ATTACHMENT A

CALIFORNIA ISO
DRAFT PROPOSAL
MARKET POWER MITIGATION PLAN

February 6, 2001

1. Summary

The next two years will be a critical transitional period for the restructured California electricity market. The current tight supply situation and unacceptable levels of market power will not be fundamentally resolved until sufficient new generation resources in California and the WSCC region are brought on-line and significant demand responsiveness programs are developed. A comprehensive market power mitigation plan must be in place during this period in order to ensure that the California market provides adequate supplies to consumers at just and reasonable prices, as required by the Federal Power Act. Inevitably this will be a difficult transition period. The Federal Energy Regulatory Commission (FERC or the Commission), in its December 15, 2000 final order "Directing Remedies for California Wholesale Electric Markets" established a general framework and some short-term measures for market power mitigation. In addition, the Commission initiated a process whereby its staff, with input from the California Independent System Operator Corporation ("CAISO" or "ISO") and market participants, would develop a market power mitigation program based on that framework to take effect on May 1, 2001; a program that would ensure an orderly transition to a well-functioning market. The market power mitigation plan presented here represents the ISO Department of Market Analysis' (DMA's) contribution to this process. The ISO's proposal provides mechanisms to protect against the exercise of market power, including both economic and physical withholding, and provides incentives for market participants to forward contract.[1] The ISO believes that the proposal outlined below includes the minimum necessary elements of an effective market power mitigation proposal.

1.1 FERC's Market Power Mitigation Framework and Short-term Measures

In its November 1 and December 15 Orders regarding the California markets, the Commission outlined a "three-pronged price mitigation" proposal, to become effective January 1, 2001, that included the following elements:

- **Elimination of PX Buy/Sell Requirement** – The Commission removed the requirement that the California Investor Owned Utilities (IOUs) -- Pacific Gas & Electric Company, Southern California Edison Company and San Diego Gas & Electric Company -- sell all their generation into and purchase all of their energy requirements from the PX, thus removing the requirement that the IOUs purchase all their needs in the volatile spot markets.
- **Forward Scheduling Requirement** – The Commission required all market participants to preschedule all of their resources and loads with the ISO and to limit their real-time energy purchases from the ISO to no more than 5 percent of their total load. The Commission also

[1] To provide additional background for understanding and assessing this proposal, at the end of this document we include a matrix that compares the market power mitigation approaches used by other ISOs with the approaches proposed here.

imposed penalties on underscheduled load and removed some of the incentives for resources to favor the real-time market.

- **Establishment of Soft Price Cap** – As a supplemental price mitigation measure, the Commission proposed to limit the use of the single price auction in the CAISO's and PX's spot markets to bids at or below $150. Suppliers who bid above $150 would be paid as-bid, subject to justification by the seller based on certain reporting and monitoring requirements, but would not be allowed to set the market clearing price (MCP). Bids above $150 would be subject to refund if found unjustified (not just and reasonable).

The Commission's directives were targeted at addressing certain fundamental problems such as over-reliance on the spot markets and reducing the impact of high prices in such an environment. These were short-term fixes that the Commission determined were necessary until longer-term reforms were in place. A review of market performance since the Dec 15th FERC order strongly suggests that even the FERC soft-cap is not sufficient to mitigate the considerable market power that continues to exist in the California market, and that further market power mitigation measures are needed. Although a soft cap was in place for the ISO's Imbalance Energy market from December 8 to Dec 31st, the average energy cost of approximately $294/MWh for December 2000 was the highest seen since the start of the California market. The average energy cost for January 2001 was approximately $291/MWh, only a minor reduction (1%) compared to December 2000, despite a 40% reduction of the level of the soft cap from $250/MWh in December to $150/MWh in January. While a dramatic rise in natural gas prices contributed to these higher prices, the ISO DMA analysis indicates that a significant portion of these higher costs can be attributed to market power[2]. Given these price levels, additional market power mitigation measures are called for. It is on those initiatives that we now focus.

1.2 DMA Proposed Market Power Mitigation Plan

DMA shares the Commission's view that a return to cost-of-service regulation is not the best answer to California's current energy crisis. DMA's Market Power Mitigation Plan maintains market based rate authority for generators and allows generators who commit a significant amount of their capacity to long-term energy contracts with California load serving entities to be subject to less stringent mitigation measures in the spot markets. DMA takes a "carrot and a stick" approach to market power mitigation. The "carrot" for suppliers is long-term contracts with California LSEs at just and reasonable rates. The "stick" is more stringent market power mitigation in the spot markets. DMA outlines below the framework and guidelines necessary to bring FERC's vision of workably competitive wholesale markets into fruition. Similar to the plan outlined by the Commission, the DMA plan lays out a four-step process for mitigating market power.

<u>Step 1 – Create a Foundation of Forward Contracts to Control Total Market Costs</u>

The first step is to ensure a sufficient level of long term forward contracting to meet the majority of expected load at just and reasonable rates. This is the foundation of the market power mitigation plan prescribed by the Commission on an interim basis and proposed here by the ISO. Without this measure, other components can not effectively mitigate the market power that has already been demonstrated to exist in these markets due to basic supply and demand conditions and suppliers ability to influence prices, which are only likely to worsen in next two years. The ISO proposes a target coverage of load equal to 85% of ISO system load, which will

[2] See DMA Market Analysis Report, ISO Board Meeting, February 1, 2001.

translate to a requirement for California's in-state suppliers other than investor-owned utilities to provide at least 70% of their capacity in forward contracts to California load during super peak periods. This requirement is not mandatory. Generators can elect not to meet this requirement but doing so will mean that their bids into California's spot markets will be subject to more stringent market power mitigation measures. Lower percentages would apply for other periods as specified in Table 1. Such contracts should be for a minimum of 2 years. As suggested in the ISO's October 20, 2000 "Offer of Settlement", we would propose exemptions for portfolios below 50 MW, renewable resources, and new capacity in California. Since importers are often pivotal in setting market prices, they will be required to offer 70% of historical sales into California at super peak hours under long-term contracts to California load in order to avoid further mitigation on their remaining sales in the California spot market. Any suppliers meeting the contract quota by April 15, 2001 at just and reasonable prices (discussed in section 2.1.1) would be subject to less stringent market power mitigation measures on their remaining capacity. For example, suppliers meeting this obligation would be allowed a generous margin above their variable costs for bids submitted to the real-time energy market. Under the ISO's proposal, all complying suppliers would be able to collect even higher market-clearing prices set by other complying suppliers (see step 4 below). Suppliers failing to meet the long-term contracting requirements would be subject to a lower fixed margin (possibly zero) in the real-time market and would be paid "as bid" rather than the MCP.

Step 2 – Adopt Improved Outage Coordination, Available Capacity Reserve Requirements and Availability Standards to Mitigate Physical Withholding

This past year the ISO has witnessed a substantial increase in the number of generating unit outages. Both the magnitude and frequency of these outages (planned and forced) has risen to a level to cause severe operational problems for the ISO. In fact, it was in large part due to generating unit outages that, for the first time ever, the ISO had to initiate wide-scale interruptions of firm service on January 17, 2001. The large increase in unit outages is in large part due to the fact that the generating units have operated at unprecedented levels this last year. That fact, combined with the advanced age of the units in California has increased the frequency of mechanical failures. Currently, the ISO authority to coordinate planned outages is limited to a small subset of units operating under Reliability Must Run contracts. The fact that the ISO does not have authority to fully coordinate planned generating unit maintenance with all unit owners has serious reliability and market efficiency implications. To address this problem, the ISO is developing a proposal through a stakeholder process for requiring all generators to coordinate their planned maintenance schedules with the ISO. Under such a proposal, the ISO would require all generators to submit their "preferred" annual planned maintenance schedules with the ISO and identify allowable "scheduling windows" for performing the necessary maintenance, repairs, and/or upgrades. The ISO would then assess each owner's plan and determine an optimal annual planned maintenance schedule for all generators in the ISO control area to levelize system reliability throughout the year. This determination would take into consideration transmission maintenance schedules (and allowable scheduling windows), local reliability needs, system needs, and market impacts.

The Commission's December 15th Order called for the consideration of installed capacity markets and reserve requirements as potential long-term market reforms. A missing element of the original design of California's restructured energy market has been a requirement for load serving entities to secure capacity reserves in advance and make them available to the ISO in order to assure the ISO's ability to match resources and demands. The Commission has approved similar requirements for all three eastern ISOs (PJM, ISO-NE, and NYISO). Clearly, some entity needs to be charged with ensuring adequate reserves are available to meet California's load. The ISO believes this responsibility should logically fall to California load serving entities. Securing capacity reserves to meet California load on a long-term basis (one to several years in advance) will enhance reliability and mitigate market power by providing significant capacity margins (supply bid into the market minus system demand) and thus promoting competition during most hours of the year. Such a requirement will also facilitate the entry of new generation, as load serving entities will have an incentive to offer contracts to companies considering building new generation in California. Available capacity requirements also impose a charge to load based on its annual and monthly peak level, and therefore provide the much needed price signal to reduce peak demand.

To meet this need, the ISO proposes to establish an available capacity reserve (ACR) requirement. Under the ACR requirement, load serving entities (LSEs) would be required to contract available capacity reserve resources equal to 115% of their annual peak load.[3] Long-term energy and ancillary service contracts, voluntary load curtailment contracts, and an LSE's own generation capacity can count as ACR. Thus, an LSE can meet its ACR requirements through any combination of these sources. In exchange for receiving these annual capacity payments, the supplier of an ACR contract will guarantee that its contracted capacity is available to the market and will deliver energy or reserve service if dispatched. Suppliers of capacity resources failing to provide their contracted service will face unavailability penalties. Making supply "available" to the market (i.e. bid) is the minimum requirement of the ACR contracts. However, LSEs are free to negotiate additional terms. For instance, an ACR contract could be a long-term ancillary service contract with the LSE. On the other hand, the LSEs could negotiate less expensive ACR contracts allowing the ACR supplier to sell interruptible export contracts (with low probability of interruption) from ACR capacity in excess of the LSEs forward energy contracts. Since not all resources are likely to be under an ACR contract, the ISO also proposes to establish and monitor generally applicable availability standards. These general availability standards are necessary to mitigate physical withholding.

Step 3 – Mitigate Locational Market Power

Ensure that local market power is mitigated by limiting the prices paid to local reliability resources and by eliminating opportunities for gaming in the congestion management system. This will be addressed on a permanent basis in the ISO's Congestion Management Reform filing. The main mitigation measure is to mitigate adjustment and Supplemental Energy bids to variable cost if it is determined that the generating unit has locational market power.

Step 4 –Mitigate Economic Withholding in the Real-time Market

Establish resource specific bid caps to mitigate the ability of market participants to exercise excessive[4] market power in real-time and any other remaining short-term markets not covered by long-term contracts. This must be supported by creating incentives to ensure that all generation and load not covered by forward contracts will fully schedule in the forward markets to minimize real-time transactions to 3-5% of the total load. Resource specific bid caps are intended to approximate the prices that would result in a competitive real-time market (i.e. a market where individual suppliers are not pivotal and demand is fairly elastic). The resource specific bid caps or "bid price thresholds" will consist of a variable cost component (or

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[3] The 115% target is based on the fact that reserve requirements (Upward Regulation, Spin and Non-spin), during periods of concern for system-wide market power mitigation, amount to about 15% of load. This requirement could be structured in one of two ways. The ACR requirements could be structured so that the LSE would be responsible for maintaining ACR requirements equal to 115% of their projected annual peak load for the entire year or the ACR requirement could vary seasonally or by some other criteria for similar load periods.

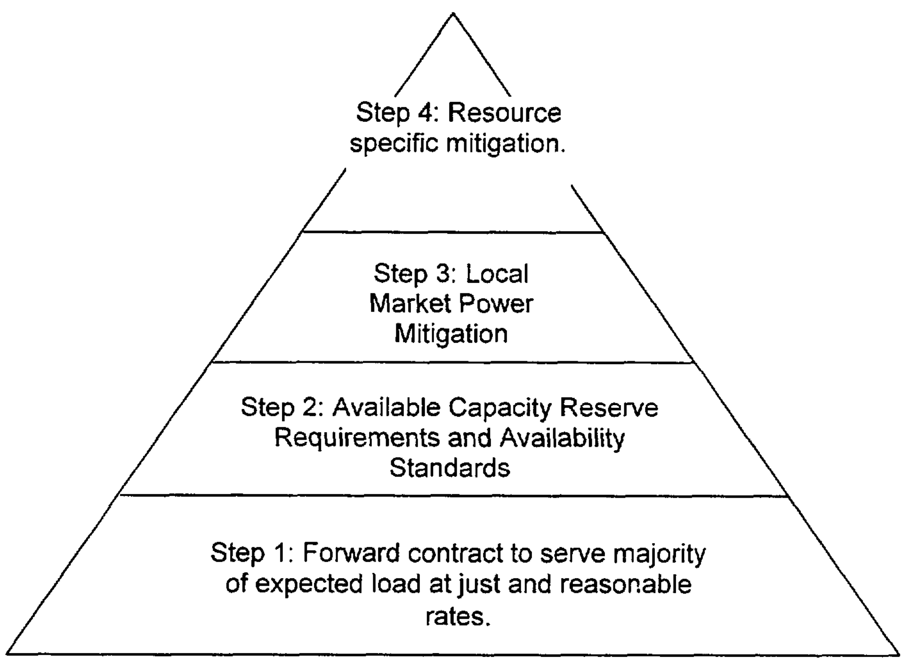
[4] Given the difficulty in detecting moderate levels of market power, the approach take here is to mitigate against the exercise of "excessive" market power.

opportunity cost for energy limited resources) plus a fixed margin to recover certain fixed and other costs (i.e. start-up and low load costs, opportunity costs, and risk premiums). Under this approach, specific suppliers might be permitted to file unit-specific cost information with the Commission or absent such filings, DMA will base variable cost estimates on existing data. Assuming that long-term contracts are in place and serve as the primary means to mitigate market power, and that effective rules are in place to minimize transactions in the real-time imbalance energy market, the bid price threshold can be generous to allow the market to send strong price signals to both demand and supply to provide incentives for development of price responsive demand and new investment in generation.

Except for the manner in which the margin above variable cost is treated, mitigation measures for economic withholding as proposed are consistent for system-wide and local market power mitigation. In both cases the variable cost (or a surrogate based on recent successful bids in competitive market conditions) is used as a component of the mitigated bid, with provision for recovery of additional cost through either an allowable margin above variable cost (for system-wide needs) or an after-the-fact true up based on verifiable cost (for locational needs). For the long-term, however, because of higher frequency of occurrence and predictability of local reliability requirements, fixed payments will be made up front for local reliability resources rather than included as a margin in their mitigated bids or paid through an ex post true up.

The four-step market power mitigation proposal is illustrated by the diagram below (Figure 1), with the primary emphasis at the foundation of the pyramid.

Figure 1. The structure of market power mitigation



1.3 Tools for Market Power Mitigation

There are three main categories of tools available to mitigate market power and to ensure competitive market outcomes:

Structural. Structural market power mitigation mechanisms or tools are those measures available to regulators and others to ensure that a market is initially structured to result in competitive outcomes. These tools are typically applied before a market begins to operate, such as the time of divestiture of utility-owned generating units and prior to the granting of market based rate authority. Structural tools are thus the most effective market power mitigation tool available. Structural tools, such as conditions on the sale on utility assets, are typically used by regulators to: (1) ensure that divestiture results in as large a number of suppliers as possible, so that no supplier is able to materially influence the price in the market, and (2) ensure that adequate quantities of divested generation are still available to serve native load (e.g., through vesting contracts). Vesting contracts have been used in other areas where divestiture was a feature of electric restructuring, such as in New York. The restructuring process in California focused only on the divestiture of IOU generation and failed to consider the importance of ensuring reasonable long-term vesting contracts. Additionally, the FERC granted market based rate authority on filings by each generator owner that they could not influence prices set in the market. This has not proven to be true under tight market conditions.

Overall, the divestiture of IOU generation resources proceeded with no supplier owning more than 10% of the entire supply needed for serve California's load. However, supply concentration measures are, by themselves, not sufficient measures of market power especially for a market facing tight supply and hampered by continuing regulatory restrictions on hedging and development of price responsive demand. Under tight supply conditions and with regulatory restrictions in place, even a supplier with 10% market share can become pivotal and set the market price at excessively high levels. Tacit collusion[5] is also an easy strategy whereby a few large suppliers adjust their bidding strategies to complement the bidding strategies of others and jointly inflate the market clearing prices. Although further divestiture is possible, it is not likely to mitigate all market power in the California market. Continued tight supply, slow development of price-responsive demand, and the inability to effectively hedge are all likely to create expectations for and result in high prices this summer. Remedies such as further divestiture of generation assets are not currently being considered by FERC and regulators in California to maintain reasonable prices in these markets. This leaves the next two tools to mitigate market power for the next two years of transition before new demand side and supply side resources can enter the market.

Contractual. This type of tool includes contractual agreements, such as Contracts for Differences (CFDs) or other long-term contracts under which a resource owner sells a fixed quantity of power at a fixed price. If the quantity "sold" under such long-term contracts is sufficiently large relative to a resource owner's entire supply portfolio, such arrangements can reduce the incentive for the owner to exercise market power in the spot markets (i.e., raise market prices by withholding capacity from 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 and Australia, and was part of the buy back conditions for plant divestiture in New York. Until recently, the investor-owned utilities in California have had state regulatory restrictions that significantly limited their ability and incentive to enter into such contracts. FERC's December 15 order, however, advocated long-term contracts as a fundamental measure to mitigate market power in the California market. The ISO DMA and Market Surveillance Committee have long advocated long-term contracts as a key market power mitigation solution. There is now general agreement on this approach as the State of California is currently negotiating such contracts.

To make this approach effective in mitigating market power, the contract must ensure supply and contain costs by covering a significant fraction of the demand and setting the price at a just

5 Tacit collusion means suppliers can bid without having explicit communication, but by iteratively changing their bids and observing the impact on the market and the behavior of other players in optimizing their bidding strategy.

and reasonable rate. Depending on the final outcome of the state's efforts to enter into long-term contracts, long-term contracts may or may not cover a significant share of expected load. Unless the combination of contracted and self-owned generation covers a large amount of the expected load and includes provisions for unexpected load (including demand responsiveness), the behavioral restrictions, the next general option, are needed to mitigate market power for the part of the market not covered by long-term contracting provisions.

Behavioral Rules. These involve restrictions on bid quantities and prices, such as price caps and resource-specific bid caps. Since either bidding significantly above cost or reducing supply in the market (with or without excessive bid price) can be a means of raising the market price, behavioral rules must set both quantity requirements and prevent market participants from submitting excessive bids in order to successfully mitigate market power.

Behavioral restrictions are a necessary feature of any market power mitigation plan but they alone cannot remedy market power. Absent structural remedies or sufficient forward contracting, behavioral rules will be ineffective at mitigating market power. That being said, behavioral rules are effective at addressing residual market power. Behavioral rules can only serve as safety net measures and should be designed to be less restrictive, allowing the market to operate on the margin to send clear price signals to load and generation to attract much needed investment in new generation and promote demand responsiveness to prices.

Therefore, the DMA's proposed market power mitigation plan is designed with long-term contracts as the foundation, to protect the majority of load (85% or more), to give suppliers a fixed stream of income in return for insuring availability of their supplies, and to remove the incentive to spike prices. The behavioral restriction component is proposed for the ISO real-time market (no more than 5% of the market), Ancillary Services markets, and possibly other short-term contract or spot markets.

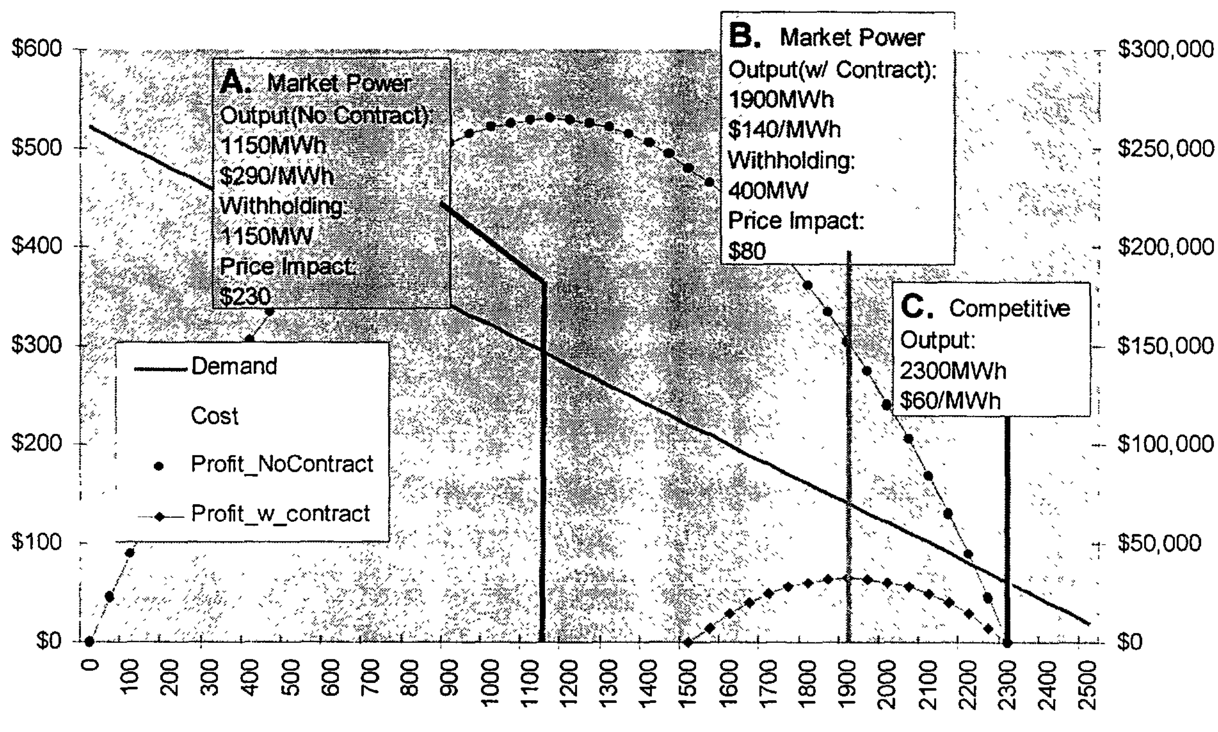
Another integral part of market power mitigation is to curtail locational market power, which arises in conjunction with local reliability needs. This will be fully addressed as part of the ISO's congestion management reform proposal, and is summarized in section 2.3 to complete the full market power mitigation plan.

1.4 Developing the Strategy for Market Power Mitigation

The general strategy of market power mitigation that is proposed herein, as embodied by the 4-step plan, protects the majority of load at fixed prices and allows a smaller portion to be exposed to mitigated spot market prices. The primary element of this plan is to ensure that a large fraction of the load is served under long-term contracts at just and reasonable rates. This keeps total market payments close to the cost of generation, helps to mitigate both physical withholding and economic withholding for the large part of the market, and reduces incentives for generation owners to exercise market power in the remaining market. The available capacity reserve requirement and availability standard are designed as extensions of long-term contracting to capacity resources that will ensure adequate supply and curb physical withholding.

Long-term contracts are often seen as voluntary agreements. It is not always understood how long term contracts can serve as a critical means to mitigate market power when full structural remedies are not available. Long-term contracting, when used as a tool to mitigate market power, performs two functions: (1) to assure fixed just and reasonable rates for the quantity of power supply under contract, and (2) to mitigate existing market power for the rest of the portfolio of the supplier. The reason long-term contracts work effectively to mitigate existing market power is that they change the incentives by which sellers provide power and maximize profits. With less capacity available to bid into the real-time market, the expected pay-off from having a high bid accepted (the portfolio effect) is significantly reduced. Consequently, suppliers have an incentive to reduce their marginal bids so as to increase their chances of having more of their bids selected. The figure below (Figure 2) illustrates how suppliers under long-term contracts will have an incentive to provide greater output into the market and at more reasonable prices.

Figure 2. Long term contracts mitigate market power by making it profitable for producers to supply more output at a lower price than without the contract commitment.

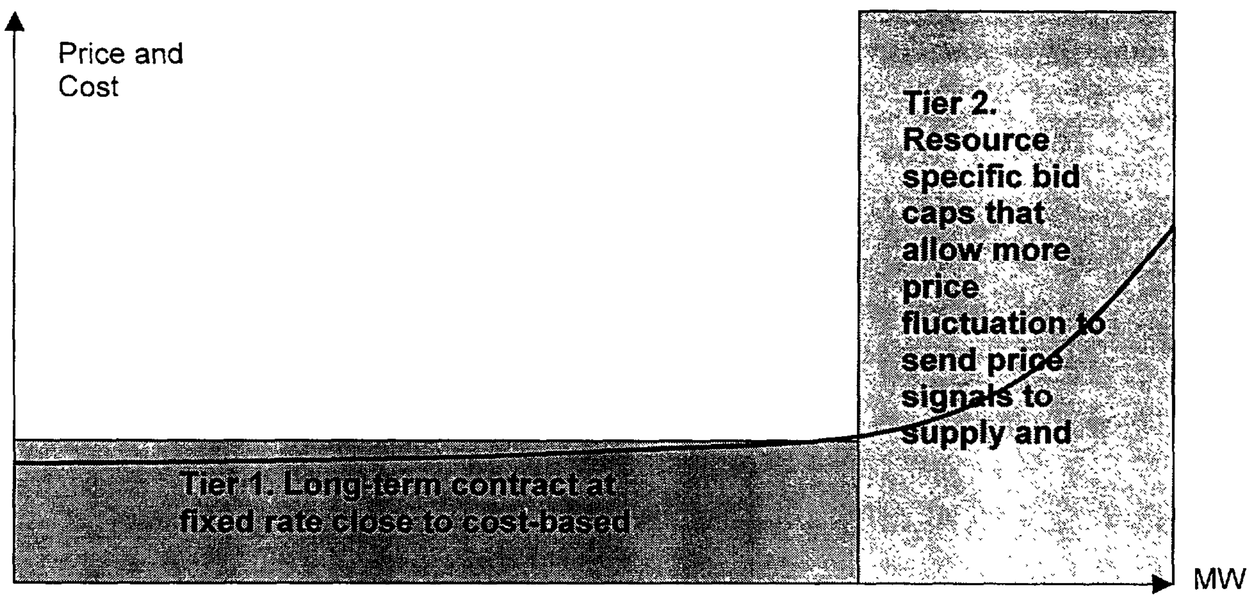


(Total Capacity 2500MW, Long-term Contract for 1500MW @ $60)

Figure 2 uses a hypothetical supplier and the demand curve it faces to illustrate how a long-term contract commitment reduces the supplier's incentive to exercise market power. If the supplier were a competitive price taker, it would bid it full capacity at cost of $60/MWh, and the output would be 2300 MWh and market clearing price equals to cost at $60 (Point C). If the supplier is allowed to exercise market power without any long term contract commitment, it will attempt to maximize its profit by only supplying 1150 MWh of energy (withhold 1150 MWh compared with the competitive output) and drive up price to $290/MWh (Point A). Now suppose there is a contract for 1500 MW at $60/MWh. The profit maximizing point is moved toward a much higher output level of 1900 MWh (withhold 400MW) and the price is at a lower level of $140/MWh. In general, long-term contract give the supplier a steady revenue stream and the incentive to supply more than their contract level and at lower prices than without the contract.

Building upon this foundation of long-term contracting, the mitigation plan relies on the resource specific bid caps, the second tier, to mitigate market power in the real-time market and remaining short-term markets. It takes the form of price thresholds for real-time bids, Ancillary Service markets, and short-term contracts. The resource specific bid caps proposed here allow a greater range of price fluctuation above cost to send strong price signals to supply and demand. Since the remaining market in tier 2 is a small part of the market, higher prices there would not drastically increase the total market cost or market power.

Figure 3. Two-tiered approach to mitigate market power



2. DESIGN AND IMPLEMENTATION DETAILS

2.1 Step 1: Create foundation of forward contracts to meet the majority of expected load at just and reasonable prices.

2.1.1 Load Serving Entities (LSEs)

LSEs must be able to forward contract at just and reasonable rates to cover their core customers' load and preferably all of their customers who desire a fixed rate option. Therefore, LSEs should be able to forward contract at just and reasonable rates for no less than 85% of their projected requirements, as adjusted by season and time of day. Generation currently owned by LSEs would be counted towards the 85% contracting goal. The contracts should be a long-term contract of 2 years or longer.

The appropriate regulatory authorities will review each contract to ensure a just and reasonable rate. The CPUC and the FERC should coordinate to set up a prudence review procedure. The basic criterion for such review could be based on a forward looking cost based rate that covers variable cost and fixed cost with a reasonable rate of return. Such a criterion would be a "safe harbor" (i.e., a price ceiling, not a floor) with the expectation that increased new supply should allow contract prices to be driven down below the contract rate ceiling over time.

2.1.2 Requirements for Suppliers

As for the supply side of the market, suppliers who sell electricity in the California wholesale markets would be required to commit a significant portion of their supply under long-term contracts with LSEs in California. Suppliers who fail to comply with this requirement but who wish to sell their remaining capacity at market-based rates in the California markets should be subject to additional mitigation measures. The contracting requirements would be as follows:

- In-state suppliers must demonstrate by April 15, 2001, that the amount of long-term energy contracts that they will have entered into with in-state LSEs by May 1, 2001meets the percent of total capacity requirements shown in Table 1.

Table 1- Forward Contract Requirements for Suppliers to Avoid Mitigation

Period	Hours/Days of Week	Months	Minimum Long-term Contract Requirements for In-state Suppliers (% total capacity)
Super Peak	Hours Ending 12-20 Mon-Fri	Jun-Oct	70%
Peak Hours	Hours Ending 7-22 Mon-Sat (Excluding holidays and Super Peak Hours)	All Year	60%
Off-peak Hours	Hours Ending 1-6, 23-24 (Mon-Sat) All day Sunday & Holidays	All Year	40%

- Out-of-state suppliers must provide at least 70% of their average historical monthly sales in 2000 for long-term contracts to in-state LSEs. These numbers were chosen to insure enough load is likely to be covered, and to reduce the quantity on which suppliers will have opportunity to raise prices significantly.
- In-state suppliers who have already signed forward contracts with entities other than in-state LSEs, and therefore cannot comply with the requirements in Table 1, can only sell into the California market at strictly mitigated rates.
- Generation powered by renewables, suppliers with a total portfolio that does not exceed 50 MW, and incremental generation (additions to existing units and new units) would be exempt from the forward contracting requirements.

Suppliers must submit evidence to FERC no later than April 15, 2001 to demonstrate that they will be in compliance with the forward contracting requirements by May 1, 2001. Suppliers who are not in compliance by May 1, 2001 will be subject to additional mitigation measures for the entirety of their sales into the California market. The market power mitigation measures for suppliers who have not met the long-term energy contracting requirements specified in Table 1 (the non-compliant suppliers) are as follows:

1. Report all sales in the forward market to FERC or other designated regulatory agency for review for a period of 60 days and subject to refund; and
2. Be subject to stricter mitigation in the ISO real-time market than suppliers who do comply.

LSEs should also be encouraged to sign long-term contracts for ancillary services with potential suppliers to contain cost and reduce price risk. The market power mitigation plan will not have a mandatory contract requirement specifically for A/S. However, the LSEs can make arrangements with their ACR providers to self provide their Ancillary Service capacity obligations from their eligible ACR capacity.

2.1.3 Other Requirements

Due to the recent and pending legislation in California and on-going negotiation among government officials and key players in the market, the details of the long-term contract may differ and may also affect other parts of the market power mitigation plan. The ISO intends to provide additional input on implementation details as final contract terms become public.

To effectively monitor the compliance of long-term contract requirement in California electric markets, the FERC will need information pertaining to long-term contracts between suppliers and California LSEs. The FERC will therefore need to institute rules for the submission of information related to long-term contracts. In Section 2.4.5 we propose some guidelines for required reporting of bilateral contract information that describes the characteristics of the contract including specific prices, quantities, and operational parameters of the transaction.

2.2 Step 2: Adopt Improved Outage Coordination Procedures, Available Capacity Reserve Requirements and Availability Standards to Mitigate Physical Withholding of Capacity

2.2.1 Outage Coordination Procedures

This past year the ISO has witnessed a substantial increase in the number of generating unit outages. Both the magnitude and frequency of these outages (planned and forced) has risen to a level to cause severe operational problems for the ISO. In fact, it was in large part due to generating unit outages that, for the first time ever, the ISO had to initiate wide-scale interruptions of firm service on January 17, 2001. The large increase in unit outages are in large part due to the fact that the generating units have operated at unprecedented levels this last year. That fact, combined with the advanced age of the units in California has increased the frequency of mechanical failures. These facts notwithstanding, the possibility of physical withholding cannot be ignored.

The fact that the ISO does not have authority to fully coordinate planned generating unit maintenance with all unit owners makes it difficult to anticipate with any certainty these outages and to plan appropriately. The ISO currently only has authority to approve scheduled outages for Reliability Must Run units. While all other generators are required under a Participating Generator Agreement (PGA) to submit annual, quarterly, and monthly details of their planned maintenance schedule, these details are provided to the ISO for informational purposes only.

Therefore, the ISO intends to develop proposals for addressing these concerns. First, the ISO intends to develop a proposal for requiring all generators to coordinate their planned maintenance schedules with the ISO. Under such a proposal, the ISO would require all generators to submit their preferred annual planned maintenance schedules with the ISO and identify allowable "scheduling window" for performing the necessary maintenance, repairs, and/or upgrades. The ISO would then assess each owner's plan and determine an optimal planned maintenance schedule for all generators in the ISO control area to levelize system reliability throughout the year. This determination would take into consideration transmission maintenance schedules (and allowable scheduling windows), local reliability needs, system needs, and market impacts.

2.2.2 Available Capacity Reserve

The Commission's December 15th Order called for the consideration of installed capacity markets and reserve requirements as potential long-term market reforms. A missing element of the original design of California's restructured energy market has been a requirement for load serving entities to secure capacity reserves and make them available to the ISO in its role of "supplier of last resort" in real time. The Commission has approved similar requirements for all three eastern ISOs (PJM, ISO-NE, and NYISO). Clearly, some entity needs to be charged with ensuring adequate reserves are available to meet California's load. The ISO believes this responsibility should logically fall to California load serving entities. Securing capacity reserves to meet California load on a long-term basis (one to several years in advance) will enhance reliability and mitigate market power by providing significant capacity margins (Supply bid into the market minus system demand) during most hours of the year. Such a requirement will also facilitate the entry of new generation as load serving entities may offer ACR contracts to companies considering building new generation in California.

To address this deficiency in the current market design, LSEs should be required to contract an amount of available capacity resources equal to 115% of their annual peak load. This requirement could be structured in one of two ways. The ACR requirements could be structured so that the LSE would be responsible for maintaining ACR requirements equal to 115% of their projected annual peak load for the entire year or the ACR requirement could vary seasonally or by some other criteria for similar load periods (i.e. similar to the periods specified for generator forward contracting requirements). This percentage is based on the fact that the ISO must secure Operating Reserves (spin and non-spin) and Regulation (AGC), which collectively have amounted to about 15% of the load. The percentage is also consistent with planning reserves typically maintained by other control areas (see Table 2). Long-term energy and ancillary service contracts, voluntary load curtailment contracts, and an LSE's own generation capacity can count as ACR thus an LSE can meet its ACR requirements through any combination of these sources. In exchange for receiving these annual capacity payments, the supplier of an ACR contract will guarantee that its contracted capacity is scheduled[6] or bid into ISO markets (Day-ahead, Hour-ahead, or Real-time) at all times. Some exemptions will apply, however, for generation resources having start-up times greater than 2 hours. These resources will be required to bid their full available capacity into the day-ahead market and if after the close of this market the unit has no day-ahead energy schedule (to serve control area load or export) or ancillary service award, it will not be required to bid into the hour-ahead or real-time market. However, if the unit does have a day-ahead energy schedule or ancillary service award, it will be required to bid all remaining capacity into the hour-ahead and real-time markets. An explanation for this exemption is provided in the next section. All other resources will be required to schedule or bid their full ACR capacity in the Day-ahead, Hour-ahead or Real-time

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6 ACR capacity could be scheduled as an export. However, the ISO would have the right to curtail these exports under emergency conditions.

market. Suppliers of capacity resources failing to provide this service after the service has been contracted and the resources identified as ACR resource would face an unavailability penalty.

The available capacity reserve requirement proposed by the DMA is significantly different from some Eastern ISOs in that payment is not made for installed capacity that can be unavailable or on forced outage. To distinguish our long-term reserve requirement from those of the Eastern ISOs, we use the term Available Capacity Reserve Requirement (ACR) in California. Three major differences between the California ACR proposal and ICAP markets in Eastern ISOs are as follows:

1. the obligation on ACR providers to schedule or bid their full capacity into the market (or substitute another resource at no cost to the LSE or the ISO if the contracted unit is on forced outage, derate, or unauthorized maintenance outage);
2. the penalty for unavailability (or derate) being the real-time energy price needed to replace the unavailable capacity; and
3. the reliance on contract procurement instead of an ISO-managed auction market.

Some key features of the proposed ACR are the following:

1. 115% of peak load obligation on LSEs (both UDCs and non-utility ESPs). To the extent that the LSE does not have adequate generation, forward energy or Ancillary Service contracts, or voluntary load curtailment contracts to cover such requirement, the LSE should seek suppliers and sign ACR service contracts with suppliers at a negotiated price for the service.

2. ACR Deficiency Penalties would have to be imposed on LSEs for failure to secure ACR obligations. Based on the experience of the Eastern ISOs and fixed cost estimates in California, the range of the penalty would be around $100/kW-yr to $150/kW-yr[7]. This would establish a de facto price cap for the bilateral ACR contracts or any secondary markets that may emerge.

3. ACR suppliers will have the discretion to determine how much of their total capacity is offered as ACR service. It does not have to be the resource's full capacity. If a supplier has a unit with 200 MW capacity, for example, it may choose to supply it fully as a 200 MW ACR service, or only supply 150MW for ACR service. Whatever level it chooses, it is held responsible to supply that full amount of ACR capacity in a day-ahead (and subsequently the hour ahead) schedule, offer it in a day-ahead (or hour-ahead) reserve market, or bid it into the real-time market. As noted above and in the next section, under certain circumstances, generators with start-up times greater than 2-hours would be exempt from the requirement to bid into the hour-ahead and real-time market. If such a resource has a non-zero energy schedule (including any export schedules), or is bid and accepted, then it should be started up to provide the service in the market it scheduled or won. A daily check of its full supply or bid would be made and any deficiency in supply would then be subject to unavailability penalty. If a phase-in period is required to reach the 115% of peak load in the first one or two years, all in-state generators can provide ACR service and be compensated for this service. If they choose not to, they will still be subject to the general availability requirements and penalty of the real-time price for all capacity not scheduled or bid.

[7] Based on the annual fixed-cost estimated based on cost numbers reported on the California Energy Commission (CEC) web page, "Power Plant Siting Cases at a Glance" (Dec 29,2000).

4. ACR can be self provided. A LSE that owns generation may choose to submit up to 100% of its rated capacity as self-provided ACR resources. Long-term energy and ancillary service contracts the LSE has in place can be used towards satisfying an equal amount of ACR obligation. Similarly voluntary load curtailment contracts would count towards satisfying the ACR requirements.

5. It is not necessary for the ISO to conduct ACR auctions. The ACR requirement is an annual requirement, with each LSE satisfying the requirement either through forward contracts (bilateral capacity contracts or purchases through some organized exchange) or through LSE-owned generation.

6. ACR resources can be out-of-state resources, and these units must be identified and deliverability must be demonstrated.

7. Availability requirements will be imposed on ACR resources. Unavailability penalties will be charged with no allowance for forced outages or derates.

8. ACR resources must meet the availability obligations in the following way:

   a. Schedule in the ISO day-ahead or hour-ahead market;

   b. Bid into any or all of the ISO's day-ahead or hour-ahead reserve markets, including regulation-up, spin, non-spin, and replacement reserves;

   c. Bid into the ISO real-time imbalance (supplemental energy) market.

   The full capacity of the resource must appear either scheduled or bid in these markets. Otherwise the ACR owner will face the unavailability penalty or charge (except for pre-approved scheduled maintenance outages). As noted above and in the next section, under certain circumstances, generators with start-up times greater than 2-hours would be exempt from the requirement to bid into the hour-ahead and real-time market if they are unsuccessful in the day-ahead market. The ISO will coordinate and approve maintenance schedules of ACR units taking into consideration system-wide needs. Note that there is no explicit bid price restriction being discussed in this section for ACR resources, since all ACR resources are subject to the same market power mitigation measures as any other units. See section 2.4 for details.

9. If the ACR resource is scheduled in the Day-ahead or Hour-ahead market (this is considered to be equivalent to a ISO dispatch instruction) or the bid is accepted and dispatched in real time, the resource must deliver in real time or it will face the unavailability penalty and other existing or additional penalties for not complying with dispatch instructions.

10. Internal ISO control area ACR generation must curtail its exports (with no compensation other than receiving the real-time instructed energy price for the curtailed export) to serve in-control-area load under emergency supply shortage conditions.

11. If the quantity of forward contracts is not sufficient to protect load for the summer 2001, then as a transitional measure, ACR participation may be mandated for in-state generators, who

must make at least 95% of all their capacity available to LSEs, during super peak periods, through a combination of forward contracts and ACR service.[8][9]

In the first year or two, it may be difficult for load (through its agent, either the UDC, LSE or the State of California) to meet all 115% of peak load through an ACR requirement. It may be necessary to phase in some of the ACR requirements and allow some variations from the complete design. There might be a state purchaser to procure the ACR or, as a last resort, the ISO may have to act as the purchaser of any deficiency. The penalty for an LSE for failure to secure ACR capacity may simply be the actual cost that ISO or the State pays to secure the service. Given the short time available to implement ACR, the obligation may be phased in from May to July 2001. The reserve margin of 15% can be lowered in the first summer if expectations are that 15% reserve on peak demand is simply not available in the WSCC region for summer of 2001.

If ACR is implemented, the details of the availability standard will become contract obligations for the ACR supplier. The supplier, having received payment for the ACR services, must deliver or face a penalty. Thus the availability requirement applies to ACR resources with zero tolerance for forced outages.

If ACR is implemented to discourage physical withholding, then the allowable fixed margin stipulated for the mitigation of economic withholding (which is defined as variable cost plus a fixed margin; see section 2.4) could be lowered since part or all of the fixed cost is recovered through the ACR contract.

2.2.3 General Availability Standards to Protect against Physical Withholding of Capacity

One means of exercising market power is the ability of generation owners to restrict output or withhold part of their capacity from the supply available to meet system demand. This can be done by declaring to the ISO that a particular unit has been forced out-of-service or experienced a forced deration. Alternatively, the unit owner can physically withhold by simply not bidding a unit's entire capacity into the market (day-ahead or real-time). The fact that there are certain times of the year when less efficient units are unlikely to be economic does not justify not bidding these units into the market. As long as there are markets where the unit can be bid in a manner that ensures it will be able to recover its operating cost if some or all of its bids are selected, all available capacity should be bid into these markets regardless of the likelihood of dispatch. While this requirement may seem superfluous at certain times of the year, it is absolutely essential to mitigate against physical withholding during those times of the year where the issue of whether a unit is "economic" is highly debatable.

Some have argued that the ISO's current market design does not enable participants to submit bids in a manner that ensures the unit owner will be made whole if some or all of its bids are accepted. The ISO recognizes that since it awards ancillary service on an hourly basis in its Day-ahead Ancillary Service Market, it can be problematic for a unit to fully recover its operating costs. For instance, if an unit is only awarded ancillary service in the day-ahead market for one

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8 A proportional margin with load, 1.15/0.85, over the minimum 70% forward contract requirement for generation, would give a requirement of about 95%.

9 For out-of-state suppliers there is no mandatory required quantity for ACR service. However, they will be required to provide long-term energy contracts to CA LSEs, at just and reasonable rates, equal to 70% of their previous year's monthly sales into California as a condition for more lenient market power mitigation for their remaining California sales.

hour of the day and has no other forward schedules for that unit, the capacity payment for that award may not cover its full start-up and no load costs. Furthermore, the unit owner would have no assurance that it could recover the costs through additional bids and awards in the hour-ahead and real-time market. In this regard, forcing the unit to bid into the day-ahead market may expose the unit to a financial risk that it would not be voluntarily willing to undertake. To address this concern, the ISO may consider a "block ancillary service market". This will be strictly a day-ahead market and will consist of "peak" (hours ending 7-22) and "off-peak" blocks (hours ending 1-6 and 23-24). With the ability to submit ancillary service bids over a 8-hour and/or a 16-hour block, a unit owner can bid so that it adequately covers its start-up and no load costs. This new block market could operate in parallel with the ISO's existing hourly day-ahead market but will only be utilized when the ISO is unable to meet its day-ahead ancillary service requirements through the hourly day-ahead market (i.e., bid insufficiency in the day-ahead hourly A/S market). When this occurs, the shortfall could be purchased from the block market (and the hourly markets re-run accordingly before publishing final A/S market procurement results). Generation resources having start-up times greater than 2 hours will be required to bid their full available capacity into the day-ahead market (hourly or block). If after the close of the day-ahead market, a unit with a start time longer than 2 hours has no day-ahead energy schedule or ancillary service award, it will not be required to bid into the hour-ahead or real-time market. However, if the unit does have a day-ahead energy schedule or ancillary service award, it will be required to bid all remaining capacity into the hour-ahead and real-time markets.

As long as generation has an opportunity to bid in a manner that reasonably ensures it can cover its costs, the ISO sees no reason why all available generation (whether or not ACR) should not be scheduled or bid into the ISO market and believes such a requirement is essential for reliability and market efficiency. For these reasons, the mitigation plan has general availability standards to regulate resources not covered under ACR contract. Three main options were considered to enforce the general availability standards:

1. Penalty for all unscheduled outages where the risk of a generation outage which is not planned and scheduled with the ISO is the replacement cost of the energy priced at the real-time market. This risk is best managed by the generation owner and not by the ISO in real-time.
2. Predetermined allowance of forced outage within a rolling time window; and
3. Market price weighted forced outage allowance in a outage budget. This budget would be based on market clearing price deviations during forced outages compared to seasonal or annual average market prices.[10]

Option 1 gives the strongest incentive to generation owners to minimize outages. It is our preferred option especially in combination with the ACR. If option 1 is not used or ACR is not implemented, then option 3 would be second best. Option 3 could also be used in conjunction with non-ACR units. Option 3 allows reasonable forced outages but weights them more on hours with higher prices, i.e., the most likely time for physical withholding.

A complete availability standard must include the requirement that all scheduled or dispatched generation does deliver in the operating hour. Criteria and penalties must apply to under-generation or under-scheduled load and the two sets of penalties (one for not bidding in market, and the other for not delivering what has been scheduled) must be consistent to prevent gaming

[10] Option 3 measures the correlation between forced outages and market-clearing prices (MCP). Average MCP computed for randomly occurring forced outages during a season or a year would likely be close to the seasonal or annual average MCP. Any excess beyond a confidence interval would hint at potential physical withholding.

to seek the form of withholding with lesser penalty. This is illustrated by the NYISO market power mitigation measure. In the category of physical withholding they have a provision of no less than 90% delivery of dispatched generation.

2.3 Step 3. Local Market Power Mitigation

Local market power arises primarily in two types of situations. The first results from a well-known problem with the ISO's current congestion management (CM) protocols, whereby intra-zonal congestion is not managed in the forward markets, thus allowing infeasible forward schedules to be established and ultimately requiring the ISO to issue corrective dispatch orders in real time. The second results from significant changes to system conditions that occur after the close of the forward markets and create additional reliability needs in specific areas of the grid. Fixing the first problem requires substantial reforms to forward CM, which are being addressed in the ISO's CM Reform effort. Some of these reforms may not be able to be implemented until 2002, however, so the present proposal does not attempt to address the infeasible scheduling problem. Rather, this proposal provides a means to mitigate the impact of local market power under both of the two situations identified above.

- **The Permanent Solution.** The ISO's CM Reform proposal will address the infeasible scheduling problem in forward CM, and will include a comprehensive approach to local reliability and local market power. This approach will cover both the forward and real-time markets, and both the ongoing needs of the local reliability areas (LRAs), which are currently met primarily through resources under Reliability Must Run (RMR) contracts, and any temporary needs that may arise due to planned or forced outages or other abnormal system conditions, which are currently met through out-of-market (OOM) or out-of-sequence (OOS) dispatch orders. At present, the ISO envisions implementing CM Reform, subject to FERC approval, during 2002.
- **The Interim Approach.** Until CM Reform is implemented the ISO needs an interim mechanism to allow it to call upon specific resources at mitigated prices when they are needed to ensure local reliability in situations where RMR units are not available.

  One possible approach being considered for this interim period has two components: (1) a rule for deciding when a specific resource's bid should be mitigated; and (2) specification of the mitigated bid that will be used in place of the resource's actual (unmitigated) bid. It is important to note that this proposal would apply only in instances where the needed resource has a real-time energy bid in the market. If the needed resource does not have a bid in the market, the ISO may use its existing out-of-market (OOM) authority to dispatch the resource at a mitigated price.

  (1). Rule for deciding when to mitigate a resource's bid

  When a resource is needed in real time at a specific location to ensure reliable operation of the grid, and it was not dispatched in the normal merit order to provide Imbalance Energy to the system, then it will be deemed to possess locational market power and its bid will be mitigated for the amount of additional MWh needed to meet the local reliability need.

  (2). Alternative bids to use when a resource's bid is mitigated

  When a resource's actual bid must be mitigated because the resource is needed in real-time for local reliability but it was not dispatched in merit order to provide Imbalance Energy, then its actual bid will be replaced by one of the following alternatives, in decreasing order of preference. Under each of these alternatives, the resource would receive the higher of its mitigated bid or the applicable real-time price.

(a) The variable operating cost of the resource, verifiable and on file with the ISO. In some cases the operating cost may not adequately cover the resource's actual cost of complying with the ISO's dispatch instruction, for example, if the resource is not running at the time of the instruction and the ISO requires it to start up. In such cases the resource owner can submit a verifiable claim and receive addition payment.

(b) If option (a) is not possible because this information is not available, calculate a weighted average of all the real-time prices or payments earned by the same resource over the past 30 days when it was dispatched in merit order to provide Imbalance Energy. The average will be weighted so as to adjust for similar operating conditions (e.g., day of week, operating hour, system load level).

(c) If options (a) and (b) are not possible, use the variable operating cost of a similar resource (i.e., a unit of the same fuel type and similar size).

Since the bid price mitigation under the condition of locational market power is to lower the bid price to variable cost this can potentially result in payment for resources in congested areas lower than non-congested areas. To prevent this inconsistent incentive, the resource will receive the higher of its mitigated bid and the real-time price in the zone where it resides.

2.4 Step 4: Mitigation of economic withholding in the real-time and other short-term markets.

Although not the core component of market power mitigation, some measures to protect the remaining real-time market and the Ancillary Service markets is still needed. As discussed in Step 2, availability standards will mitigate one form of exercising market power, physical withholding. Bid mitigation will curb the other form of market power, economic withholding.

The mitigation measures proposed here encompass the following areas:

- Bid price monitoring and mitigation in the real-time and Ancillary Services markets;
- Measures to discourage real-time transactions and to keep real-time transaction to 3-5% of total load; and
- Price monitoring and mitigation in other short-term contracts or markets.

It also discusses using a lower margin (possibly zero) and payment cap equal to their mitigated bid price to give disincentives to suppliers who do not comply with the long-term contract requirement.

Except for the manner in which the margin above variable cost is treated, mitigation measures for economic withholding as proposed are consistent for system-wide and local market power mitigation. In both cases the variable cost (or a surrogate based on recent successful bids in competitive market conditions) is used as a component of the mitigated bid, with provision for recovery of additional cost through either an allowable margin above variable cost (for system-wide needs) or an after-the-fact true up based on verifiable cost (for locational needs). For the long-term, however, because of higher frequency of occurrence and predictability of local reliability requirements, fixed payments will be made up front for local reliability resources rather than included as a margin in their mitigated bids or paid through an ex post true up.

2.4.1 Real Time Market Mitigation

The basic goal of resource specific mitigation is to curtail economic withholding. One possibility for accomplishing this is to use a bid price threshold equals to variable cost (or opportunity cost for energy-limited resources) plus a margin that considers fixed-cost recovery and market conditions. Assuming that long-term contracts play the main role of market power mitigation and the rules to minimize real-time imbalance energy market are in place, the bid price threshold can be much more generous than the just and reasonable pricing criterion for long-term contracts. The other reason that a bid price threshold should be generous is to allow the market to send strong price signals to both demand and supply to provide incentives for new investment in generation and development of price responsive demand.

- The variable cost formula will be a simple standard formula that allows fuel cost for thermal plants and opportunity cost for hydro plants. It may not allow emission cost as part of the variable cost, but instead will offer some adder in the margin to allow for investment in emission reduction equipment. Some form of opportunity cost may be used for energy limited hydro generation plants, which may depend on water availability and checked with a forward price duration curve for the region.
- The fixed margin will be based on the need to recover fixed cost, start-up and low load costs, and risk. Since a fixed cost requirement is an annual lump-sum number, the hourly margin or threshold will consider the frequency the threshold will be hit.
- With the frequency of hitting the threshold expected to fall when more new generation comes on line, the margin should be increased in subsequent years.
- The design will strive for simplicity and transparency with threshold (variable cost plus margin) set at large round numbers, such as $200, $250, $300, in intervals of $50. These margins may be lower if the ACR requirement is in place and provides additional revenue for fixed cost recovery.
- Bid mitigation may need to apply to imports as well. It is the same format of variable cost plus a fixed dollar value margin. The difference may be in the calculation of variable cost. Due to the lack of unit specific cost information and due to the difficulty of identifying specific sources of generation outside of the ISO control area, the variable cost may be based on a regional system marginal cost. Since the fixed margin is designed to be fairly generous, there is no need to have a very accurate variable cost estimate. A few broad regional load levels can be used to estimate a few regional marginal costs, which will be indexed to fuel price, if meaningful. The relevant geographic region can be drawn broadly, for example, the Northwest Region and the Southwest Region. On any given day, all imports from the same region could be subject to the same bid price caps. Alternatively, it is possible to use the recent (past 90 days) successful bids from a resource under competitive market conditions for comparable system conditions (e.g., load forecast level) as a surrogate for its "variable cost".
- As a deterrent to refusal to supplying power under a long-term contract, in-state generators contracting less than the percentage requirements reported in Table 1 or importers contracting less than 70% of previous year's sales would receive more restrictive real-time price mitigation, including a lower fixed margin and *payment cap* under which unit owners would be paid the mitigated bid price instead of market clearing price. The lower margin may only pay for forward looking fixed cost and provide no allowance for return on investment or may be set to zero.
- The market power mitigation will be executed in real time, and unit owners should be notified of their generation units' bid price thresholds at the beginning of each week. If any bid exceeds the threshold for the unit it will be mitigated down to the threshold. After bid price mitigation, all dispatched generation and import that satisfies the forward contract threshold requirement will receive the market clearing price in the real-time market. As noted above, resources without adequate forward contracts (non-compliant

resources) will be *paid as-bid*, so that the mitigated bid price would function as a payment cap for these resources.

- The value of the fixed margin is the key parameter for the bid price mitigation. There are a few considerations in determining the fixed margin: the design and coverage of the long-term contract, the design of the available capacity reserve requirement, and the resulting market power impact in the next two or three years. For example, the requirement and outcome of long-term contracts will affect the appropriate value at which the margin should be set. The higher the rate set for the long-term contract, the lower the margin in real time, whereas the higher the fraction of system load covered by long-term contract the higher the margin. In addition, the ACR provision should also reduce the fixed margin, since a large part or all of the fixed cost may be recovered from the ACR contract payment made by LSEs. Finally, the ISO should have the discretion to adjust the fixed margin based on the market monitoring results. If the overall market power impact is too high, the margin may be lowered and vice versa. As an initial reference value, we propose the following value for the fixed margin. Assuming ACR is implemented, and assuming the rate for long-term contract is very close to the cost of production, the fixed margin as a function of percent of ISO system load covered by long-term contracts, might look like the following:

Long-term Contract Coverage	Fixed Margin
60%	$ 50
70%	$100
80%	$200
90%	$500

These fixed margins can be adjusted annually as competitive conditions (i.e. supply sufficiency, demand responsiveness) change. As market conditions become more competitive the fixed margins can be increased. Of course, once markets become more fully competitive, the real-time market bid mitigation measures could be completely removed. The margins show above would apply to all generators and importers that have met the long-term energy contracting requirements. As mentioned above, generators and importers that have not meet their long-term contracting requirements would be subject to a smaller fixed margin and would be paid as-bid rather than the MCP.

- The variable cost allowance will be based on the average fuel prices of the previous week and will only be adjusted if the average fuel price moves by more than 5% or $5, which ever is larger. In special cases if the price jump within a week will likely produce a change in average prices greater than twice the weekly change threshold (10% or $10), the allowance can be adjusted within a week.

2.4.2 Measures to minimize real time transaction

Measures to minimize real-time transactions are critical to the effectiveness of the bid price mitigation. The Commission's Order on December 15, 2000 required all market participants to preschedule all of their resources and loads with the ISO and to limit their real-time energy purchases from the ISO to no more than 5 percent of their total load. The Commission also imposed penalties on underscheduled load and removed incentives for resources to favor the real-time market.

In its compliance filing of January 2, 2001, the ISO adopted the policy stated in the FERC order involving a penalty of twice the real-time price, but no more than $100/MWh, on real-time load that exceeds the scheduled load by 5% or more. A 10 MW minimum deviation allowance was made to accommodate smaller load entities (e.g., a 100 MW metered load with a schedule of 91 MW (9% real-time deviation) would not incur an underscheduling penalty). The penalty revenues will be distributed to those market participants that scheduled accurately during the same trading hour. In its request for rehearing, filed January 16, 2001, the ISO requested that FERC extend the underscheduling penalty to generation as well. However, if the resource specific bid mitigation measures contained in this proposal are implemented and sufficient forward contracting does occur, the extension of the underscheduling penalty to generation may not be needed. Under these conditions, the more stringent real-time bid price mitigation measures that are proposed for suppliers who do not adequately forward contract should be a sufficient penalty.

2.4.3 Ancillary Services Markets

Market power mitigation measures are needed for the Ancillary Services (A/S) markets as well. After fixing some major design flaws in its A/S market in late 1999, the ISO has had rather smooth and efficient A/S markets. However opportunities for the exercise of market power have occurred. The Rational Buyer procedure has been very effective in reducing the impact of economic withholding, and we intend to preserve it.

It is difficult to determine an appropriate cost for ancillary service bids. One could argue that the cost of providing ancillary service is simply the opportunity cost of not selling it as energy, i.e. the foregone profit (MCP-variable cost). However, as discussed earlier, there may be significant start-up and no-load costs associated with providing ancillary services.

Given the complexity associated with trying to determine the reasonableness of an ancillary service bid, the ISO favors applying resource specific bid caps that are based on the average ancillary service bid price of that unit in hours where the market was competitive and the bid was selected. The same fixed margin applied to the real-time market would be added to the average bid price and this sum would constitute a bid price threshold for ancillary services. The average bid price would be computed for hours over the preceding 90 days where the units ancillary service bid was accepted and the market was competitive (market RSI exceeded 150%). If the unit had no awarded ancillary service bids in the competitive hours of the preceding 90 days, the average MCP during those competitive hours would be used instead

2.4.4 Other Short-term Markets and Contracts

Other short term contracts and forward markets will be needed to fill in the gap between long-term contracts and short-term unhedged load. It is currently uncertain whether this will represent 40% of load or 10% of load, depending upon the success of the long-term energy contract negotiations currently underway between the State of California and market participants.

- Short-term contracts and forward market transaction prices would be reported to FERC or any designated agency for review and be checked against a predetermined threshold.
- Price mitigation can be based on a general formula of variable cost plus a margin that allows fixed cost recovery including a reasonable return to investment. Although we outline a mechanism below to illustrate the option of price mitigation in the short-term market, it is not intended to prescribe the actual implementation. We believe FERC or some other regulatory body must go beyond a simple formula to review all transactions of each supplier in a longer period of time, such as a season, to determine any necessary price mitigation.
- The variable cost calculation will use standardized formulas and fuel cost indices.

- The margin will be calculated based on the margin threshold set for the real-time market with a sliding scale based on the length of the contract. The longer the contract, the lower the margin allowance.
- The suppliers who do not satisfy the long-term contract requirement (the non-compliant suppliers) will be subject to lower margin allowances linked to the lower margin set for them in the real-time market.

In conjunction with the price mitigation in the real-time market, additional provisions may be needed to discourage or limit "megawatt laundering" while allowing California UDCs to compete at the margin during times of true regional scarcity. Some of the provisions are as follows:

- Strict requirements for reporting bilateral contracts, perhaps with heightened requirements (including pre-approval) for any arrangements including "buy-back" or "supply-back" provisions and/or arrangements in which payments or contract terms are linked to prices or conditions in the California market.
- Total portfolio reporting requirements on suppliers including power marketers that place burdens on these entities to prepare and file reports showing the hourly gross and net flow of power from different supply sources and sales sinks. The reports should explicitly show a reported cost of supply offered into the ISO's real time market as an import.
- Provide notice that arrangements are subject to refund and sanctions if they are designed to or have the effect of displacing thermal generation within the ISO or from a thermal generation source outside the control area as the source of energy bid into the ISO's market as an import from a different source. A simple rule of thumb that might be adopted is that refunds would be based on an assumed cost derived based on a relatively low heat rate (10,000 Btu) multiplied by index of gas costs based on futures prices (e.g., So Cal Border or PG&E Citygate).
- Other general reporting requirement for bilateral contracts is discussed in Section 2.4.5.

One critical question is if there is enough supply (or willing supply) to meet the need of full system load in the form of long-term and short-term contracts and forward market purchases. It is also not entirely clear what form a short-term forward market will take, and how to implement the market power mitigation measure proposed above.

There is also a proposal for a regional price cap. It may or may not displace the need for this type of short-term mitigation, depending on the design of the regional price cap and the coverage of the long-term contract. Properly designed and coordinated with the rest of the market power mitigation components, a regional price cap can be very effective in market power mitigation.

2.4.5 Bilateral Contract Monitoring

To effectively monitor the compliance of long-term contract requirement in California electric markets, the FERC will need information pertaining to long-term contracts between suppliers and LSEs. The FERC will therefore need to institute rules for the submission of information related to long-term contracts. Provided below is a general outline of information that should be required for all bilateral contracts to ensure that FERC can assess key characteristics of the contract, including specific prices, quantities, and operational parameters of the transaction.

1. General Contract Information Requirements:
   - Contract Type – whether the transaction in an Internal Transaction (i.e., between the LSE and another division of the same parent company) or External Transaction

- Contract Parties – named seller and buyer to the transaction and all affiliations
- Market Products – energy and/or ancillary services
- Contract Duration – the start date and time and end date and time for the transaction.

2. Contract Detail Information
   - Asset Contract Details – the name of a specific generator or load asset and the percentage of that asset that is being sold or purchased in the transaction
   - Contract Price and Quantity Information
     - Price – the prices that are applicable to the relevant market product quantities submitted for the transaction
     - Quantity – the MW amount or percentage entitlement representing the availability of the contract for the transaction
   - Must take portion of the contract
   - Dispatch Information
3. Schedule Information – The schedule information consists of data related to the transmission reservations and operational tagging requirements associated with the transaction.
4. Non-Standard Contract Provisions
   - High Operating Limit
   - Low Operating Limit
   - Ramp Rate
   - Minimum Run Time
   - Start Time from Hot Conditions
   - Start Time from Cold Conditions
   - Minimum Down Time
5. Any Pre-Determined Conditions – conditions that determines the extent to which a contracted product is available to the buyer in any given period.

2.4.6 Streamline Investigations and Increase Penalty and Sanction Authority

Although the ISO's Market Monitoring and Information Protocol (MMIP) provides broad authority for the ISO to identify practices subject to scrutiny and identify potential abuses of market power, the MMIP fails to specify explicit penalties or sanctions for such behavior. On several occasions, the ISO has been denied site access or access to company information and had no authority to invoke penalties or sanctions against such behavior.

The ISO believes a code of conduct for market participants with sanctioning authority by the CEO and ISO Governing Board is essential to a well functioning market. The ISO would like to work with the FERC staff to develop a streamlined investigative processes as well as a code of conduct for market participants.

The ISO recommends an investigative process that involves a review of market incidences, notification to market participant of any violation of market rules or code of conduct, opportunity for reply, and referral of any action on penalties and sanction to the CEO and ISO Board. The Department of Market Analysis could carry out the investigation in coordination and consultation with the ISO Market Surveillance Committee (MSC). A process to recommend penalties and sanction would need to be established by the CEO and ISO Board. This would also require an appeal process. FERC's input is needed on whether the Commission or some other agency should review and rule on the appeals.

Sanctionable behavior may be defined as any of the following:

1) Failure to perform in markets such as the failure to provide energy, services, or respond to dispatch instructions;

2) Failure by market participants to provide requested data and information, or refusal of ISO inspection at any participating generating facility ;

3) Abuse of market power through physical withholding and economic withholding and abuse of locational market power beyond the limits set in the market power mitigation plan;

4) Activities of gaming the market rules, i.e., take advantage of market rules to engage in bidding, scheduling and operation activities that seek profit or other self-interest for the market participant but result in significant damage and cost to the overall market or other market participants; Due to the complexity of gaming and unpredictability, not all sanctionable gaming behavior can be all specified in advance. The Department of Market Analysis will conduct inquires and investigations, allow for response the market participant being investigated, issue warnings to market participants, and bring violations to the CEO and ISO Board who would have authority to levy penalize violation including publication of the violation.

5) Inaccurate Bid or Operating Information such as the understatement of a units high operating limit, misrepresentation regarding operating conditions, or the misrepresentation of resource availability; and

6) Failure to follow ISO instructions such as the failure to follow scheduling procedures, transmission instructions, or information.

Monetary penalties will be based on the impact the infraction had on the market. The CEO should have the authority to apply a factor of 3 to any monetary penalty that involves market power mitigation. Also the penalty must be larger than the profit extracted through the sanctionable behavior.

This investigative and enforcement function should have the ability to mitigate bids or use other corrective actions before markets are run. Such mitigation should allow the exclusion of bids from the market, the adjustment of bids to some predetermined level, and the ability to force the submission of bids when participants have inappropriately withheld bids from the market. In addition, sanctions should include publication of violation of market rules, abuse of market power, gaming and other anomalous activities. The DMA should also report these anomalous activities to FERC and other regulatory agency and request additional sanction.

2.5 Comparison of Market Power Mitigation Plans in other ISOs

The following table summarizes the main features of CAISO's proposed Market Power Mitigation Plan, along with related or comparable measures adopted by the Eastern ISOs.

Table 2. The Market Power Mitigation Plan of the California ISO in Comparison to Current Market Power Mitigation Measures in the Eastern ISOs

	CA ISO (Proposal)	PJM	ISO-NE	NYISO
Long Term Contract	The fundamental part of the market power mitigation plan. To cover large fraction of load at a just and reasonable rate. Obligation for LSE to procure long-term contract to cover a large fraction of their load and for generation owners (in-state and out-of-state) to supply a large fraction of their capacity for long-term contract. Contract rate are subject to review to ensure it be just and reasonable.	No mandatory requirement but widely used by LSE.	No mandatory requirement but widely used by LSE.	No mandatory requirement but widely used by LSE.
Installed Capacity Markets	Mandatory Available Capacity Reserve Requirement (ACR). LSE to secure available generation capacity to cover 115% of their annual peak load. Provider of capacity resources has the obligation to make their capacity available in the California market and follow dispatch instruction. Penalty to suppliers for	ICAP obligation about 120% of LSE's annual peak. Eligible ICAP capacity = Capacity*(1-FOR) ICAP mostly (96%) self-provided, or bilateral. ISO conducts daily, monthly, seasonal, and annual auctions. Average prices $18-25/kW-yr.	ICAP obligation on monthly basis, based on the Loss of Load Probability (once in 10 years) of the LSE. ICAP market was volatile with prices varying from $0/kW-yr to $120/kW-yr ICAP auction eliminated as of Aug 1, '00. De facto price = penalty for failure to provide ICAP= $105/kW-yr	ICAP obligation 118% of LSE's coincident peak for winter and summer. ISO conducts 6-month and monthly auctions. De facto price = penalty for failure to provide ICAP= $150/kW-yr Explicit price cap in new York and LI: $105/kW-yr

	CA ISO (Proposal)	PJM	ISO-NE	NYISO
	unavailable capacity. No auction market for capacity resources initially and LSE can either self provide ACR or pay ISO to purchase the capacity for them.	Price cap: $128/kW-yr.		
Physical Withholding Mitigation	Option 1(In combination with ACR) Penalty for all unscheduled outages or any unavailability. Option 2: Penalty based on outages weighted by market clearing prices. This further discourages physical withholding at times of high prices. Option 1 will be adopted if ACR is approved by FERC, and option 2 will be used if ACR is not implemented. All these measures also depend on outage scheduling being closely managed by ISO (see outage coordination items below.	Requirement on ICAP units (almost all units) to bid all available capacity in day-ahead market. Unit can hold back an amount, (Max_op – Max_economic) for liquidated damages. No penalty for capacity withholding. No restriction to export power, but must cut export under system emergency. Almost 96% of capacity under bilateral contracts.	Market Rule 3 requires all units to bid full capacity. No restriction to export power, but must cut export under system emergency.	Dependable Maximum Net Capability (DMNC) based on 4-hr continuous rating of unit is reference for capacity withholding. Also use as max eligible ICAP. Physical withholding is assessed if the unit fails to show up in the market (energy plus A/S, including exports) at 90% or higher of its DMNC, or if the units in a generation owner's portfolio show up in the market below 95% of the total portfolio DMNC, AND such conduct causes or contributes to a material change in one or more NYISO markets. For large units and portfolios the withholding allowances are smaller (lower of 10% or 100 MW at unit level and lower 5% or 200 MW at portfolio level). Physical withholding is assessed in real-time if the unit operates below 90% of the NYISO instructed (dispatch) level.
Economic Withholding Mitigation	Safety-net: Resource specific bid caps in real time market and price threshold in other short-term market Threshold is based on variable cost plus a fixed margin. The threshold will be	No specific penalties or sanctions against economic withholding.	Broad ISO authority prior to July 2000 to sanction or penalize for economic withholding; FERC ordered development of brightline measures. ISO filed Nov. 1, along the lines of NYISO; no FERC decision yet.	Reference levels (default bids) defined as the lower of the mean or median of a unit's accepted bids over the previous 90 days for similar hours or load levels, adjusted for fuel prices. Economic withholding is

<table>
<tr><th></th><th>CA ISO
(Proposal)</th><th>PJM</th><th>ISO-NE</th><th>NYISO</th></tr>
<tr><td></td><td>announced to generation owners at the beginning of each week and bids above the threshold will be mitigated before real time operation.

In other short-term market, all transactions must be reported to FERC or a designated agency for review against price threshold. Threshold will be based on the real time fixed margin but reduced as the length of contract increase.</td><td></td><td></td><td>assessed if a bid exceeds the reference price by:
- The lower of $100/MWh or 300% for Energy or reserves (other than Spinning Reserve),
- The lower of $50/MWh or 300% for Spinning Reserve, or 200% for start-up.

These measures have not been effective to mitigate economic withholding. NYISO has had to institute a price cap of $2.52 in the Non-spinning Reserve market.</td></tr>
<tr><td>Locational Market Power Mitigation</td><td>[Interim Measure]

Unit-specific bid caps apply for units dispatched out of merit order due to congestion. The unit-specific bid caps may be based on:

(a) The incremental operating cost of the resource, verifiable and on file with the ISO.

(b) If option (a) is not possible because this information is not available, calculate a weighted average of all competitive real-time prices earned by the same resource over the past 30 days when it was dispatched in merit order.

(c) If options (a) and (b) are not possible, use the incremental operating cost of a similar resource.</td><td>Unit-specific bid caps apply for units dispatched out of merit order due to congestion, if the commissioning of the unit commenced before July 1996 (which includes the majority of the in-control area units).

The unit-specific bid caps may be based on:
1) the unit's variable cost, as filed, plus 10%,
2) weighted average of Locational Marginal Prices at the unit's location during recent periods when the resource was dispatched in economic merit order, or
3) a pre-negotiated price.</td><td>Structural and price screens are used to determine whether or not to invoke mitigation under congestion conditions.

In cases of local market power, the ISO pays a default compensation to generators based on a mitigated price.

The mitigated price is based on short-run marginal costs; however, generators are allowed the opportunity to demonstrate cost data to support a higher level of compensation.</td><td>Mitigated bid caps are used for congestion constrained areas, if constrained nodal prices exceed the price at a relatively unconstrained node (Indian Point) by more than 5%.

For local reliability day-ahead SCUC commits additional units in its Pass 3 (i.e., after allocating competitive bids without regard to local reliability needs). The uplift to meet local reliability requirements is charged to the loads within the zone where local reliability requires the incremental commitment</td></tr>
<tr><td>Other Market Power Mitigation</td><td>Long-term contract that covers majority of load and at just and reasonable rate. This will be the fundamental measure for</td><td>$1,000 bid cap. Large amount of bilateral contract. ICAP market.</td><td>$1,000 bid cap. Some long term contract.</td><td>$1,000 bid cap. Some long term contract. ICAP market.</td></tr>
</table>

	CA ISO (Proposal)	PJM	ISO-NE	NYISO
Measures	*market power mitigation in CA market.* Discourage real time transaction.			
Outage Coordination	Generation owners to provide annual maintenance schedules to the ISO, along with adjustment windows. ISO to advise adjustments within the adjustment windows provided by unit owners to levelize reliability throughout the year. Provisions for seasonal revisions and updates. Deviations from agreed upon baseline maintenance schedules subject to ISO approval. Unauthorized changes subject to penalty. Reporting requirements for forced outages. ISO authority to access plant premises and records to verify forced outages.	Units are required to coordinate maintenance outages with the ISO. No penalty for not following maintenance schedules. Indirect penalty , derate of eligible ICAP, (1-FOR)*CAP	Units are required to submit annual maintenance schedules to the ISO. ISO levelizes reliability levels throughout the year. Modifications up to 5 days before planned outage. No limitations on forced outages. Generators can not deny ISO access to facilities or logs.	Generation and Transmission owners coordinate maintenance schedules. ISO can ask for modifications based on reliability. No specific penalties for forced outages or deviations from maintenance schedules. ISO has authority to request outage records and make site visits to verify.