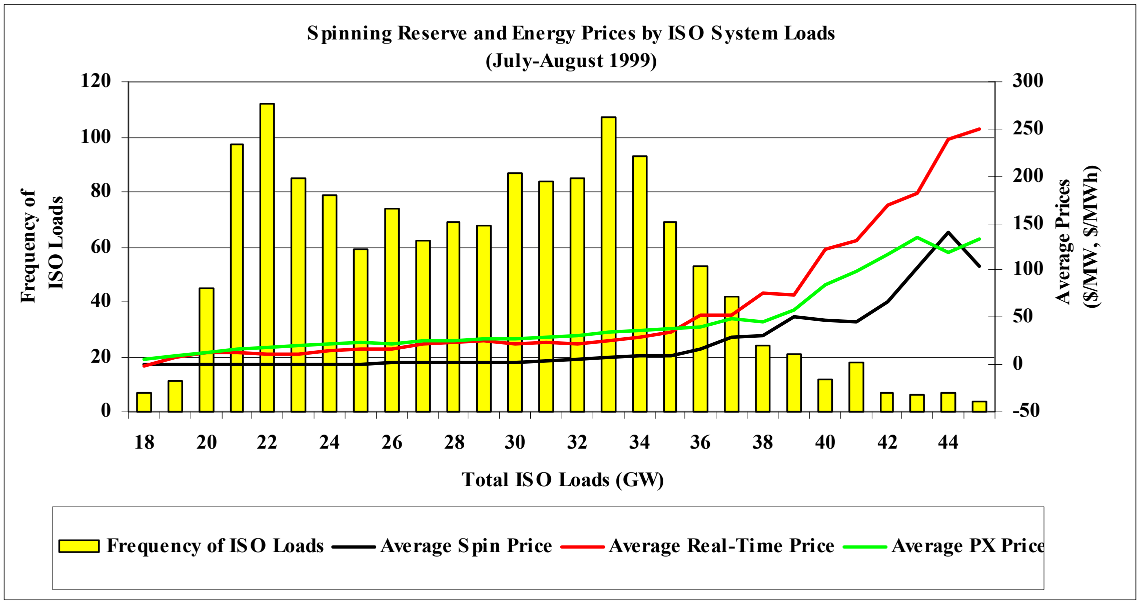


Figure 18 shows how prices for spinning reserve compared to system loads and energy prices for July through August 1998. During this period, spinning reserve prices on average exceeded energy prices under most load conditions. In hours where loads were exceptionally high (>42,000 MW), average spinning reserve prices were below the average ISO real-time price but greater than the average PX price.

Figure 19 shows how prices for spinning reserve for July-August, 1999 compared to system loads and energy prices. For this month, prices in the spinning reserve market were consistent with what one would expect from a workably competitive market. With the exception of extremely high load conditions, spinning reserve prices were on average below the average ISO real time energy price and the average PX day-ahead energy price.

Figure 19



The same patterns of improved market performance occurred in the non-spinning reserve and replacement reserve market as is evident from Figures 20-23.

Figure 20

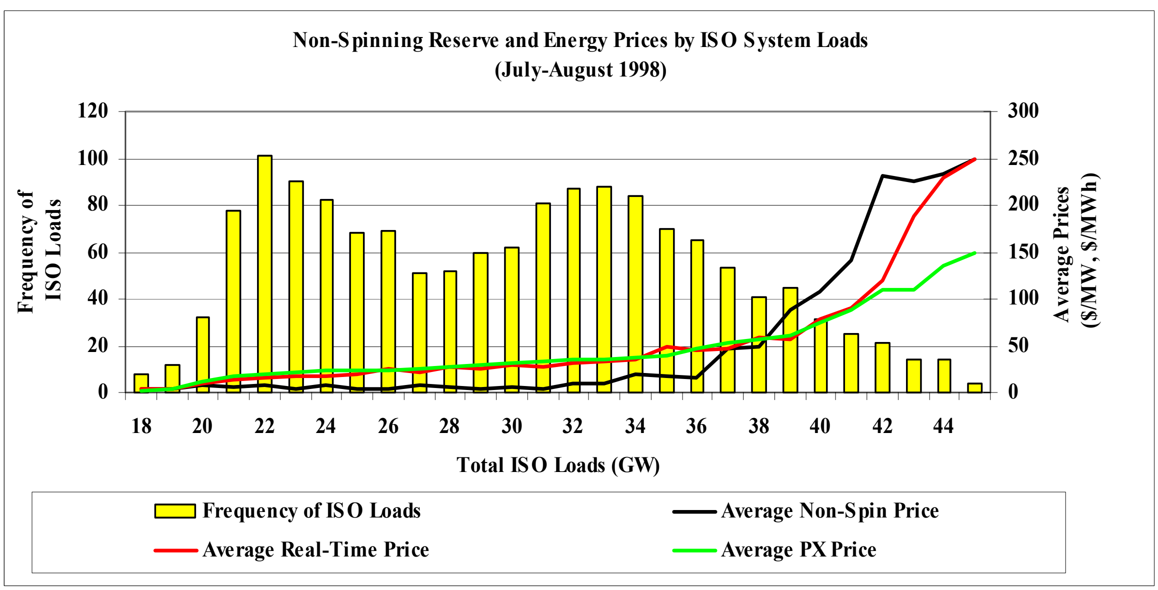


Figure 21

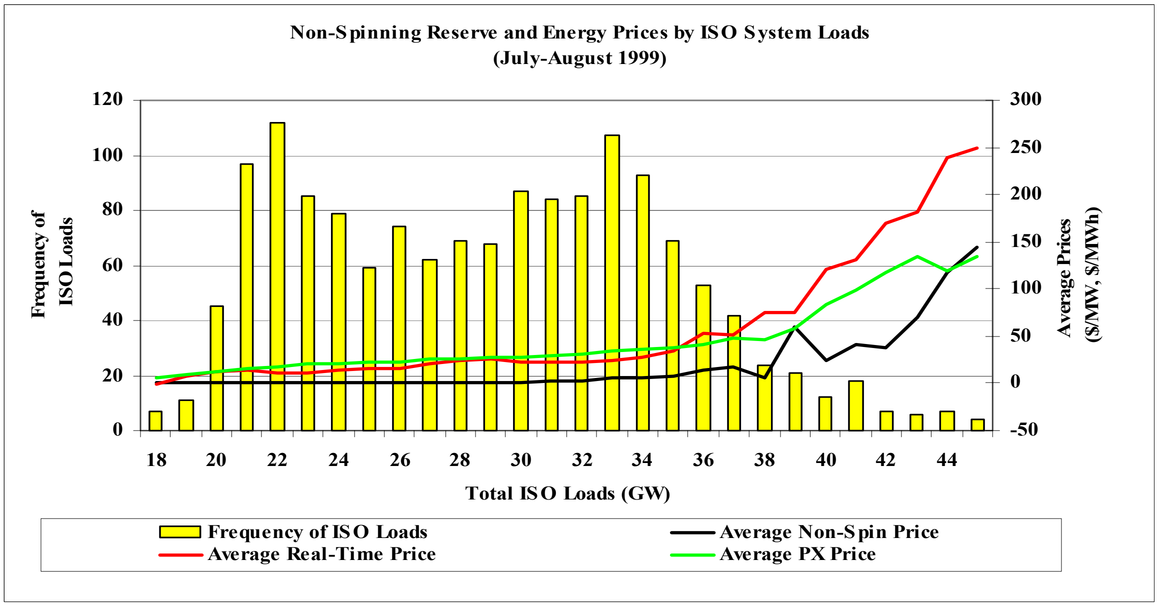


Figure 22

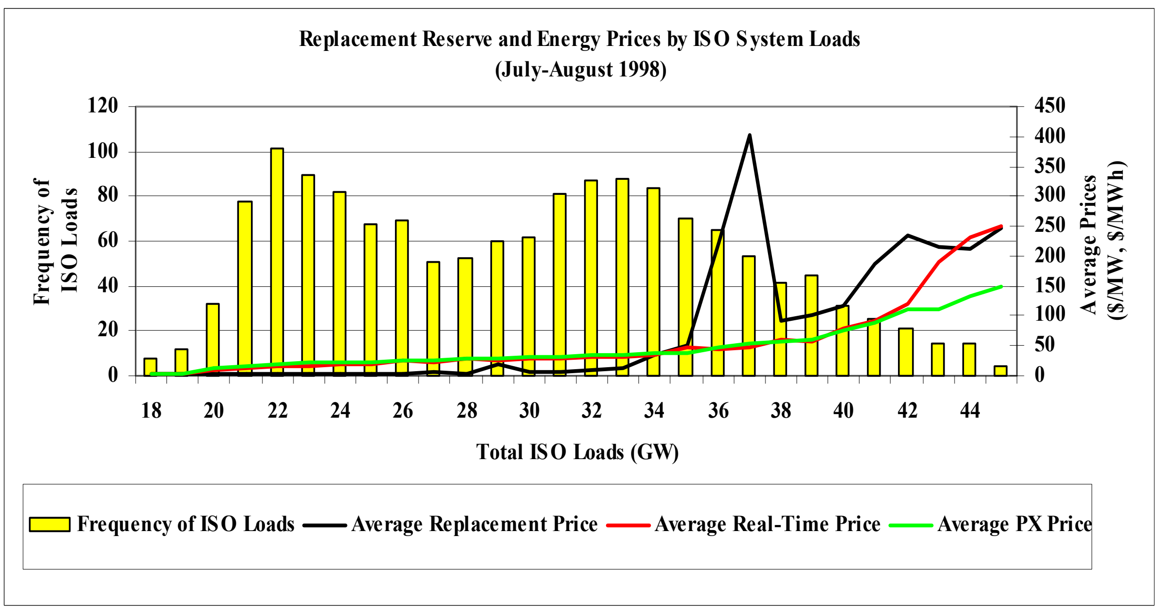
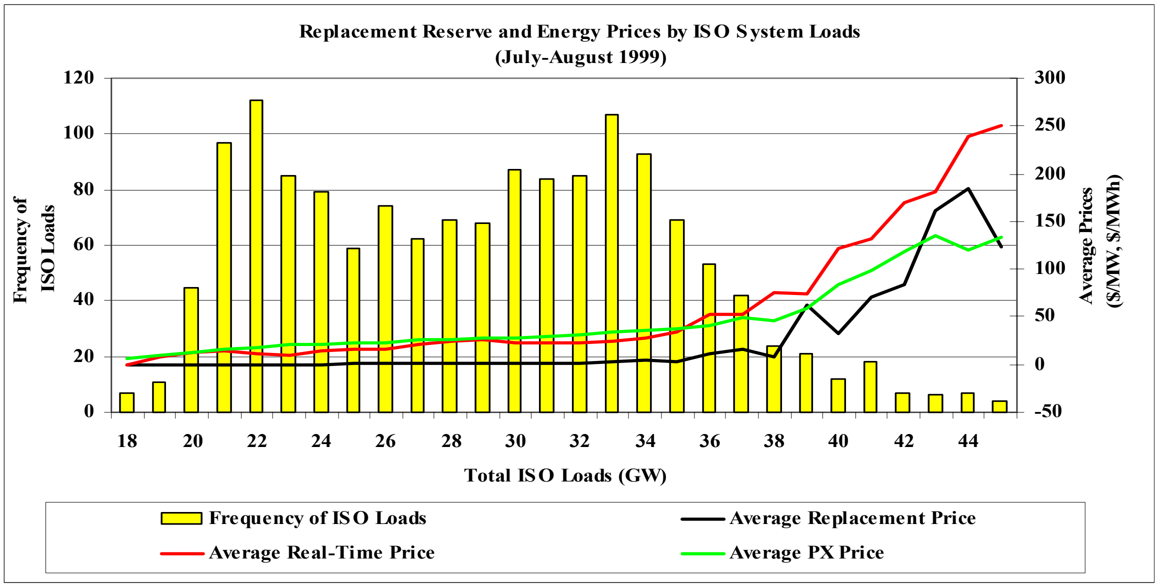


Figure 23



We now investigate the extent to which lower average hourly total ISO loads during the summer of 1999 versus the summer of 1998 led to lower ancillary services prices across the two summers. We perform a similar regression analysis to the one described above for the market requirement for each day-ahead ancillary service price in each congestion zone. Define the following two additional variables:

PAS(c,i,j) = the market-clearing day-ahead price ancillary services i, for congestion zone c, during hour j

CONG(j) = an indicator variable that equals one if the ISO procures ancillary services on a zonal basis during hour j.

For each congestion zone and each hour from June 1, 1998 to August 17, 1999, we regress PAS(c,i,j) on a constant term, a sixth order polynomial in ISOLOAD(j), a complete set of DAY, HOUR, MONTH indicator variables, the indicator variable CONG(j), and the three indicator variables, JUNE99, JULY99 and AUG99. The regression coefficient on JUNE99 gives the average difference in day-ahead ancillary services prices in June 1999 versus June 1998, controlling for differences in the level of total ISO load across the two months. A similar interpretation holds for the coefficients on JULY99 and AUG99.

Table 1 gives the point estimates and standard errors for the coefficients associated with the indicator variables JUNE99, JULY99, and AUG99 for each of the ancillary services. This table is consistent with the view that the reduction in average ancillary services prices from the summer of 1998 to the summer of 1999 cannot be solely attributed to the lower average hourly ISO loads during the summer of 1999. The difference in average day-ahead prices for each ancillary service between 1999 and the same month in 1998 are for the most part negative and very large relative to their standard errors. In addition, none of the positive estimated load-adjusted average hourly prices differences are very large relative to their standard error.

Table 2: Load-Adjusted Year-to-Year Difference in Day-Ahead Prices-NP15

Month	Load-Adjusted Difference in Average Hourly NP15 Ancillary Services Prices Between Summer of 1999 and Summer of 1998			
	Regulation	**Spin**	**Non-Spin**	**Replacement**
June	-15.34 (3.21)	-34.73 (1.69)	-4.21 (1.35)	-6.09 (1.33)
July	-5.68 (3.51)	-15.94 (1.85)	-18.95 (1.44)	-20.56 (1.45)
August	-1.67 (4.20)	-19.21 (2.22)	-9.18 (1.73)	-18.92 (1.74)
Standard Errors in Parentheses				

Table 3: Load-Adjusted Year-to-Year Difference in Day-Ahead Prices-SP15

Month	Load-Adjusted Difference in Average Hourly SP15 Ancillary Services Prices Between Summer of 1999 and Summer of 1998			
	Regulation	**Spin**	**Non-Spin**	**Replacement**
June	-9.25 (3.51)	-31.07 (2.28)	-3.53 (1.41)	-10.73 (12.47)
July	-19.04 (3.84)	-29.44 (2.50)	-9.41 (1.55)	-74.78 (13.63)
August	2.04 (4.59)	-16.01 (2.99)	-12.70 (1.85)	6.01 (16.31)
Standard Errors in Parentheses				

The results in Tables 1-3 taken together provide evidence that the ISO's ancillary services markets are operating more efficiently this summer than last summer for the values of hourly total ISO load that occurred during the summer of 1999. However, it is important to emphasis that that these results tell us less about how well the ISO's ancillary services markets would operate this summer if load conditions had been as high as they were last summer.

D. Ancillary Service Bid Price and Market Price Inequalities

We now consider a puzzling outcome of the ancillary services market noted in both the August 1998 and April 1999 MSC reports that continues to occur. The market-clearing price for an inferior product in terms of its technical specifications is greater than the market-clearing price of a superior product in terms of its technical specifications. One such example would be regulation selling for less than replacement. Regulation requires that the generation unit have AGC installed. Any generation unit that can provide regulation can certainly provide replacement, but opposite is not the case.

Table 4 shows, by month and by congestion region, the percent of times an inferior energy product cleared at a higher price than a superior energy product. The first two percentage columns show the percent of hours an inferior ancillary service was priced above a superior ancillary service. For the months in which REPA was in effect, an *effective price* for regulation was used equal to the regulation market clearing price plus REPA. The last two columns show the percent of times an ancillary service was priced above either the PX day-ahead energy price or the ISO real-time imbalance prices. This table shows that the frequency of price inversions for ancillary services changed very little and average around 12%. However, the frequency in which the price of an ancillary service exceeded either the PX day-ahead energy price or ISO real-time energy price declined significantly after August 1998. August 1999 is separated into two periods as rational buyer was implemented on August 18, 1999. Though the frequency of price inversions increased under rational buyer, loads were much higher during the last week of August. So, it may not be appropriate to attribute this change to rational buyer. This result illustrates the necessity of collecting more data on the market performance under the Rational Buyer before an assessment of its full impacts on the ISO's operations can be provided.

Table 4

	Ancillary Service Price Violations		Ancillary Service/Energy Price Violations	
Month	SP15	NP15	SP15	NP15
Jun-98	14%	14%	66%	64%
Jul-98	14%	21%	46%	22%
Aug-98	14%	14%	27%	20%
Sep-98	9%	10%	10%	8%
Oct-98	4%	4%	1%	0%
Nov-98	5%	4%	2%	2%
Dec-98	9%	9%	8%	5%
Jan-99	14%	14%	1%	0%
Feb-99	13%	13%	0%	0%
Mar-99	11%	11%	2%	2%
Apr-99	13%	13%	4%	4%
May-99	12%	13%	8%	6%
Jun-99	8%	8%	9%	8%
Jul-99	18%	18%	14%	14%
Aug-99 (Aug 1-17)	9%	9%	2%	2%
Aug-99 (Aug 18-31)	15%	15%	10%	8%

Table 5

Frequency of Ancillary Service Bid Price Inversion		
Month	IOU	NGO
Jun-98	2%	2%
Jul-98	4%	7%
Aug-98	2%	5%
Sep-98	1%	5%
Oct-98	7%	4%
Nov-98	8%	5%
Dec-98	8%	6%
Jan-99	10%	10%
Feb-99	9%	10%
Mar-99	7%	10%
Apr-99	3%	42%
May-99	5%	37%
Jun-99	6%	20%
Jul-99	10%	19%
Aug-99	14%	16%

Table 5 shows the frequency (the fraction of generation unit-level bids) in which investor-owned utilities (IOUs) and new generator owners (NGO) submitted ancillary service bids that violated the bid value conventions, that the bid price for regulation should exceed that for spin, which should exceed that for non-spin, which should exceed that for replacement. Though this occurred fairly infrequently from June 1998 to March 1999 (averaging about 6% for both IOUs and NGOs), it increased significantly for NGOs beginning in April 1999. This change is due to the bidding behavior of one particular NGO.

E. Bid Sufficiency

Figures 24-27 provide a profile of day-ahead bid sufficiency levels for each ancillary service and for each month since the ISO began operation. These Figures demonstrate that bid sufficiency improved in all markets relative to 1998 levels. The greatest improvement occurred in the regulation market, which for the first two months of operation had bid sufficiency levels below 100% in 80% of peak hours (Figure 24).

Figure 24

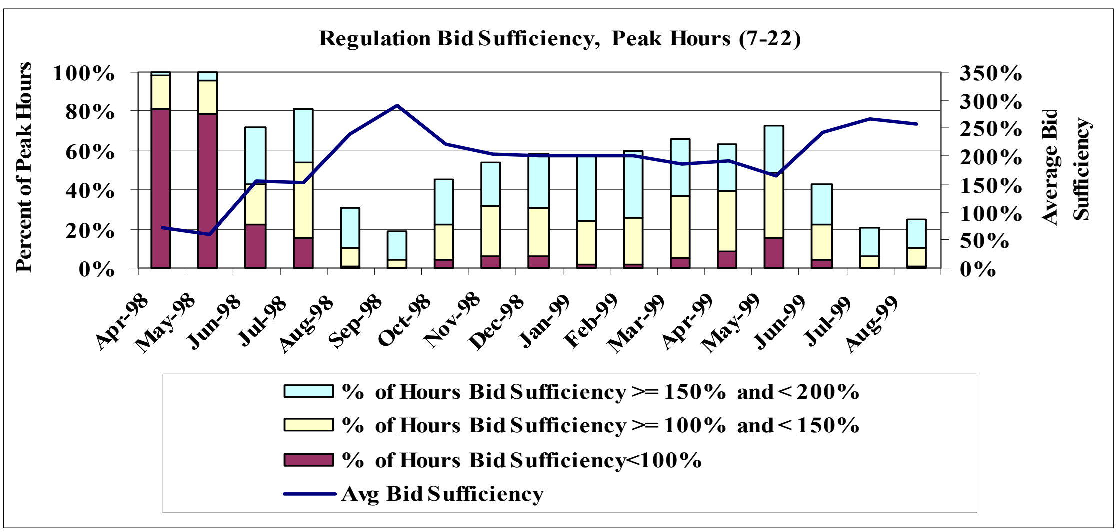
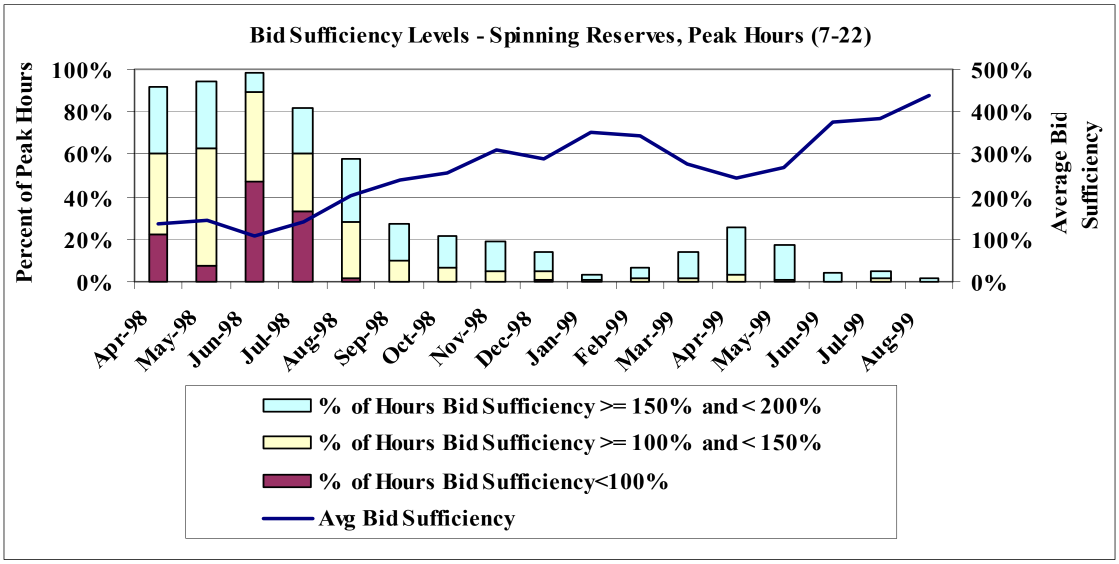


Figure 25



With the introduction of REPA on May 21, 1998 bid sufficiency levels in the regulation market improved significantly. In July 1998, bid sufficiency levels fell below 150% in about 54% of the peak hours whereas in July 1999, bid sufficiency levels fell below 150% in about only 6% of the peak hours. Bid sufficiency levels for August 1998 and August 1999 were very similar, with bids sufficiency falling below 150% in only 10% of peak hours.

Figure 26

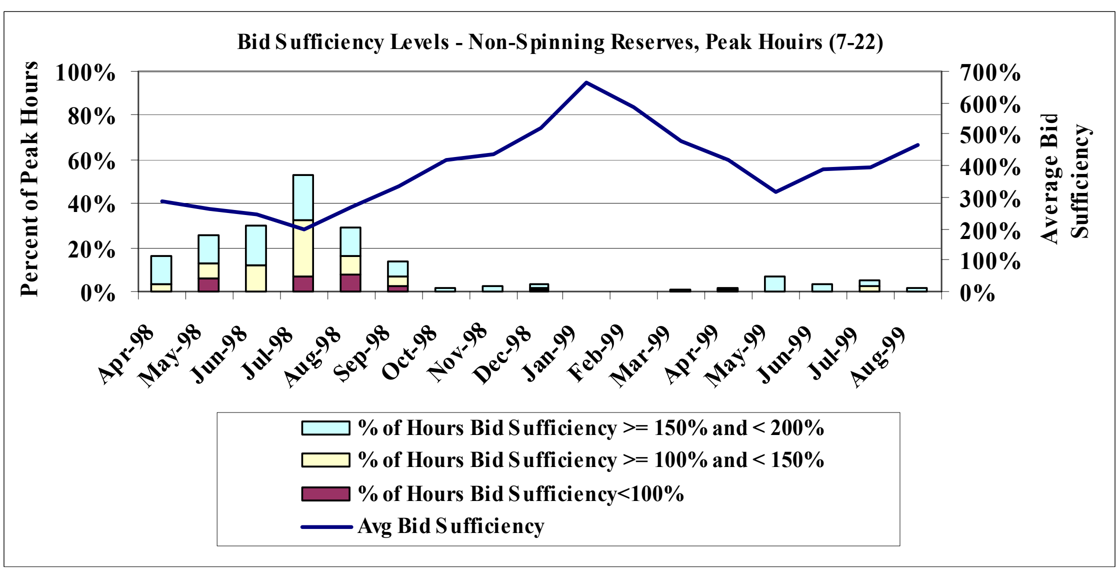
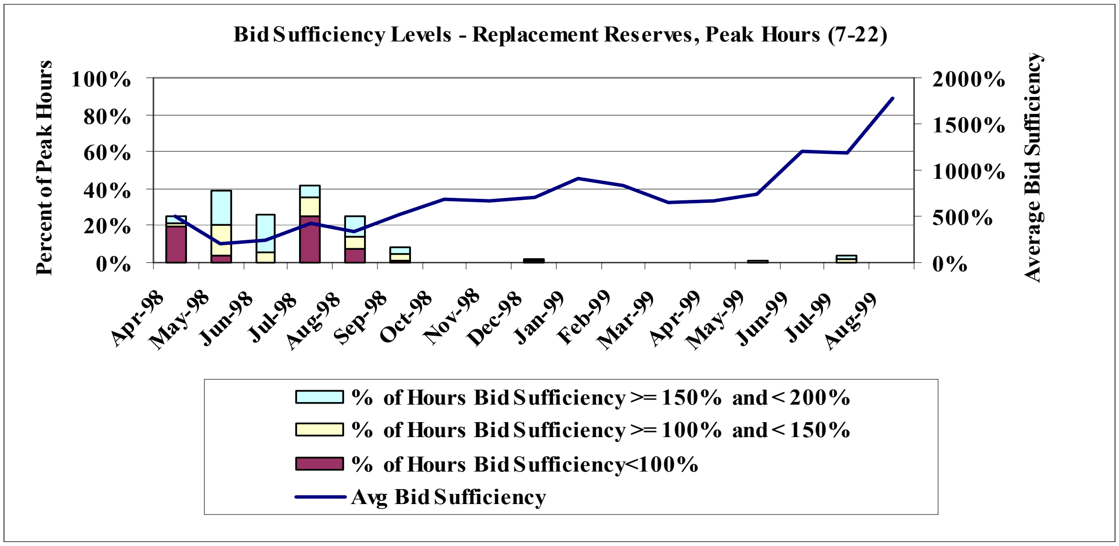


Figure 27



Figures 28-31 show a break down of the average quantity of day-ahead ancillary service bids by various bid price categories and average ancillary service requirements for peak hours. These Figures demonstrate that after the ISO's first four months of operation, there was, on average, an ample supply of bids relative to demand. These Figures also demonstrate that in recent months there has been a large share of bids in excess of $25/MW compared to the same months in 1998. In the summer months of 1998, the IOUs, who at the time were still constrained to cost-based caps for ancillary services and owned more generation capacity than in 1999, were providing a large share of bids to the ancillary service markets. In 1999, new generator owners are providing a larger share of ancillary service bids.

Figure 28

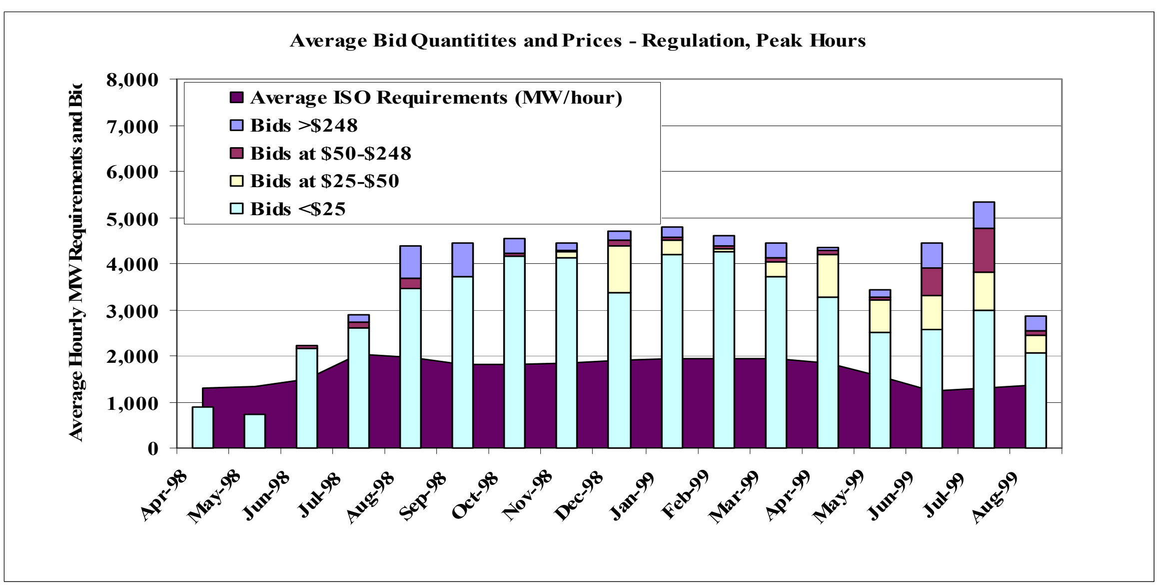


Figure 29

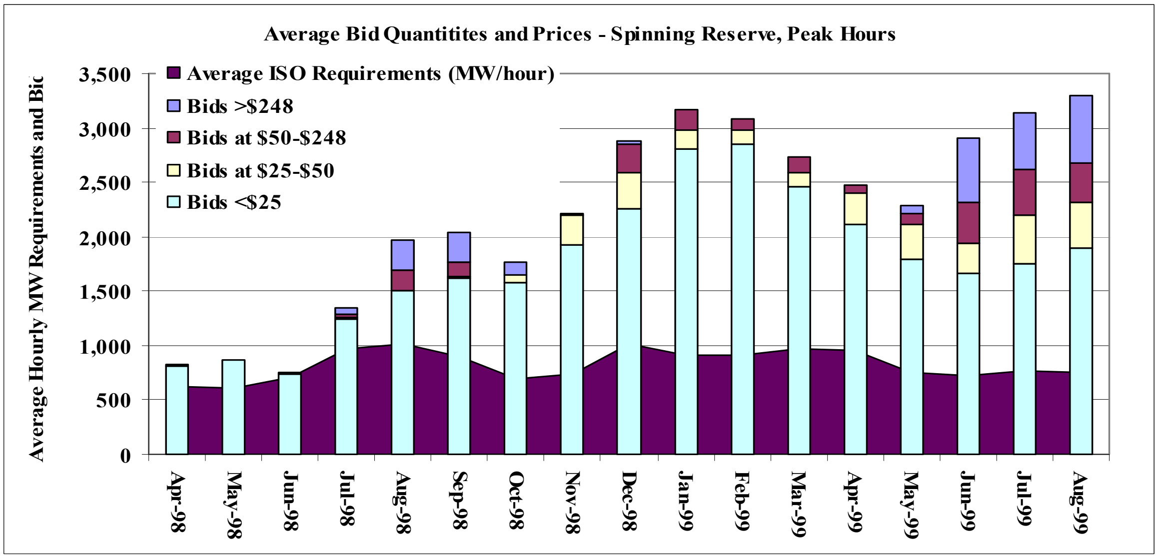


Figure 30

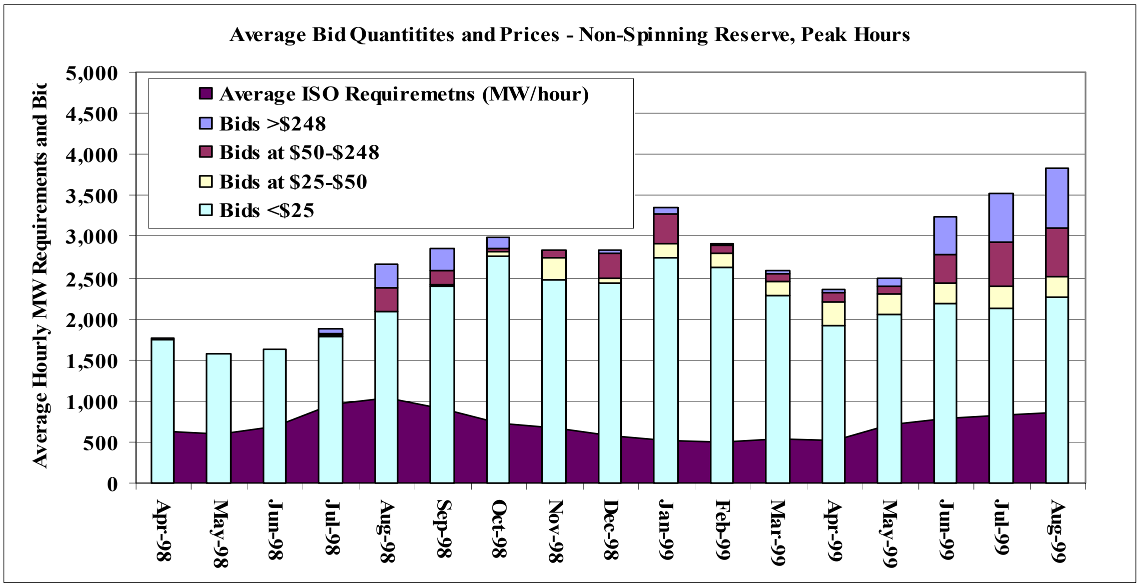
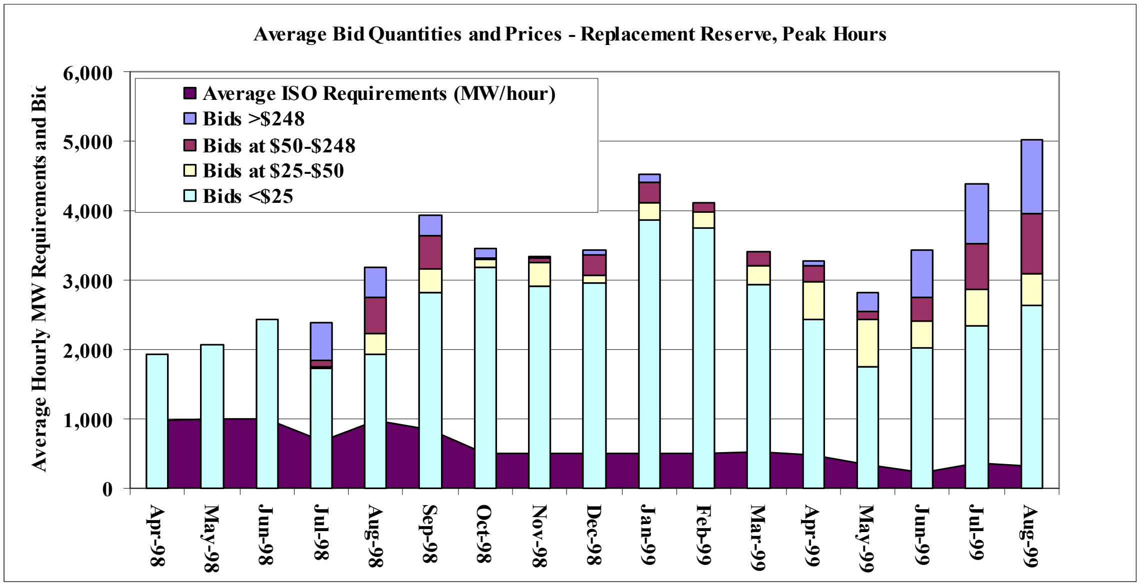


Figure 31



F. The ISO Real-Time Imbalance Market

Supplemental energy bids comprise most of the available energy bids in the ISO real-time imbalance market. The total available bids during July through August 1999 was down considerably from July-August 1998. The reduction in available bids is largely due to lower demand in 1999 for incremental energy (Figures 35-36). Almost half of the available supplemental energy comes from outside the ISO control area (Figures 33-34).

Figure 32

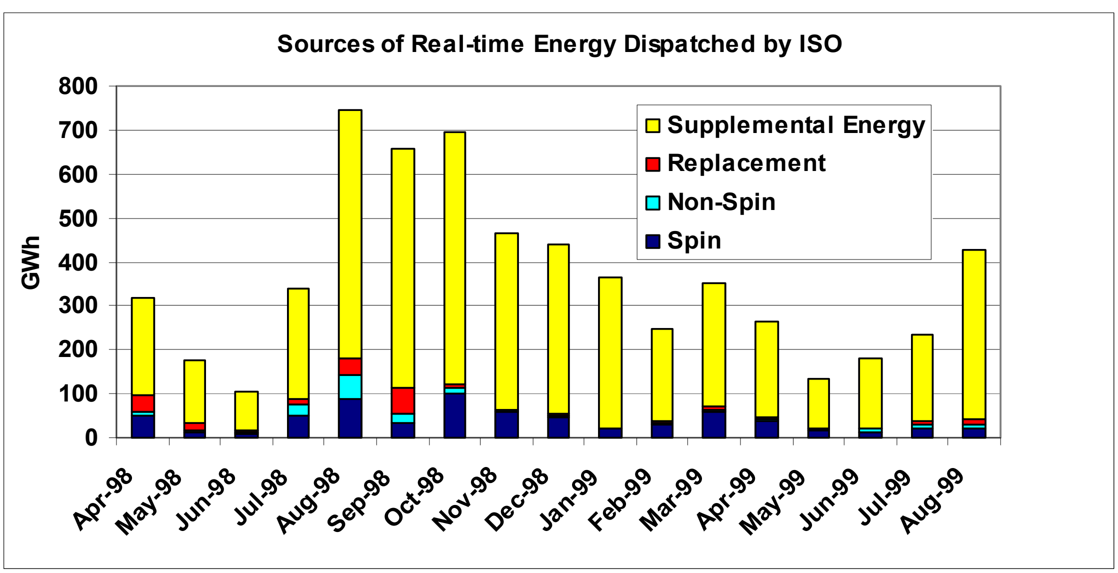


Figure 33

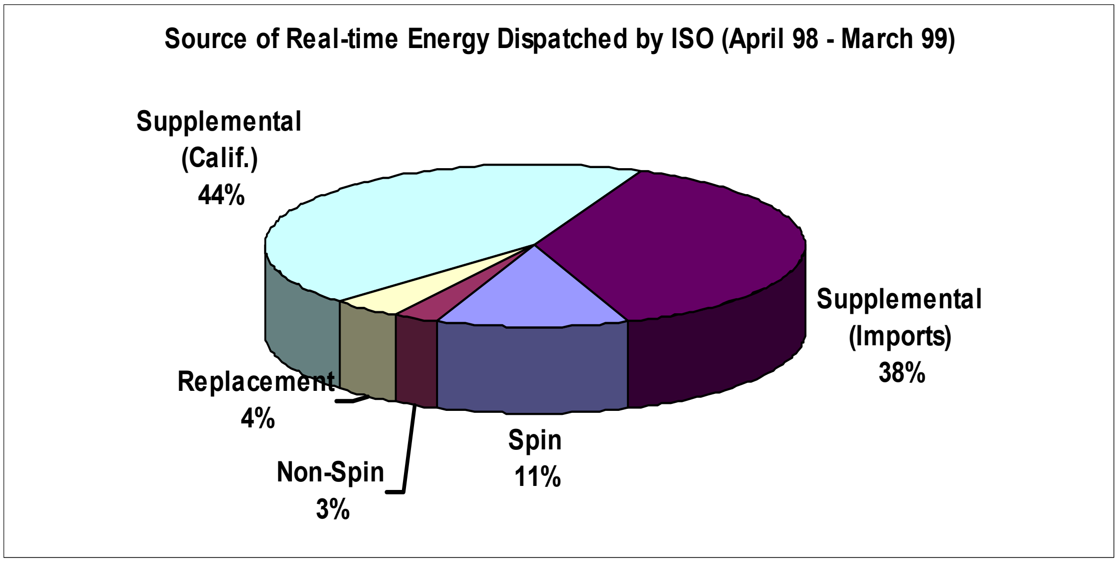


Figure 34

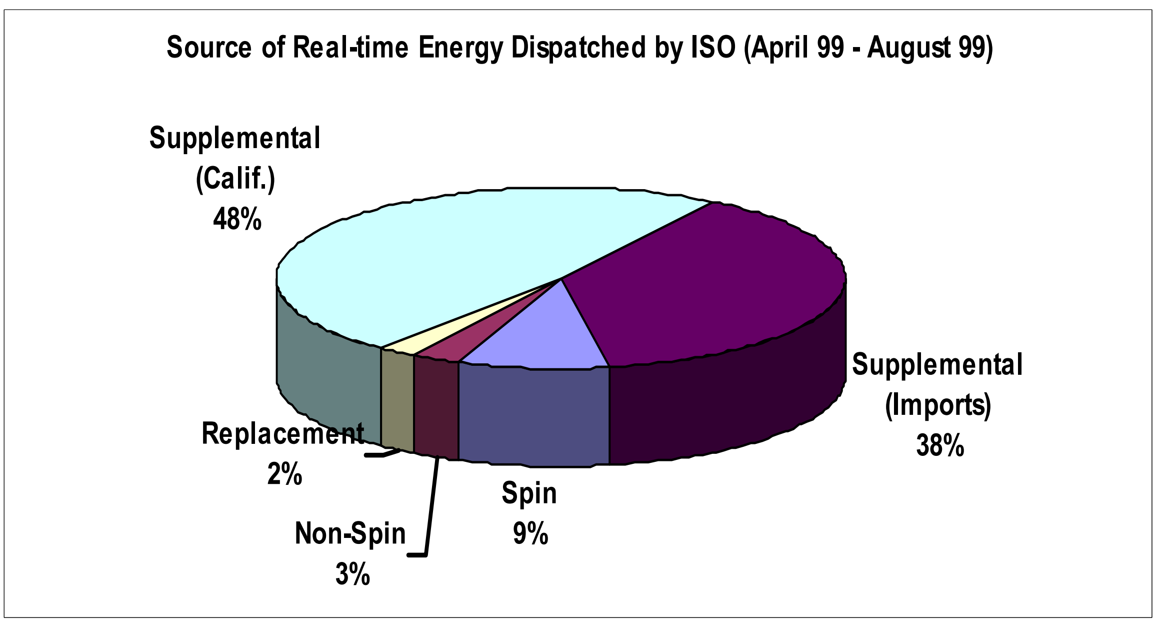


Figure 35

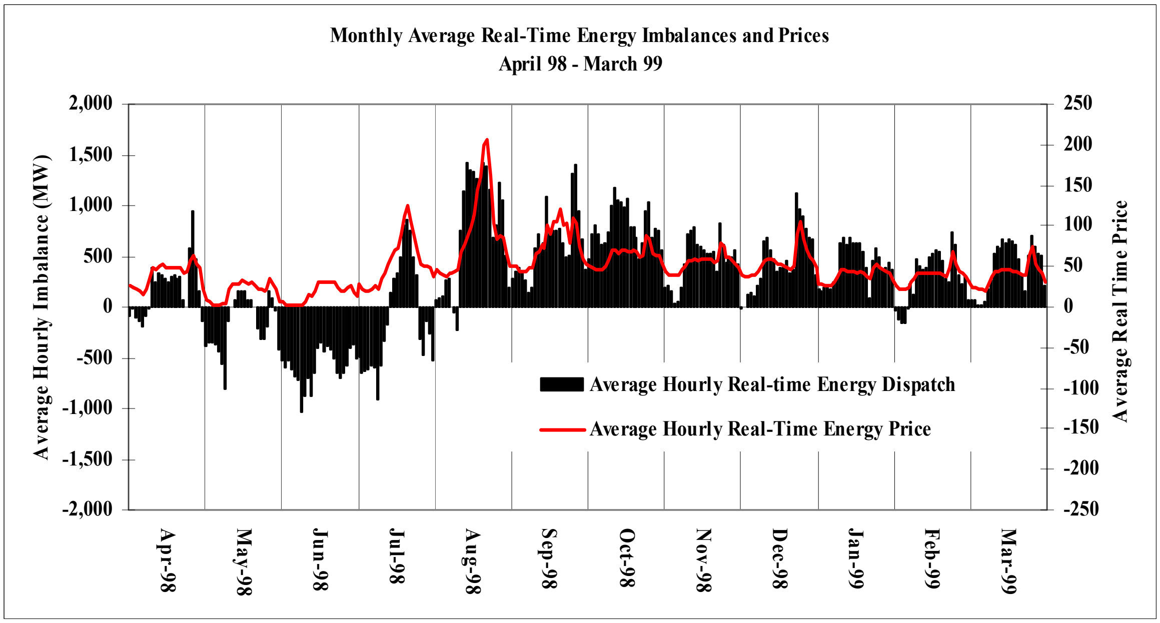
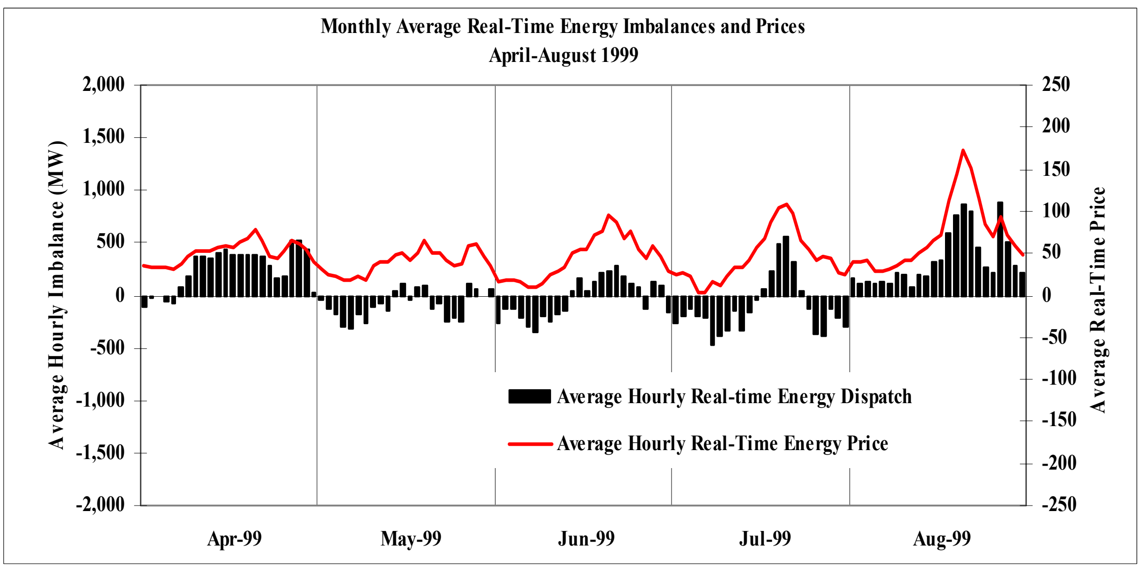


Figure 36



Figures 37-39 compare the ISO real-time price and the PX day-ahead unconstrained energy price for July-August 1998 and July-August 1999. These Figures demonstrate that in July through August 1999, average energy prices in both the PX and ISO real-time markets were very similar under low to average load conditions but for high load conditions (loads greater than 38,000 MW), the average ISO real-time energy price was significantly higher.

Figure 37

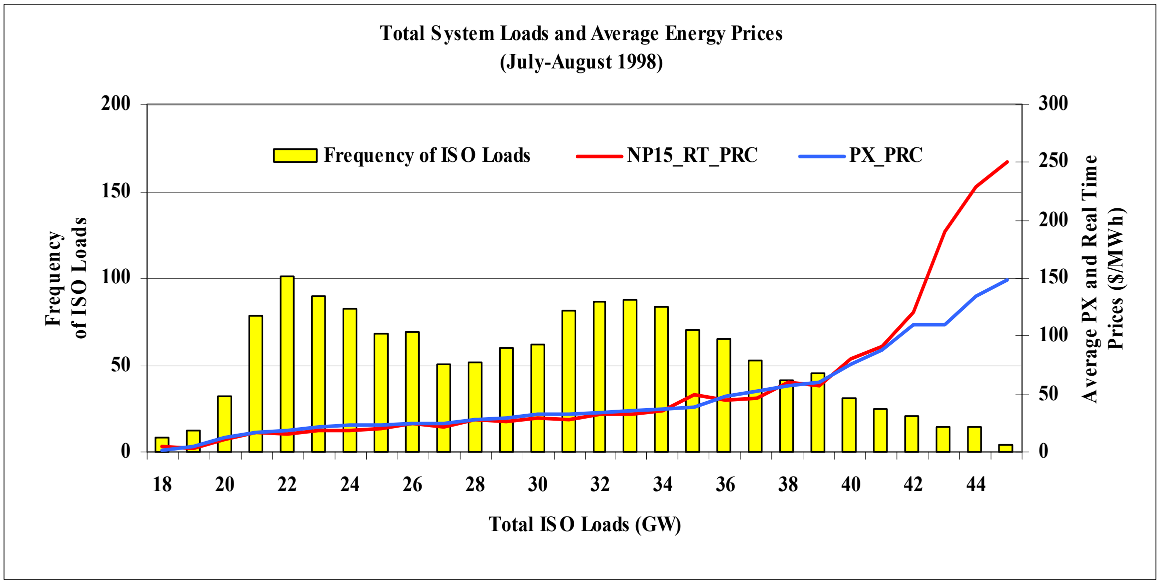
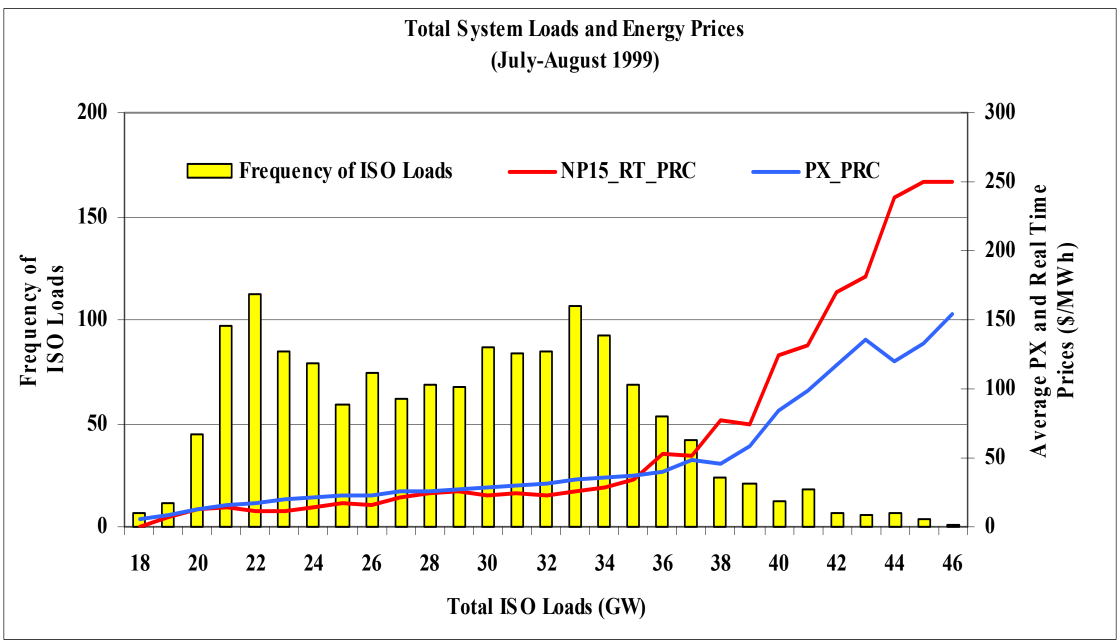


Figure 38



Figures 39 and 40 show, for different ranges of ISO loads, the percent of hours the ISO real time price hit the $250/MWh price cap and the percent of hours it exceeded $200/MWh. These Figures demonstrate that price spikes in the energy markets tends to only occur when system loads exceed 40,000 MW. In hours when system loads exceed 42,000 MW, the real time prices exceed $200/MWh most of the time. Though there were much fewer hours when system loads exceeded the 40,000 MW level in 1999, when this did occur, prices exceeded $200/MWh in a larger percent of the hours than in 1998.

Figure 39

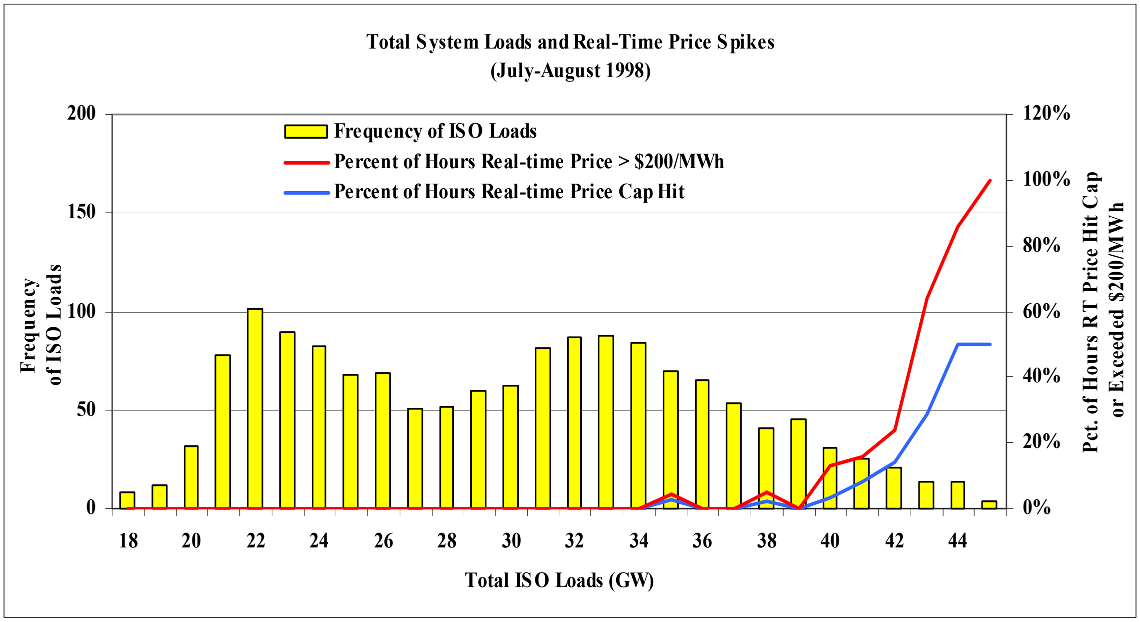
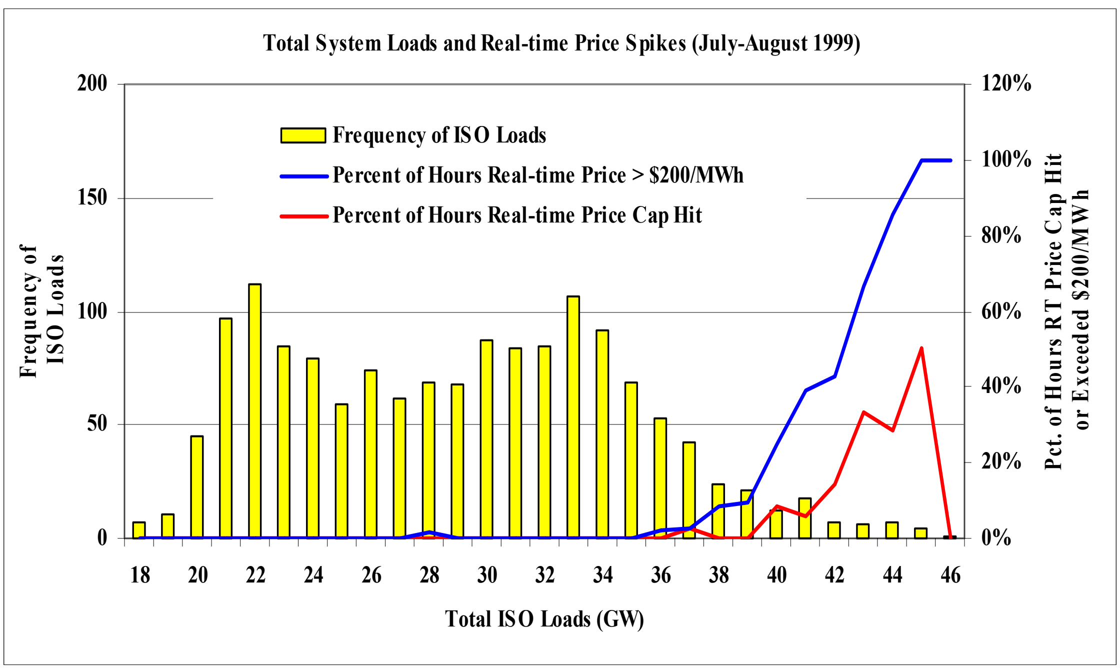


Figure 40



Figures 41 and 42 are plots of system loads and the hourly net energy dispatched marked by different levels of price spikes for July-Sept. 1998 and July-August 1999, respectively. These figures show that most of the price spikes in excess of $200/MW occur when system loads exceed 40,000 MW. They also show that most of the price spikes during July through September 1998 occurred when the ISO was incrementing around 1,500-3,000 MWh of energy. During July through August 1999, the price spikes involved increments of 3,000-5,000 MWh. The fact that the ISO was generally needing to call on larger amounts of energy when loads exceeded 40,000 MW explains to some extent why there was a greater frequency of prices above $200/MWh during these hours, compared to 1998.

Figure 41

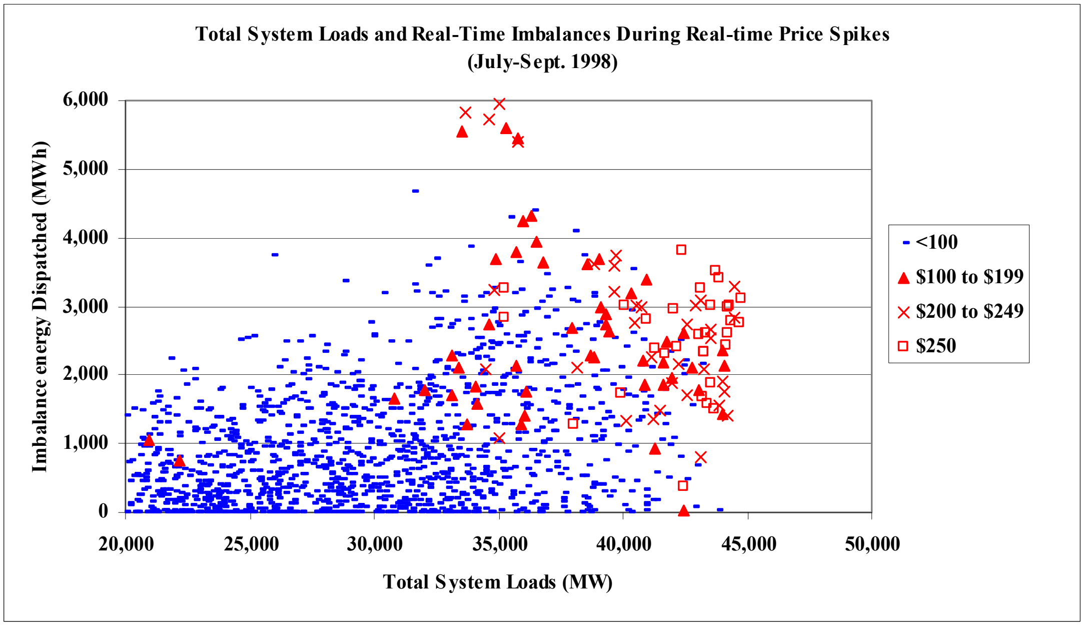
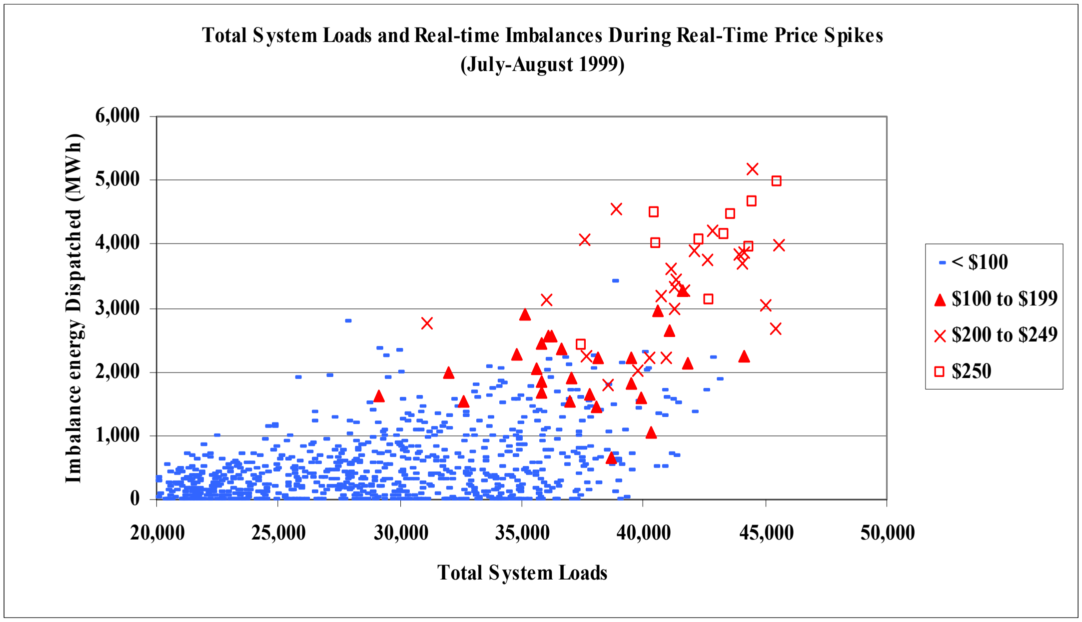


Figure 42



Figures 43 and 44 show average energy prices by load category and by the percent of actual load not scheduled in the forward energy markets for July through August 1998 and July through August 1999, respectively. In 1998, in hours with higher system loads, a higher percentage of these loads went unscheduled in the forward market (Figure 43). When loads exceeded 40,000 MW, over 6% of the actual system load went unscheduled. This explains why the real-time price is significantly higher than the PX price during periods of high loads. This pattern of load under-scheduling during periods of high loads is mainly the result of IOUs hedging the risk of being exposed to a high price in the PX market. By submitting price responsive demand bids to the PX market, IOUs are able to hedge against having to pay a high price for their entire load, particularly when they do not own generation that they can bid into the PX. Even though load that does not clear the PX market ends up being exposed to a high price in the real-time market, because it is only a small portion of the IOU's total load, they are relatively better off.

Interestingly, in 1999, the pattern of load under-scheduling is much more pronounced relative to the pattern in 1998 (Figure 44). A likely explanation for this is that the IOUs own significantly less generation than they did in 1998. The generation that they previously bid into the PX to serve their load is now in the hands of new owners operating under very different financial incentives. With less low bid-price energy available in the PX, more load gets shifted to the real-time market. Note, that in high load periods, PX prices are generally higher that they were in 1998-reflecting the fact that generation is bidding a steeper aggregate supply curve into the PX market.

Figure 43

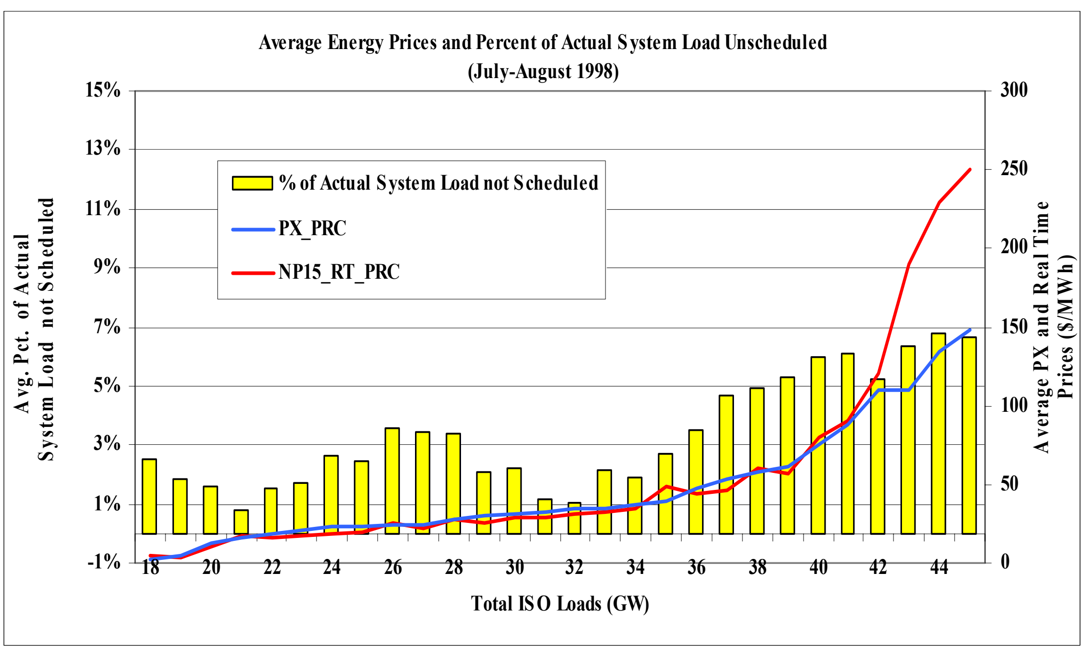


Figure 44

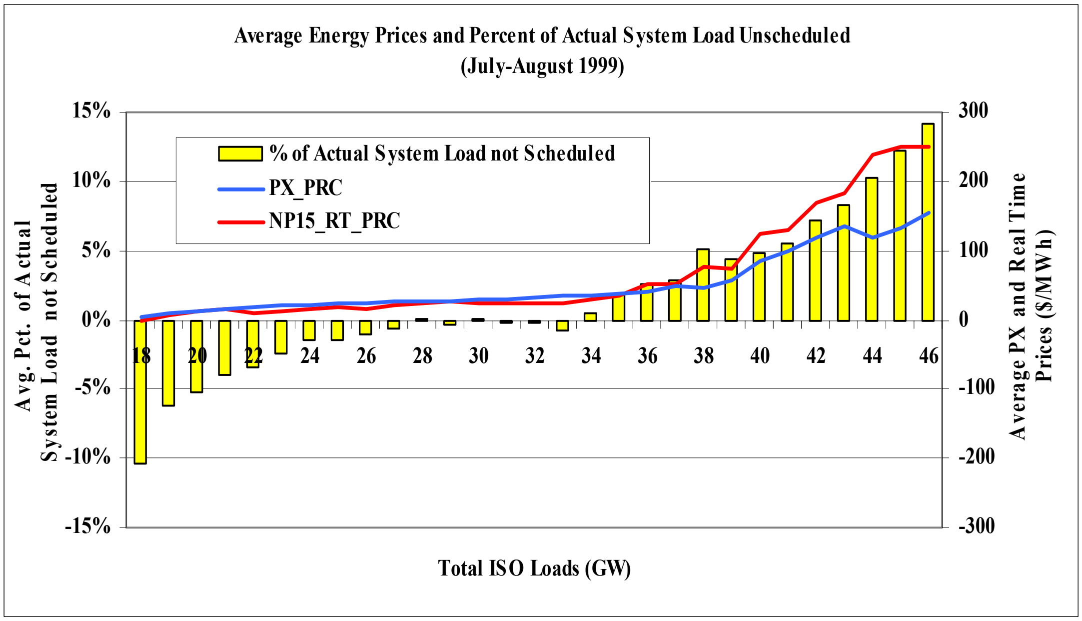
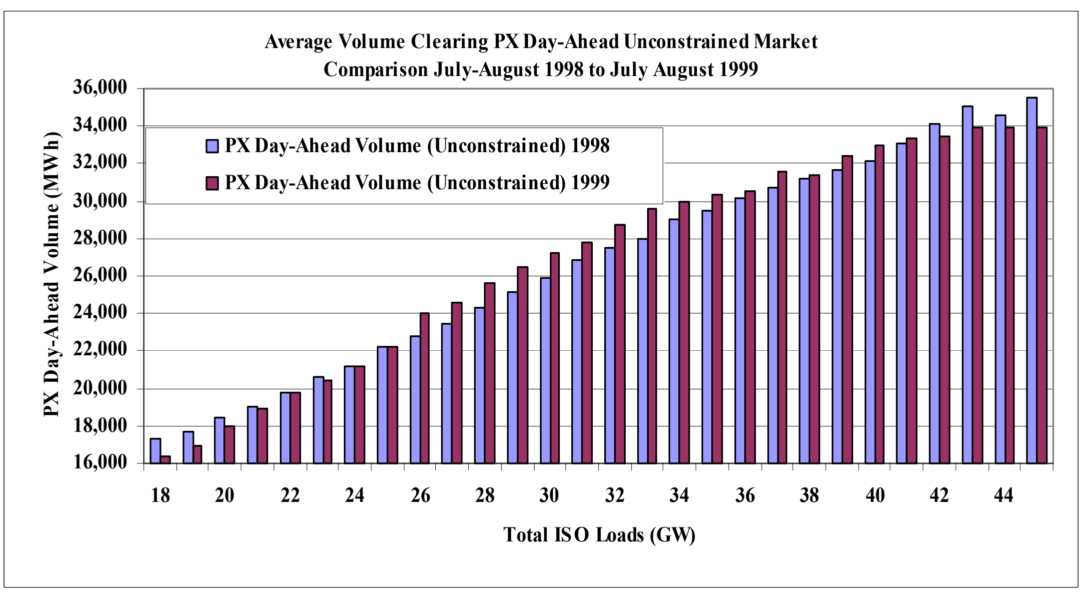


Figure 45 compares the average market-clearing quantities from the PX Day-Ahead unconstrained market to load conditions for July through August 1998 to July through August 1999. This Figure demonstrates that under normal summer load conditions (41,000 MW or less), there was more load hedged in the Day-Ahead PX market in 1999. However, under high load conditions (greater than 41,000 MW), there is less load being hedged the Day-Ahead PX market in 1999. This result supports the notion that the IOUs are less able to hedge against high energy prices in 1999.

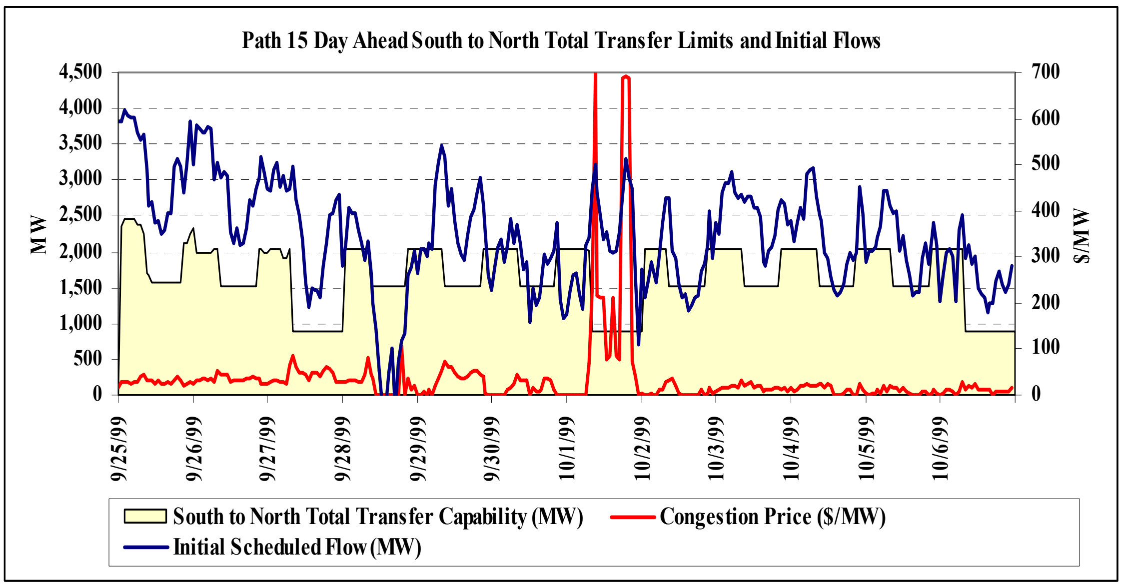
Figure 45



G. Recent Market Experience Under $750 Price Cap

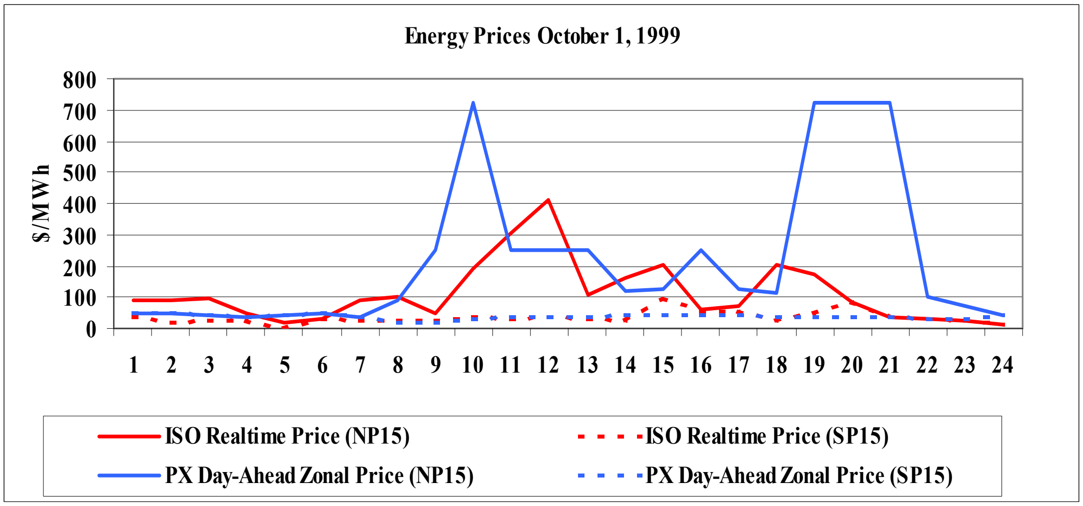
The ISO's recent experience under a new price cap of $750/MW (implemented October 1, 1999) shows that situations can arise where market participants can exercise market power and will do so to the full extent of the price cap. On October 1, 1999), the primary transmission path between southern and northern California (Path 15) was de-rated to 900MW in the south to north direction for most hours of the day causing south to north congestion. In addition, the primary transmission path between the northwest and northern California, the California-Oregon Intertie (COI), was congested in the north to south direction. This simultaneous congestion situation meant that to alleviate congestion on Path 15, the ISO was limited to incremental adjustment bids in northern California (NP15). With only a limited supply of incremental adjustment bids in northern California, very high adjustment bids were used and the day-ahead congestion prices neared $700/MWh in four hours of the day (Figure 46).

Figure 46



These high congestion prices on Path 15 resulted in zonal market clearing prices in the PX Day-Ahead energy market for northern California (Congestion Zone NP15) of $725/MWh (Figure 47).

Figure 47



In addition because of Path 15 congestion, the ISO was forced to procure ancillary services regionally (i.e. separate markets for northern and southern California) for the day-ahead market for October 1, 1999. This resulted in some significant price spikes in the northern California ancillary services market. In this case, one market participant owning generation in northern California substantially increased its capacity bids into the ancillary services market and this change in bidding behavior resulted in a market clearing price for replacement reserve in excess of $300/MW for 4 hours, including a price of $534/MW. Price spikes in excess of $250/MW also occurred in the Spinning and Non-Spinning reserve markets (Figure 48). In addition, there were numerous price spikes of $675-750/MW in the hour-ahead market

Figure 48

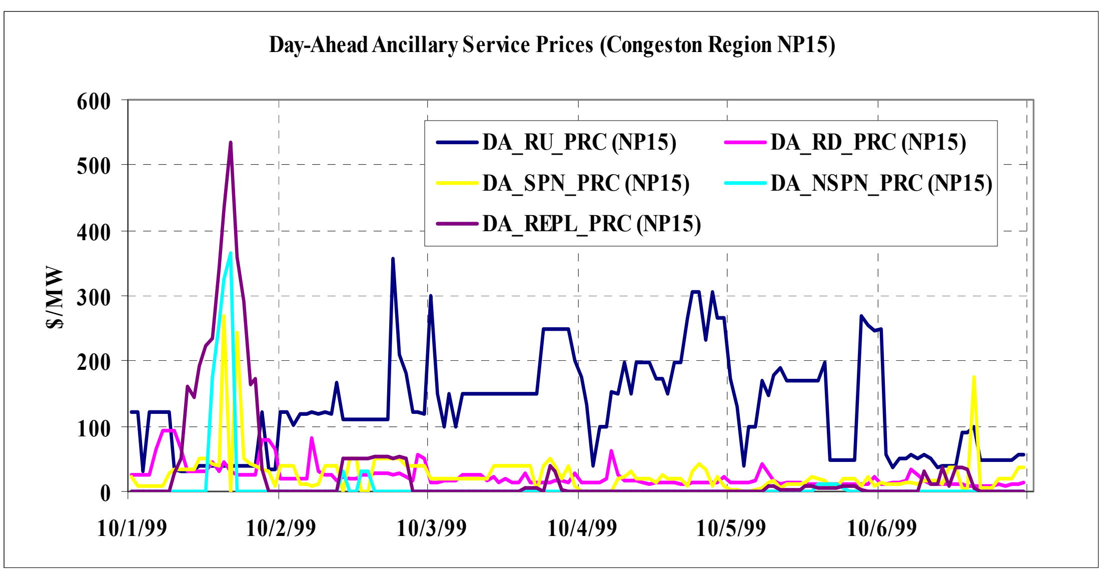


Figure 49

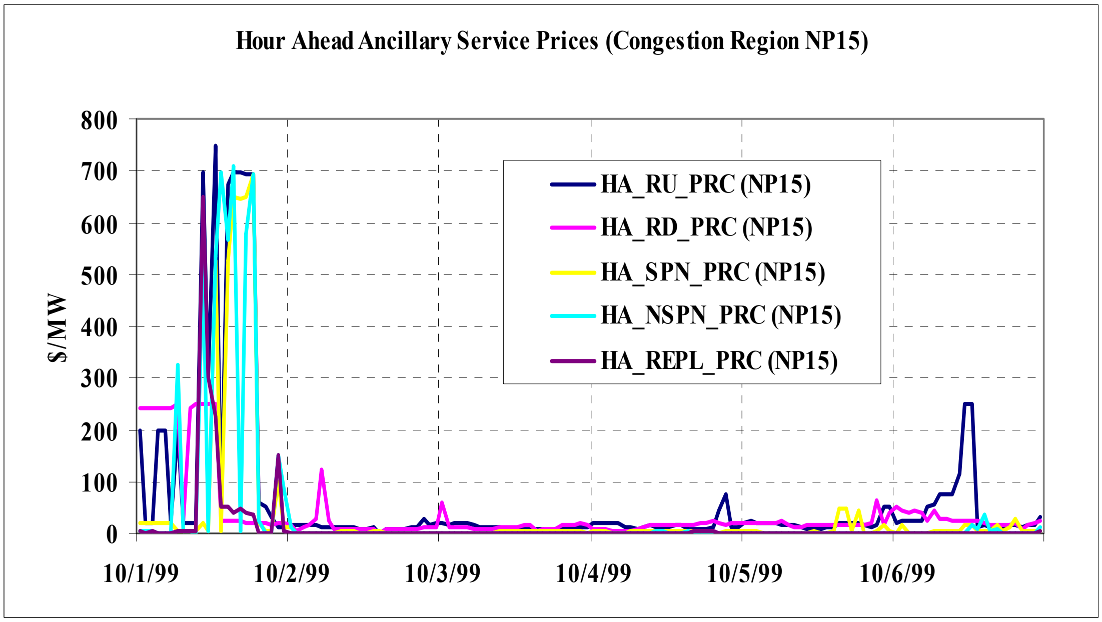
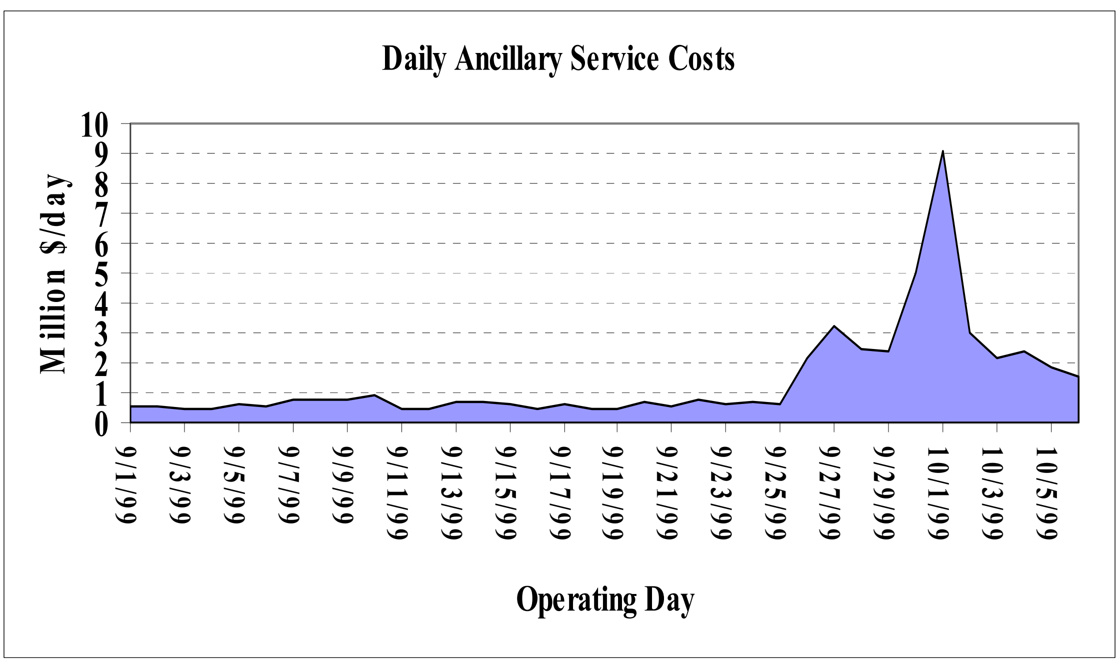


Figure 50 shows the total daily ancillary service costs from 9/1/99-10/6/99. As can be seen, the price spikes of October 1, 1999 resulted in a total ancillary service costs of over $9 million, roughly 18 times the average daily cost for September, 1999.

Figure 50



As the above incident illustrates, significant market power remains in the California electricity market, particularly when there is limited transmission capacity into the ISO control area and across congestion zones. Historically market power in the California has been exercised to greatest extent during periods of high total ISO load.

4. Measuring Market Power in the California Wholesale Electricity Market

Borenstein, Bushnell and Wolak (1999) analyze the extent of market power exercised in the California energy market by comparing the market-clearing price of wholesale energy, in this case the unconstrained PX price, to the market-clearing price that would arise in a fully competitive electricity market. The competitive benchmark price assumes that all generators behave as if they were unable to influence the market-clearing price through their bidding behavior. In this case, the market-clearing price each hour would equal the cost of producing an additional unit of output beyond the quantity of actual total ISO generation during that hour.

The Borenstein, Bushnell and Wolak (1999) analysis utilizes hourly metered data on electricity produced from each generating unit in California and electricity flowing over each intertie into the ISO control area. In the process of constructing the counterfactual competitive market price the authors make several conservative assumptions against finding market power. In particular, they assume that no market power is being exercised by in-state hydroelectric facilities in their bidding and dispatch decision and by must-take facilities in their dispatch decisions. The authors also account for the fact that less imports should flow into the ISO control area in response to lower energy prices in California. This implies that in-state facilities would be required to produce additional energy to make up the imbalance created. They make use of adjustment bids submitted across all interties into the ISO control area on a day-ahead basis to construct the new equilibrium level of imports into the state as result competitive pricing in California. The authors also account for weekly variation in the price of fossil fuels to the various in-state fossil facilities in determining the production cost for each generating unit. Using data from the National Electricity Reliability Council (NERC) on forced outage rates for all instate fossil facilities, the authors use Monte Carlo methods to integrate out with respect to the joint outage distribution of all instate fossil facilities to compute the expected fully competitive market price for each hour of the day during their sample period. The authors also acknowledge that some generating capacity is not available to provide energy in real-time should system demand rise because it will continue to be used as system reserve. The authors assume that the amount of capacity procured to provide upward regulation during each hour represents capacity that is dedicated to the provision of this reserve and is therefore unable to provide additional energy should the need arise. As a consequence, the authors add this quantity of reserve capacity to total ISO load in determining the appropriate total system demand necessary to compute the expected competitive price of electricity each hour.[11]

[11] Copies of the report "Measuring Market Power in California's Restructured Wholesale Electricity Market," by Severin Borenstein, James Bushnell and Frank Wolak, which explains this methodology in detail can be obtained from http://www.ucei.berkeley.edu/ucei/ or http://www.stanford.edu/~wolak.

For the period June 1998 to November 1998, these authors estimate that the actual total costs purchasing electricity in the California market was 29% above the expected total costs that would have resulted from fully competitive pricing in the California market. This calculation does not attempt to quantify the extent of market power exercised in the ISO's ancillary services market. However, the opportunity cost of selling capacity in the ISO's ancillary services markets is the foregone profits the unit owner could have earned in the PX and ISO wholesale energy markets. Therefore, it is reasonable to expect that similar amounts of market power exist in these markets as well during the same time period.

We hoped to report the results of this analysis for the period June 1999 to September 1999 to compare to the 1998 numbers presented in Borenstein, Bushnell and Wolak (1999). Because complete ISO settlement data, a vital input to this analysis, is only available as of July 26, 1999, this was not possible. Using the available settlement data, we performed this analysis for the months of December 1998 to July 26, 1999. The only difference between the methodology followed in our analysis versus the one in Borenstein, Bushnell and Wolak (1999) is that we used \$2.5/MBTU as the price of natural gas for all plant locations and hours during our sample period. This was necessitated by our current lack of a complete time series on natural gas prices in California for the sample period.

We compute the average hourly percentage increase in the cost of purchasing electricity from the California wholesale electricity market during each month from December 1998 to July 26, 1999 relative to the pure competitive market benchmark. Similar to what Borenstein, Bushnell and Wolak (1999) found for the months of October 1998 and November 1998, the total wholesale energy cost increase above the competitive benchmark for the period December 1998 to June 1998 was relatively small. It is important to remember that during these months the daily peak total ISO is significantly less than the daily peak in July, August and September. In addition, during the spring of 1999 hydroelectric energy was in plentiful supply so that these unit owners were often faced with the choice of spilling water or generating energy with it.

For the month of July 1999, first month in 1999 with a sustained period of high total ISO loads, conditions in the wholesale energy market more closely resembled those during summer of 1998 rather than conditions during the winter and spring of 1999. According to our calculations, the total wholesale energy costs, excluding energy produced under must-take arrangements, were 20% above those that would have resulted from the pure competitive market benchmark for the period July 1 to July 26, 1999. These results illustrate that although the wholesale energy market appears to be operating more efficiently in 1999 versus 1998, during periods of high total ISO load there appears to be a significant amount of market power exercised in the California wholesale electricity market. The comparable figure for July 1998 was approximately 39%, so that although a significant amount of market power was exercised this July it is considerably less than the amount exercised last summer during same month. Once ISO settlement data for the months of August, September and October is available, the Borenstein, Bushnell and Wolak (1999) analysis can be repeated for entire summer of 1999. This will provide a clear answer to question of how the extent of market power exercised in the wholesale energy market this summer compares to that exercised last summer.

To determine if the market performance in the real-time energy market last summer versus this summer can be attributed to the significantly lower load conditions this summer, we estimate the price regressions described above for the real-time energy market over the time period June 1, 1999 to August 17, 1999. This regression gives an estimate of the average hourly zonal energy price difference between the same month this summer and last summer that controls for differences in total ISO load across hours this summer versus last summer. Specifically, for each congestion zone and each hour from June 1, 1998 to August 17, 1999, we regress REALP(c,j), the real-time price of electricity in hour j for congestion zone c, on a constant term, a sixth order polynomial in ISOLOAD(j), a complete set of DAY, HOUR, MONTH indicator variables, the indicator variable CONG(j), and the three indicator variables, JUNE99, JULY99 and AUG99. The regression coefficient on JUNE99 gives the average difference in real-time energy prices in June 1999 versus June 1998, controlling for differences in the level of total ISO load across the two months. A similar interpretation holds for the coefficients on JULY99 and AUG99.

Table 6 gives the point estimates and standard errors for the coefficients associated with the indicator variables JUNE99, JULY99, and AUG99 for the real-time price in NP15 and SP15. This table is consistent with the view that much of the apparent improvement in the performance in the real-time energy market can be attributed to the lower average hourly load conditions in the summer of 1999 relative to 1998. With the exception of July, the average load adjusted prices in 1999 are in fact higher than they were during 1998. The lower load adjusted real-time average price in July 1999 is consistent with the reduced total wholesale energy costs increase due to the exercise of market power that we find in July 1999 versus that number for July 1998 reported in Borenstein, Bushnell and Wolak (1999).

Table 6: Load-Adjusted Year-to-Year Difference in Real-Time Zonal Energy Prices

Month	Load-Adjusted Difference in Average Hourly Real-Time Energy Prices Between Summer of 1999 and Summer of 1998	
	NP15	SP15
June	6.71 (0.99)	6.58 (0.99)
July	-5.68 (1.09)	-5.94 (1.08)
August	2.16 (1.30)	3.85 (1.29)
Standard Errors in Parentheses		

The results in Tables 6, together with the evidence from the ancillary services markets, provides evidence in favor of the view that a significant portion of the apparent improvement in the performance of these markets can be attributed to the milder weather and load conditions experienced this past summer versus last summer. As will shown below, several important structural flaws in the California market design remain, which explains why this market power remains. We then provide various recommendations for correcting these deficiencies in the market design.

5. Remaining Market Design Flaws and Recommendations for Correcting Them

The ISO management and Board have worked extremely hard over the past year implementing many changes in the market design that should: (1) increase the efficiency of the California electricity market, (2) improve the reliability of the California transmission grid, and (3) lead to a sufficient quantity of new generating capacity in California to meet its growing electricity demand. However, several important market design issues remain unresolved from previous MSC Reports. We continue to believe that they must be satisfactorily addressed before the California electricity market can become workably competitive. These issues are: (1) the timing of calls for reliability must-run (RMR) units and dispatch obligations under the new RMR contracts, and (2) eliminating the restrictions on the ability of demand to respond to high hourly wholesale energy and ancillary services prices.

Three issues have grown in importance since the April 1999 MSC Report. They are: (1) the impact of market participant non-compliance with ISO dispatch instructions or the technical standards necessary to participate in the ISO's energy and ancillary services market on the prices in these markets and reliability of the ISO transmission grid, (2) the perverse incentives for generation unit scheduling and dispatch caused by the ISO's intra-zonal congestion management protocols, and (3) integrating the operation of the firm transmission rights (FTR) market with the ISO's congestion management protocols. The ISO management is aware of these issues and has taken significant actions to address them, particularly the first and third ones. It our understanding that a recommended solution to this problem will be filed along with the ISO's request for a re-hearing on Amendment 19, the ISO's New Generation Interconnection Policy. Below we provide our analysis of this issue and provide recommended market design changes to address this problem. We also provide recommendations for integrating the market for FTRs into the ISO's congestion management protocols.

The final set of issues concern the long-term health of the California electricity market. Given the importance of attracting new generation investment that is sufficient to meet California's growing electricity demand without leading to significant excess capacity in the California market (which would then lead to a period of depressed prices for energy and ancillary services), these long-term market design issues become very important. First is designing the appropriate financial and local reliability obligations for new generation entrants when they connect to the ISO grid so that they locate at points in the transmission grid that enhance the efficiency of the market. Second is creating incentives for transmission capacity expansions in the ISO grid to substitute for new generation facilities, where this substitution reduces annual total delivered electricity costs.

6. Pre-Dispatch and Scheduling of RMR Energy in the Day-Ahead Market

One aspect of the Reliability Must Run (RMR) contract reforms recommended by the MSC in its March 25, 1999 report that has yet to be implemented concerns the timing of RMR calls relative to the operation of the day-ahead energy market and the corresponding day-ahead scheduling requirements for units called to provide RMR energy. The structure of the current RMR contracts have been revised to take the basic form recommended in the August 1998 Report and further elaborated on in the April 1999 MSC Report: a fixed annual payment (independent of number RMR calls made within the year or the number start-ups that are caused by RMR calls) and a variable cost payment per unit of RMR energy provided. Currently, RMR calls are made following the close of the day-ahead energy market.

We continue to remain convinced that the pre-dispatch and day-ahead scheduling of RMR units outlined in the April 1999 MSC report is an essential feature of the RMR contract reform process. The three basic features of our recommendations are:

1. Pre-dispatch of all RMR units before the start of the day-ahead energy market. Based on its assessment of the load conditions in the California transmission grid, the ISO would determine the minimum reliability energy requirements from each RMR unit.

2. All RMR unit owners with non-zero minimum reliability energy requirements would have the option to elect to receive, on an hour-by-hour basis, a PX or ISO market-clearing energy price for that hour or that unit's RMR variable payment rate for this quantity of energy. This election for all hours of the following day would be made before the opening of the day-ahead energy market.

3. All RMR unit owners with non-zero minimum reliability energy requirements would be required to submit to the ISO in a balanced day-ahead energy schedule a generation quantity from each RMR unit that is greater than or equal to the minimum reliability energy requirement from that RMR unit.

The benefits to market efficiency from this scheme are:

1. It is consistent with the market design principles of the California electricity market where all day-ahead and hour-ahead energy requirements are submitted to the ISO in balanced schedules. The current RMR dispatch scheme requires the ISO to take financial position in the real-time energy market.

2. It would enhance the efficiency of operation of both the energy and ancillary services markets. Loads would have greater certainty about when RMR energy requirements are scheduled. The ISO, and therefore loads, would no longer run the risk of purchasing capacity for ancillary services in the day-ahead market that cannot be used because of an RMR energy need from that capacity.

3. It would reduce the volatility of wholesale energy prices in the PX and ISO markets as well reduce average wholesale energy costs.

4. It would delay less generation scheduling decisions to the real-time market, thereby improving system and transmission grid reliability.

Because there do not appear to be any significant costs to market efficiency from implementing this scheme, we strongly urge FERC to adopt this recommendation, given its many market-efficiency-enhancing properties.

The purpose of this section is to provide the logic underlying our recommendations and conclusions about the impact of pre-dispatch and day-ahead scheduling of RMR energy on prices in the PX and ISO markets, as was requested by the FERC. To provide the necessary background for our analysis, we first summarize the current RMR dispatch protocols. This is followed by an analysis of the impact of the current protocols on the operation of California energy and ancillary services markets. We then describe how our recommendations will improve the efficiency of the energy and ancillary services markets. Included in this discussion is a qualitative analysis of the impact of pre-dispatch and day-ahead scheduling on prices in the PX and ISO energy markets.

A. Current RMR Dispatch Procedures

Under the current RMR dispatch procedures, after the ISO has received a day-ahead energy schedules for all generating units and intertie points, it determines the minimum necessary operating level, or Minimum Reliability Requirement (MRR), for each RMR unit for each hour of the following operating day. This MRR is determined based on local weather conditions, forecast ISO load, and the operating conditions of other RMR generating units. For example, all generating units, including RMR units, have a minimum operating level, below which the generating unit becomes electrically unstable. Consequently, the Minimum Reliability Requirement for a RMR unit can never be below the minimum operating level for that unit.

After determining the hourly Minimum Reliability Requirement for that unit, the ISO then compares this quantity to the final day-ahead schedule submitted by the RMR unit. If the final day-ahead schedule for that hour is below the Minimum Reliability Requirement, then that unit's day-ahead schedule is adjusted upward to the Minimum Reliability Requirement. The ISO implements this through a Schedule Change to the RMR unit owner, which gives the increase in the unit's day-ahead energy schedule necessary to guarantee that it operates at or above the minimum reliability requirement for that hour. For example, if a unit schedules 20 MW into the day-ahead energy market, and its minimum reliability requirement is 40 MW, then a Schedule Change will be issued to that RMR unit for 20 MW. If the day-ahead energy schedule for that hour exceeds the minimum reliability requirements for that hour, then no Schedule Changes will be issued during that hour for that RMR unit. For example, if a unit schedules 60 MW into the day-ahead energy market, and its minimum reliability requirement is 40

MW, then no schedule change will be issued because the unit has already included more than its minimum reliability requirements in its day-ahead energy schedule. Dispatch notices are issued to RMR unit owners notifying them of either the ISO's minimum reliability requirement and any schedule change necessary to meet this requirement.

If a Schedule Change is necessary, then under the new RMR contracts (that have been in effect since June 1999), a unit owner has the option of meeting these reliability requirements through either the market or contract path. Under the contract path the RMR unit owner agrees to operate at a level that at least meets the minimum reliability requirement from that unit and receives a previously agreed upon contractual variable cost payment (VCP) for each MWh of RMR energy provided. Any remaining capacity from that unit may be used to supply energy or any ancillary service that unit is technically capable of providing through a market transaction.

The market path allows owners to schedule RMR energy in the hour-ahead market or in the real-time market. Under the hour-ahead market option, the RMR owner receives the hour-ahead PX price or a bilateral transaction price that the unit owner has managed to negotiate for this RMR energy. Under the real-time market option, the increment to the generator's day-ahead schedule is treated the same way as any other uninstructed deviation from a unit's final hour-ahead schedule. Under this scheme, the RMR unit owner is paid for this incremental energy at the real-time imbalance energy price for that hour. According to the September 1999 report prepared by the ISO's Department of Market Analysis (DMA) on pre-dispatch and scheduling of RMR energy in the day-ahead market[12], since the new RMR contracts have been in effect, less than 1.4% of total RMR schedule changes issued after the day-ahead market (excluding real-time dispatches) have been compensated according to the market path.

It is important to note that under the current RMR protocols, the additional energy provided under a Schedule Change through either the market or contract path is not matched with a corresponding increase in load. The current RMR protocols do not require that this additional RMR energy be submitted as part of a balanced schedule. This incremental energy obtained through Schedule Changes results in an excess supply of day-ahead energy that is unmatched with demand until the real-time market. The existence of this excess supply of energy on a day-ahead basis is inconsistent with a fundamental design principle of the California market that day-ahead energy schedules should be balanced.

Assume that all Scheduling Coordinators (including the PX) submitted balanced day-ahead schedules, and made no changes in their consumption or generation plans between the close of the day-ahead energy market and the start of the real-time market. Under the current RMR protocols, the ISO would have to decrement energy from generators in the real-time market equal to the total amount of the Schedule Change energy procured through RMR contract calls following the close of the day-ahead market. Consequently, the current RMR dispatch protocols require the ISO to take a

[12] "Pre-Dispatch and Scheduling of RMR Energy in Day-Ahead Market," Department of Market Analysis, California Independent System Operator, September 1999, p. 3.

financial position in the real-time energy market as a result of its RMR Schedule Changes. This is inconsistent with another basic principle of the California market design that the ISO not take a financial position in any of the markets that it operates. All the inefficiencies introduced by the current ISO RMR dispatch practices can be traced to the violation of these two basic design principles.

B. *Market Inefficiencies Caused by a Current ISO RMR Dispatch Practices*

The current ISO RMR dispatch practices increase the volatility of real-time ISO and PX energy prices and artificially increases the quantity of generation in the ISO's real-time energy market. This can lead to increased ancillary services purchase costs to all Scheduling Coordinators and increased reliability risks for the system operator because larger discrepancies between the supply and demand for energy from SCs must be balanced in the real-time energy market. As discussed above, the current RMR dispatch practices also result in more energy being purchased and scheduled in real-time. Finally, by dispatching RMR requirements after the close of the day-ahead energy market, the current RMR dispatch practices still provides the incentive for generators to bid the opportunity cost of their RMR variable payment rate into the day ahead energy market.

Although the revised RMR contracts have significantly reduced the magnitude of the variable payment rate, there are still many hours when the market-clearing price in the PX or real-time energy market is below the variable payment rate for many RMR units. During these periods, RMR unit owners would prefer to receive the variable payment rate rather than the PX price or the real-time energy price for their RMR energy. If the RMR unit owner's marginal cost of production is above the expected PX or ISO energy price, then it is clearly rational for the RMR unit owner not to schedule into the day-ahead energy market and to receive a market-clearing price below its marginal cost. However, because all RMR unit owners have non-RMR units, bidding sufficiently steep aggregate supply curves into the PX market (so that unit owner does not win a large enough quantity to justify including these units in their day-ahead energy schedules to the ISO) may be profit-maximizing. Occasionally the favorable outcome that the high-priced bid necessary to schedule the RMR capacity on day-ahead basis sets the market-clearing price for all units owned by that RMR unit owner.

C. *Increased Wholesale Price Volatility and Purchased Energy Costs*

Under the current RMR dispatch protocols, if all loads submitted their anticipated demand for the each hour during the following day in a balanced day-ahead energy schedule, the ISO would be required to decrement energy in the real-time market equal to the quantity of RMR Schedule Changes issued after the close of the day-ahead energy market. We therefore expect loads to attempt to anticipate the quantity of RMR energy that will called after they submit their day-ahead energy schedules. It is extremely unlikely that all buyers of energy will jointly be able to anticipate the precise quantity of aggregate RMR Schedule Changes and adjust their day-ahead energy schedules accordingly.

Any error in the forecast of aggregate RMR Schedule Changes by any load will result in either too much or too little demand being shifted from the day-ahead to the hour-ahead and real-time market energy markets. These RMR Schedule Change forecast errors by loads will increase the price volatility in both the PX day-ahead and hour-ahead markets and the ISO real-time energy markets. During some periods day-ahead PX prices will be lower because loads shift too much demand to the hour-ahead and real-time markets. In other periods, this price will be significantly higher because loads shift too little demand to the hour-ahead and real-time markets. Because the PX supply aggregate bid supply curve increases at an increasing rate and takes a reverse L-shape in both the day-ahead and hour-ahead markets, this increased price volatility will result in higher expected wholesale energy costs than would be the case if wholesale prices had the same mean but a lower volatility. This conclusion follows because the lower prices due to an unexpected small amount demand bid into the PX will tend to be only slightly lower. The unexpectedly high demand bid into the PX will lead to a much higher price, because in these instances the increased aggregate demand curve will now cross the very steep portion of the PX aggregate supply bid curve.

Figure 51

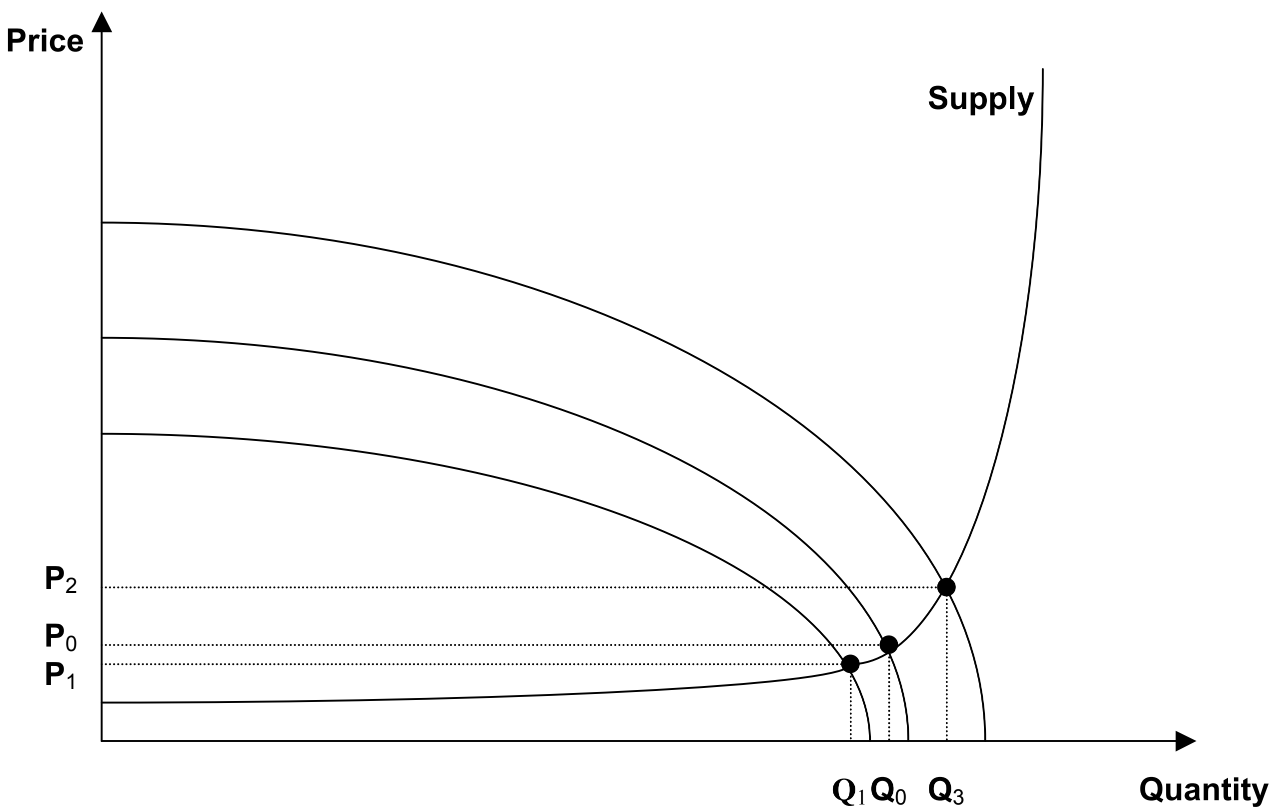
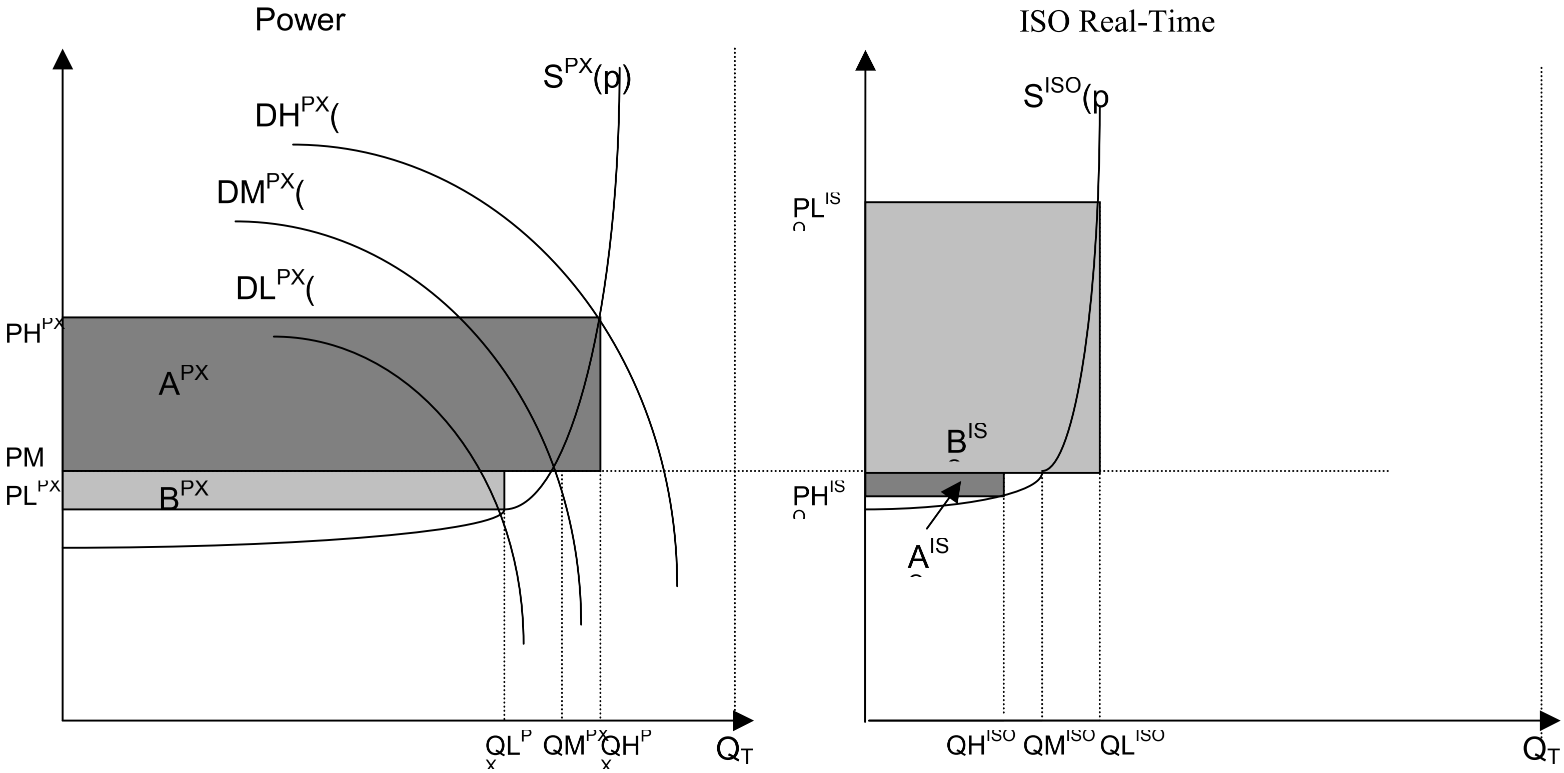


Figure 51 illustrates this phenomenon by plotting a representative PX aggregate supply curve and three PX aggregate demand curves. The middle curve represents the aggregate demand curve which perfectly anticipates the amount of aggregate RMR energy that will called after the close of the PX day-ahead market. The market-clearing price and quantity in this case are P_0 and Q_0. The lowest curve represents the aggregate demand when too much load is shifted to the hour-ahead and real-time market. The market-clearing price and quantity in this case are P_1 and Q_1. The highest curve represents the aggregate demand when too little load is shifted to the hour-ahead and real-time market. The market-clearing price and quantity in this case are P_2 and Q_2. Note that because of the very steep slope of the aggregate bid supply curve, P_1 is only slightly below P_0, whereas P_2 is significantly larger than P_0.

A similar result holds for the hour-ahead and real-time energy markets because their aggregate supply bid curves also resemble this reverse L-shape. Consider the case of the real-time market. The same logic holds for the hour-ahead market. When too much load is scheduled in markets other than the real-time market, the real-time price will be slightly below the value that would occur if the all of the loads perfectly anticipated the aggregate quantity of RMR Schedule Changes. If too little load is scheduled in other markets besides the real-time market, the real-time price will significantly higher than the value that would occur if all of the loads perfectly anticipated the aggregate quantity of RMR Schedule Changes. By this logic, both the day-ahead and hour-ahead PX prices and the real-time ISO price will be more volatile than would be the case if RMR energy were pre-dispatched and included in a balanced schedule on a day-ahead basis.

The more important market inefficiency is the increased expected wholesale energy purchasing costs caused by the combination of the shape of the PX and real-time energy supply curve and loads incorrectly forecasting how much demand to bid into PX and ISO energy markets. As noted above, both the PX and ISO aggregate supply bid curves resemble a reverse-L shape. For simplicity we focus on the case of the day-ahead PX market and the ISO real-time market. Because final demand is essentially inelastic with respect to the hourly wholesale price of energy, we assume that both generators and loads know this quantity is equal to Q_T. The question facing wholesale demanders is how to bid into the PX given that they do not know how much RMR energy will be scheduled between the close of day-ahead market and the real-time market. Suppose $S^{PX}(p)$ is the aggregate bid supply curve into the PX and $S^{ISO}(p)$ is corresponding curve for the ISO real-time market. Both aggregate bid supply curves are unknown to wholesale loads at the time they bid. Suppose that $DM^{PX}(p)$ is the aggregate demand bid curve that loads would submit if they collectively knew that all RMR energy was required to be scheduled on a day-ahead basis according to our recommendations given above. This aggregate demand bid curve would result in the market-clearing price P_M in both the PX and ISO real-time markets. The quantity QM^{PX} would be sold in the PX and the quantity $QM^{ISO} = Q_T - QM^{PX}$ in the ISO real-time market.

Figure 52



Now suppose that because of uncertainty about where RMR energy will be scheduled under the current RMR dispatch protocols, loads end up jointly bidding aggregate demand bid curves $DH^{PX}(p)$ and $DL^{PX}(p)$ with equal probability. This implies that the PX price is PH^{PX} with probability ½ and PL^{PX} with probability ½. The ISO price corresponding to PH^{PX} is PH^{ISO}, and the ISO price corresponding to PL^{PX} is PL^{ISO}. Because of the reverse-L shape of the PX and ISO aggregate supply bid curves, PL^{PX} is only slightly below PM and PH^{ISO} is only slightly below PM. However, because the market demand crosses in the steep portion of the respective aggregate supply bid curve in each market, PH^{PX} is significantly higher than PM, and PL^{ISO} is significantly higher than PM. In addition, the amount of energy sold in the PX at PH^{PX} is significantly higher than the amount sold at PL^{PX} and the amount sold in the ISO at PL^{ISO} is significantly higher than the amount sold at PH^{ISO}. These two equally probable market outcomes imply that loads pay expected additional energy purchase costs equal to one-half times the shaded area A^{PX} minus the shaded area A^{ISO} plus one-half times the shaded area B^{PX} minus the shaded area B^{ISO}, beyond what they would pay relative to the case that that they jointly know where all RMR energy will be scheduled. In the no scheduling-uncertainty case they would pay PM for Q_T, the total quantity of ISO load.

Depending on the slopes of the PX and ISO aggregate supply bid curves at the price PM and the difference between two aggregate demand bid curves $DL^{PX}(p)$ and $DH^{PX}(p)$, area A^{PX} can be significantly larger than area B^{PX} and area B^{ISO} can be significantly larger than area A^{ISO}, so that total expected wholesale energy costs can be significantly higher as result current ISO dispatch practices relative to the protocol we recommend where loads will jointly know that all RMR energy requirements will be scheduled on a day-ahead basis.

The Department of Market Analysis of the ISO in their September 1999 report follows a different methodology to estimate that wholesale energy costs would be approximately 2% lower as a result of implementing pre-dispatch and mandatory day-ahead scheduling.[13] This magnitude of estimated cost savings is consistent with our analysis.

D. Current Dispatch Policy Encourages Under-Scheduling of Load

The ISO proposed a policy, which the FERC approved, to charge loads for the additional Replacement reserves that the ISO procures to cover any forecast deficiencies in available energy in the real-time market. The cost of additional Replacement reserves is allocated to loads in proportion to the extent that their hour-ahead energy schedules are below their real-time consumption. As discussed above, because loads know that some RMR energy will show up in the real-time energy market without a corresponding load, they will rationally attempt to under-schedule their energy requirements on a day-ahead basis to account for this excess supply of energy due to RMR Schedule Changes. Consequently, the current RMR dispatch protocols and the FERC-approved policy of charging loads for additional Replacement Reserves based on the amount of under-scheduling of demand are in direct conflict with one another. Under-scheduling by loads on a day-ahead and hour-ahead basis is a rational response to anticipated RMR Schedule Changes. However, such responses will result in loads being charged for any additional Replacement Reserves procured by the ISO to cover this under-scheduling. These increased costs will cause loads to be less likely to attempt to anticipate this additional after-market supply of energy in their day-ahead energy scheduling decisions.

E. Increased Reliability Risks and Increased Costs of Ancillary Services

Because RMR Schedule Changes supply additional energy to a balanced day-ahead market, a larger quantity of energy imbalances must be settled in the real-time energy market than would necessary if RMR units were pre-dispatched. This creates unnecessary reliability risks for the ISO in managing the transmission grid in real-time. As noted in the DMA's September 1999 report on the pre-dispatch of RMR units, during the 17 months from April 1998 to August 1999, approximately 25% of the RMR energy dispatched after the day-ahead market had to be accommodated by decrementing energy from scheduled generation in real-time. Over the three-month period from June 1999 to

[13] "Pre-Dispatch and Scheduling of RMR Energy in Day-Ahead Market," Department of Market Analysis, California Independent System Operator, September 1999, p. iii.

August 1999, the DMA estimated that over 27% of the energy provided under the contract path created the need to decrement other generation in real-time. In many regions of the ISO control area, the market for decremental energy is often extremely thin. As a result, the ISO is often forced to rely on out-of-market and out-of-control-area calls for decremental energy. The ISO has often had to resolve over-generation conditions by accepting negative decremental energy bids. A negative decremental energy bid implies that the generator is being paid by the ISO to not generate, whereas a positive decremental energy bid implies the generator is buying back the decremental energy from the ISO.

Purchasing energy in the day-ahead market that must subsequently be bought back in the real-time market even at a positive price, also increases wholesale energy procurement costs to loads because generators are willing to be decremented only at price significantly less than the day-ahead price of energy. To the extent that these decremental bids are accepted out-of-sequence in the real-time energy market, the costs to loads from the ISO accepting these decremental bids will not be reflected in a lower zonal energy price but in higher intra-zonal congestion costs.

The process of scheduling additional energy in the form of RMR Schedule Changes after the close of the day-ahead market and then decrementing energy in real-time results in a significantly less efficient and more expensive generation dispatch process. This process also involves greater grid reliability risks relative to an RMR dispatch procedure which pre-dispatches RMR generation before running the day-ahead energy market. In order to guard against the increased reliability risks caused by the current RMR dispatch protocols, the ISO may need to purchase a greater quantity of quick-response ancillary services such as Regulation. By purchasing a greater quantity of this ancillary service, the ISO can expect to pay a higher price. This increased price is then multiplied by the greater demand, resulting in higher ancillary services costs than would be occur under a scheme involving pre-dispatch of RMR units.

Under the current RMR dispatch protocols, Schedule Changes are issued after day-ahead energy schedules have been finalized and the day-ahead ancillary services market has been cleared. Because of this sequencing, the ISO must sometimes buy back ancillary services commitments won by RMR units in the day-ahead ancillary services market so that the generating unit can meet an RMR Schedule Change for energy. Under current RMR dispatch protocols, the RMR unit owner is paid for the ancillary services that it wins in the day-ahead market as well as for the additional energy it provides under the terms of its RMR contract. Consequently, under the current ISO protocols, an RMR unit owner can be paid for providing both energy and ancillary services from the same increment of generating capacity in the same hour, despite the fact the ISO has purchased ancillary services capacity in hour-ahead market to substitute for this unavailable capacity from the RMR unit. During periods when the ISO purchases unusable day-ahead ancillary services capacity, it is purchasing more total ancillary services capacity than it would need if RMR energy was pre-dispatched in a balanced day-ahead energy schedule. By purchasing an excess amount of ancillary services capacity, the ISO further increases ancillary services prices and total costs.

During the summer of 1999, the procurement of day-ahead ancillary services capacity that cannot actually be used because it is required to provide RMR energy has become increasingly frequent, further increasing the ancillary services costs associated with current RMR dispatch protocols.

F. Increased Energy Prices Due to RMR Variable Payment Rate

Even though the RMR variable payment rates have been significantly reduced relative to the levels in the original type A RMR Contracts, for many generators, their current RMR variable payment rates is often above the market-clearing PX price or real-time energy price. Therefore, during hours when the PX price is expected to be below the unit's RMR variable payment rate, we would expect the opportunity cost of supplying RMR energy at the variable payment rate to be the binding lower bound on the price at which the unit owner will bid that capacity into the PX. This follows from the same logic given in the April 1999 MSC Report for the bidding behavior of a generator under a type A RMR Contract. An RMR unit owner would bid this capacity into the PX at a price that yields at least the same expected profits that it could obtain from providing energy at the variable payment rate under the terms of its RMR contract. Consequently, we would expect that generators bidding the opportunity cost of their RMR units into the PX market to result in higher market-clearing PX and ISO energy prices.

Because a very small number of the variable payment rates are above $100/MWh, none are above $500/MWh, and the vast majority are below $50/MWh, the impact of RMR unit owners bidding the opportunity cost of their RMR variable payment rate into the PX and ISO energy markets is likely to be substantially less than under the old type A RMR contracts. As a result, the unweighted average PX and ISO hourly electricity prices may be somewhat higher than those that would result from the pre-dispatch of RMR energy. However, as discussed above the volatility of the PX and ISO electricity prices is likely to be significantly greater and total purchased energy costs (or equivalently, the quantity-weighted average price) higher for the reasons discussed above and in the DMA's September 1999 report on the pre-dispatch of RMR units. In addition, total ancillary services demand and costs are also likely to be noticeably higher as result of current RMR dispatch practices relative to the case of pre-dispatch of RMR energy in a balanced day-ahead energy schedule.

G. Recommended RMR Dispatch Protocols with New RMR Contracts

The guiding principles of the California market design provide a clear recommendation for designing RMR dispatch protocols that eliminate the market distortions and increased costs associated with the current RMR dispatch protocols described above. This is the recommendation given in the April 1999 MSC to pre-dispatch RMR capacity before the start of the day-ahead energy market and require all pre-dispatched RMR requirements to be submitted as part of a balanced day-ahead energy schedule. While more complex schemes have been proposed by the DMA in its

September 1999 report, there are three features that should be a part of any protocol that is adopted.

1. **Pre-Dispatch of RMR Units**. The ISO would determine all energy RMR requirements for all hours of the following day before the start of the day-ahead energy market. We refer to this as pre-dispatch of RMR units. Under this scheme, the ISO would determine the RMR energy requirements from all RMR units and make this unit-specific information available to all market participants before the start of the day-ahead energy market.

2. **Pre-Declare Market or Contract Payment Option**. After learning the quantity of RMR energy requirements for all RMR units for all hours of the following day, each RMR unit owner would have the option to declare for each hour of the following day whether it would like to receive the market price of energy or the RMR contract variable payment rate for RMR energy supplied from that unit. The RMR unit owner electing the market option for a given hour, would have the option of electing to be paid the zonal PX day-ahead price, zonal PX hour-ahead price, or ISO real-time zonal price for that hour for the congestion zone that contains their generating unit for energy supplied under the terms of the RMR contract.

3. **Unit-Level RMR Energy Must Be Included in a Balanced Day-Ahead Schedule**. All RMR units with non-zero RMR energy requirements must have their unit-level RMR generation obligations included in a balanced day-ahead energy schedule submitted to the ISO. This requirement places no restrictions on how the unit owner must bid its RMR capacity into day-ahead or hour-ahead PX markets or the ISO real-time energy market. If the RMR unit owner elects the market path for its payment for RMR energy, then the unit owner should be able to hedge its RMR energy obligations in any manner it sees fit. The unit owner could bid this capacity into the PX day-ahead or hour-ahead market, or the ISO real-time market. The unit owner could also arrange to hedge this quantity of energy through a bilateral contract. However, it is important to emphasize that no matter how the unit owner constructs a financial hedge for the pre-dispatched energy from its RMR units, it must submit a balanced day-ahead energy schedule to the ISO with a total quantity of generation from each RMR unit exceeding its pre-dispatch RMR energy obligations.

To order to clarify how this protocol would work, consider the following example. Suppose a market participant owned two RMR units. At 5 am the day before the actual quantity of electricity would be delivered, the ISO would notify this market participant of the Reliability Requirement from both of its RMR units. Suppose that the capacity of each unit was 250 MW and that for the hour in question the ISO determined that 100 MW was the Reliability Requirement for each unit. This information and the Reliability Requirements for all RMR units would be made available all market participants. All RMR unit owners would then have one hour to notify the ISO which hours in the following day they would like to receive the market price (and what market price for energy they would like to receive) and what hours they would like to receive the variable payment rate. Thus, by 6 am, one hour before final bids must be submitted to the PX day-ahead market, all RMR unit owners would complete their election of how they would like to be compensated for providing the quantity of RMR energy required from each RMR unit.

Following the close of the day-ahead energy market, the RMR unit owner is required to submit a balanced energy schedule to the ISO for the hour in question that includes at least 100 MW of generation, the Reliability Requirement for that hour, from each of the RMR units. It is the responsibility of the RMR unit owner to procure the load necessary to submit a balanced day-ahead energy schedule. One option is to bid the quantity of pre-dispatched RMR energy into the PX day-ahead market or hour-ahead market at a price of zero to guarantee that this generation is balanced against an equivalent demand. Another alternative is for the RMR unit owner to sell this energy to a third-party under a bilateral contract. The final alternative is for the RMR unit owner to balance the total unit-specific RMR generation that it must provide in its day-ahead energy schedule with a fictional load. In this case, the unit owner is simply selling this generation in the real-time energy market.

H. Impact of Pre-dispatch and Mandatory Day-Ahead Scheduling of Energy Prices

The most likely outcome from implementing the above recommendations is a noticeable reduction in total wholesale energy purchase costs from the day-ahead and hour-ahead PX energy markets and the real-time ISO energy market. Another benefit should be less energy price volatility because of a reduction in the frequency of price spikes in the day-ahead, hour-ahead or real-time energy markets when an unexpectedly high level of demand is purchased in the day-ahead, hour-ahead or real-time energy market as discussed above. The constraints a generation unit owner faces when it attempts to maximize expected profits by its bids into the day-ahead energy market justify the view that these changes in RMR dispatch protocols do not artificially depress energy prices in the PX and ISO markets.

The logic for this view goes as follows. Because the maximum amount of total RMR energy requirements in any hour rarely exceeds 4,000 MW, and most often is in the neighborhood of 1,500 MW, only a small fraction of the capacity of any single generator is producing energy under an RMR contract. Consequently, the length of a market participant's bid curve that may be bid at a zero price in the PX because of the pre-dispatch of RMR energy, is likely to be very small relative to the total capacity a generation owner would bid into the PX or submit to the ISO in its day-ahead energy schedule.

In Wolak (1999), optimal bidding strategies for a firm participating in a bid-based-dispatch electricity market are derived.[14] Wolak shows that a generation owner's optimal strategy is constrained by the residual demand curve that it faces. Its residual

[14] F.A. Wolak, "An Empirical Analysis of the Impact of Hedge Contracts on Bidding Behavior in a Competitive Electricity Market," May 1999, available from http:/www.stanford.edu/~wolak.

demand curve is the difference between the aggregate demand bid curve for energy in the market and the aggregate supply bid curve of all firms besides the firm bidding. If SO(p) is the aggregate supply bid curve of all market participants besides the firm under consideration and D(p) is aggregate market demand bid curve for energy, then the residual demand curve faced by the firm is DR(p) = D(p) – SO(p). If S(p) is the firm's aggregate supply bid curve, the market-clearing price is determined from the intersection of the firm's residual demand curve with its aggregate supply bid curve, or equivalently the price, p^*, that solves the equation $DR(p^*) = S(p^*)$. The residual demand curve faced by the generation owner depends both on an aggregate demand bid curve and the aggregate supply bid curves of all other firms in the market, both of which are unknown at the time this firm submits its aggregate supply bid curve. This implies that the residual demand curve faced by the firm can be thought of as stochastic at the time a generation unit owner submits it bids. Consequently, unit owners submit supply bid functions which attempt to cross each possible residual demand curve it might face during that hour at a price that maximizes the firm's profits for that residual demand curve. This optimal bidding strategy can be used study the impact of the proposed RMR dispatch protocols on market-clearing prices in the PX and ISO energy markets.

Figure 53 graphs the aggregate demand bid curve, the aggregate supply bid curve of all other market participants and the resulting residual demand curve faced by the firm, DR(p), and a candidate bid curve for the firm, S(p), which passes through the profit-maximizing market-clearing price associated with that residual demand curve. As discussed in Wolak (1999), at the time the unit owner submits its bid into the energy market, neither the value of SO(p) nor the value of D(p) is known. Consequently, the generator must set the bid supply curve, S(p), so that it maximizes the generation unit owner's expected profits over all possible realizations of DR(p). However, if the generator were able to predict the realization of the DR(p), then a bid curve through the point (P_M,Q_F) would maximize its profits from bidding into this market.

By taking the smallest possible residual demand curve that a generator might face and computing the profit maximizing price and quantity associated with that residual demand curve yields the end point of the determinant portion of the profit-maximizing bid function. Figure 54 plots the highest possible residual demand curve and the associated marginal revenue curve and the lowest possible residual demand curve and the associated marginal revenue curve. The figure also plots the firm's marginal cost curve. On each residual demand curve the best response price and quantity are noted. Any bid curve that is upward sloping from the origin to the point (Ps,Q_S) would yield the same level of expected profits to the firm, because a residual demand curve will never cross this generator's bid curve at a point to the southeast of the point (Ps,Q_S) in Figure 54. A zero price and positive quantity segment of the bid curve that is of length less than Q_S will yield the same expected profits to the firm as an aggregate supply bid curve that is steadily increasing from the origin to the point (Ps,Q_S). If Q_S is greater than the pre-dispatch RMR quantity allocated to the firm, then mandatory submission of the quantity of RMR energy in a balanced day-ahead schedule will not affect the firm's expected profit-maximizing bidding behavior into PX day-ahead energy market.

Figure 53

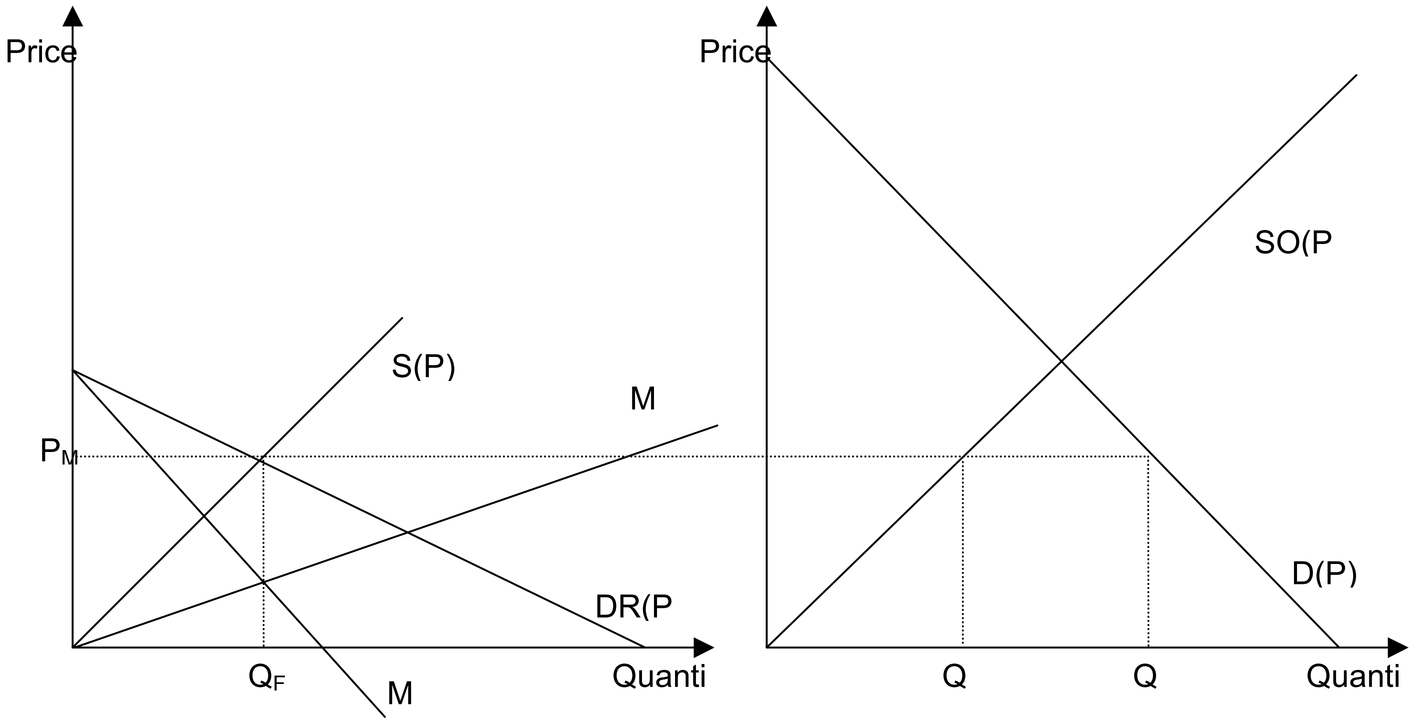
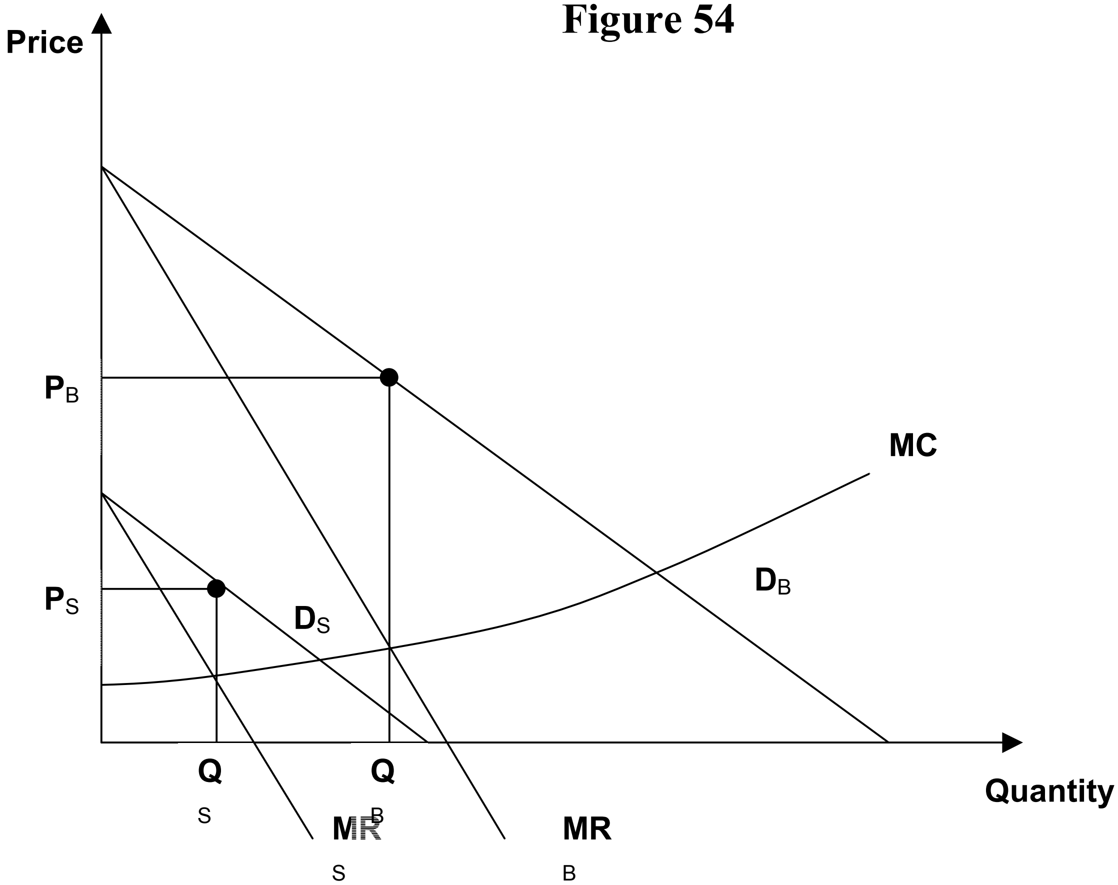


Figure 54



Only if the value of Q_S in any hour is below the quantity of RMR energy pre-dispatched will the recommended RMR dispatch protocols be likely to affect generator bidding behavior. There are two additional factors which make it unlikely that Q_S in a given hour is less than the quantity of RMR energy required to be supplied by an RMR unit owner. First, during the hours in which residual demand faced by the first is likely to be particularly small (in the neighborhood of D_S given in Figure 54), total ISO load is likely to be small and therefore the transmission grid is not likely to be stressed. In this case a very small quantity of aggregate RMR energy will be required. This in turn implies that even a small value of Q_S for a specific generation owner will be larger than its total RMR energy requirements for that hour. Second, during periods when total ISO load is high, the total quantity of energy needed from all generation owners is likely to be substantial so that the value of Q_S in these hours is likely to be very high. This implies that a substantial quantity of RMR energy will still be less than $Q_{S,}$ implying that the recommended RMR dispatch protocols are likely to have little impact on generator bids during periods with both low and high total ISO system loads.

Only if unit owners withhold significant amounts of their generation capacity from the PX day-ahead market by bidding most of their capacity at high prices in attempt to raise market prices in the PX, should this constraint have any impact on generation unit owner bids into the PX. We should note that this is precisely the sort of behavior the pre-dispatch and a mandatory day-ahead scheduling requirement is attempting to eliminate. Consequently, the we do not believe that implementing these recommendations will artificially depress PX or ISO energy prices, only eliminate the incentives generators have to exploit their ownership of RMR units to raise market prices.

Besides a lowering wholesale energy price volatility and a reducing total wholesale energy purchase costs, the other significant benefit of pre-dispatch and mandatory submission of a balanced day-ahead schedule containing the unit-specific RMR requirements is that the ISO will no longer need to decrement generation in real-time to make room for RMR energy not submitted in a balanced day-ahead schedule. Because units scheduled to provide RMR energy on a day-ahead basis can only supply ancillary services from unused capacity, this scheme also eliminates the need to decrement ancillary services quantities won in the day-ahead market to allow RMR energy to be supplied from that generating facility.

This scheme is also consistent with the ISO's current policy of charging for additional replacement reserve in proportion to the amount that a load under-schedules its demand on an hour-ahead basis relative to its real-time consumption. Because all pre-dispatched RMR energy must be submitted as part of a balanced day-ahead schedule, there will no longer be excess energy appearing in the real-time market as a result of RMR Schedule Changes which loads must account for in their day-ahead and hour-ahead energy schedules. Consequently, loads will no longer have an incentive to under-schedule in anticipation of this incremental RMR energy in the real-time market. Because all market participants know the unit specific RMR energy to be supplied in a balanced day-ahead schedule from each RMR unit before they submit their bids into to

PX day-ahead energy market there is no uncertainty about when and from what units that RMR energy will produced. This greater certainly about the timing and location of the supply of RMR energy will give loads greater confidence about which markets they should bid their demand into. This will reduce the volatility of prices in both PX day-ahead and hour-ahead energy markets and the ISO real-time energy market.

Finally, the greater certainty about the timing and location of the supply of RMR energy will delay less grid management and generation dispatch activities to the real-time market and therefore reduce the reliability risk associated with RMR dispatch, which should reduce the ISO's demand for quick-response ancillary services capacity. This should reduce the price the ISO must pay for these ancillary services, as well as total ancillary services costs.

7. Regulatory Impediments to a Price-Responsive Demand for Energy and Ancillary Services

Often regulatory policies designed to solve one market design problem can create significant market distortions. The stranded asset recovery mechanism, known in California as the Competition Transition Charge (CTC) is an excellent example of this phenomenon. The current CTC mechanism creates several impediments to involving price-responsive demand in the day-ahead, hour-ahead and real-time energy markets, thereby significantly decreasing the competitiveness of the California electricity market. The market distortions created by the CTC mechanism provide a strong argument in favor of the continued imposition of damage control price caps on all ISO energy and ancillary services markets until the CTC recovery period ends or some of its major market distortions are corrected.

There are two aspects of the stranded asset recovery process that creates these market inefficiencies. First is the retail rate freeze and the associated CTC recovery mechanism. The second is prohibition against any forward financial contracting outside of the PX markets for generation owned by any of the three investor-owned utilities (IOUs) in California or load served by the utility distribution companies (UDCs) owned by any of the three (IOUs). The separation of wholesale market and retail market regulatory oversight in California between FERC and the California Public Utilities Commission (CPUC) also creates an additional impediment to increasing the competitiveness of the California electricity market. We show that certain current CPUC policies significantly dull, if not eliminate, the incentive retail customers have to respond to hourly energy and ancillary services prices, thus rendering the California wholesale market less competitive, particularly during high load periods. This section points out these structural problems with the current design of the California market and suggests several remedies.

The major flaws with the current market design are:

1. The CTC recovery mechanism eliminates virtually all incentives for the vast majority of final loads to be price-responsive with respect to hourly wholesale electricity prices.

2. The only market participants with a financial incentive to take actions to lower wholesale electricity prices in any single hour are the IOUs. They achieve a higher CTC recovery rate during hours when energy and ancillary service prices are lower. Competitive energy service providers (ESPs) receive no financial benefit from lower hourly wholesale prices during the rate freeze period.

3. Under the retail rate freeze incentives, the only way for the IOUs to make it attractive for their retail customers to reduce hourly demand in response to high hourly wholesale electricity and ancillary services prices is to pay them to reduce demand. This alternative is not financially viable for the ESPs, because they receive do not receive CTC payments.

4. The prohibition on forward contracting by UDC load outside of the PX limits the avenues for price-responsiveness available to loads in the California market. This leads to higher wholesale prices than would be the case if loads could hedge their electricity and ancillary services consumption further in advance of its delivery.

5. Prohibition of forward contracting by UDCs for ancillary services beyond day-ahead market unnecessarily forces ISO to take a financial position in the day-ahead and hour-ahead ancillary services market as buyer of ancillary services requirements for PX load.

6. Lack of coordination between retail competition policy and wholesale competition policy can lead to market failures in either or both markets. The extent of the price-responsiveness of hourly wholesale demand is determined by the extent that there is a price-responsive hourly retail demand.

Although all of these distortions can be traced directly or indirectly to the CTC recovery mechanism, they will not automatically be eliminated when the CTC recovery period ends. Steps should be taken as soon as possible to eliminate these distortions. We make several recommendations in the regard.

1. Maintain ISO authority to set maximum purchases prices in energy and ancillary services markets until the CTC recovery period ends.

2. Eliminate all prohibitions on forward contracting by UDCs outside of PX for energy and ancillary services.

3. When rate freeze ends for a UDC, do not implement a default provider retail rate which passes through hourly wholesale electricity purchase costs. This locks-in a lack of hourly price responsiveness in retail demand with detrimental consequences for competitiveness of wholesale electricity markets.

4. Instead, when rate freeze periods for a UDC, require it to offer a default provider rate to equal original rate freeze retail or some fraction of rate freeze rate (to account for elimination of CTC recovery). All UDCs must offer this new rate to all of its customers.

5. After rate freeze period, allow both UDCs and ESPs to offer any bundle services and prices in order to create full diversity retail valued-added services. Retail competition with UDC required to offer default provide rate described in point 4 will lead to *de facto* wholesale pass-through tariff it this is desired by customers. This policy should also lead to full range of value-added metering and load monitoring service tariffs customers desire.

6. The FERC and CPUC should attempt to coordinate policies to foster price-responsive hourly demand in a cost-effective manner. California retail and wholesale markets are highly inter-related.

A. CTC Mechanism Eliminates Incentives for Final Load to Be Price Responsive

Under the current rate freeze in California, the retail electricity rates are frozen at their 1996 level less 10%. Define P_R as this fixed retail price. Under the current CTC recovery mechanism, generally speaking, this fixed retail price can be broken down into the following components: P_R = PE + T&D + CTC + RES, were PE is a weighted average of the various California electricity and ancillary services prices (principally the PX price), T&D is the price of transmission and distribution services, CTC is the competition transition charge, and RES is a residual category charge which pays for a variety items such as demand-side management programs and the rate reduction bonds. An important implication of this equation is that the CTC component is defined so that it holds on a monthly basis. Electricity is sold to the final consumer at the price P_R. This energy is purchased from PX and ISO markets, and transmission and distribution charges are paid at the rate T&D and the residual category payments are made at the rate RES, and any money left over goes to the CTC payment. This means that the difference between monthly retail revenues and the monthly amounts paid for wholesale electricity, transmission and distribution, and the residual expenses category yields the monthly amount of CTC recovery.

Because retail rates are fixed and final demand is a function of this fixed retail price, the total revenue collected from customers on these frozen retail rates is independent of movements in wholesale electricity prices. Therefore, total retail revenues for the state of California collected from customers on these frozen rates is essentially independent of hourly wholesale electricity prices for energy and ancillary services. Because CTC payments are defined as the difference between monthly retail revenues and the monthly amounts paid for wholesale electricity, transmission and distribution, and the residual expenses category, the investor-owned utilities (IOUs) have a strong incentive to keep electricity prices low during the rate freeze period. Other wholesale generation market participants must earn all of their revenues from energy and ancillary services sales in the PX and ISO markets. They are not entitled to receive any CTC payments. For this reason, these generation owners prefer high energy and ancillary services. During the rate freeze period, there is a fixed amount of retail revenues available in the California market that does not depend on the actions of wholesale market participants to influence hourly energy or ancillary services prices. Investor-owned utilities receive a larger share of this revenue pool through their CTC payments if energy and ancillary services prices are low. Other generation unit owners receive a larger share if energy and ancillary services prices are higher through direct payments for wholesale energy. CTC payments to the IOUs fall by the same amount that revenues received by the other generation owners increase as result of higher wholesale energy and ancillary services prices, because the total amount received by all market participants must equal the fixed (with respect to the actions of market participants in the wholesale market) pool of retail revenues.

Because ESPs, compete with the incumbent UDC in supplying retail electricity to final customers, it is important to understand their incentives during the rate freeze. In order to provide retail electricity, an ESP must produce electricity or purchase wholesale electricity from the PX and ISO energy markets. It must purchase transmission and distribution services, as well as pay RES and CTC per unit of electricity delivered to final retail customers. To the ESP, the CTC charge is simply a cost of doing business in the retail market. The ESP receives no benefit from lower energy prices because the ESP's total CTC payments rises to exactly compensate for these lower energy prices on a monthly basis. The only electricity retailers with a financial incentive to take actions to lower wholesale electricity prices are the UDCs, because their parent companies will receive larger CTC payments during the months in which wholesale energy prices are low. The ESPs on the other hand, receive no direct financial benefit from lower wholesale electricity prices.

The combination of the CTC recovery mechanism and the retail rate freeze implies that it is unprofitable or economically irrational for an ESP to supply electricity at a retail price is below P_R. Suppose the ESP sold electricity at a retail price P_R^* that is less than the retail rate freeze price P_R. Because the ESP must still pay the same values of T&D, RES, and CTC that the UDC must pay for delivering the same amount of electricity to the final customer, the ESP is effectively selling wholesale electricity to the final customer at a price below PE. However, the ESP must buy its wholesale electricity from the PX and ISO markets if it does not own any generation. If it does own generation, the opportunity cost of it selling electricity produced from its generating units is the wholesale electricity price in the PX and ISO markets. Consequently, by selling retail electricity at a price below the rate freeze price, the ESP is selling wholesale electricity at an average price below what it can be sold at in the PX and ISO markets.

This aspect of the CTC recovery mechanism and retail rate freeze explains why such a small number of residential customers have switched electricity suppliers. According to the latest California Energy Commission (CEC) figures through May of 1999, slightly more than 1% of customers of the 3 UDCs—San Diego Gas and Electric, Southern California Edison, and Pacific Gas and Electric—have switched electricity suppliers since the start of the California electricity market.

Besides giving little incentive for retail consumers to switch from the incumbent UDC to a competitive ESP, the current CTC recovery mechanism and retail price freeze also provides little incentive for customers to install real-time metering technology and purchase their electricity according to the hourly PX or ISO price. The customer must continue to pay T&D, RES, and a CTC payment, that increases when wholesale energy prices are low and decreases when wholesale energy prices are high, no matter what company supplies the retail electricity. This implies that a customer electing to purchase retail electricity according to some weighted-average hourly wholesale price of electricity should receive little, if any, cost savings from this decision. In addition, either the customer or the energy supplier (who then must recover this cost from the customer) will have to pay the cost of installing real-time metering technology on customer's premises. Consequently, during the CTC recovery period virtually all retail customers have no incentive to install the metering technology necessary to purchase electricity according to the hourly wholesale price.

As discussed above, the UDC would like its retail customers to reduce their demand during hours when ISO load is expected to be high in order to reduce wholesale prices and increase its rate of CTC recovery. However, the option of a frozen retail price and the CTC payment mechanism gives retail customers no incentive to reduce their demands during these time periods. Consequently, all demand reduction mechanisms proposed by the UDCs have involved payments to customers for reducing their demand during periods when the wholesale price is expected to be high. In this way the UDC shares with the retail consumer the increased CTC revenues that it receives as a result of lower wholesale prices.

Even though the UDC would like its customers to reduce their demand in periods of high ISO load, it has very little incentive to switch these customers to a real-time meter. A customer with a real-time meter can compute precisely how much it is costing the UDC to supply electricity using their hourly electricity consumption and the hourly wholesale prices of energy and ancillary services. This customer will be more likely to switch suppliers following the end of the rate freeze period if the UDC's retail price is not as low as the one the customer can obtain from an alternative supplier. By installing a real-time meter on a customer's premises, the UDC creates a far more sophisticated customer who has the ability to respond to hourly price signals and can be billed based on his consumption during each hour of the day. A customer whose meter is read on a monthly basis can only be charged based on some function of his total monthly consumption. Consequently, the set of pricing schemes that can be devised to compete for customers with hourly meters are much more sophisticated than the pricing schemes that need to be devised to compete for customers whose meters can only be read on a monthly basis.

If a significant number of customers had hourly meters, ESPs and the UDCs would then be able to compete to offer many different types of pricing structures to match the heterogeneity in the willingness of customers to respond to real-time price signals. We would expect some customers to want to face the hourly price of electricity and therefore face the full risk of hourly wholesale price spikes and also receive the full benefits of very low wholesale prices in their month electricity bill. Some customers may only want to hedge against the upside risk of hourly wholesale price spikes and therefore pay more for consumption during hours when wholesale prices are low. Despite the large potential benefits to both retail and wholesale competition from the widespread implementation of hourly meters, because the incumbent UDCs currently have only slightly less than 99% of their original customers, they have little financial incentive to pay to create more sophisticated customers who they must then compete more vigorously to retain.

Because ESPs do not receive CTC payments, they cannot offer a payment scheme for demand reduction during periods expected to have high wholesale prices. An ESP may wish to install a real-time meter to offer a customer rate package that is superior to what the customer currently receives from the UDC. However, the current CTC recovery mechanism and availability of service from the UDC at the rate-freeze retail price makes it very unlikely that a rate package that causes the customer to switch will be profitable for the ESP. Consequently, the combination of the CTC recovery mechanism and the retail rate freeze severely limits the opportunities for retail competition and, more important, the incentives for the installation of real-time metering technology to increase the amount of final demand that is price responsive on an hourly basis.

B. Prohibition Against UDC Contracting Outside of PX Forces Forward Sales of Energy and Ancillary Services to Day-Ahead Market

The prohibition under the CTC recovery mechanism against UDCs forward contracting for any of their load outside of the PX markets further limits the ability of loads to be price responsive over longer time horizons than a day ahead-basis. This forward contracting prohibition on UDCs requires the vast majority of total ISO system load to the hedged on a day-ahead basis. An average of over 80% of total ISO load is hedged through the PX energy markets. This implies that over 80% of wholesale energy purchase commitments are being hedged on a day-ahead or hour-ahead basis, and approximately half of the remaining quantity of total ISO load is purchased at the real-time ISO price. The remaining energy consumed is produced by non-UDC generators and sold through bilateral contracts.

This prohibition on forward contracting outside of the PX unnecessarily forces loads to hedge their forward energy requirements with no more advance notice than a day-ahead basis. While the recently introduced PX block forwards market for energy is tremendous step in the right direction, loads still need more opportunities to be price-responsive with a longer lead-time that the day before delivery of energy takes place.

These limitations on forward contracting reduce the competitiveness of the California energy market. Most of the UDC's load is known with a very high degree of certainty far in advance of the day before the electricity is actually delivered to final customers, and for this reason the UDC would therefore prefer to have the option to hedge its load further in advance. By prohibiting forward contracting outside of the PX far in advance of the delivery date, a UDC unnecessarily gives up any advantage it has because of its superior information about the nature of its final demands in the near future. In a market with unrestricted forward contracting, the UDC would be able to exploit this superior information to obtain more attractive energy prices when signing forward financial commitments with generators. In a market which allows many different avenues for forward financial contracting far in advance of delivery, loads would negotiate larger forward financial commitments with generation owners during hours when they expect their demand for electricity to be unusually high. If UDCs have some discretion as to when unexpected load increases can occur they may move them to those periods when they are able sign particularly attractive forward hedge contracts. Once these forward financial commitments are signed, generation owners holding the other side of the hedge contract will find it in their financial interest to bid more aggressively in the day-ahead, hour-ahead and real-time energy markets. As shown in Wolak (1999), these forward contracts commit generation unit owners to compete aggressively to supply at least their forward financial positions made in the day-ahead, hour-ahead or real-time energy markets.[15]

On a day-ahead basis, UDCs have very limited opportunities to reduce their purchases of wholesale electricity. However, on a day-ahead basis it is very easy for a generation unit to reduce its supply of electricity. It simply shuts down. Therefore, on a day-ahead basis the threat of generation owners not supply into the market is far more credible than the threat of loads not to purchase from the market. Consequently, during hours forecast to have a high total ISO demand, loads must purchase energy and ancillary services on a day-ahead basis at very high prices. A year or even a month before the hour or hours under consideration, a load can plan in advance not to consume if it expects to pay very high prices. With enough advance notice, a load can commit not to consume electricity for a significant period of time at a fairly low cost. The shorter the time lag, the more costly it is for loads to reduce their demand for electricity and ancillary services. Giving loads more advance notice reduces the asymmetry in the bargaining position between generation owners and loads that occurs on day-ahead basis. Loads should therefore be able purchase forward commitments for energy and ancillary services on more favorable terms far in advance of delivery than on a day-ahead basis as is required during the CTC recovery period. By restricting the forward contracting activities on the part of the UDCs, the ability of the new generation owners in the ISO control area to exercise market power in the day-ahead and hour-ahead energy and ancillary services markets is unnecessarily enhanced.

This asymmetric treatment of UDC load and generation relative to that of the new generation owners (NGOs) (who are not prohibited from forward contracting outside of the PX market) unnecessarily handicaps UDCs in their attempts to limit the exercise of market power by the NGOs. Even if the UDCs are able to predict accurately more than one day in advance that loads will be extremely high and the likelihood of the exercise of market power during several hours in that day will be very high, they must wait until the

[15] F.A. Wolak, "An Empirical Analysis of the Impact of Hedge Contracts on Bidding Behavior in a Competitive Electricity Market," May 1999, available from http:/www.stanford.edu/~wolak.

day-ahead market to hedge their energy purchases and contract for their associated ancillary services requirements. In the markets for most all products, consumers are allowed to benefit through lower prices by their ability to intelligently plan ahead for unforeseen market contingencies through their advance-purchasing decisions. The California market design prohibits UDCs and their retail customers from realizing many of these benefits from advance planning, even although the NGOs are able to contract to sell or purchase energy far in advance of the actual delivery date, in any manner they see fit and with any other market participant.

The prohibition on forward contracting outside of the PX also forces the ISO to take an unnecessarily active role in the ancillary services market as the agent to purchase all ancillary services requirements for the PX on a day-ahead or hour-ahead basis. Under current ISO rules all scheduling coordinators, including the PX, have the opportunity to self-procure their ancillary services requirements. The PX currently does not run a forward ancillary services market on behalf of their customers through which they could self-procure their own ancillary services requirements. For example, the PX could offer to pay all of the market participants whose capacity did not win in PX a some fraction of the PX price for the right to use this capacity to meet some or all of its ancillary services requirements. Rather than simply notifying the ISO of its day-ahead energy schedule and allowing the ISO to serve as its agent in purchasing ancillary services from the day-ahead and hour-ahead ancillary services markets, PX could become an active participant in ancillary services markets.

This prohibition also puts the ISO in the uncomfortable position of needing to be a strategic player in the ancillary services markets or face the prospect of extremely high prices in this market. Because total ISO load is largely exogenous to wholesale energy prices, the total hourly demand for ancillary services capacity is, for the most part, perfectly price inelastic. The ISO's Rational Buyer algorithm has introduced price-responsiveness for each ancillary service individually, but the total quantity of capacity demanded is still inelastically demanded. Consequently, the ISO must take actions through its purchasing behavior in the day-ahead and hour-ahead markets to limit the ability of other market participants to exercise market power in these markets. Otherwise, very high prices would occur in these markets during periods of high demand. By eliminating the prohibition on forward contracting outside of the PX for ancillary services and energy, the ISO would no longer need to be placed in this position. All loads in the ISO market would have the opportunity to self-procure their ancillary requirements through long-term bilateral negotiations, forward financial contracts-for-differences linked to the day-ahead ancillary services price, or through inter-SC trades. If a load did not like the forward contract for ancillary services that it had, it could switch to another supplier whose terms it liked better. Under this scheme the ISO could be effectively eliminated from the process of ancillary services procurement. The ISO's ancillary services markets would simply become day-ahead and hour-ahead imbalance markets for ancillary services were market participants can buy or sell incremental ancillary services capacity.

We would still expect occasional price spikes in these incremental ancillary services markets because of temporary capacity shortages and the associated scarcity value of generating assets. These should also continue to occur in the real-time energy market, as they do in all spot markets. However, it is important to note that under this forward contracting scheme, loads would only have to pay these very high prices for the incremental demand for ancillary services beyond the quantities they contracted for in advance of the day-ahead or hour-ahead market, not for their entire ancillary services capacity, as is the case under the current prohibition on forward contracting for ancillary services outside of the PX.

As evidence that both generators and loads would prefer to hedge significantly less energy on a day-ahead basis than occurs under current CTC recovery mechanism, we note that less than 20% of total annual electricity sales in the Nordic Power Exchange (Nordpool) are hedged through the day-ahead market.[16] The Nordpool has been in existence for almost ten years and has grown from initially serving just Norway to now include Sweden, Finland and Denmark, yet the annual fraction of energy hedged on a day-ahead basis has never been more than 20% of total annual sales. The vast majority of transactions on this market are arranged according to long-term contracts signed far in advance of the day before the energy is delivered. This fact provides evidence consistent with the view that the efficiency of the California energy and ancillary services markets would be significantly enhanced if the prohibition on UDC forward contracting outside of the PX was eliminated.

In closing, we would like to emphasize that we do not recommend that the current requirement under the CTC mechanism that all UDCs use the PX as their scheduling coordinator be eliminated. Particularly during the initial stages of the California market when many design flaws remain and others are yet to be discovered, the PX provides the extremely valuable service of providing a transparent and deep day-ahead market for energy. Throughout the CTC recovery period, with the resulting market efficiencies that it creates, this very important role of the PX seems more than worth the potential productive inefficiencies that may arise because of the PX's statutory monopoly in providing Scheduling Coordinator services to the UDCs for their load and generation.

C. Separate Regulation of Wholesale and Retail Competition Can Harm Both Markets

In the United States, FERC regulates wholesale electricity supply and the state public utilities commissions regulate retail electricity supply. As the above discussion has illustrated in the restructured electricity industry in California, these two activities are highly inter-related. A retail competition policy that does not foster the development of a price-responsive hourly final retail demand will not result in a price-responsive hourly wholesale electricity demand. As has been discussed in the previous two MSC reports, a

[16] See Wolak, F.A., "Market Design and the Behavior of Prices in Restructured Electricity Markets: An International Comparison," (1998), available from http:/www.stanford.edu/~wolak, for discussion of the market rules and operation of the Nordic Power market.

price-response hourly wholesale electricity demand will significantly enhance the competitiveness of the California electricity market. However, as described above, many of the retail competition policies and stranded-asset recovery policies enacted at the state level are contrary to the goal of a price-response hourly wholesale electricity demand.

One example of such a policy is the CPUC decision to allow a direct access customers to switch from the UDC to an ESP without installing an hourly meter. Instead, this customer is billed according to a representative load profile which effectively allocates the customer's total monthly electricity consumption to all of the hours during the month. These allocated hourly consumption amounts are then multiplied by a weighted-average hourly wholesale price to arrive at the customer's estimated hourly cost and these are added together over all hours to yield that customer's monthly bill for energy. However, as is well known, a customer whose monthly bill is determined according to a representative load profile receives the same cost savings from a 1 KWh reduction in consumption during an hour when the PX price is $700/MWh as he does for by 1 KWh reduction in an hour when the PX price is $0/MWh. Even in a world without the CTC recovery mechanism, a customer billed according to a load profile has little incentive to substitute consumption away from hours in the month when PX or real-time ISO prices are extremely high. This customer only has an incentive to reduce total monthly consumption during months when the average wholesale energy prices are high. However, he will most likely do this during hours that when it is cost for him to reduce demand in rather than hours when the PX or ISO price is extremely high, as would be required to have a price-responsive hourly retail demand. By allowing retail competition with load profiling, virtually all of the financial incentives have been eliminated for any market participant to foster the formation of a price-responsive hourly final demand for electricity vital for a workably competitive wholesale market during high ISO load periods.

Without a retail market that has a large fraction of final demand facing an hourly price for each unit of consumption during that hour that is tied directly to the wholesale price of electricity during that hour, it is impossible for electricity suppliers to credibly bid into the day-ahead and real-time markets to reduce their demand in response to high wholesale prices. Currently, the UDCs and other market participants bid price-responsive demands into the PX day-ahead and hour-ahead markets. However, all market participants know that the vast majority of these demand-side bids are not credible commitments to reduce final demand in response to high prices. They understand that because all but a very small fraction of final customers in California purchase electricity at fixed retail prices, final UDC demand does not depend on the value of the hourly PX or ISO energy price. Therefore, any UDC load obligations that are not hedged in the PX day-ahead or hour-ahead markets must be purchased at the real-time ISO price. Consequently, as noted in Section 3, during high periods of high ISO load, generation unit owners are able to set extremely high prices, with the only limit being the ISO's purchase price cap.

Without coordination between the CPUC and FERC to foster a price-responsive hourly final demand for electricity, it will be extremely difficult to develop a price-responsive wholesale electricity demand to mitigate against the exercise of market power and reduce the frequency of extremely high wholesale electricity price spikes during periods of high ISO load.

D. Limiting Market Inefficiencies Caused by CTC Recovery Mechanism

The most direct way to eliminate the market inefficiencies caused by this mechanism is to end the rate freeze. As discussed above, because of the incentives created by the CTC recovery mechanism, very few final customers have an incentive to alter their hourly demand in response to high hourly wholesale prices. Therefore, throughout of the rate freeze period, virtually all final customers are indifferent movements in hourly wholesale energy and ancillary services prices. During this period, all generation owners (except the UDCs) prefer high hourly wholesale energy and ancillary services prices. Only UDCs would prefer low wholesale electricity prices to increase the amount of CTC payments they receive. However, none of the three UDCs besides Pacific Gas and Electric own a significant quantity of flexible generation capacity (non-must-take capacity) to exert a substantial influence on wholesale energy or ancillary services prices. Even Pacific Gas and Electric's flexibility is severely limited during certain times of the year because the most of its non-must-take capacity is hydroelectric. Consequently, for the remainder of the rate freeze, the economic agents with the greatest ability to limit hourly wholesale prices—final customers—have virtually no incentive to do so, and the only agents with any incentive to limit hourly wholesale prices have a very little ability to do so relative to the first year of the market, when all three UDCs owned a significantly larger quantity of flexible generation capacity. All remaining market participants have strong incentives to take actions to set high wholesale prices.

1. Necessity of Maximum Purchase Price Caps During Rate Freeze

Other mechanisms must therefore be put in place in order to more quickly end the rate freeze period and the reduce the amount of time the market must tolerate the market inefficiencies described above. One such mechanism is a price-cap on the ISO's real-time energy market and the ancillary services markets. Because the retail price paid during the rate freeze and CTC recovery period is fixed for the vast majority of customers, when total ISO load is high to due to hot weather or other factors, energy and ancillary services prices can get extremely high. Generation unit owners know that even extremely high prices will be met with little, if any, reduction in total ISO load and ancillary services demand. The only limit on the market-clearing prices during days of very high total ISO load is the purchase price cap, which is frequently hit during several hours of the day in the real-time energy market and in several of the ancillary services markets.

If the authority of the ISO to set and adjust this purchase price cap is removed, it is unclear how high prices will go in these markets during the very high ISO load periods. The non-UDC generation unit owners understand the very limited incentives final demand has to respond to hourly prices during the rate freeze period and the limited ability the UDCs have to limit price spikes with their available generation capacity. They should therefore correctly perceive that it is very unlikely that extremely high prices bid into the real-time energy and ancillary services market will result in significantly less of their generation capacity being sold in these markets. Therefore, during the high total ISO load days, there would be virtually no limit, besides ISO software constraints (which can accept enormous bid prices) on how high a price might be set in the energy market or in any ancillary services market. The only way these high prices may cause final consumers to reduce their demand is when wholesale prices are so high, for so many hours during the month, that total monthly CTC payments are in fact negative. This would occur if the difference between monthly retail revenues and the sum of monthly wholesales energy costs, transmission and distribution costs, and the residual category expenses is negative. Consequently, one very strong justification for the continued imposition of the ISO's purchase price cap is the CTC cost recovery mechanism and associated retail rate freeze. Until the incentives against developing retail competition and price-responsive hourly demand caused by the CTC mechanism are eliminated, ISO energy and ancillary services markets without a purchase price cap are at risk for periods of enormous wholesale energy and ancillary services prices. These periods of high prices will further delay the end of the rate freeze because CTC payments will comprise a smaller fraction of monthly California retail electricity revenues, which lengthens the time until the retail competition and a price-responsive final demand becomes a significant part of the California electricity industry.

Because of the potential for very high energy and ancillary prices without a purchase price cap during the rate freeze regime and the fact that frequent high prices will delay the end of the rate freeze, a prudent policy would be to allow the ISO to continue have the authority to set a maximum purchase price cap on the energy and ancillary services markets. The logic presented above also argues in favor of a price cap that is shaded downward relative to the level of a "damage control" price cap, in order to speed-up the CTC recovery rate and shorten the length of time the California electricity market must tolerate the market inefficiencies caused the CTC recovery mechanism. The very limited incentive final demand has to respond to hourly wholesale energy and ancillary services prices implies that whether the purchase price cap is set at $250/MWh or $750/MWh it will most likely be hit during the same the hours during the month. Generation unit owners have a very good idea of what system load conditions allow them to hit the price cap. These load conditions are virtually independent of the level of the price cap given the limited amount of price-responsive hourly final demand in the California market.

2. Policies to Improve Efficiency of ISO Markets After End of Rate Freeze

The CPUC should prepare for the end of the retail rate freeze for all UDCs by putting in place policies that promote the form of retail competition necessary to increase the competitiveness of the wholesale electricity market. There are three major policies that should be put in place as soon as possible. The first is to end the prohibition on forward contracting outside the PX for all UDCs. The second is the elimination of any cost-based cap on retail electricity prices in the service area of any UDC that ends its rate freeze.[17] The third is the elimination of any regulated revenue recovery for electricity meter installation, reading and repair for any UDC as soon as it ends its retail rate freeze.

The design of the California electricity market anticipates that the PX will face direct competition from other scheduling coordinators once the rate freeze ends. However, for the reasons cited above, we believe it is prudent to continue the requirement that all UDCs use the PX as their SC until the rate freeze ends for all UDCs. Continuing the prohibition on forward contracting outside of the PX unnecessarily perpetuates the market inefficiencies described above. We believe that all prohibitions on forward financial contracting outside of the PX should end.

The end of the retail rate freeze is a very important event in the process of fostering meaningful competition for electricity supply and metering services. Recall the equation described above relating the rate freeze retail price to the CTC:

$$P_R = PE + T\&D + CTC + RES.$$

At the end of the rate freeze, the CTC component of this equation is set equal zero. Because monthly the CTC contribution has been positive for all months since start-up of the California market, there is an opportunity for significant price reductions as result of the end of the rate freeze for customers in that UDC's service area. However, as noted earlier, the availability of real-time metering technology and other information systems necessary for final demand to become a more sophisticated participant in the California market is currently very limited and likely to stay so for remainder of the rate freeze period for the reasons described above.

However, policies can be put in place at the end of the rate freeze to provide maximal incentives for final demand to become an active market participant, so that the full benefits of retail and wholesale competition can be realized by all California consumers. To this end, we recommend retail competition policies that will create the opportunities for the kinds of retail competition necessary for a workably competition wholesale electricity market. This policies should also increase the likelihood that vibrant retail competition will occur as rapidly as possible following the end of the rate freeze period.

Two keys features of this retail competition policy are: (1) rely on competition wherever possible to limit retail prices, and (2) where output price caps are deemed necessary to protect the UDC's less sophisticated existing customers, do not set these caps based on the UDC's cost of production. By allowing competition rather than explicit price regulation to limit retail prices, ESPs and the UDC have the maximal incentive to offer the full diversity of products and services consumers demand. One of the anticipated benefits of retail competition is that it will create incentives for innovative ways to provide electricity and other services in bundles that provide tangible benefits to

[17] This proposed policy change is particularly relevant for San Diego Gas and Electric, which announced the end of its rate freeze effective July 1, 1999.

retail customers. In order protect consumers who may be initially unwilling or apprehensive about becoming active participants in the retail electricity market, we recognize the necessity of a regulated default provider rate. However, for all of the reasons that cost-of-service regulation was abandoned in favor of competition, we believe that this default provider rate should not be set based on the UDCs costs, but using a revenue cap approach. Directly passing through wholesale energy and ancillary services costs in a default provider rate significantly dulls the incentives for the retail competition to occur or result in the sort of final demand necessary for a workably competitive wholesale market. Fortunately, because of the structure of the CTC mechanism, the rate freeze price can easily be used as a starting point for a revenue cap approach to setting the default provider rate.

Therefore, we recommend that following the end of its rate freeze, the UDC be required to offer the rate freeze retail price or some fraction of this retail price to all customers as a default option. Otherwise, there should be no cap on the prices the UDC is allowed to charge its retail customers besides this requirement that the UDC continue to offer this modified rate freeze tariff option as the default provider rate. This modified rate freeze rate could be determined by taking the total amount of CTC dollars paid over past year by that UDC's customers divided by the total amount electricity sold to these customers. Call this the average CTC recovery rate, CTCA. Some fraction of CTCA, say 50%, could then be subtracted from the original rate freeze price to determine the new default provider rate (DPR). Under this scheme, the DRP would be approximately another 10% below the rate freeze average price. Customers that choose not to switch to an alternative ESP or to different tariff structure with the UDC should be able to purchase their electric according to the DPR.

There should be no restrictions on the other tariffs the UDC is allowed offer, or the tariffs that other ESPs offer. Specifically, the UDC should be allowed to offer a tariff with average prices for electricity above the DPR. Unless this tariff involves the provision of additional value-added services that a customer values highly, we would not expect a customer to choose this tariff over the DPR. Tariffs that do not deliver consumer benefits will not exist for long. First, any ESP has the option to undercut the rate offered by the UDC and provide the same or superior services, if the UDC is making excessive profits from certain tariff. Second, if the consumer is not receiving any benefit from these the supposed value-added services bundled with a new tariff, he can always elect to purchase electricity under the DPR. A higher priced tariff can only survive because the UDC or ESP offers a bundle products and services that the customer finds superior to the DPR.

The UDC should also have the opportunity to offer tariffs with average prices below the DPR. Clearly, this option also exists for ESPs. It is certainly possible to do so because the UDC and other ESPs in that service area no longer have to pay the CTC charge per unit of electricity delivered to final customers. We would expect that competition among the ESPs and the UDC to provide bares-bones retail electricity would drive average prices to something approximating the average wholesale price of electricity plus T&D and the RES expenses. However, by placing no restrictions on retail prices set by the UDC (besides the requirement to offer the DPR) creates the possibility of a retail margin from serving some classes of customers during the initial period following the end of the rate freeze. A retail margin is necessary to justify many of the up-front investments necessary for new and existing retail competitors to provide value-added retail services such as hourly metering and real-time load-monitoring information systems to final customers.

Mandating that the UDC offer a default provider rate that passes through a weighted average of the hourly wholesale energy and ancillary services prices using representative load-profiles eliminates the incentive for the development of these value-added services. This in turn, eliminates any opportunities for the price-responsive hourly final demand necessary for a price-responsive hourly wholesale electricity demand and a workably competitive wholesale electricity market. This cost-of-service regulation default provider strategy is unnecessary if one believes that retail competition is viable. We believe that the international experience from markets further along than California provides ample evidence on the viability of retail competition. The competitive process can be relied upon to offer this bare-bones retail pricing option if this is what retail customers demand. However, mandating a wholesale price pass-through rate for all customers virtually guarantees that any benefits from retail competition will be delayed almost indefinitely and the adoption of real-time metering and electricity load monitoring and control information technology dramatically slowed.

A strategy that should provide more long-term consumer benefits is to rely on the competitive process to set the diversity of price and service quality options for final retail customers with the DPR option described above. Competition among ESPs and the UDCs should then allow customers to find the combination of price, metering technology, information systems (e.g., mechanisms for notifying customers of wholesale prices and technologies for automating their response) and other product characteristics that best suit their preferences. One of goal of introducing competition into a former monopoly industry is to serve the full diversity of consumer demands by offering a far wider range of products than the former monopolist. Those electricity retailers (ESPs or the UDC) that provide true value-added to consumers in their retail product offerings will be profitable and remain in the industry. Those that contribute no value-added will exit the industry. Only by allowing this competitive sorting out process to take place will the full benefits of retail competition come to pass in a timely manner. The end of the CTC collection mechanism provides this opportunity.

Perhaps the most complex and difficult aspect of fostering retail competition is determining how much to charge each entity for metering services. One way to think of the UDC's existing metering infrastructure is as a stranded asset that is likely to be uneconomic on a going forward basis in the new competitive retail market. Clearly, remote metering reading technologies are more cost-effective on a going-forward basis than the labor-intensive procedures currently used. Consequently, one way to handle the issue of charging ESPs for metering services, is to include any remaining unrecovered meter installation costs on the UDC's accounts as a stranded asset. Once the rate freeze ends the UDC no longer receives any regulated cost recovery for meter installation, reading and repair costs. An equivalent alternative that does not involve creating additional stranded assets allows the recovery of any remaining historical metering installation costs in the UDC's regulated distribution rates, but includes new meter installation costs and meter reading and repair costs in the competitive supply side of the UDC's business. These costs must then be recovered out of retail rates, rather from the regulated distribution tariff. Coupled with the above recommendation of only requiring the post-rate-freeze UDC to offer the DPR described up, shifting all metering services to the competitive side of the UDC's business creates additional opportunities for competitive entry into the provision of hourly metering services and the associated information systems necessary to use these hourly meters to manage the customer's electricity consumption in response to hourly prices.

One aspect of the mechanism by which real-time metering technology creates a competitive wholesale electricity market in California deserves emphasis. For the beneficial effects of a price-responsive final demand to effect the bidding behavior of generation owners, total consumption over some time horizon does not have to be lower as a result of high prices during some hours of that time period. What is more important to disciplining the exercise of market power is that demand be able to shift hourly consumption from hours when prices are high to hours when prices are low. Although the ability to reduce total daily consumption in response to high prices during the day is certainly desirable, the major benefit of a price-responsive wholesale demand in disciplining generator bidding behavior is the ability to shift demand to other hours in the day in response to high prices, thus creating a more price-elastic aggregate hourly wholesale electricity demand.

A more price-responsive aggregate hourly wholesale electricity demand function will cause all generation owners to bid more aggressively into the wholesale electricity market. These firms know that if they bid too high they will not be dispatched in that hour because a significant amount of load will decide not to consume during that hour in response to high prices. By this logic, it is easy to see that all loads, even those that are not price-responsive on an hourly basis, benefit in terms of lower prices and reduced price volatility from a significant amount of price-responsive demand in the market. This suggests that there are benefits accruing to all consumers from the existence of price-responsive consumers, and that a significant fraction of these benefits are not captured by the customers providing them. This positive externality that price-responsive customers provide to all other customers implies that it may be desirable to subsidize the installation of hourly metering technology. For many customers the private benefit of installing hourly meters does not exceed the private cost, but the social benefit to that customer from installing an hourly meter may exceed his private cost.

8. Market Participant Compliance with Market Rules

Since the April 1999 MSC report was submitted we have continued to study the issue of over-procurement of ancillary services. One aspect of this involved interviews with the ISO system operators. During these conversations we discovered that a significant problem during the initial year of operation of the California market was generator compliance with ISO system operator dispatch instructions. This non-compliance took two forms.

In the first, a market participant would promise specific quantity of generating capacity that met certain technical specifications, yet they would be unable to deliver this quantity of capacity according to these technical specification when called to do so. One such example of this problem occurred frequently in the Regulation reserve market. A generator might bid to supply 100MW of upward regulation and all of this capacity would win in the ancillary services market. However, after 50 MW of the upward regulation capacity purchased was used and ISO requested that the unit regulate upward further, the generating unit would notify the ISO that certain modifications of the unit were necessary before it could proceed to this higher level of regulation and that these modifications would take a some time to implement. Under the ISO's current ancillary services market software, there is no way to detect and modify or reject a regulation bid of this type. Consequently, this created the need to purchase a larger nominal quantity of regulation reserve to insure that the ISO had sufficient regulation capacity that met the technical specifications necessary to meet its reserve requirements.

The second form of non-compliance occurred primarily in the real-time energy market. This problem arose primarily during periods of very high ISO prices. Under these circumstances, when generators were quite certain that the hourly ex post price for imbalance energy would be quite high, they would begin to supply more than their day-ahead energy schedule in anticipation of being paid for this according to an attractive hourly imbalance price. When this activity occurred on a large enough scale, it could create an oversupply of energy to the ISO grid so that the ISO system operator would then have to call on decremental bids in the real-time energy bid stack. However, at these times, generators in the real-time bid stack were extremely reluctant to reduce their generation given that they knew net energy imbalances would be paid for at an attractive ex post real-time price. Consequently, unit operators often did not comply with the terms implied by their decremental energy bids. The ISO system operator would then have to move down to the next unit owner in the BEEP sequence while the over-generation situation became even more extreme. The likelihood of this non-compliance with obligations associated with bidding into the real-time energy market further increased the ISO's demand for reserve capacity to guard against shortages of available generation to manage the grid in real-time.

It is important to bear in mind that the vast majority of these interactions between the ISO operations staff and generation unit owners took place via the telephone. Therefore the amount of time spent attempting to find some generating unit willing to supply the service usually made system reliability problem even larger. Guarding against this compounding of problems due to time delays when non-compliance occurred further increased the nominal demand for ancillary services reserve capacity.

Although it is difficult to quantify the cost of these non-compliance problems, it is easy to imagine instances when the costs can be extremely large. To address these issues, the ISO is in the process of implementing the Automated Notification, Acknowledgement and Logging Operations Program Environment (ANALOPE) to provide clear, indisputable dispatch instructions from the ISO to its market participants and an automated repository of responses to those instructions. ANALOPE is designed to integrate with the operation of the real-time energy market to accomplish a timely and transparent dispatch. It will log, archive, and easily retrieve all information associated with the dispatch process. ANALOPE will send an electronic dispatch instruction to a SC, receive response acknowledgement, log the transaction, and store the information to support dispute resolution. The information collected from ANALOPE will be essential to resolving disputes over non-compliance with ISO dispatch instructions or technical specifications for the provision of an ancillary service.

In order to eliminate non-compliance behavior to the greatest extent possible, we encourage the ISO to publicize particularly egregious instances to all market participants and impose the maximum penalties possible under the terms of the ISO tariff.

Additional aspect of the non-compliance problem in the real-time energy stack is currently acknowledged and tolerated by the ISO system operator in an effort to increase the depth of the real-time energy bid stack. Although the BEEP process dispatches resources in ten-minute intervals based on economic merit, in practice the ISO has been accommodating in this process several pre-dispatching resources with minimum run-time requirements such as: (1) interties, (2) large base-load units, (3) hydro resources for water management, and (4) gas turbines. These resources are dispatched for the whole hour whether they are in the 10-minute BEEP stack or not. Currently, resources pre-dispatched in-sequence with minimum run-time requirements set the real-time market-clearing price for each of the six, ten-minute intervals in the hour, even if these resources are not marginal. Resources pre-dispatched in-sequence receive payments, or charge, based on 10-minute BEEP market-clearing prices, not hourly ex post prices. Resources pre-dispatched out-of-sequence receive payments, or charge, based on "as bid" prices. Resources pre-dispatched out-of-market receive payment, or charge, based on Hourly Ex Post prices. This process of accepting bids with minimum run-times requirments has created an undue reliance on dispatcher's judgement in determining which bids to accept, and because this judgement affects the hourly ex post price, this has lead to disputes between the ISO and market participants. Given the ISO market rules, allowing this form of non-compliance is unnecessary.

While during the initial stages of the ISO's existence, it may have been necessary to compromise the market rules to insure that sufficient generation was available to maintain system balance at all times and points in the grid, this is no longer necessary or advisable. Under the current ISO rules, loads with minimum run-time requirements can participate in the ISO market by paying for deviations from 10-minute instructions given by the ISO according to the provisions of the current ISO tariff, under the same conditions that generating units without minimum run-time requirements now participate in the real-time energy market. Both types of generating units have the opportunity to deviate from their hour-ahead energy schedules and ignore ISO dispatch instructions in real-time if it is in their financial interest to do so. The ISO tariff charges resources differentially for instructed and uninstructed deviations from schedule to provide incentives for resources to follow real-time dispatch instructions. There are no further penalties for either type of deviation. By symmetric treatment of all resources using the current ISO rules these slow-response resources can maintain their minimum run-time requirement, yet bear they full cost that this requirement imposes on the real-time energy market. By treating these resources differently from resources that are able to respond more quickly, the ISO is subsidizing slow-responding resources at the expense of quick-responding resources. This differential treatment also dulls the incentive these slow-responding resources have to undertake the investments or regulatory rule changes necessary to become more responsive to 10-minute dispatch instructions. A frequent complaint of market participants is the lack of transparency in the real-time energy stack. Generators complain that they often do not understand why a bid to produce in real-time was not accepted. By treating all resources symmetrically in the BEEP dispatch process, much of this lack of transparency will be eliminated.

It is our understanding the ISO is currently considering a proposal to dispatch all resources on 10-minute dispatch interval and streamline payment or charge methods throughout the 10-minute interval for all resources. For the reasons discussed above, we strongly support this proposal.

As the California market matures, the ISO should continue to take steps to transfer more of the risk associated with maintaining system reliability to those market participants best able to manage it. Because the California market design allows generators and loads the flexibility to deviate from their hour-ahead energy schedules and make up the imbalances in the real-time energy market, the ISO must use financial incentives to manage the system in real-time. This is a major strength of the California market design relative markets where generators are explicitly penalized for deviations from day-ahead commitments. Generators in the California market are not unduly constrained by day-ahead commitments should system conditions change from those anticipated on a day-ahead basis. However, this strength can be one of the market design's greatest weaknesses if the economic signals generators receive in real time are not closely matched with current conditions in the ISO system. For example, suppose electricity demand in the ISO grid is currently rising, yet real-time energy prices are low because of delays in reflecting electricity supply and demand conditions in the real-time price of electricity. This lag in system operations between economic signals to generators and the current supply and demand condition within the grid can increase rather than decrease the shortfall between electricity supply and demand. Consequently, given the California market design, it is extremely important to the efficiency of the ISO's market that the physical condition of system as closely as possible match the financial conditions in market. For this reason, increasing the responsiveness of all resources or making them pay the full cost of their lack of responsiveness is critical to the success of the California market design.

9. Intra-Zonal Congestion Management, New Zone Creation, and Interconnection by New Generators

This section deals with three interrelated issues: (1) intra-zonal congestion management, (2) the conditions for new congestion zone creation, and (3) the terms and conditions under which a new generation owner can interconnect with the ISO grid. The first issue has to do with the day-to-day operation of the ISO grid, while the second two have to do more with the long-term operation of the California electricity industry. Current ISO policies for creating a new congestion zone depend on the frequency of congestion along transmission paths within an existing congestion zone on a six-month or annual basis. Consequently, the incentives that generators have for managing intra-zonal congestion directly impact the number of new congestion zones and when and where each new congestion zone is created. Continuing this logic, the timing and location of new congestion zones and the methods for managing congestion within these zones is a major factor in new generation location decisions within the ISO grid. For these reasons, we believe these issues should be dealt with in a sequential manner, because the proper intra-zonal congestion management policy will make formulating a new zone creation policy significantly more straightforward. An intra-zonal congestion management policy that provides the best incentives to eliminating intra-zonal congestion combined with a new zone creation policy that does not unnecessary favor new or existing entrants will simplify the process of formulating a new generation connection policy.

The major market design flaws identified in this section are:

1. The ISO's current intra-zonal congestion management policy rewards the creation and subsequent mitigation of intra-zonal congestion. For certain grid conditions, strategically located generators can earn significant revenues from causing and then mitigating intra-zonal congestion.

2. Under ISO's current intra-zonal congestion management policy, no market participant has any incentive to eliminate intra-zonal congestion. Intra-zonal congestion costs are simply a cost of selling energy in that congestion zone.

3. The ISO's current intra-zonal congestion management policies make an artificial distinction between intra-zonal congestion management and local grid reliability. Supplying energy to relieve intra-zonal congestion or for local grid reliability reasons are observational equivalent from an economic perspective. In both cases, generation units are being called to supply energy out of the bid sequence within a zone.

4. The ISO's new zone creation policy does attempt to control for the extent to which the frequency of intra-zonal congestion along a transmission path depends on the economic incentives faced by generators within the congestion zone. A major determinant of the frequency of congestion along a transmission path (besides load conditions on either side of the path) is the profitability of intra-zonal congestion on this path to generation unit owners on either side of the path.

5. The opportunities for generators to exercise market power in the ISO's day-ahead ancillary services markets are considerably enhanced during periods when ancillary services are procured on a zonal versus a statewide basis.

Our major recommendations for correcting these market design flaws are:

1. Revise ISO's current intra-zonal congestion management protocols in one of the following two ways:

   - Contract in advance for generation units to provide intra-zonal congestion relief services on an annual basis at variable cost for an up-front annual payment similar to the current RMR contracts. Procure these services through an annual competitive bidding process which involves loads and transmission operators.

   - Manage intra-zonal congestion by using RMR units to supply the incremental generation to relieve the intra-zonal congestion unless the unrestricted zonal market can provide this energy. Generators are decremented according to their bid prices to relieve intra-zonal congestion, but they must buy back the decremental energy at the ex post hourly real-time price, not their decremental bid price.

2. Do not implement a policy to mitigate intra-zonal congestion in the forward market until a policy with strong incentives to eliminate real-time intra-zonal congestion is in place. Otherwise, generators may very likely be able to create intra-zonal congestion in the forward market, get paid to relieve it, and then create it again in the real-time market and get paid to relieve it there as well.

3. Because of the increased opportunities to exercise market power in small congestion zones, do not create any new congestion zones, including the current proposed congestion zone south of Path 26 as a way to reduce intra-zonal congestion costs. Unless creating a new congestion zone substantially improves the system reliability, this process should be delayed until there is sufficient experience with the revised intra-zonal congestion management protocols. An intra-zonal congestion management policy that has incentives for all or some generators to eliminate intra-zonal congestion should significantly reduce the frequency of intra-zonal congestion and therefore eliminate the need to create a new congestion zone.

4. Any viable new generation connection policy must contain a policy for managing intra-zonal congestion. For the reasons discussed above, any analysis of the economic efficiency properties of any new generation connection policy will crucially depend on the intra-zonal congestion management policy in force.

The remainder of this section describes the current ISO policy for intra-zonal congestion management and the incentives it creates for generator behavior. We then present evidence from the operation of the ISO markets over the past year which illustrates the significantly increased opportunities for the exercise market power in the

ISO's day-ahead ancillary services market when they are cleared on a zonal basis. This followed by a discussion of the ISO's new zone creation policy, with specific application to the zone south of Path 26. We then discuss the ISO's new generation connection proposals.

We then turn to our recommendations for a revising the current intra-zonal congestion management protocols. The incentives for generator behavior provided by each policy are described. A discussion of the pros and cons of each proposal follow. We then give the rationale underlying our recommendation against new zone creation as means to reduce intra-zonal congestion costs using our methodology for determining workably competitive congestion zones described in Section 13. Finally, we discuss the ISO's new generation connection proposal, and the logic underlying our recommendation that it must contain an mechanism for giving market participants the incentive to eliminate intra-zonal congestion.

A. Current Intra-Zonal Congestion Management Policy

In order to gain a better understanding of the intra-zonal congestion problem in the California, it is instructive to clarify the distinction between intra-zonal congestion and inter-zonal congestion. The ISO's market-clearing process uses incremental and decremental energy bids within the same SC to relieve inter-zonal congestion in both the day-ahead, hour-ahead and real-time markets. This implies that the outcome of accepting decremental bids on one side of a inter-zonal transmission path and incremental bids on the other side of the zonal transmission path will increase the market-clearing price in one zone and decrease the market-clearing price in the other congestion zone. Higher incremental energy bids lead to higher market-clearing zonal prices on the uncongested side of the path and lower decremental bids lead to lower market-clearing prices on the congested side of the path. In contrast, under the ISO's current intra-zonal congestion management protocols, if the markets on both sides of the intra-zonal path are deemed workably competitive, then the generator with the lowest incremental energy bid that can relieve this congestion is paid his bid price for the additional energy generated. The generator with the highest decremental energy price that can relieve this congestion buys back the necessary energy at his bid price. If either side of the intra-zonal path is not deemed workably competitive, then RMR units, if they are available, are used to relieve intra-zonal congestion on that side of transmission path.[18]

Neither bid prices nor the RMR variable payment rates (if RMR units are used to relieve intra-zonal congestion) sets the zonal market-clearing price. By definition of intra-zonal congestion, one or both of these dispatch instructions are out-of-merit-order because there are lower-priced incremental energy bids and/or higher-priced decremental bids within the congestion zone that cannot be taken because they cannot relieve the intra-zonal congestion. Due to their location in the grid, only certain generators can relieve the intra-zonal congestion, so their bids are the only ones that can be accepted. The generator called out-of-merit-order in the real-time energy bid curve will not affect

[18] Currently the only intra-zonal congestion path deemed to have workably competitive generation markets on both sides is the Path 26 interface.

the hourly price of energy in that zone. Total hourly intra-zonal congestion costs are paid by all SCs serving load in that congestion zone and exporting power from that congestion zone in proportion to the amount of electricity they consume or export during that hour, regardless of the location of the resources used to mitigate the intra-zonal congestion. As consequence, intra-zonal congestion costs simply become an unavoidable cost paid by all SCs serving load in that congestion zone. There is no way for any SC serving load in that area to reduce its intra-zonal congestion costs without also reducing the intra-zonal congestion costs of its competitors in that zone by exactly the same amount per unit of electricity sold.

These rules for managing intra-zonal congestion create the following incentive for day-ahead scheduling and bidding into the supplemental energy market. Assume that during a given hour, a 500 MW generator must sell its power along a path with 200 MW of remaining capacity. Suppose the day-ahead market has been run and the zonal price of energy is $20/MWh and this generator won a hedge quantity of 500 MWh at this price. This generator then schedules 500 MW of capacity along a path that can only take 200 MW. Suppose that this generator is the only facility that can alleviate congestion along this path in real time and it bids $10/MWH for decremental energy. When the ISO attempts to dispatch energy in real-time it will be forced to take the generator's decremental bid of $10/MWH for 300 MW of capacity, because only 200 MW of the 500 MW scheduled can actually be produced in real-time. This generator pays ($10/MWh)*(300 MWh) = $3000 to buy back the 300 MW of capacity that it cannot deliver in real-time. Consequently, a generator that knew it was only able to sell 200 MWh along the path receives (500 MWh)*$20/MWh = $10,000 for day-ahead energy sales, and net revenues from both these and the real-time purchase of 300 MW at $10/MWh, of $7000. Despite the fact that the day-ahead zonal price was $20/MWh, by scheduling capacity in this manner, the generator was able to receive an average price of $7,000/200MWh = $35/MWh for the energy it sold during that hour.

How confident a generator is that it owns the only facility that can alleviate the intra-zonal congestion will determines the level of its decremental bid price. For example, a generator that knows with virtual certainty that it owns the only unit that can relieve the intra-zonal congestion may bid the negative real-time energy price cap of -$750/MWh for decremental energy. In this case, the generation would be paid $750/MWh for each MWh that it sells back to the ISO in real time. This case the generator would receive $225,000 = ($750/MWH)*300 MW for these decremental energy purchases in addition to the $10,000 for day-ahead energy sales for an average price for 200 MWh of energy delivered of $1,175/MWh = $235,000/200 MWh. Although this example may seem to be extreme, during the first few weeks of June 1999 a generator was in this very favorable position for many hours and frequently submitted decremental energy bids at the negative real-time energy price cap at that time of -$250/MWh.

The profitability of the above strategy relies on the fact that: (1) generators are paid their decremental bid to reduce the amount of energy they are willing to produce in real time, and (2) only a small number of generation owners are able to relieve this intra-zonal congestion. If there were a large number of firms able to relieve the intra-zonal congestion, then we would expect competition among market participants to raise the price of decremental energy bids. Viewed from this perspective, we can see that there is no meaningful distinction between an RMR call for local reliability reasons and an RMR call to mitigate intra-zonal congestion when the market to relieve intra-zonal congestion on one side of the transmission path is not workably competitive. In both cases the generation unit owner is the only entity, or one of a very small number of entities, that can provide this essential service. If a spot market was run for the provision of this service, then the generator could bid virtually any price to provide either service--intra-zonal congestion mitigation services or local grid reliability services—and it must be taken.

Consequently, intra-zonal congestion mitigation in the case that the market on one side of the path is not workably competitive is observationally equivalent to the provision of local reliability services in those instances when a generator's location in the grid makes a minimal amount of energy from it essential to maintain the integrity of the grid. For the case in which the uncongested side of the path is not workably competitive, the level of output from this unit necessary for local grid reliability is amount supplied after the increase in generation necessary to relieve the intra-zonal congestion. In the case in which the congested side of the path is not workably competitive, the level of output from this unit necessary for local grid reliability is the amount supplied after the decrease in output necessary to relieve the intra-zonal congestion.

Although the vast majority of intra-zonal congestion costs during the first year ISO operation was due to congestion along Path 26, over the past few months intra-zonal congestion has frequently occurred on many other transmission paths. In addition, despite concerns about the competitiveness of the energy market one or both sides of these paths, there are often no RMR units which can be used to relieve this intra-zonal congestion. Consequently, the prospects for larger intra-zonal costs along many paths in the ISO control area over the coming year may result in the creation of more congestion zones. However, as shown above, because no market participant has an incentive to reduce intra-zonal congestion costs, yet, depending on system conditions, all generation unit owners have an incentive to cause intra-zonal congestion. The ISO's intra-zonal congestion management protocols should be revised to create incentives for market participants to eliminate intra-zonal congestion.

B. Competitiveness of ISO's Zonal Ancillary Services Market

The advantage of the ISO's zonal market design is that if market participants have the strong incentives not to cause intra-zonal and inter-zonal congestion, then competition among market participants to supply energy and ancillary services will be over the largest market possible. This implies that generators will have strong incentives to bid aggressively to win in the statewide market for energy and ancillary services. However, when either inter-zonal or intra-zonal congestion occurs, this creates smaller markets for the provision of both energy and ancillary services. Under these conditions, a generation unit owner may be able to exercise significantly greater market power over the smaller market that occurs as a result congestion.

We investigate the extent that this logic is true for the ISO's ancillary services markets in two ways. In the first, we compare market-clearing zonal prices for ancillary services when the ISO's markets clear on a zonal basis versus statewide, controlling for differences in total ISO load across these two market outcomes. In the second analysis, we compared the monthly frequency that at least one of the three IOUs or at least one the of the new generation owners was pivotal in the ISO's ancillary services markets when the markets were cleared statewide versus on a zonal basis.

Our methodology for determining the impact of zonal market-clearing on zonal ancillary services prices uses the regression equation used to determine the average ISO-load-adjusted ancillary services prices last summer versus this past summer discussed in Section 3. The only difference is that we estimate separate equations for each congestion zone, separately for the period from June 1, 1998 to December 31, 1998 and for the period January 1, 1999 to August 17, 1999. The dependent variable in each regression is:

PAS(c,i,j) = the market-clearing day-ahead price for ancillary services i, for congestion zone c, during hour j

The variable of interest in this case is the coefficient associated with

CONG(j) = an indicator variable that equals one if the ISO procures ancillary services on a zonal basis.

The coefficient associated with this variable measures the ISO-load-adjusted difference in ancillary services prices in the congestion zone that results from procuring ancillary services on a zonal basis. For each congestion zone and each hour for the 1998 and 1999 separate sample periods, we regress PAS(c,i,j) on a constant term, a sixth order polynomial in ISOLOAD(j), a complete set of DAY, HOUR, MONTH indicator variables, and the indicator variable CONG(j).

Table 7 reports the values of the coefficient associated with CONG and associated standard errors for the NP15 and SP15 congestion zones for the June 1, 1998 to December 31, 1998 time period. The results presented in this table tell a very plausible story about the impact of zonal procurement of ancillary services in light of the CTC recovery mechanism in place and the large amount of generation capacity in the NP15 congestion zone owned by Pacific Gas and Electric for much of 1998. When ancillary services were procured on a zonal basis, prices tended to be significantly higher in SP15, which is consistent with the fact that NGOs, who receive greater revenues from higher ancillary services prices, owned the vast majority of capacity able to provide ancillary services in SP15. In NP15, zonal procurement of ancillary services led to lower prices. This is consistent with the fact that over the majority of this sample period Pacific Gas and Electric was the major supplier of ancillary services in the NP15 and its incentives are to keep energy and ancillary services prices low in order to increase its CTC recovery. The conclusion to be drawn from this time period is that the overall impact of zonal procurement is ambiguous. Those in NP15 tend to pay less and those in SP15 tend to pay more.

Re-running these regressions for 1999 provides a different result. Table 8 reports the values of the coefficients associated with CONG and the associated standard errors for the NP15 and SP15 congestion zones. Here the conclusion is that zonal procurement has little impact on prices in the NP15 congestion zone in 1999, whereas for Regulation and Spinning Reserve zonal procurement lead to dramatically higher zonal prices in the SP15 congestion zone. The NP15 result for 1999 is consistent with the view that the transfer of a significant amount of Pacific Gas and Electric capacity to the Southern Company has led to less aggressive bidding (a higher bid price for the same quantity of capacity) into the NP15 ancillary services market during periods when markets are cleared on a zonal basis. We should note that in light of these results it is very fortuitous that the ISO procured ancillary services on a zonal basis during 1999 very infrequently.

Table 7: Average Price Difference Due to Zonal Market-Clearing of Ancillary Services Market for Period June 1, 1998 to December 31, 1998

Market	Congestion Zone	CGFLAG	
		Estimate	Standard Error
Regulation	NP15	-18.73	2.30
	SP15	20.60	2.83
Spin	NP15	-18.98	2.08
	SP15	64.06	2.84
Non-Spin	NP15	-16.06	1.57
	SP15	-1.24	1.68
Replacement	NP15	-21.35	1.59
	SP15	50.60	15.89
Real	NP15	0.15	0.95
	SP15	-0.73	0.94

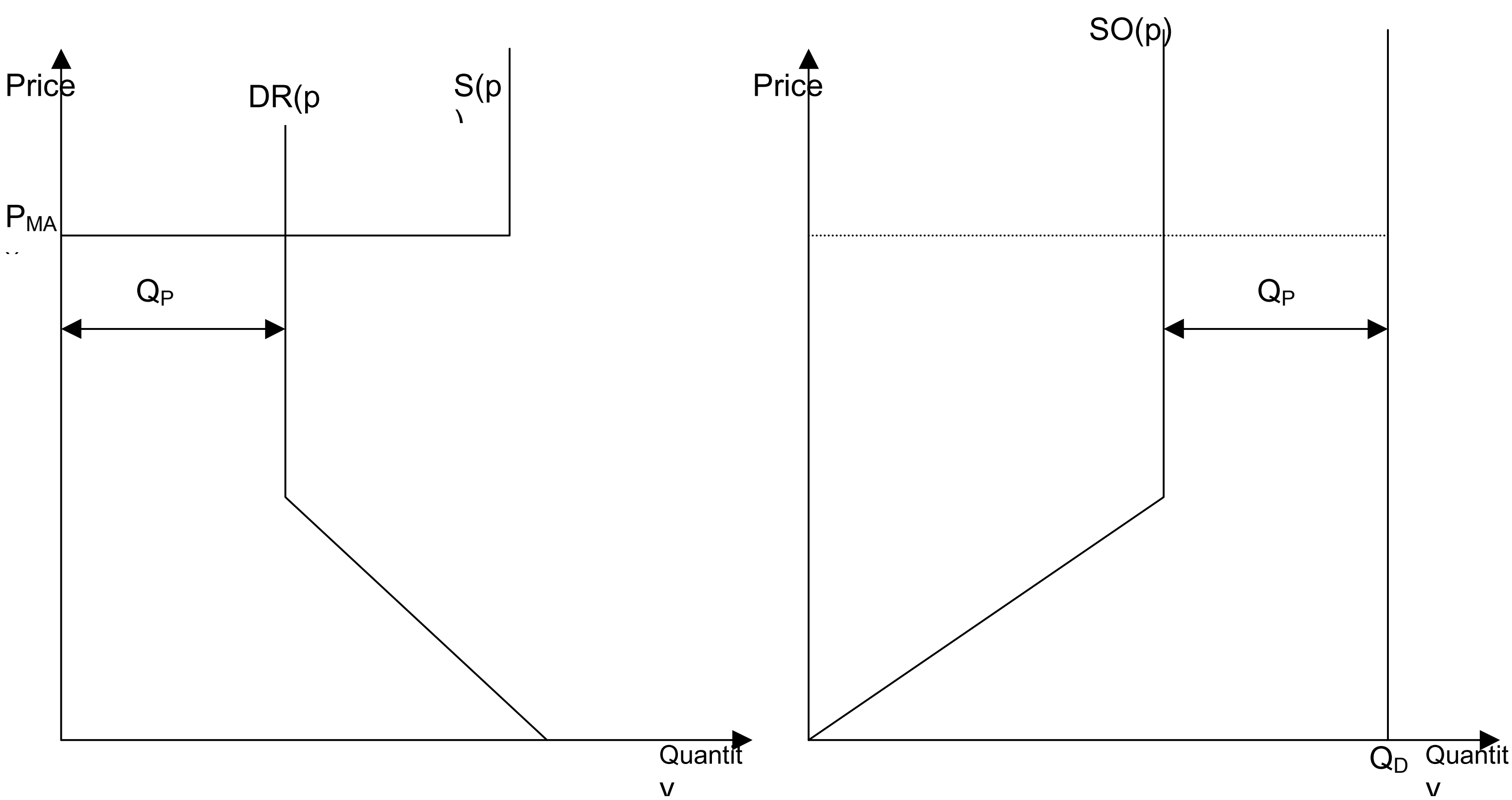
Table 8: Average Price Difference Due to Zonal Market-Clearing of Ancillary Services Market for Period January 1, 1999 to August 17, 1999

Market	Congestion Zone	CGFLAG	
		Estimate	Standard Error
Regulation	NP15	1.03	11.53
	SP15	87.14	11.63
Spin	NP15	-0.70	1.83
	SP15	83.26	2.24
Non-Spin	NP15	-0.23	1.83
	SP15	1.33	1.82
Replacement	NP15	0.82	1.68
	SP15	-0.27	1.68
Real	NP15	0.93	2.85
	SP15	1.05	2.85

The second analysis we perform uses the concept of a bidder being pivotal in the ISO's ancillary services. We say that a bidder is pivotal during a certain hour if by removing all of its bids from the market, regardless of their bid price, this causes the market to have an insufficient supply at any price to meet the aggregate demand for that ancillary service. During an hour that a bidder is pivotal, it should be able to set whatever price it would like in the market by its bid and still sell a positive amount of capacity into the market. Because all bidders submit their ancillary services bids at the same time, a bidder can only learn if it is pivotal after all bids have been submitted.

Figure 55 repeats our construction of a residual demand curve for the case in which the bidder is pivotal. In this case, SO(p), the supply curve of all other market participants besides the firm under consideration, becomes vertical before it crosses the aggregate demand curve Q_D. For simplicity, we have drawn aggregate demand to be completely price inelastic. For the reasons discussed above, this is not an unrealistic assumption for the aggregate demand for of any of the ISO's ancillary services markets over the time period we study. The resulting residual demand curve for the firm is DR(p). The minimum amount that SO(p) falls short of Q_D is equal to Q_P. This implies that the firm faces a completely price inelastic residual demand for the quantity Q_P. From the diagram it is clear that the firm earns the greatest revenues by bidding all of its capacity at the price cap of P_{max}. This strategy sets the market price at P_{max} and earns the unit owner $(P_{max})x(Q_P)$ in total revenues. Consequently, during periods in which a generator estimates that with very high probability it is pivotal, this is the optimal supply bid function so long as Q_P is not too small. Note that the larger P_{max} is the smaller Q_P can be and still result in the optimal bidding strategy being all of the generator's remaining capacity at the price cap.

Figure 55



In a market without a price cap, if a generator knows with very high probability that during a certain hour it will be pivotal then there should be no upper bound on its economically optimal bid price. (There may be other constraints on how high a price a generation unit owner can bid.) What the generator loses on the volume of sales, it can make up in the bid price for those sales. To the extent that a market participant is able to accurately forecast when it will be pivotal and the frequency that this event occurs are both measure of the extent of potential market power possessed by that market participant. It seems reasonable to assume that if the event occurs more frequently, then it should be easier for the market participant to forecast when this event will occur. Consequently, we take the frequency of this event as our measure of potential market power.

Because of confidentiality concerns we do not report pivotal bidder frequency by individual market participants. Instead we compute, for each day-ahead ancillary services market, the monthly frequency—percentage of hours in the month--that at least one of the three IOUs was pivotal in that day-ahead ancillary services market. We also report, for each day-ahead ancillary services market, the monthly frequency that at least one of the NGOs was pivotal in that market. We account for generation unit ownership changes in over the sample period when computing these two pivotal bidder frequencies. Tables 9(a)-9(c) contain the monthly IOU and NGO pivotal bidder frequency when the day-ahead market was cleared on a statewide basis and the pivotal bidder frequencies for NP15 and SP15 separately when the day-ahead ancillary services markets were cleared on a zonal basis for the summer months of 1998. Table 10(a)-10(c) computes these same numbers for the summer months of 1999. The sample for August 1999 ends on August 17, the day before the Rational Buyer protocol was implemented. Because the ancillary services markets were not cleared on a zonal basis during July or August 1999, these rows are omitted from Tables 10(b) and 10(c).

Table 9(a): Pivot Bidder Frequency: Statewide Market-Clearing June - August 1998

Month	Owner	Ancillary Services Markets			
		Regulation	Spin	Non-Spin	Replacement
June	IOU	0.95	0.91	0.09	0.42
	NGO	0.35	0.48	0.06	0.09
July	IOU	0.45	0.29	0.20	0.10
	NGO	0.09	0.07	0.09	0.10
August	IOU	0.25	0.15	0.13	0.12
	NGO	0.02	0.24	0.13	0.14

Table 9(b): Pivot Bidder Frequency: Zonal Market-Clearing (NP15)
June - August 1998

Month	Owner	Ancillary Services Markets			
		Regulation	Spin	Non-Spin	Replacement
June	IOU	1.00	1.00	1.00	1.00
	NGO	0.49	0.86	0.91	0.57
July	IOU	1.00	0.83	0.97	0.84
	NGO	0.69	0.32	0.44	0.28
August	IOU	1.00	0.78	0.83	0.98
	NGO	0.10	0.37	0.41	0.63

Table 9(c): Pivot Bidder Frequency: Zonal Market-Clearing (SP15)
June - August 1998

Month	Owner	Ancillary Services Markets			
		Regulation	Spin	Non-Spin	Replacement
June	IOU	0.16	1.00	0.19	0.00
	NGO	0.03	0.59	0.19	0.19
July	IOU	0.89	0.85	0.26	0.08
	NGO	0.25	0.75	0.17	0.17
August	IOU	0.19	0.08	0.07	0.00
	NGO	0.02	0.17	0.08	0.01

Table 10(a): Pivot Bidder Frequency: Statewide Market-Clearing
June - August 1999

Month	Owner	Ancillary Services Markets			
		Regulation	Spin	Non-Spin	Replacement
June	IOU	0.08	0.00	0.00	0.00
	NGO	0.00	0.00	0.00	0.00
July	IOU	0.04	0.003	0.004	0.008
	NGO	0.02	0.004	0.004	0.008
August	IOU	0.013	0.00	0.00	0.00
	NGO	0.005	0.00	0.00	0.00

Table 10(b): Pivot Bidder Frequency: Zonal Market-Clearing (NP15)
June - August 1999

Month	Owner	Ancillary Services Markets			
		Regulation	Spin	Non-Spin	Replacement
June	IOU	1.00	0.00	0.00	1.00
	NGO	0.64	0.00	0.00	0.00

Table 10(b): Pivot Bidder Frequency: Zonal Market-Clearing (SP15)
June - August 1999

Month	Owner	Ancillary Services Markets			
		Regulation	Spin	Non-Spin	Replacement
June	IOU	0.00	0.00	0.00	0.00
	NGO	0.00	0.00	0.00	0.00

Several conclusions emerge from these Tables. First, when the ancillary services markets were cleared on a statewide basis the pivotal bidder frequencies for the summer of 1998 were significantly higher than the pivotal bidder frequencies for the summer of 1999. The other conclusion that holds across both years, is that when the markets are cleared on a zonal basis, the pivotal bidder frequency is significantly higher than when the markets clear on a statewide basis. These results argue in favor of the view that the many of the market structure and market rule changes over the past year have reduced the extent of market power in the ancillary services market. However, there are two important caveats associated with this conclusion. The first is that when markets clear on a zonal basis, even during the summer of 1998, the pivotal bidder frequencies are extremely high for several ancillary services. Second, some portion of the reduction in pivotal bidder frequencies for both the IOUs and NGOs when these markets clear on a statewide basis between the summer of 1998 and summer of 1999 can be attributed to the reduced demand for ancillary services in 1999 due to mild weather conditions. A major reason for the lower pivotal bidder frequencies in the day-ahead ancillary services markets in 1999 is the ISO's policy, implemented in April 1999, to delay some day-ahead purchases to the hour-ahead market in order to lower total ancillary services costs and increased the liquidity of the hour-ahead market. These results provide significant evidence that this strategy has be effective at reducing the potential for generation unit owners to exercise market power in the day-ahead ancillary services markets.

C. ISO New Zone Creation Policy

ISO's tariff allows for the creation of a new congestion zone according two criteria: (1) the cost of intra-zonal congestion mitigation, and (2) the existence of a workably competitive market in each of the two new zones. The ISO tariff states that if the cost of intra-zonal congestion mitigation over a 12-month period exceeds at least 5% of the product of the rated capacity of the path and the weighted average Access Charge of the participating Transmission Operators (TOs), the ISO may create a new zone. If during the initial the 6-months of ISO operations this cost exceeds 10% of an analogous magnitude, the ISO may create a new congestion zone. Intra-zonal congestion on Path 26 during both the first six months and first year of ISO operation exceeded the cost criterion for new zone creation.

However, following the methodology outlined in Section 13, we arrive at the conclusion that it is very unlikely that there is a workably competitive zone on at least one side of the interface. Our logic is first based on our results on the impact of zonal market-clearing on ancillary services prices in SP15. The proposed structure of the new zone north of Path 26 and south of Path 15 (SP15-NP26), the new SP15-NP26 zone will take approximately 3,000 MW of generation capacity from the old SP15 zone, but it will only have approximately 300 MW of load within the zone. Path 26 had a 3,000 MW bi-directional rating until November 1998. It was reduced to 2,400 MW for the 1998-99 winter season and increased to 2,800 for the summer of 1999. When there is congestion flowing from north to south on the SP26 interface, load in this new zone will only be reduced by approximately 300MW, but it will now have to be served by approximately 3,000 MW less capacity. One can expect that during these periods, the opportunities to exercise market power in the energy and ancillary services markets within the SP26 zone are significantly greater than the opportunities that previously existed under similar load conditions in the old SP15 zone. In addition, if SP26 transmission path is de-rated, then we would expect an even greater imbalance between load and available generation capacity within the zone, leading to even greater opportunities to exercise market power in the new zonal market for energy and ancillary services beyond what was possible in the original SP15 zone.

D. New Generation Connection Policy

The two main proposals considered by the ISO Board for charging a new generator to interconnect are summarized below. The economic efficiency properties of each New Generation Interconnection Policy (NGIP) proposal are then analyzed. We argue that neither the Advance Congestion Cost Mitigation (ACCM) proposal nor the No Grandfathering of Transmission Rights (NGTR) proposal provides the proper economic incentives for when and where to construct new transmission and generation facilities to alleviate intra-zonal congestion. This is due in large part to the current ISO protocols for relieving intra-zonal congestion.

The zonal nature of the California electricity market and the current ISO protocols for managing intra-zonal congestion, combined with the fact that transmission upgrades can often substitute for generation capacity in meeting many local reliability needs makes designing an NGIP an extremely complex task. An NGIP must give generation companies locational price signals for siting new facilities which increase the efficiency of the energy and ancillary services markets. Transmission owners must face price signals which cause them to make transmission upgrades when these result in a lower cost solution to local reliability problems than investment in new generation capacity. Transmission owners should also have a financial incentive to maintain the amount and geographic distribution of transmission capacity necessary for the energy and ancillary services markets in California to function efficiently.

Designing an NGIP requires trading off the financial gains of some market participants against those of other market participants. One conclusion to emerge from our discussion of these proposals is the necessity of a revision of the ISO intra-zonal congestion management protocols to provide incentives for market participants to alleviate intra-zonal congestion. Given an intra-zonal congestion management policy that enhances market efficiency, designing an appropriate NGIP becomes a significantly more straightforward task.

1. New Generation Interconnection Policies under Consideration

If the owner/representative of a new generating unit (NewGen) would like to connect that unit to the ISO grid, the NewGen must request a system impact and facilities study (Impact Study) from the associated Participating Transmission Owner (PTO). That study will identify reliability issues as well as incremental intra-zonal congestion caused by the NewGen. The ISO Tariff states that the NewGen must mitigate any reliability issues identified by the Impact Study. The NewGen may accomplish this by paying for transmission system upgrades to correct the problem or, in some cases, by implementing a Remedial Action Scheme (RAS) that would change the unit's operations as necessary to relieve the reliability concern. However, the ISO Tariff is not clear on whether or how the NewGen must address incremental congestion, specifically intra-zonal congestion, caused by the new unit.

On this issue, the ISO Board considered two primary policy options:

1. "Advance Congestion Cost Mitigation" (ACCM): With this policy, NewGens would be required to either pay for transmission upgrades or implement operating procedures (e.g., curtail their generator's output) that would, under certain circumstances, mitigate the incremental congestion they cause. In addition, this policy would require "future generators" (those that connect to the grid after NewGen's project) to complete the same mitigation measure. As a result, congestion in the local area surrounding NewGen will be approximately the same after it and any future generator connects in the area.

2. "No Grandfathering of Transmission Rights" (NGTR): With this policy, NewGens would not be required to pay to mitigate the increased intra-zonal congestion "caused" by their projects, nor would any future generators be required to mitigate the additional intra-zonal congestion. SCs would use existing ISO real-time energy market tools to manage any future intra-zonal congestion.

Under both the ACCM and NGTR approaches, NewGens would be required to address all grid upgrades necessary to maintain the reliability of the ISO grid. Under both proposals, NewGens could voluntarily invest in grid upgrades and would be entitled to any "system benefits" that arise as a consequence of their investment. These system benefits result primarily from the lumpy nature of transmission upgrades, and the fact that only a portion of the upgrade is necessary to mitigate the intra-zonal congestion caused by the NewGen's entry.

If the connection of the NewGen to the grid leads to excessive intra-zonal congestion and results in the creation of a new zone based on ISO Tariff Section 7.2.7, there should be no difference between the two methods. This is because the Tariff allows the new zone to be created only if there is a competitive generation market in each of the two new zones. If this is the case, the NewGen would have to be exempt from paying to mitigate intra-zonal congestion, because it will now be inter-zonal rather than intra-zonal congestion, and the former can be mitigated through the inter-zonal congestion management across the competitive zonal markets. The two methods would lead to different results only when the NewGen connection leads to excessive intra-zonal congestion, but there is insufficient competition to allow creation of a new zone. However, one can imagine instances where the mitigation measure undertaken by the new entrant under the ACCM proposal would reduce the frequency of intra-zonal congestion so that a new zone would not need to be created. Whereas under the NGTR approach a new zone will be created because no mitigation measures were undertaken in advance of entry.

To determine the impact of the NewGen on intra-zonal congestion in the "impact" studies, the "worst-case" scenario (for the most severe credible contingency in the hour where the system is most stressed) is compared with and without the NewGen. If an intra-zonal interface is congested with the NewGen with a flow increase of 5% or more compared with the no NewGen case, the NewGen is assumed to be responsible for creating the intra-zonal congestion. Implicitly, it is assumed that such a condition could eventually lead to the creation of a new zone if the cost of congestion exceeded 5% of the annual access fee and there exists competitive generation markets on both sides of the zone which is created. To determine whether or not congestion can be mitigated through competitive markets, the ISO Board has adopted the 20% rule, i.e., to have a competitive market no one firm can own more than 20% of generation in the new zone.

2. *Analysis of Two Proposals*

The main question we address is whether the ACCM or NGTR will lead to the most efficient market for electricity in California given the current ISO protocols for managing intra-zonal congestion and creating new congestion zones. The ACCM assigns responsibility for all additional intra-zonal congestion to the new entrant, despite the fact that this new entrant sometimes provides benefits to all consumers within the zone or the state by relieving intra-zonal congestion at a lower price or setting a lower state-wide or zonal price for energy. In this dimension, the ACCM is inferior to the NGTR. However, the NGTR does not address the incentives in a zonal electricity market, such as the one that exists in California, for new generators to locate where they can create and benefit from intra-zonal congestion. For this reason, the NGTR proposal in its current form is not recommended. Finally, neither proposal provides incentives for the Participating Transmission Operator (PTO) to undertake transmission upgrades necessary to reduce the incidence of intra-zonal congestion or to substitute for additional generating capacity when a transmission upgrade yields a lower cost solution to a local grid reliability problem.

3. *ACCM Proposal*

Any firm considering whether to enter the California market must determine if it will be able to recover all of the up-front fixed costs associated with constructing a new generating facility and connecting it to the ISO grid from selling electricity in the California market. Any increase in the up-front cost necessary to enter the California market will tend to raise the average price of electricity in California necessary to cause new generation to enter the market. Because the ACCM charges all incremental intra-zonal congestion costs to the new entrant, this policy implies that a higher average market price will be required to trigger new entry into the California electricity market. The NewGen must recover these up-front congestion charges from the revenues it expects to earn from participating in the market.

However, if the NewGen has a lower marginal cost than existing generators, there will be times when the zonal or statewide price of electricity will be lower because this firm is present in the market. In addition, there will also be times when this firm is able to relieve intra-zonal congestion at a lower price than existing firms. Because all customers in a zone pay the same price of energy and pay intra-zonal congestion costs in proportion to their electricity consumption, the presence of this firm provides tangible benefits to consumers during many hours. The ACCM proposal does not compensate generators for these system benefits, but requires them to pay all of the incremental intra-zonal congestion costs they impose on the transmission grid. This asymmetry of charging new entrants for the costs they impose on the system without netting out all of the benefits they provide to the system can increase the cost of entry by new generators.

Unfortunately, it is extremely difficult to compute the benefits that a new entrant provides to the market. During periods when the new entrant sets the market price, the difference between the price bid that would clear the market without the new entrant and the bid that actually cleared the market could measure of how much lower prices are as a result of the new entrant. However, this measure does not capture the impact of more aggressiveness bidding by other market participants as a result the presence of a new entrant. In addition, if the new entrant was rewarded with a portion of the benefits that it provided to market as defined by the above measure, it may distort its bidding behavior to set lower market prices.

In addition, it is extremely difficult to determine the cost of incremental intra-zonal congestion that a new entrant imposes on existing firms. Such a calculation will require value judgements that are likely to exert and a large influence on the results. Specifically, the cost of intra-zonal congestion depends on the bids generators submit and the ISO accepts to relieve the congestion. It is also very difficult to distinguish grid upgrades required for reliability reasons and those undertaken to relieve intra-zonal congestion. Clearly grid upgrades made for reliability a very likely to reduce the level of grid investment necessary to relieve intra-zonal congestion. Also, depending on the financial incentives a generator faces, it can produce in a manner that does not adversely impact grid reliability yet causes intra-zonal congestion, produce in a manner that adversely impacts grid reliability yet does not cause intra-zonal congestion, or produce in a manner that does not adversely impact grid reliability or cause intra-zonal congestion.

Because the ACCM policy charges the new entrant for incremental intra-zonal congestion in the form of an up-front payment that does not net out the benefits that this entrant provides to other market participants described above, ACCM creates two potential sources of efficiency losses. First, existing generators are able to earn higher prices as a result of the up-front payment charged to new entrants under the ACCM scheme, because an upper bound on the annual average price of electricity in California is the expected average total cost of a new entrant. Second, new entry may be delayed relative to the case in which the ACCM scheme does not exist, because new entrants must wait longer for sufficient demand growth to occur and produce wholesale electricity prices that are high enough to make new generation capacity economic.

A new entrant treats the ACCM as a sunk cost of entry, i.e., a cost which cannot be recovered upon exit from the industry. Furthermore, this cost is not paid by existing generators. The higher are the perceived sunk costs of entry, the higher market prices can be above the marginal cost of production and not trigger new entry. One major goal of an efficient market design is to eliminate unnecessary barriers to entry. Efficient entry is encouraged if entrants are charged for the negative externalities their entry imposes on other market participants, and credited for any positive externalities their entry imposes on other market participants. Net entry charges in excess of those implied by this principle constitute unnecessary barriers to entry.

An additional shortcoming of the ACCM scheme arises because it assigns an unwarranted level of significance to the current level and location of intra-zonal congestion by requiring new entrants to maintain the pre-entry level of intra-zonal congestion. There is no definitive evidence that the current level and location intra-zonal congestion is the optimal in the sense that it leads to the most efficient mode of operation of the California energy and ancillary services market. By requiring new entrants to mitigate intra-zonal congestion to current levels with grid upgrades, the ACCM may unnecessarily prevent some of market-efficiency-enhancing upgrades of the transmission grid, or require too many upgrades of other transmission paths.

The potential barrier to entry caused by the ACCM may be even greater for subsequent entrants. Because the ACCM requires all new entrants pay to enhance the transmission grid so that the level of intra-zonal congestion is approximately same as before it entered the market, the cost of this intra-zonal congestion mitigation measure under the ACCM proposal could be even larger for subsequent entrants. Consequently, entry barriers may rise over time, delaying subsequent new entry and increase the price of electricity necessary to attract such new entry. Alternatively, because of the lumpiness of transmission enhancements, the second entrant could “free ride” off of the proposed upgrades of the first entrant and therefore incur very small or even zero ACCM payments. This free-riding problem could be so extreme that neither entrant wants to be first into the market. As result, neither firm enters the market first, despite the fact that either would enter second. This could create a circumstance where all market participants recognize the need for new generating capacity in California, but no new investment occurs, because no prospective entrant wants to be the first to commit to a new generation project and pay the significantly higher first-entrant ACCM charge. This could also create the situation that once entry occurs and the first mitigation measure is complete, there would then be a rush to be the one of the next entrants that do not have to undertake costly mitigation measures. In theory, coordination between entrants to mitigate intra-zonal congestion could solve these free-riding problems, but whether such coordination will be achieved in practice is an open question.

The analysis up to now has assumed that the cost to enhance the grid so that the level of intra-zonal congestion is the same as before the new entry occurred is known, or at least relatively easy to calculate. However, determining the magnitude of this cost is likely to be an extremely contentious process particularly because the new entrant must pay it. For this reason, existing firms have a strong incentive to inflate these costs. In addition, because the PTO has a financial stake in this process, it has incentives to produce Impact Studies for new entrants that favor its financial interests. Consequently, implementing this proposal is likely to cause disputes over the mitigation measures required, which themselves could delay entry.

4. NGTR Proposal

The NGTR proposal does not create potential barriers to entry similar to the ACCM proposal, because new entrants do not have to pay up-front to mitigate incremental intra-zonal congestion. Both new entrants and existing generators are treated symmetrically in terms of the intra-zonal congestion they cause. Under the NGTR scheme, if a new generator can produce energy more cheaply than an existing generator, that generator will find it profitable to enter and undercut the existing generator. Because the sunk costs of new entry are lower under the NGTR scheme than under the ACCM scheme, we would expect that lower electricity prices would be required to attract new entry. In addition, new entry could occur more rapidly in response to a growing demand for electricity than it would under the ACCM scheme.

However, the NGTR scheme can lead to excessive entry if entrants cause congestion and thus impose negative externalities on existing generators. Even more pointedly, NGTR also fails to address the major problem with the ISO's intra-zonal congestion management protocols that can lead to incentives for new entrants to locate their facilities to increase intra-zonal congestion. As noted above, current intra-zonal congestion management protocols allow unit owners to buy back energy commitments on the congested side of a path according to their unit-specific decremental bid prices, and sell additional energy on the uncongested side according to their unit-specific incremental bid prices. If generators on the congested side of the path whose decremental bids are accepted have some of their forward energy commitments met by the ISO, they receive the difference between the forward energy market price and their decremental bid for the amount of capacity that is decremented.

It is important to emphasize, that by definition of intra-zonal congestion, at least one payment to relieve intra-zonal congestion is out of merit order, because there are lower-priced incremental energy bids and/or higher-priced decremental bids within the congestion zone cannot be taken because of intra-zonal congestion. Due to their location in the grid, only certain generators can relieve the intra-zonal congestion, so their bids are the only ones that can be accepted. The generator called out-of-merit-order in the real-time energy bid curve will not affect the hourly price of energy in that zone. Any out-of-merit-order decremental or increments payments will not affect the hourly real-time price of electricity in that congestion zone.

The NGTR proposal combined with the current ISO market rules may make it profitable for a firm to enter at points in the California grid which satisfy two criteria: (1) supplying more electricity at this point will increase the frequency of intra-zonal congestion, and (2) the generation owner is the only market participant able to relieve this intra-zonal congestion. If there are other generators able to relieve this intra-zonal congestion, the above strategy of scheduling to cause intra-zonal congestion should be less profitable, because there will be competition to supply the decremental energy bids necessary to relieve this congestion.

The shortcomings of the current ACCM and NGTR proposals described above highlight the challenges that must addressed by any NGIP because of the current ISO protocols for relieving intra-zonal congestion. The major goal of an NGIP is to give the locational price signals for new generators to enter where they provide the greatest benefits to California electricity consumers. A second goal is to provide incentives for PTOs to undertake transmission upgrades that alleviate intra-zonal congestion along a transmission path at a lower cost than out of merit purchases and sales of electricity. A third goal is to involve loads in the intra-zonal congestion management process to the greatest extent possible. Currently, all loads within the zone pay higher prices because of intra-zonal congestion in form of charges levied on all energy consumed in the congestion zone, regardless of the load's location in the zone. This mode of pricing intra-zonal congestion provides very muted incentives for loads to consume in a manner that reduces the cost of relieving intra-zonal congestion. All of these goals for a NGIP require the ISO to have an intra-zonal congestion management protocol that gives as many market participants as possible strong incentives to eliminate intra-zonal congestion. In the next section we describes changes in the ISO's intra-zonal congestion management protocols that come closer to achieving this end.

E. Recommended Changes in Intra-Zonal Congestion Management Protocols

The major problem with the ISO's intra-zonal congestion management protocols is that they provide no market participants with a strong incentive to eliminate intra-zonal congestion and give many market participants the incentive to cause intra-zonal congestion. Both of our recommended modifications eliminate some of the incentives to cause intra-zonal congestion by giving other market-participants strong incentives to reduce the amount of intra-zonal congestion. One approach builds off of the logic described earlier about the false distinction between local grid reliability services and intra-zonal congestion mitigation services. In this case, we propose to use RMR units to mitigate intra-zonal congestion because intra-zonal congestion mitigation is economically equivalent to providing local reliability services. The second approach attempts to use a more market-based solution. For this reason it may be more risky in terms of the opportunities for the exercise of market power, but it also has the greater upside in terms of solving the current incentives to cause intra-zonal congestion.

1. Cost-Based Intra-Zonal Mitigation

The first scheme relies on the logic expressed earlier that the distinction between requiring energy from a single unit or one of a small number of units for local grid reliability reasons is difficult to distinguish from a requiring energy from a unit or one of a small number of units to relieve intra-zonal congestion. In both cases, the generator is required to provide this service regardless of the magnitude of its bid price relative to the market-clearing price. Consequently, this scheme would use RMR calls whenever it is necessary to skip over bids in the real-time energy bid stack to relieve intra-zonal congestion. Specifically, if the ISO is required to skip over bids on either side of a congested path, then it would be required to call on a RMR unit to relieve congestion on that side of the path. If the congestion on one side of the path could be satisfied without skipping over bids in the real-time energy stack, then that bid would be taken. For example, if incremental energy to relieve intra-zonal congestion happens to set the unconstrained 10-minute price in the zone, then there is no need to use an RMR unit to relieve intra-zonal congestion. However, if relieving intra-zonal congestion in the incremental and/or decremental direction requires skipping over bids in the real-time energy bid stack, then RMR units should be used to meet the incremental and/or decremental energy.

This scheme would eliminate the somewhat artificial distinction between local monopoly power because of local grid reliability concerns and local monopoly power because of the unit's location relative to the location of intra-zonal congestion. This scheme prevents RMR unit owners from exercising market power at times they are a monopoly or part of a duopoly for intra-zonal congestion mitigation. Clearly, because bids are being skipped, an unrestricted zonal market for energy is no longer operating similar to the case that it would be necessary to skip bids to pick generation units in specific locations to solve local grid reliability problems which motivated the creation of RMR contracts.

Under this scheme, the threat of RMR calls if the unrestricted zonal energy market does not operate gives a strong incentive for this group of market participants to dispatch all of their generation units (RMR and non-RMR) to reduce the likelihood of intra-zonal congestion preventing this outcome from occurring. RMR unit owners now have a financial interest in eliminating intra-zonal congestion and supporting an unrestricted zonal market. Under the current RMR contracts they are paid variable cost for supplying RMR energy, and would clearly prefer to receive a market-determined price above their variable cost. Under this scheme they will receive such a price only if the unrestricted zonal market clears.

In order to eliminate the unavoidable cost feature of the current intra-zonal congestion management protocols, this scheme would charge these RMR calls to the PTOs. Charging PTO's for RMR calls give them a financial incentive to make the appropriate grid upgrades if this is cheaper than paying for RMR calls to relieve intra-zonal congestion. This logic is also in line with our view that there is no essential economic distinction between local reliability services and intra-zonal congestion mitigation under local monopoly or duopoly situations. The PTOs currently pay for RMR calls for local reliability services, so that this requirement would make our scheme internally consistent with this logic.

This scheme could also allow other market participants--loads and new generation entrants--to relieve intra-zonal congestion. For example, each year the ISO could put out to bid the up-front fixed payment for an RMR contract to satisfy certain system reliability needs for a given geographic region in the ISO control area. Given these bids, the PTOs could then decide instead to reduce their RMR unit capacity requirement and the magnitude of associated up-front payments. They would undertake transmission grid expansion to reduce the level of intra-zonal congestion. In this way, a trade-off between new generation and transmission upgrades would enter into the process for relieving intra-zonal congestion.

The downside of this scheme is the increased reliance on RMR contracts, which runs contrary to the ISO Board's stated goal of reducing the number of RMR units. Despite this apparent increased reliance on RMR contracts, it does not follow that there will be more RMR units or a larger quantity of energy provided under the terms of RMR contracts. The PTOs will undertake transmission upgrades to eliminate the need for RMR units where the costs of relieving intra-zonal congestion from RMR calls is more than the cost doing so through a transmission upgrade. Because RMR unit owners have a financial stake in reducing the level of intra-zonal congestion, they will have a financial incentive to dispatch all of their units to reduce the likelihood of intra-zonal congestion during periods expected to have high zonal energy prices. This should result in as much energy as possible being sold through an unrestricted zonal energy market, which could result in a smaller total quantity of energy sold under the terms of the RMR contracts than under the current intra-zonal congestion management protocols.

Under the ISO's current congestion management protocols, the creation of new congestion zones is unlikely to solve the incentives generation unit owners have to cause intra-zonal congestion, despite the fact that creating a new zone transforms some intra-zonal paths into inter-zonal paths. However, there will still be intra-zonal paths that are susceptible to congestion using the strategies described above. Consequently, short of moving to a full nodal-pricing model for energy and ancillary services in the California market, some RMR units are necessary to solve the local market power problems in the day-ahead or real-time markets due to either intra-zonal congestion or local grid reliability concerns. In addition, due the increased market power opportunities in small markets, it is not clear that a full nodal-pricing model for the California market would mitigate the market power problems associated high ISO load periods more efficiently that the current California zonal market would do with RMR units used in this manner.

In light of the above discussion, it is appropriate to think of RMR units as providing liquidity to the zonal energy and ancillary services markets. By supplying energy at certain points in the grid from RMR units and other units the firm owns, it can increase the likelihood that an unrestricted market for energy and ancillary services can operate within the zone. This generator is compensated for providing this liquidity through the fixed payment it receives as an RMR unit owner. Allowing competition from PTOs (in the form of transmission upgrades), existing loads and generation, and new generation entrants to provide a portion or all of this local reliability service, should yield a market-determined up-front payment, which pays for the cost of providing this liquidity to the market.

This designation of RMR units as market liquidity providers unifies their use for both local grid reliability and intra-zonal congestion mitigation during times when the unrestricted zonal energy market does not clear. By facing these unit owners with risk of an RMR call at a cost-based rate to mitigate intra-zonal congestion, gives them strong incentives to reduce the likelihood of intra-zonal congestion particularly in the periods when zonal energy prices are likely to high. Zonal energy prices are likely to be high particularly during the periods when total ISO load is high, so that this scheme provides the greatest incentives to eliminate intra-zonal congestion during periods when the incentives other market participants have cause intra-zonal congestion are greatest. In exchange for taking on the task of eliminating intra-zonal congestion, RMR unit owners are paid an up-front annual payment which is determined through a competitive bidding process.

2. Market-Based Intra-zonal Congestion Management Scheme

The second proposed intra-zonal congestion management scheme treats decremental energy supplied for congestion mitigation as if it was a deviation from the generator's hour-ahead schedule. All decremental measures taken to relieve intra-zonal congestion are settled at the ex-post hourly real-time price. During any period when the unrestricted zonal incremental energy market fails to clear (bids must be skipped over to relieve intra-zonal congestion), incremental energy would be provided by RMR unit owners at their variable cost, similar to the previous proposal. However, if this RMR unit's variable cost is above the current zonal price, then this variable cost will set the zonal market-clearing price. Under this proposal, decremental bids would be used to determine the order in which out-of-sequence bids are used to decrement units able to relieve intra-zonal congestion.

This scheme provides very strong incentives for all market participants not to attempt play to the so-called decremental energy game described earlier. This is because all generators know that if they cause intra-zonal congestion and must be decremented, there may be a corresponding generator in that zone who is incremented to maintain balance within the zone. The ten-minute price must also be above this generator's bid in order for it to be dispatched in unrestricted zonal market. Consequently, a generator playing the decremental energy game faces a significant risk of having to buy back energy at an ex post price that is significantly above the day-ahead energy price or other energy price its day-ahead energy schedule was hedged at. In those instances when an out-of-bid-sequence call must be made for incremental energy, an RMR unit would instead be used to provide this energy. Even in this case the decrementing generator faces the risk that this RMR unit's variable payment rate will set the zonal price.

The downside of this scheme is that because all intra-zonal congestion must be mitigated as imbalance energy and generators can only be called to supply energy if the real-time price is above their bid price, there are concerns about the potential exercise of market power in the incremental energy market. However, existence of the RMR energy backstop in the those instance when an out-of-bid-sequence call would be required for incremental energy limits the extent of market power than can be exercised to the variable cost of the RMR unit owner able to relieve the intra-zonal congestion. In addition, working against this incentive of one or a small number of generators to exercise market power in selling real-time energy is the incentive of generators on the decremental side of market who stand the risk of having buy back imbalance energy at the real-time price. These market participants would like to reduce to the zonal price of energy during that hour to reduce the costs of selling back their decremental energy. Because every congested intra-zonal interface has generation on the other side of it, this scheme always has a market participant with an incentive to limit the likelihood of intra-zonal congestion.

F. New Zone Creation Recommendation

The evidence presented earlier on the impact of zonal market clearing on ancillary services prices argues in favor keeping as few zones as possible in the California market. Implementing either of the intra-zonal congestion mitigation recommendations described above should significantly reduce the incidence of intra-zonal congestion, thus eliminating the necessity of undertaking the costly process of creating a new congestion zone. Embarking on a new zone creation process for the Path 26 interface may solve this problem at the expense of significant market power when there is inter-zonal congestion on paths across the newly created zones. In addition, the ISO may ending up having to create more congestion zones in the near future as a result of more market participants being able to exploit the flaws in the current intra-zonal congestion management protocols. A superior strategy seems to be to first implement a revised intra-zonal congestion management protocol. Then monitor the incidence of intra-zonal congestion to determine if the creation of a new zone is necessary under these protocols. This strategy eliminates the very significant risk of increased market power when there is north to south congestion across the zonal interface between NP26 described above.

Only if the ISO management and Board feels that the improvements in system reliability along Path 26 as result of creating a new zone significantly outweigh the increased market power risks from creating a zone should this new zone be created without some period of observation of the interface under the revised intra-zonal congestion management protocols.

G. New Generation Connection Policy Recommendation

As the above discussion has hopefully made clear, without changes to the current intra-zonal congestion management protocols, any new generation connection policy is not likely to lead to the geographic distribution of new generation entry and transmission upgrades that will enhance the efficiency of the California electricity market. Consequently, it seems prudent to incorporate into any proposed new generation connection policy a revised set of intra-zonal congestion management protocols. Without a clear statement of these new congestion management protocols, it will be extremely difficult to assess the efficiency properties of any new generation connection policy.

To this end, it our understanding that the ISO management is in the process of formulating revised intra-zonal congestion management protocols that are largely consistent with the recommendations for revising the existing intra-zonal congestion management protocols given above, and these protocols will be included in its New Generation Connection Policy filing.

10. Transmission Pricing and Firm Transmission Rights (FTRs)

We continue to have concerns about the release of FTRs with scheduling priority for all available capacity, as required by the FERC in its May 3, 1999 order. Such FTRs are not required in order for market participants to be able to hedge congestion risks; such hedging can occur using purely financial transactions. The release of this magnitude of FTRs also will tend to make the ISO's markets for inter-zonal congestion, using adjustment bids, thinner and more volatile. Furthermore, the concentrated ownership of FTRs with scheduling priority could well enable some companies to obtain market power over transmission rights, with adverse implications for energy markets themselves.

Given that plans are well along for the release of these FTRs with scheduling priority, we strongly favor imposing *position limits* on these FTRs. Position limits are ultimately a way of preventing any one entity from assembling a dominant position in the provision of transmission over a congested interface, with the market power dangers attendant to such a position. Put simply, we regard it as prudent to begin the FTR experience by flatly prohibiting the monopolization of FTRs that include scheduling priority. Indeed, if a dominant position in FTRs would yield genuine market power, economic theory warns that a single player would have the incentive to assemble just such a position, to the detriment of those who are likely to require transmission across the interface during congested period of time. With a position limit equal to 40% of the available transmission capacity, for example, we do not believe that legitimate business uses of FTRs are likely to be blocked in any significant way, yet no one company could assemble a dominant FTR holding on a specific interface.

We realize that a imposing position limits requires a certain degree of monitoring and reporting regarding FTRs. Certainly, meaningful compliance would require monitoring of the secondary market for FTRs, not just the transactions associated with the initial release of FTRs. To simplify compliance, secondary FTR transactions could be subject to self-reporting, with the ISO performing after-the-fact verification of the accuracy of such reports, imposing penalties and sanctions in cases of non-compliance. It is our understanding that with self-policing and after-the-fact verification of compliance, information from the ISO's Secondary Registration System (SRS) could be used with few changes or additions.

We will, of course, have more to say about FTRs by December 1, 2000, when the FERC has instructed us to file a report on the experience with FTRs. Certainly we will be better able to assess the impact of FTRs if we are able to monitor FTR holdings. We also hope to observe how FTRs are being used, to determine whether in fact there are legitimate business purposes that might require relatively concentrated holdings, e.g., in excess of 40% of the available transmission capacity.

We realize that possible abuses of FTRs are just that—possible but not proven, and perhaps not even all that likely. But our experience with the transition to competitive markets to date has shown us that many market participants are sophisticated and quite able to maximize their profits subject the regulatory rules constraining their behavior. Because we see no compelling reason why large assemblages of FTRs are needed, and because we remain relatively ignorant of how these FTRs will actually be used, we believe that California consumers will be best served by at least starting the FTR release with meaningful position limits and reporting requirements in place.

11. PG&E Divestiture

PG&E controls over 4,500 MW of hydroelectric capacity in Northern California of which approximately 3,500 MW is subject to divestiture. This capacity spans five major watersheds and includes the 1,200 MW Helms pumped storage plant. As a number of observers have pointed out, this capacity is an extraordinarily valuable asset both for PG&E and for the electric power system in California. PG&E ownership of the hydro system, even after divestiture of its fossil units, is sufficient to give it market power over provision of ancillary services under certain load conditions, and over PX energy prices when transmission paths into Northern California are constrained. At present, PG&E has strong incentives to use its hydro capacity to constrain rather than raise prices, because it is still subject to the rate freeze and CTC recovery mechanism. However, once the hydro assets are divested under California's restructuring plan, the new owner or owners will have every incentive to do the opposite, potentially exacerbating volatility and above-competitive prices in these already concentrated markets.

A number of competing proposals have been advanced by PG&E and others for divesting the hydro system. PG&E originally proposed to divest the major part of the system to an unregulated subsidiary. The California legislature has not accepted this proposal and PG&E reportedly is proceeding to sell the system off to unaffiliated buyers.

The timing and terms of the sale are important to the successful functioning of the Northern California power market. The proceeds of sale of the facilities are likely to be well in excess of book value of the facilities. The value over book will reduce the balance of PG&E's CTC account and reduce the time until a more competitive retail market in PG&E's service area exists by hastening the of end PG&E's CTC recovery and rate freeze period.

The terms of the divestiture transaction are equally important. As the ISO's Department of Market Analysis has pointed out, selling the assets to a single buyer or to a buyer that owns other fossil-generating units in Northern California, can increase the likelihood that generation owners can exercise market power in the ancillary services markets. (The DMA paper is attached as Appendix B). The DMA suggests alternative structural, contractual and "behavioral" measures to migrate potential exercise of market power. The Committee concurs in the DMA's assessment that the terms of this divestiture (which ultimately will have to be approved by the Commission under §§ 8 and 203 of the Federal Power Act) are critical to the functioning of California's ancillary services markets, and that effective market power mitigation measures must be put in place. The Committee's view is that "behavioral" mitigation measures (such as bidding rules and minimum capacity availability requirements) are complex and difficult to enforce. Structural mitigation measures, such as a requirement that the hydroelectric systems be sold off on a watershed-by-watershed basis to separate companies that are independent of major owners of Northern California generation, are better designed to effectively mitigate market power, and are the preferred coverage. For this reason we strongly recommend the assets be divested on a watershed-by-watershed basis to a buyer unaffiliated with PG&E or other major generation owners in Northern California. Structured in this manner, the divestiture of PG&E's hydro system can decrease, rather than increase market power in California's wholesale electricity market.

12. Maximum Purchase Price Caps

The Commission's May 26 Order (Redondo Beach Docket No. ER98-2843-005 et. al., May 26, 1999) allows the ISO to retain its current authority to set maximum prices at which it will purchase ancillary services and imbalance energy only until November 15, 1999. After that date, the ISO's authority to set maximum purchase prices, which the Order refers to as "price caps", will be eliminated.[19] The ISO sought rehearing of the May 26 Order and on September 17, 1999, filed tariff amendments which; if approved, would extend the maximum purchase price authority until through November 15, 2000. On August 26, 1999, the ISO Board also took action under its existing maximum purchase price authority to increase the price limits on ancillary services from $250 to $750 effective October 1, 1999. If its authority is extended for 12 months as requested, the price limits will stay at this level unless the ISO makes a subsequent determination to change them.

[19]The term "price cap" may be a misnomer since it is authorization for the ISO to decline to purchase ancillary services and real-time energy when bid prices exceed a particular level, not a limit on what generator can bid into the market. When the ISO sets maximum purchase prices, it specifies the highest price it will pay for ancillary services. Generators are free to sell real-time energy or ancillary services at a higher price if they can find a buyer (such as a self-providing SC or an out-of-state purchaser).

On June 24, 1999, the ISO's Market Surveillance Committee and the PX Market Monitoring Committee ("MMC") submitted a joint memorandum to the ISO and PX in which the two Committees stated that they concurred with the FERC that the then-current $250 purchase-price limits on ancillary services and imbalance energy should be raised as soon as possible consistent with the maintenance of competitive markets for electricity in California. The Committees stated, however, that they strongly believed that the price caps should not be raised until the ISO's redesign of its ancillary services markets and the reform of the Reliability Must-Run ("RMR") contracts were fully implemented. In their view, setting a date certain for the removal of the price caps that is independent of the completion of these necessary redesign and reform efforts, leaves the California markets unprotected from massive unanticipated price movements that could arise from market-design flaws or the exercise of market power.[20]

The MSC has been extremely reluctant to recommend imposing purchase-price caps on the energy and ancillary-services markets in California. However, we continue to have concerns about the competitiveness of the California energy and ancillary-services markets, as we have detailed in Sections 3 and 4 of this report. For that reason, we believe that until the market-design problems identified in our prior reports are remedied and it is clear that any remaining generator market power has been mitigated, purchase-price limits should be retained on the imbalance-energy and ancillary-services markets. The Committee also believes that until there is sufficient confidence that the structure of the California wholesale electricity market allows unrestricted market forces to yield efficient results, there will still be a need for a maximum purchase price limitation or other mechanism by which the ISO and the PX can facilitate the smooth functioning of the market and protect California consumers from inefficiently high prices for energy and ancillary services.

As the MSC has emphasized in this report and in its August 1998 and March 1999 reports to the FERC, the California markets for energy and ancillary services are highly interdependent. In particular, given the sequential structure of the California electricity markets, expectations about prices in the ancillary-services markets have a major impact on prices in the PX day-ahead market, and the expected price for imbalance energy has strong effects on the energy prices in both the PX day-ahead and day-of markets. Consequently, the PX is heavily dependent on the ISO's authority to establish maximum prices that it will pay for real-time energy, and on the ISO's exercise of any such authority. Since a price limit in the ISO real-time energy market will effectively serve as a price constraint on the PX day-ahead and day-of energy markets, the ISO's authority to establish maximum purchase prices for ancillary services and imbalance energy protects both sets of markets.

[20]The Committees also stated that the specific choice of a November 15, 1999 termination date was especially problematic because the second stage of the RMR reform cannot be completed before December 1st, even if the ISO files the necessary changes on the earliest date it can, October 1st, because of the 60-day notice provision of the Federal Power Act.

Finally, although the California electricity market is unique in some respects, the MSC believes that the issues of market-supporting interventions that now face the ISO and the PX in California have arisen and will continue to arise in other newly deregulated electricity markets that are emerging in other parts of the U.S., particularly in New England. The Committee believes that the FERC should deal with these questions now in a way that will have general application and not wait to address these issues in the context of emergency situations that are very likely to arise in different jurisdictions.

In the remainder of this section we discuss the need for market protecting interventions and, in particular, the basis of our recommendations to retain for the next 12 months, the maximum purchase price limits for ancillary services and imbalance energy in the California electricity markets.

A. The Role of Purchase-Price Caps

With a strong consensus among market participants that all the flaws in the design of the markets for energy and ancillary service had been eliminated, with a large number of consumers purchasing energy or ancillary services at the hourly spot price, and with a fairly full and robust set of forward and financial contracts available to market participants, there would be very little reason to consider price-intervention mechanisms in the California electricity market. But the California market presently falls far short of this. In the near term, until the market-design problems that have already been identified are remedied, there is a continuing need for the ISO to have authority to set maximum purchase prices. In the longer term, when those design flaws are corrected but price responsive demand and robust markets for forward and financial contracts are not yet fully developed, the ISO will still need a mechanism to ensure orderly and efficient markets for energy and ancillary services. That is, once the current price caps are lifted, the ISO must retain some residual authority to intervene during market emergencies to limit the prices it will pay for energy and ancillary services.

1. Market Flaws Remain

The California market for electricity has been in operation for 18 months. Although the Committee hopes that the most market-design flaws have been identified, only experience with the new market design when all the necessary changes have been implemented will enable us to determine whether more problems remain. Some flaws create opportunities that can produce extremely high prices, and without a damage-control purchase-price caps, there is no limit to how high these prices could go.

If the ISO lacks the authority to limit the prices at which it purchases energy or ancillary services, it will be forced as it was in July 1998 to accept bids of $5,000 or $9,999 per MWh for ancillary service, even in times of moderate demand and ample supply. A market perturbation in thin ancillary services markets -- such as the one that occurred on May 30, 1999–could have extraordinary impacts on prices and costs. In that case, the unavailability of one large hydroelectric facility drove regulation prices to $250 for 10 hours. For those 10 hours, regulation capacity costs totaled $4.1 million. If the ISO had not had authority to limit the price at which it purchased regulation, and the market had cleared at $5000 as it did on July 9, 1998, California consumers would have had to pay 20 times more than they did for the service. This would come to more than $80 million for one day. Had the market cleared at $9,999 (as it did on July 13, 1998), the cost to consumers would have been almost 40 times more than it was. Market perturbations in the broader PX markets, such as the one that occurred on October 1, 1999, and is described in Section 3, can have even greater consumer cost impacts.

The Commission's May 26th Order leaves the ISO with no residual authority to cope immediately and directly with severe market perturbations that may occur after November 15th. Unless the Order is modified, it effectively requires the ISO to return to the FERC to seek remedial authority after any problem occurs. By the time the Commission acts on such a request, California consumers may have incurred many hundreds of millions of dollars in higher energy costs.

2. *The Importance of Price-Responsive Final Demand*

As we discuss throughout this report, an essential element of a smoothly functioning competitive market for electricity is a price-responsive demand-side of the market. When final customers--residential, commercial, and industrial--can respond in real-time to spot prices for energy and ancillary services, the market itself provides an appropriate and effective check on the ability of supply-side participants to raise prices to inefficient levels. Until the demand-side of the market becomes much more price responsive, there need to be other checks on the exploitation of market-design flaws and the exercise of market power; market-intervention measures by the ISO are a prime candidate.

3. *The Need for Forward Contracts*

The current California market rules present various impediments to consumers who might try to set an implicit purchase-price cap in the energy and ancillary services market through creative financial forward-contracting schemes, just as those rules diminish the effects of actions by those who might financially benefit from shifting their consumption in response to hourly electricity prices. Consequently, without some changes in these market rules and some period of time to adjust to such changes, it would be inadvisable to remove the ISO's ability to invoke some damage-control market intervention in its energy and ancillary services markets.

4. *Legal Sufficiency*

Because it leaves California consumers unprotected from exercise of market power by generators selling into the state's electric power market, the Commission's current policy with respect to maximum purchase price raises fundamental questions of legal sufficiency. All generators in California (other than Federal and state agencies and municipalities) that sell energy or ancillary services to the ISO or PX are "public utilities" under the Federal Power Act because they make sales for resale in interstate commerce. 16 U.S.C. § 824(e). Under §§ 205 and 206 of the FPA, 15 U.S.C. §§ 824d and 824e, the prices at which these sales are made must be "just and reasonable." The Commission has removed cost-based price caps on these generators' sales and allowed them market-based rates, after making an explicit finding in each case that the generator cannot exercise market power over generation or transmission and cannot erect other barriers to entry by competing generators.[21] If the Committee's analysis presented in this report is correct, the predicate for allowing market-based rates may be incorrect. The Committee's analysis indicates generators are capable of exercising market power at certain times in some markets. Under well established precedent, seller rates need not be regulated if, but only if, regulation of the buyer is sufficient to ensure just and reasonable rates. FPC v. Texaco Inc., 417 U.S. 330 (1974). For that reason, in a circumstance where sellers have market power, the Commission need not regulate the sellers rates directly by imposing cost-based price caps on the sellers, so long as it can assure itself that buyers will be able to discipline sellers' market power. Giving buyers (in this case the ISO and PX) authority to impose maximum purchase price limits is one mechanism for doing so. However, we fail to see how the Commission, in the face of significant evidence of the exercise of market power by generators in the California markets, can remove all price caps on sellers and at the same time disable the ISO as buyer, from protecting itself and California consumers from the exercise of seller market power. The Supreme Court in the Texaco case reiterated that no particular rate-making methodology is required under the just and reasonable standard of the Natural Gas Act. Texaco 417 U.S. at 338. That standard is identical to the just and reasonable standard in §§ 205 and 206 of the Federal Power Act. Under both statutes, the Commission and the courts look to the end result. FPC v. Hope Natural Gas Co., 320 U.S. 591, 602 (1944).[22]

According to legal analysis provided to the MSC, the Commission cannot lawfully abandon its statutory duty to assure that the mechanisms it adopts result in just and reasonable rates under FPA §§ 205 and 206. It has no general authority to waive this fundamental requirement. Market- based rates can be consistent with the statute only in the absence of market power. Thus, "[t]he Commission allows power sales at market-based rates if the seller and its affiliates do not have, or have adequately mitigated, market power in generation and transmission and cannot erect other barriers to entry."[23] This approach is endorsed by the courts. Cajun Elec. Power v. FERC, 28 F.3d 173, 176 (D.C. Cir. 1994); Elizabethtown Gas Co. v. FERC, 10 F.3d 866, 870 (D.C. Cir. 1993). The Commission acts unlawfully, however, if it seeks to stimulate supply "by sales freed from meaningful regulation"[24] that do not assure just and reasonable rates. FPC v. Texaco, *supra*; c*f.* Farmers Union Cent. Exchange, Inc. v. FERC, 734 F.2d 1486, 1502-1504 (D.C. Cir. 1984). (". . . [V]irtual deregulation of oil pipeline rates oversteps the proper bounds of agency discretion under the 'just and reasonable' standard").

[21] AES Huntington Beach, L.L.C., 83 FERC ¶ 61,100 (1998); AES Huntington Beach, L.L.C., 83 FERC ¶ 61,358 (1998); Long Beach Generation, L.L.C. et al. 84 FERC ¶ 61,011 (1998); Ocean Vista Power Generation, L.L.C., 84 FERC ¶ 61,013 (1998).

[22] "Under the statutory standard of 'just and reasonable ' it is the result reached, not the method employed, which is controlling." Id.

[23] AES Huntington Beach, L.L.C., 83 FERC ¶ 61,100 at p. 61,481 (1998).

[24] Consumer Federation of America v. FPC, 515 F.2d 347, 360 (D.C. Cir. 1975).

Here, the opportunities for the exercise of market power, will, in the absence of price caps, produce unjust and unreasonable rates in violation of the statutory standard. As this report points out, in July of 1999 total wholesale energy purchase costs were estimated to be 20% in excess of the pure competitive market benchmark.

5. Position on Board Action

The Committee is strongly of the view that the ISO needs continuing authority to impose maximum purchase price limits and at least temporarily to keep the current limits in place. For that reason, the Committee supports the ISO's September 15 tariff filing and most elements of the ISO Governing Board's August 26, 1999, price cap resolution.

Under that resolution:

1. The price caps in Ancillary Service and Imbalance Energy markets would be raised from $250 to $750 (per MW or MWh, respectively), effective September 30, 1999;

2. The price caps will be reduced to $500 effective June 1, 2000 if the ISO Governing Board determines, based on a report from ISO management, that:

   (a) the markets are not workably competitive;
   (b) there are not practicable demand side management options in place; or
   (c) the IOU Utility Distribution Companies have sought and not obtained practicable options to self-provide Ancillary Services and applicable hedging products in the Power Exchange consistent with California Public Utilities Commission Preferred Policy Decisions;

3. ISO Management is authorized to lower price caps in a market without Board action upon Management's assessment that the affected market is not workably competitive, provide that Management promptly notifies the Board of its action and presents supporting analysis to the Board (the Safety Net"); and
4. ISO Management is directed, after completion of the summer of 2000, to analyze the results and recommend to the Board an implementation plan to eliminate price caps.

6. Conclusion on Maximum Purchase Price Caps

With respect to maximum purchase prices:

1. The Committee recommends that the ISO raise its maximum purchase price limits to $2500 as soon as market conditions permit.

2. The Committee supports the ISO's request for a one-year extension of its authority to maintain maximum purchase prices, and its increase of maximum purchase prices from $250 to $750 effective October 1, 1999. The caps should be left at this level for a full 12 months unless the ISO exercises Safety Net authority to lower them.

3. The Committee supports the ISO's Safety Net recommendation – (the ability of the ISO management to lower caps temporarily to deal with market disruptions).

4. The ISO should review the need to continue maximum purchase price limits after the summer of 2000.

5. Even if maximum purchase price limits are ended after summer of 2000, the ISO should retain "safety net authority" thereafter.

13. Workable Competition and New Zone Creation

Our ultimate aim is to help assure that the various electricity markets[25] in California perform in an efficient fashion, bringing reliable electricity to consumers at least cost over the long run. If these inter-related markets are as close to this ideal as can be expected in practice, we say they are "workably competitive." The concept of a market being "workably competitive" is clear enough: we do not expect "perfect competition," i.e., price-taking behavior by all market participants, but neither does any one firm enjoy significant market power; nor is there collusion permitting the collective exercise of market power. But how is this concept to be made operational in California's electricity markets?

Beyond the general interest in assessing whether competition is "working" in California's electricity markets, for the purposes of creating new zones to manage congestion, the ISO is required to assess whether the market for electricity generation in each of the two new proposed zones is "workably competitive" a substantial portion of the time. We indicate here the steps we believe should be followed in making such an assessment.

A. General Principles

In a market for a homogeneous good such as electricity, the ideal of *perfect competition* is easily defined: each supplier, acting independently and lacking the ability to affect the market-clearing price, maximizes its own profits by bidding in its generating units at marginal cost. Likewise, each buyer, also acting independently and lacking the ability to affect the market-clearing price, bids in its demand at its willingness-to-pay.[26]

[25] The principles articulated here apply equally to markets for ancillary services, or transmission rights for that matter, to markets for energy itself.
[26] Even if the supply side of a market is highly competitive, the buyer(s) could still exert monopsony power. Under perfect competition, both buyers and sellers are price-takers.

The resulting equilibrium prices and quantities are efficient in two senses: (1) least-cost production of the electricity that is actually produced, and (2) the quantity of electricity maximizes total net value (benefits to buyers less cost of production).

In practice, this ideal can only be approached, raising the question of how "close" a given market must be to the ideal for us to declare victory and characterize that market as "workably competitive." Economists have been grappling with the concept of "workable competition" for over 50 years, and have yet to identify a set of diagnostics that can be applied to determine reliably whether or not a market is in fact "workably competitive."

While some market participants and observers may seek a simple formula or bright-line test to determine whether an electricity market is "workably competitive," we do not believe that any formulaic approach is likely to be reliable. Just as the Department of Justice and the Federal Trade Commission regard market shares as a *starting point* for evaluating the effects of horizontal mergers, not the end of the analysis, we favor an approach that looks at a variety of market indices, and may incorporate substantial institutional detail, for assessing the state of competition in a given electricity market.

This is not to say that the proper inquiry is unpredictable or unfocused. To the contrary, we believe that research findings and practical experience from both antitrust and regulatory spheres provide substantial guidance for assessing the state of competition in a given electricity market.[27] Drawing on that body of knowledge, and on our own experience evaluating competitive conditions, we sketch here some of the key questions that we believe should be addressed when determining whether a given electricity market is "workably competitive.[28]" We express these tests through a list of (cumulative) conditions that tend to support a conclusion that a given electricity market is "workably competitive." This list is intentionally designed to apply to short-term bidding markets for a homogeneous good subject to substantial fluctuations demand, in which a market-clearing price (MCP) is determined through the equating of supply and demand.

B. Significant Quantity is Bid But Not Called

If there is a "thick" stack of bids at prices just above the MCP, it is unlikely that any single supplier can exert meaningful control over price. If Supplier X were to attempt to withhold its capacity, or raise its bid, the MCP would change little if at all: Supplier X's electricity (or capacity) would simply be replaced with electricity (or capacity) bid by others at or near the MCP.

[27] See Severin Borenstein, "Understanding Competitive Pricing and Market Power in Wholesale Electricity Markets," University of California Energy Institute, August 1999, for a well-reasoned discussion of pricing and investment decisions in competitive electricity markets.

[28] We focus here on "workable competition" among suppliers, assuming that monopsony power is not a significant problem, either because demand is unconcentrated or because buyers are unable to reduce demand to depress prices. However, the same principles developed here can be used to assess buyer power in electricity markets.

For a given set of bids by suppliers, it is relatively straightforward to determine the (residual) demand curve facing any given supplier: if that supplier raised its bids, or reduced its supply, what would be the impact on market price? In general, if a single supplier (a) has a significant market share, and (b) has the ability to materially affect the MCP through its bidding behavior, that supplier is likely to possess some meaningful market power. Using bid data, the ability of any single market participant to elevate the MCP can be directly estimated.

The ISO's Department of Market Analysis (DMA) has developed a summary measure, called the "Residual Supply Index" ("RSI"), that partially captures the "thickness" of the stack of bids above the MCP. (See *Annual Report on Market Issues and Performance,* California ISO, June 1999, pages 7-4 through 7-20.) Define "Bid Sufficiency," B, as the ratio of total quantity bid (at the highest allowable price) to the total quantity demanded (taken as fixed, i.e., independent of price). Define the "share of supplier X," S_X, as the quantity bid by supplier X as a fraction of total demand. The RSI for a given supplier is then defined as $RSI_X = B - S_X$. The RSI is meant to capture the sufficiency of suppliers *other than X* to meet demand. A high value of RSI_X thus tends to indicate that supplier X lacks market power.

We agree with the DMA that their RSI can be a useful way of summarizing "bid sufficiency" in a given electricity market at a given point in time. However, we should point out that a high value of RSI may be consistent with significant market power *if the supply bids are well above the MCP*. For this reason, the RSI seems better suited to evaluating whether the market is in danger of not clearing at all (due to bid insufficiency) rather than assessing the degree of market power of any individual supplier.[29] Put differently, there is no reason to restrict attention to a summary measure such as the RSI for the purpose of assessing market power when we have available the full set of bids. We believe that this is also the position of the DMA, which proposes to use the RSI for screening purposes when the information, the resources, or the time is not available to conduct an in-depth study of market power. DMA has also proposed a refinement which will examine RSI for bids under certain price level, such as $100/MWh. This can help to address the question whether the supply bids are well above MCP.

C. Bids are Close to Marginal Cost

The strongest single piece of evidence that a given supplier lacks market power is the observation that this supplier bids its energy and/or capacity into the market at or near

[29] The DMA offers a classification system (see p. 7-4) in which a Bid Sufficiency of greater than 150% indicates "Low Potential Market Power." While we agree that the RSI can be a useful and practical indicator of likely market power, and an RSI of greater than 150% may in practice be highly correlated with the absence of significant market power, we would prefer to look directly at the thickness of bids just at or above the MCP. Situations could arise in which there is ample Bid Sufficiency, but the rejected bids are well above the MCP. In this situation, one or more suppliers could indeed enjoy significant market power. Of course, if for some reason information about the level of bids above the MCP were not available, but the total quantity bid were available, the RSI could be observed, but not the ability of any individual bidder to elevate the MCP; in this situation, the RSI could well be the best observable measure of likely market power.

its marginal cost.[30] Although we can readily observe bids in California's electricity markets, we may have some difficulty comparing these bids to marginal cost if the latter is difficult to observe or estimate.

If a supplier bids some or all of its capacity into the market well above marginal cost, we ask ourselves why such a bid was more profitable than bidding at, or slightly above, marginal cost. The most likely answer is that this supplier believed it could (with some likelihood) cause the marginal to rise by raising its own bids. The larger is the supplier's share of the market, and the larger is the gap between the supplier's marginal cost and its bid, the greater is the inference of market power.

We hasten to add that we do not in any sense regard such bidding as objectionable; its is merely the result of profit-maximization by the supplier possessing some power over price (at least probabilistically). But the observation, or inference, that this supplier (and perhaps others) enjoys market power may well be relevant for policy decisions such as the lifting of a price cap or the creation of a new zone.

We also should emphasize that we would expect suppliers lacking market power to bid at marginal cost even during periods of peak demand. What is different during peak periods is that more costly units (as measured by marginal cost) are active, which requires a higher MCP. Units with lower marginal costs will thus enjoy the largest margins (between MCP and marginal cost) during these periods. Naturally, the frequency and intensity of these peak periods affects investment incentives.

Some commentators have pointed out that in many markets firms are unable to recover their fixed costs if they price at marginal cost, suggesting therefore that to view prices in excess of marginal cost as indicative of market power must be faulty. We have two main responses to this assertion. First, the mere fact that a supplier bids marginal cost does not been that the price *received* by this supplier equals marginal cost. To the contrary, the MCP exceeds the bids of all suppliers except the marginal supplier(s), i.e., those with the highest bids that are accepted. So most suppliers most of the time will receive a margin equal to the gap between the MCP and their marginal cost (which equals their bid) under competitive conditions. Second, in many other markets where a supplier's bid indeed determines the price it receives, we have *differentiated products*, so individual firms are not price-takers. It is usually recognized that these firms—from restaurants to manufacturers of branded consumer goods to publishers of movies and computer software—indeed have some technical market power (but usually not any meaningful market power for antitrust purposes), and that this is a necessary reward for incurring the fixed costs necessary to produce a differentiated product valued by consumers. We do not explore this point further here as the markets of concern to us involve homogeneous goods; we merely wish to point out that drawing analogies between bidding markets for a homogeneous good and posted-price markets for differentiated products is perilous.

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[30] By "marginal cost" we mean the true (economic, not accounting) incremental cost of fulfilling the bid. For a supplier that is capacity-constrained, the marginal cost may be an opportunity cost, e.g., of not selling that same power or capacity in another market.

D. Supply is Not Concentrated

Market concentration is the single most commonly-used measure of whether a market is "competitive" or not. In many antitrust cases, for example, including both mergers and monopolization cases, both the antitrust enforcement agencies and the Courts look to market shares as a measure of market power.

We certainly believe that market shares, and market concentration, are important measures in electricity markets as well. However, we would like to stress that market shares are usually employed as a *proxy* for market power *because the direct measurement of market power is difficult or impossible with available data*. Happily, we have excellent data about prices and quantities in California's electricity markets. So, we regard market shares as a useful additional measure, but not the very best available measure of market power in California's electricity markets. Our preferred measures are those two indicated just above: the "thickness" of bids at or just above the MCP, and the (percentage) gap between various suppliers' bids and their marginal costs.[31]

E. Buyers are Flexible

Market power by sellers is inevitably reduced if buyers have the flexibility to reduce their demand in the presence of high prices and/or to turn to other sources of supply (either a substitute product or the same product provided from a different geographic area).

So far, wholesale buyers of electricity in California have sadly little ability to reduce demand in the presence of high prices. And the ISO has very little ability to reduce its demand for ancillary services or real-time energy given its duty to meet various reserve requirements and assure grid reliability. The fact that demand is extremely inelastic (insensitive to price) in the short run in most of California's electricity markets is arguably the single most important factor *preventing* these markets from being "workably competitive."

F. There Are No Unnecessary Institutional Barriers to Rivalry or to Demand Flexibility

Given the elaborate regulatory regime in place in California's electricity markets, it is all too easy for regulations to impede "workable competition." We have previously expressed concerns about the Reliability-Must-Run rules and the impact they have on bidding behavior; hopefully the new arrangement for RMRs will greatly alleviate those

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[31] Having said this, we hasten to add that we expect firms with relatively large market shares to be precisely the ones that enjoy and exercise market power. Basic economics tells us that the optimal markup of price (bid) over marginal cost depends directly upon the number of "infra-marginal" units sold by the supplier in question, i.e., units of output that would be sold at a slightly lower bid. The number of such units can be considered proportional to the supplier's market share. However, a supplier with a small market share *could* have power over price if that supplier is the marginal supplier (at the MCP) and there are few bids just above the MCP.

concerns. We have previously expressed concerns that the tariff governing the ISO has limited the ISO's flexibility as a buyer of ancillary services and thus made it harder for competition to work; hopefully the new "Rational Buyer Protocols" will go far to address those concerns. But these are merely two examples of how various institutional rules or regulations can serve to exacerbate market power problems. Generally speaking, an assessment of whether a market is "workably competitive" will include an evaluation of whether there are institutional features that reduce rivalry among actual and potential suppliers, or than hinder buyer flexibility.

G. Collusion is Difficult

Collusion has no place in a "workably competitive" market. If collusion is easily achieved, or at least a dangerous probability (e.g., because of a concentrated market structure or because the suppliers have ample opportunities to meet and reach illegal agreements), a market may fail to be "workably competitive." To date, we are not aware that collusion has been a major problem in California's electricity markets, but consumers, regulators, and the California and Federal antitrust agencies must, as always, be vigilant about detecting and punishing any price fixing or market division agreements.

H. Entry into the Market is Easy

The final factor that should be considered in evaluating whether a market is "workably competitive" is the ease of entry into that market. In California's electricity markets, we would expect entry typically to come in one of two ways: (1) the supply of energy or ancillary services from outside the State (these suppliers would just as well be called market participants as "entrants"), and (2) the construction of new generation facilities. Evaluation of these two types of entry is quite distinct. The ability of imports to come in California in increasing quantities as needed is the key to evaluating that type of entry. And the entry obstacles and costs faced by new generators are key to the second type of entry. Of course, entry by new generators is more likely to undermine market power in the long run than in the short run.

I. Application to the Creation of New Zones

Section 7.2.7 of the ISO Tariff contains provisions for the creation, modification, and elimination of zones. The Tariff lists two main necessary conditions for the creation of a new zone within an existing zone: (1) the presence of significant congestion on a path within that zone; and (2) the existence of workably competitive generation markets on both sides of the corresponding interface for a substantial period of the year.

As an example, intra-zonal congestion on Path 26 recently satisfied the first criterion for the creation of a new zone. Thus, it became necessary to assess whether generation markets on both sides of Path 26 were in fact "workably competitive."

Applying the methodology above to this example, we would look at the demand and supply of energy and ancillary services on both sides of Path 26 to see if there were a “thick” set of bids just above the MCP, after segregating supply and demand on the two sides of Path 26. We would also look at the margins between bids and (estimates of) marginal cost for generators on both sides of Path 26.

Both of these tests can be conducted under various load and congestion conditions. For example, conditions may vary depending not only upon load but upon the presence, degree, or direction of congestion on Path 15.

14. Appendix A

ISO MARKET SURVEILLANCE COMMITTEE OPINION ON FIRM TRANSMISSION RIGHTS PROPOSALS

The Market Surveillance Committee (Frank Wolak and Carl Shapiro), and its advisors (Robert Wilson, and James Bushnell) have analyzed the current two proposals for the creation of firm transmission rights (FTRs) for the California electricity market.

It is the opinion of the Committee that the issuance of a set of FTRs with an aggregate capacity equal to 100% of the current physical capacity of the system could potentially lead to several serious, negative consequences to electricity consumers in California. The committee is particularly concerned about the allocation of FTRs that include a scheduling priority to be invoked when the ISO adjustment markets do not clear. There is concern that an issuance of such rights equivalent to 100% of transmission system capacity could eliminate the incentive of rights holders to participate in ISO congestion protocols and weaken the ability of the ISO to oversee the reliable operation of the transmission resources under its jurisdiction. Several negative consequences may ensue from a marginalization of the ISO's role in congestion management:

1. The transparency of transmission prices could be seriously reduced or eliminated. The lack of a transparent and reliable price signal for transmission congestion could undermine the ability of both producers and consumers to effectively participate in a regional market. Without clear signals about the costs of moving power throughout the California grid, decisions about where to locate new generation or what transmission paths should be upgraded and when become extremely difficult to make. Market participants will be forced to make decisions that affect congestion costs without a clear idea of what these costs are.

2. The movement of the majority of transmission market transactions to secondary, and perhaps non-transparent markets may seriously impede the ability of the ISO and other institutions to monitor market abuses in transmission, energy, and ancillary service markets. More importantly, the ISO would lose the ability to monitor FTRs holdings, and therefore find it significantly more difficult to detect the exercise of market power that arises from concentrated holdings of FTRs, until that market power has actually been used.

3. The potential lack of price-transparency and concentration of scheduling priorities may lead many non-rights holding consumers and producers to shift their scheduling decisions from day-ahead markets to real-time markets. Significant differences between day-ahead schedules and real time operations

would place increased strain on the ISO's ability to maintain reliability in the real-time balancing of the system.

While it is not certain that all, or any, of these negative consequences may actually arise, there is sufficient concern to warrant a cautious approach to the issuance of FTRs in this market. The committee recommends an initial issuance of FTRs equal to no more than 1/3 of the aggregate capacity of the associated transmission interfaces. These rights would have a duration of one year. If needed, to provide adequate incentive for the owners of existing transmission contracts (ETCs) to convert their rights and enter the ISO system, 100% of the capacity of these ETCs could be converted to FTRs upon entering the ISO system, if this initial level of FTRs is not found to cause serious market power and system reliability problems. After this one year experiment, there should be a rigorous assessment of: (1) the performance of the market for evidence of market power, (2) the impact of the FTRs on congestion management, and (3) the need for additional FTRs or the need to continue with these experimental FTRs at all.

The MSC and its advisors see no significant economic benefit to California consumers from giving scheduling priority to holders of financial transmission rights. Hedging inter-regional price differentials due to transmission constraints can be accomplished by purely financial transmission rights with no scheduling authority, if all scheduling coordinators submit incs and decs in accordance with the ISO's congestion management protocols. If scheduling coordinators submit sufficient bids on all links, congestion will be cleared and there will there no need to impose the default usage charge, and use the scheduling priority. Consequently, given the significant potential costs to the market and California consumers discussed above, a very cautious policy towards FTRs seems prudent at this time.

15. Appendix B

Divestiture of PG&E Hydro Resources and Market Power Mitigation
Anjali Sheffrin, California ISO Department of Market Analysis
August 6, 1999

Summary

The legislature has requested that we analyze the market power risks of several alternatives to the plan to transfer the entire PG&E hydro portfolio to a non-regulated subsidiary (the whole transfer). Since we do not know what the final divestiture design will be, we reviewed four possible divestiture scenarios and evaluated the potential market power risk of each. Based on our preliminary analysis, we believe that potential risks from alternative disposition of the PG&E hydro portfolio can be mitigated in each alternative. In each case, it will be necessary to have the flexibility to design measures to mitigate the specific risks that will emerge. It is important that legislation not attempt to prescribe one specific remedy in advance.

In analyzing the specific scenarios, we find there is an increased likelihood of market power if the divested hydro asset is owned by a market participant who also operates thermal or other generation resources in the California energy market. We expect there will be less chance that a participant could exert market power if the hydro asset is divested among many owners having no other generation resources. The key provisions of the principles proposed by PG&E and the ISO for mitigating market power for the whole transfer (the "Principles") can be applied to most of the divestiture scenarios. However, the specific percentage of minimum bid quantity requirement may need to be modified for different conditions. In the event that the new hydro owners also operate other thermal resources in the California energy market, the bid requirement should be extended to the combined portfolio of the new owner to effectively mitigate the potential for market power.

In designing market power mitigation, our overriding principle is to create correct incentives for market participants rather than relying on extensive and continuous monitoring and imposing quantity and price restrictions. The need for monitoring behavioral rules can become burdensome if there are numerous market participants subject to these restrictions. In those cases structural remedies such as divestiture to a large number of suppliers, or contractual remedies, such as requiring the output of the facility to be sold in advance so there is no profit from manipulating market prices, are worthy of consideration. In all cases, the ISO would require the flexibility to design the most effective rules.

<u>Background</u>

The traditional sources of market power in any market are inelastic demand in the market (demand not responsive to price changes) and concentrated supply with limited capacity. The ISO ancillary service markets face both of these problems. Ancillary services purchase quantities are fixed amounts based on reliability criteria and cannot vary in response to prices. As a result, the ISO's demand for ancillary services is inelastic. The available supply of ancillary services is also smaller than that for energy generation due to the requirement that generation units be able to immediately respond to dispatch instructions. The ancillary service capability is concentrated among few suppliers with PG&E hydro units being the dominant supplier in many hours of the ancillary service markets. These factors constitute the market power risk of hydroelectric generation operation.

There are three main options for market power mitigation in California energy market:

- Structural. Divesting hydro resources among a large number of suppliers.

- Contractual. Allowing contractual agreements, such as Contracts for Differences (CFDs), under which an owner, in effect, sells output at a fixed price under a long-term contract. Currently, CFDs cannot be used in California's markets due to CPUC restrictions on investor-owned utility loads entering into bilateral contracts.

- Behavioral Rules. Rules on bid quantities and prices like those proposed in the Principles developed by the ISO and PG&E.

The current ISO/PG&E Principles, proposed to apply to the transfer of PG&E's hydroelectric portfolio to an unregulated subsidiary, are an example of behavioral rules and include the following key provisions:

- Constraints on both price and quantity of bids in energy market and ancillary service capacity market;

- The new owner must to act as a "price taker" when it has market power to set prices for ancillary services (A/S)

- Minimum bid quantities and bid price caps for A/S markets are set so the owner can earn an equal or greater profit than if its capacity was committed to energy markets
- When competitive market conditions exist, the owner is allowed to bid in all markets

- Bi-lateral sales are subject to restrictions to ensure that the subsidiary may not inappropriately withhold the purchased capacity from the market or that PG&E cannot transfer any "market power" to its subsidiary.

The exact requirements for any possible divestiture outcome must consider specific factors such as:

- The total amount and type of generation resources owned by the entity.

- The amount and type of other generation resources available relative to demand in the California energy and ancillary service markets.
- The possibility that other means to mitigate market power mitigation, such as Contracts for Differences and long term contracts may become available.

Scenario Analysis

There are a number of ways in which PG&E's hydro generation could be divested. Compared to whole transfer option, there can be increased or reduced market power risk.

– Base Line Scenario: A transfer of the entire hydro portfolio to one unregulated company not operating any thermal generation units in the California energy market. The proposed Principles are designed to mitigate market power under this scenario. This is used as a basis to compare the market power of other scenarios.

– Increased Market Power Scenario: The entire hydro portfolio or a majority of it is transferred to a company who also operates thermal generation units in the California energy market. In this scenario, increased market power mitigation is required. The requirements of the Principles would have to be extended to the owner's entire portfolio.

– Medium Market Power Scenario: No new owner of the hydro facility owns more than 50% of the PG&E hydro capacity and any resulting combined hydro and thermal capacity is less than the original PG&E hydro capacity (about 5000 MW), then the new owner will have significant market power but less than in the Base line scenario.

– Low Market Power Scenario: No new owner holds more than 20% of the PG&E portfolio (about 1000 MW) and, either owns no other generation capacity or has combined capacity of less than 20% of the total capacity in North of Path 15 zone. Under this scenario the new hydro owner would have limited market power.

We can apply the behavioral rules of minimum quantity bid and bid price rules to market power mitigation in each of these scenarios. The general principles remain the same with specific value for minimum bid quantity and maximum bid price adjusted to reflect the portfolio of the new owner. In the case when a new owner owns other generation in addition to the hydro capacity purchased from PG&E, a critical modification of the principles would be to base restrictions on the combined generation capacity of the new owner. The bid requirement, for example, would be calculated based on the combined portfolio and applied to both new hydro capacity and existing capacity.

The reason to apply the bid restriction to the combined capacity of the new owner is that even if the new owner were to be a price taker by bidding its entire new hydro capacity at zero price (which would be more than fulfilling the minimum requirement), it may still have more market power with its other resources than before the purchase. It can be demonstrated that a new owner who purchased 1000 MW of PG&E hydro and owns another 1200 MW of other generation capacity, has greater ability to inflate the market price than it had before the purchase even if it bids the entire 1000 MW hydro at zero price. The new owner would only need to withhold, for example 1000 MW of its other generation capacity, to inflate the market price and maximize profit. The 1000 MW of hydro capacity, although bid at zero price, will receive the market clearing price inflated by its actions and earn a profit higher.

When the new owner operates more than 5000 MW of generation in California, the minimum bid quantity requirement, both in terms of the absolute MW value or the percentage of its total capacity would need to be increased to effectively mitigate its market power. Due to the increased market power risk, this scenario should be avoided if possible.

It is very likely, however, that the current percentages in the Principles will be adequate for the medium market power and low market power scenarios. Under the low market power scenario, the bidding restrictions outlined in the Principle can be used as a safeguard, although they may be relaxed or eliminated when a new owners has demonstrated little market power.

Methodology

Options to Mitigate Market Power

There are three mains options for market power mitigation in California energy market:

- Structural. This includes divestiture of the hydro resource to a large number of suppliers. One option is divestiture by watershed to a number of different owners. The issue of whether each individual watershed is significantly small so that an entity holding only that one set so resources would need to be addressed by a more detailed study. In addition, for this option to provide an effective mitigation against market power, entities purchasing hydro assets must not own significant other thermal resources, so that transfer of ownership reduces or protects market power, rather than creating or exacerbating market power.

- Contractual. This option includes contractual agreements, such as Contracts for Differences (CFDs), under which an owner, in effect, sells output at a fixed price under a long term contract. If the quantity of an owners portfolio that is effectively "sold" under such long-term contracts is sufficiently large, this can removes an incentive for the owner to exercise market power to raise market prices by withholding capacity form the market (or bidding capacity at very high prices and increasing revenues by selling less at a higher price). This contractual form of mitigating market power is widely used in England, Australia, and is being proposed in New York. CFDs are currently prevented from being applied in California's markets due to CPUC restrictions on investor-owned utility loads entering into bilateral contracts.
- Behavioral Rules. These are restrictions on bid quantities and prices, such as have been proposed in the Principles developed by the ISO and PG&E. These Principles were developed as a set of market power mitigation measures that would be sufficient to cover a scenario in which the entire PG&E's hydro portfolio were sold to an unregulated subsidiary. The bidding restrictions are designed to restrain the two means to exercise market power: bidding excessive price and withholding capacity. The generation owners can either bid significantly above cost or reduce its supply in the market (with or without excessive bid price) and thus reduce total market supply and push up market price. Bidding restriction must be set both as a quantity requirement and bid-price cap. The proposed Principles for transfer of the PG&E hydroelectric portfolio to a subsidiary is an example of behavioral rules used in market power mitigation.

The appropriateness and details of using any of these approaches (individually or in combination) must be addressed on a case by case basis, based on factors such as:

- The total amount and type of generation resources owned by the entity.
- The amount and type of other generation resources available relative to demand in the California energy and ancillary service markets.

- The feasibility of other sources of market power mitigation which are currently unfeasible or very limited in California's energy market, such as Contracts for Differences and long term contracts between buyers and sellers, and greater elasticity of demand for in the energy and ancillary service marketplace.

Assumptions Used in Developing Possible Divestiture Scenarios

PG&E's current hydro portfolio are shown in the following table:

River Basin	Capacity (MW)	Notes
Pit/Fall	768	
Feather River (North Fork)	738	
Helms Pump Storage	1,200	Pump Storage
Misc.	299	
Shared (PG&E)	1155	
Shared (MUDs and Other)	1268	
TOTAL	5,428	

In examining the PG&E hydroelectric generation portfolio, we developed the following divestiture scenarios. We made two assumptions in our projection: First, power plants in the same river basin would be sold entirely to one new owner. Second, public agencies with joint ownership of the shared hydro facilities of PG&E would buy most of the PG&E share. PG&E would retain only one of the shared facilities. In this case, excluding the units to be purchased by public agencies, there would be 5 blocks of PG&E hydro system on sale

River Basin	Capacity (MW)	Notes
Pit/Fall	768	
Feather River (North Fork)	738	
Helms Pump Storage	1,200	Pump Storage
Misc.	299	(Can be owned by more than one firm)
Shared retained by PG&E	400	(assumed as a space holder)
TOTAL PG&E subject to divestiture	**3,405**	
Shared to be sold to MUDs and other public agencies	755	
Shared (MUDs and Other)	1,268	
TOTAL Public after divestiture	**2,023**	
TOTAL Hydro	**5,428**	

Based on our assumptions and the PG&E system configuration, at least one firm would fall in the medium market power category, i.e., the owner of Helms would have more than 1000 MW of hydro. Other firms may fall in the low market power category if each buys only one block of the PG&E hydro and does not own significant amount of other generation capacity. The increased market power scenario becomes possible if one company purchases the entire hydro capacity and also owns other generation capacity or acquires additional generation capacity in the future.

Market Power of Alternative Divestiture Scenarios for PG&E Hydro System Configuration

Based on the system configuration and our two assumptions, there are, at most, 5 blocks of PG&E hydro system subject to sale or divestiture. (The misc. block can be further divided, but considered as one block for market power analysis due to its small capacity). Based on these assumptions, we have attempted a crude classification of market power risk based on FERC's rule that no one owner should control more than 20% market share. We recommend further evaluations of the appropriate market power mitigation measures, and a more carefully look at the structural remedies and contract for differences methods for mitigating market power.

Alternative Divestiture Scenarios Using the 5 Blocks

Scenario 1. PG&E retains greater than 50% share of hydro system.

If PG&E or its subsidiary retains the majority share of the current PG&E hydro system (50% or more), including Helms pump storage, then PG&E should be subject to some monitoring and bid restrictions.

The Principles discussed by the ISO and PG&E can be modified to apply to PG&E in this scenario. The price cap should remain the same. The minimum quantity required for ancillary services and forward energy market may need to be adjusted. There are two main factors that affect these requirements: they would have lower market share which reduces market power, therefore it would be possible to reduce the minimum quantity requirements; however the higher market power of other hydro owners (especially if the new owners also own thermal resources) may require increased PG&E supply to curb others' market power. Additional study would be required to determine the appropriate quantity rules.

Any buyer who purchases less than 1000 MW of hydro and does not own other generation capacity would be considered a low risk of having market power. They would not be subject to any restriction initially and would be monitored. Restrictions may be applied if a significant market power problem is detected.

Any buyer who purchases more than 1000 MW of hydro or owns other generation capacity would be considered to pose a market power risk. See discussion in Scenario 4.

Scenario 2. Full divestiture to 5 non-thermal owners – The Helms owner will be the main market power concern. Others pose low market power concerns.

In this scenario, PG&E retains less than 50% of total hydro. The 5 blocks would be divested to five different firms who do not already own thermal or other generation resources.

In this scenario, only the firm who owns Helms pump storage facility may be subject to restrictions. Other new hydro owners should be considered as low risk for market power.

The restrictions on the owner of Helms would be different than those in the Principles. First, the new Helms owner has a moderate market share (less than 35%). Second, pumped storage has special characteristics. The current principles would be modified significantly for Helms.

Scenario 3. Full Divestiture to Small Thermal Owners – Market power concern slightly more than scenario 2

Under the following conditions, this scenario will be similar to scenario 2:
1. Helms does not go to a thermal owner;
2. Other buyers each have less than 1000 MW new hydro capacity;
3. Each new owner's combined hydro and thermal capacity is less than 20% of total NP15 ISO market generation capacity.

In this case, the Helms owner may be regulated as in scenario 2, and the other firms will be considered low risk in market power and will need only to be monitored.

Scenario 4. Divestiture to Large Thermal Owners – higher market power risk, may be higher market power than the base line case.

This scenario covers the following high market power risk conditions:
1. Helms goes to a company who also operates thermal or other generation capacity in ISO market; or
2. Any new owner purchases more than 1000 MW of hydro; or
3. Any new owner with thermal or other generation capacity and its total capacity including the new hydro capacity in NP15 is more than 20% of the total capacity in NP15.

Any of these conditions can potentially result in significant market power. If a new owner's combined capacity is more than the current PG&E hydro portfolio (about 5000 MW), it may have market power greater than the base line whole transfer case. Due to the serious market power concern, we recommend that no new owner of PG&E hydro should operate a combined generation capacity of more than 5000 MW in California Energy market.

These owners should be regulated by some measures. Possible options include:
1. Bid Cap and Quantity requirement to <u>both hydro and thermal units</u> of the new owner. When a large new owner operates both hydro and thermal, restriction on hydro alone

may not be effective. Thermal units may be put under variable cost-based bidding under certain market conditions, and will be required to bid more than certain minimum quantities. When the new owner operates more than 5000 MW of generation in California, the minimum bid quantity requirement, both in terms of the absolute MW value or the percentage of its total capacity may be increased to effectively mitigate its market power.

2. Contracts for ancillary services such as Contracts for Differences. With properly designed contracts, spot market prices do not change the contract holder's revenue and profit. The contract holder, therefore, has no incentive to inflate market prices.

Additional Study

This has been a cursory evaluation. We recommend further research to properly design the restrictions. Areas that will require further study are the following:

- When and how often will ancillary services be purchased separately for NP15 and SP15?
- What season and hours do these split purchases happen? What is the system load and the ancillary services requirements under these conditions? What are the ancillary services prices under these conditions?

This research will assist us in reaching a conclusion on how often we would expect to see market conditions that could be prone to market power problems.