January 31, 2002

The Honorable Magalie Roman Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: California Independent System Operator Corporation,
Docket No. ER02-____-000
Amendment No. 42 to the ISO Tariff

Dear Secretary Salas:

Pursuant to Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, and Sections 35.11 and 35.13 of the Commission's regulations, 18 C.F.R. §§ 35.11, 35.13, the California Independent System Operator Corporation ("ISO")[1] respectfully submits for filing an original and six copies of an amendment ("Amendment No. 42") to the ISO Tariff. Amendment No. 42 would modify the Tariff in the following respects:

- New provisions to facilitate participation in the ISO markets by eligible intermittent resources (*e.g.,* wind);
- Changes in allocation for ISO Settlement Charge Type 487;
- Changes in management of Intra-zonal Congestion; and
- Changes in the calculation of the Target Price for incremental and decremental Imbalance Energy bids.

Revised Tariff sheets reflecting the changes proposed herein are contained in Attachment A and black-lined Tariff sheets are contained in Attachment B.

[1] Capitalized terms not otherwise defined herein are defined in the Master Definitions Supplement, ISO Tariff Appendix A, as filed August 15, 1997, and subsequently revised.

I. THE PROPOSED AMENDMENTS

The proposed modifications to the ISO Tariff have been conceptually approved by Motion of the ISO Board of Governors. They are designed to enhance participation in the ISO Markets; ensure fairness in Imbalance Energy cost allocation; respond to significant operational concerns; and prevent gaming. The ISO urges the Commission to act expeditiously in favor of the proposed modifications.

A. Intermittent Resources

1. Background

Wind generators and other intermittent Energy resources have special operational characteristics. Such units generally are unable to adjust their generation output to ISO Dispatch instructions. In addition, “as-available” Energy from intermittent resources is difficult to forecast accurately for more than one or two hours into the future due to the significant variability of the fuel source, *e.g.,* wind, sunlight.

Intermittent resources, especially those based on renewable Energy sources such as wind, can be competitively priced and at times displace Energy generated from non-renewable resources, such as traditional thermal generation. While development of significant new intermittent Energy resources in California is feasible, assured access to fixed price contracts is an important requirement for acquisition of project financing for many such projects. Intermittent resources often are at a disadvantage for such fixed price contracts since their output cannot be reasonably determined very far in advance. Moreover, through participation in ISO markets, intermittent resources are likely to incur charges for failing to follow their Schedules, and, as a result, they also may be unable to submit forward Schedules and instead be forced to take variable prices in the ISO Real Time Markets.

At its July 2001 meeting, the ISO Board of Governors directed ISO Management to work with representatives of the California Wind Energy Association, the American Wind Energy Association, the Independent Energy Producers Association, the California Department of Water Resources, the Governor’s office, the investor-owned utilities and other interested parties to develop a consensus proposal for facilitating the participation of intermittent resources in ISO markets. Shared objectives include encouragement of investment in new wind, solar and other environmentally-benign intermittent Energy resources, a need for new rules for the scheduling of intermittent resources that will mitigate the variability of the financial impact of Imbalance Energy costs resulting when such resources inevitably go “off-schedule” (*e.g.,* when wind patterns change), help such projects gain access to debt financing, ensure operational reliability of the ISO Control Area while permitting grid access to such Energy resources and finally, minimize cost shifting to other Market Participants as may transpire through the effort to encourage a greater diversity in California's Energy resource portfolio.

As a result of the Intermittent Resource Working Group's efforts, a consensus was developed for the ISO to propose certain Tariff modifications to facilitate greater participation by intermittent resources.

2. Proposed Modifications

Eligible Intermittent Resources must meet both static and dynamic requirements to receive the treatment proposed herein for "Participating Intermittent Resources." Each such entity must execute the ISO's Participating Generator Agreement, install an ISO-approved meter, and install an ISO-approved Data Processing Gateway to permit the real-time telemetry of operation and meteorological data. Scheduling Coordinators for such Participating Intermittent Resources must submit Schedules that are consistent with an hourly Energy forecast that is developed under ISO supervision. The forecasting process is designed to provide statistically unbiased forecasts of generation output on an hourly basis. Participating Intermittent Resources will be assessed a fee to defray the ISO costs of the forecasting services.

The ISO proposes that all estimated Energy from Participating Intermittent Resources must be Scheduled in the Hour-Ahead Market, and that updated forecasts of Energy be available to the ISO thirty (30) minutes prior to the operating hour, to thereby minimize potential impact on ISO operations. The ISO also will monitor for any costs to the ISO and Market Participants and the impacts on ISO grid operations and reliability from unanticipated changes in Energy output from these intermittent resources. To further facilitate access to the ISO Controlled Grid and markets, the ISO also proposes certain modifications to the billing and settlement process for Participating Intermittent Resources. Specifically, settlement of Uninstructed Energy will be aggregated and netted across all BEEP Intervals in a calendar month. The net monthly deviation will be paid or charged at the monthly weighted average MCP. There is no change in the settlement of Uninstructed Energy for Scheduling Coordinators that do not represent Participating Intermittent Resources. The difference between what Participating Intermittent Resources are paid or charged for Uninstructed Imbalance Energy on the basis of net monthly deviations, and what they would have been paid or charged if such deviations had been settled by BEEP Interval, will be tracked in a balancing account and settled, as described *infra.*

The ISO proposes that ISO Settlement Charge Types ("CT") 487 and

114[2] charges to all Scheduling Coordinators initially be calculated to include deviations by Participating Intermittent Resources. Settlement of CT 487 and CT 114 with Scheduling Coordinators not representing Participating Intermittent Resources will be conducted on the basis of this initial calculation. Charges for Scheduling Coordinators representing Participating Intermittent Resources will be re-calculated by removing the charges for their uninstructed deviations. The CT 487 and CT 114 charges for Scheduling Coordinators representing Participating Intermittent Resources will be tracked across the calendar month and placed in a single balancing account. The net monthly amount in such an account will be allocated to all Scheduling Coordinators with negative uninstructed deviations *pro rata* as the proportion of their accumulated negative uninstructed deviation to the sum of all accumulated negative uninstructed deviation over the calendar month.[3] Lastly, given that the forecast models that will be used for hourly forecasting will be calibrated to be statistically unbiased, the ISO does not expect significant deviations for Participating Intermittent Resources and therefore the expected value of such allocation adjustments for deviations is expected to be small or zero.

B. Settlement Charge Type 487

1. Background

In December 2000, through adoption of ISO Tariff Amendment No. 33, the Commission authorized the ISO to establish a "soft" price cap for the purchase of real-time Imbalance Energy. 93 FERC ¶61,239 (2000), <u>reh'g pending</u>. In its April 26, 2001, Order, 95 FERC ¶61,115(2001), <u>order on reh'g</u>, 95 FERC ¶61,418 (2001), <u>reh'g pending</u>, the Commission replaced the soft price cap with a variable price cap determined by proxy bids that are based on the marginal operating costs of gas-fired units. If ISO real time Imbalance Energy requirements are such that the ISO needs to Dispatch only bids below the relevant mitigated price, the Market Clearing Price ("MCP") will be set by the highest bid price of those Dispatched bids. If ISO real time Imbalance Energy requirements are such that the ISO is required to Dispatch bids above the relevant mitigated price, the MCP will be set to the highest bid price of the Dispatched bids that are below the cap. In this way, the MCP will never exceed the mitigated price. Bids above the mitigated price, when Dispatched, are paid as bid, with the bidder receiving two payments: a CT 401 payment based on the MCP and a CT 487 payment that makes up the difference between the MCP and the bid price. The CT 487 payments (*i.e.,* "Above MCP Payments") are allocated to SCs having negative Uninstructed

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[2] Charge Type 487 is "Allocation of Excess Costs for Instructed Energy" and Charge Type 114 is "Replacement Reserve Due ISO."

[3] Inasmuch as any Participating Intermittent Resources have uninstructed negative deviations, a commensurate portion of the cost (or benefit) of such deviations will accrue to Scheduling Coordinators representing Participating Intermittent Resources.

Energy during the same trading interval (*i.e.,* negative deviations). Above MCP Payments are subject to refund if the corresponding bids are determined by the Commission to be unjust or unreasonable.

The allocation methodology for ISO CT 487 became effective on December 12, 2000. In implementation, the ISO changed CT 487 from a regional allocation to a Control Area allocation. The ISO consistently allocates the entire amount of Above MCP Payments among those Scheduling Coordinators with negative deviations.

Under ideal operational conditions, the ISO would procure just enough Instructed Energy to balance the real time Energy requirements of the ISO Control Area. Under such optimal conditions, Market Participants causing negative deviations would pay for all of the resulting Above MCP Payments. There are certain operational conditions, however, when the amount of Instructed Energy exceeds the amount of negative deviations. Such over-procurement of Instructed Energy can occur for a number of reasons, including:

- When positive Instructed Energy is needed to balance Unaccounted For Energy ("UFE") in the System;

- When positive Instructed Energy is part of a pre-dispatch of ISO Control Area interties, that cannot be altered during the following operating hour; or

- When positive Instructed Energy is needed to balance other decremental instructions that may have been pre-dispatched.

2. Proposed Modifications

The ISO proposes to allocate to Negative Instructed Deviations a modified rate equal to the total Above MCP Payments divided by the greater of the total negative deviation in the System <u>or</u> the amount of positive Instructed Energy procured above the MCP. The modified rate will achieve the following:

- When the amount of Instructed Energy procured with a cost component above the MCP is less than or equal to the amount of negative deviation, the modified rate is the same as the existing rate and the entire Above MCP Payments are allocated to the Scheduling Coordinators with negative deviations; and

- When the amount of Instructed Energy procured with a cost component above the MCP is greater than the amount of negative deviation, each Scheduling Coordinator with negative deviations will be assigned one (1) MWh of weighted average above MCP costs for each MWh of negative deviation. As a result, the total costs recovered through CT 487 will be less than the payments made through CT 481. The difference will be allocated to all Scheduling Coordinators based on their *pro rata* share of System metered Demand.

The following examples illustrate the proposed modification to calculation of the rate for CT 487:

Example 1: Instructed Energy Procured Above The MCP <= Negative Deviation

Instructed Energy at MCP = 100 MWh at $108
Instructed Energy above the MCP = 70 MWh at $120
Total system negative deviation = 100 MWh
Excess Costs (CT 481 Payment) = $ [70 * (120 – 108)] = $840

	Existing Scheme	Proposed Scheme
CT 487 Rate	$8.4/MWh ($840/100MWh)	$8.4/MWh ($840/100MWh)
Total CT 487 Charges	$840	$840

Example 2: Instructed Energy Procured Above The MCP > Negative Deviation

Instructed Energy at MCP = 100 MWh at $108
Instructed Energy above-MCP = 70 MWh at $120
Total system negative deviation = 10 MWh
Excess Costs (CT 481 Payment) = $ [70 * (120 – 108)] = $840

	Existing Scheme	Proposed Scheme
CT 487 Rate	$84/MWh ($840/10MWh)	$12/MWh ($840/70MWh)
Total CT 487 Charges	$840	$120MWh($12/10MWh)
New CT C Charges (allocated to metered demand)	N/A	$720 ($840-$120)

C. Intra-Zonal Congestion

1. Background

The ISO implemented its zonal congestion management market in 1998 under the assumption that most transmission congestion would occur *between* price zones (i.e. “inter-zonal congestion”) and that congestion *within* zones (i.e. “intra-zonal congestion”) would occur infrequently. Consequently, the ISO began operations with tools and a system to manage inter-zonal congestion in the forward markets, but with no comparable bid-based way to manage intra-zonal congestion in the forward markets.

The ISO has Reliability Must-Run ("RMR") contracts with generators that are required to run under certain conditions to maintain grid reliability. Thus the ISO has had some limited ability to dispatch RMR units, both before real-time and in real-time, to manage intra-zonal congestion. Owners of RMR Generating Units, concerned that the RMR contracts would interfere with the market prospects for their units, worked to narrow the ISO's ability to Dispatch RMR Generating Units under the RMR contracts. Ultimately, while the ISO maintained broad authority to increase a Generating Unit's output for reliability purposes through the RMR Contract, the ISO's ability to reduce such a unit's output under the RMR contract now is limited to reducing a unit's output to provide Ancillary Services.

The other tool the ISO has to manage intra-zonal congestion is the use of adjustment bids left over, *i.e.,* not Dispatched, from the forward congestion management process and incremental ("INC") and decremental ("DEC") supplemental energy bids ("INC bids" and "DEC bids," respectively). However, because the ISO does not manage intra-zonal congestion in the forward markets, these bids can only be used in real time for that purpose.

Since limited and specific criteria are used to designate RMR Generating Units,[4] such units were not available to solve every local reliability problem. This is especially true for problems that develop when transmission lines are taken off-line for maintenance or are forced out of service. Generators have realized that in situations where no RMR units could be used to mitigate intra-zonal congestion, the ISO must take a market bid out of economic merit order to re-dispatch generation to ensure reliability. Under these circumstances, supplemental Energy bid prices have increased significantly following the loss of a transmission line once generators became aware that their non-RMR units had to be re-dispatched to mitigate congestion resulting from this outage. Moreover, generators have discovered that, in situations where a transmission line was out for maintenance, requiring that the generation in that area be limited to prevent the remaining line(s) from overloading, they could schedule their unit(s) far beyond the limited local transfer capability in the forward markets and force the ISO to use their DEC bids in real-time to mitigate the resulting congestion – a process known as the "DEC game." While some DEC bids are positive, (*i.e.,* representing an amount the generator is willing to pay the ISO to reduce its output, effectively buying Energy from the ISO's Real Time Imbalance Energy Market to avoid having to generate that Energy), generators playing the DEC

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[4] The ISO designates RMR units based on the combination of a transmission line outage and a generator outage that has the greatest effect on the grid.

game often submit negative decremental bids – effectively requiring the ISO to pay *them* to *take* Energy from the ISO. While negative DEC bids and low, or even negative, prices possibly may be justifiable during System over-generation conditions, negative DEC bids submitted to the ISO under other conditions, and especially during periods of intra-zonal congestion, simply represent the exercise of local market power.

In response to this growing problem, the ISO submitted proposed Tariff Amendment No. 23 on November 10, 1999. Amendment No. 23 was intended to accomplish three things: 1) provide a new formula payment price for generation dispatched out-of-market (i.e., not according to a bid) as an alternative to the ISO's Hourly Ex Post Price, which generators claimed did not always cover their costs; 2) allow the ISO to Dispatch units out-of-market, and pay either the Hourly Ex Post Price or the new formula price to mitigate intra-zonal congestion, even when the generator had submitted a bid, if there was not a competitive supply (*i.e.,* from at least three non-affiliated suppliers) of available bids; and 3) allocate such Dispatch costs to the Participating Transmission Owner in whose area the congestion occurred.[5]

In its January 7, 2000 order,[6] the Commission accepted the new formula price for out-of-market calls and the new cost allocation methodology but rejected extending the ISO's authority to Dispatching units that had submitted bids through out-of-market calls to manage intra-zonal congestion. The Commission further directed the ISO to reform its approach to congestion management, noting:

> "[t]he ISO's proposal does not address what the ISO has identified as a fundamental flaw in the overall congestion management scheme, i.e. the intrazonal congestion program approved for the ISO is premised on competitive market solutions and now the ISO has learned that there may never be a competitive market in any circumstance involving intrazonal congestion. …. This strikes at the heart of the existing approach and calls out for the design of a comprehensive replacement congestion management approach."

January 7 Order, 90 FERC at 61,013-14.

To comply with the Commission's directive, the ISO undertook a comprehensive year-long stakeholder process to develop an alternate

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[5] Reliability Must-Run costs are allocated to the Participating Transmission Owners in whose area the RMR units are located.

[6] *Order Accepting For Filing in Part and Rejecting In Part Proposed Tariff Amendment and Directing Reevaluation of Approach to Addressing Intrazonal Congestion* 90 FERC ¶ 61,006 (2000) ("January 7 Order").

comprehensive congestion management system. However, the ISO was unable to file a proposal for an alternate congestion management system due to the crises that engulfed the California electricity markets, which necessarily focused the ISO's efforts on these matters and away from congestion management reform from late 2000 through the present time. The ISO has kept the Commission informed of the status of its congestion management redesign efforts through a series of reports.[7] In November 2001, the ISO designated a Market Design Team, which has prepared and released a high-level market redesign proposal and discussed this proposal with stakeholder groups the week of January 14, 2002.

Meanwhile, the problems of intra-zonal congestion management and the "DEC game" have continued. In a 2001 case emblematic of the problem of the market power that can be exercised through having to use unrestrained market bids to mitigate intra-zonal congestion, one supplier agreed to refund $8 million to the California ISO following an investigation directed by the Commission on this practice.[8] More recently, the addition of new generating units in California, whose output is badly needed during peak System conditions, often contributes to intra-zonal congestion and increased the opportunities generators have for playing the DEC game during off-peak conditions. Figure 1 shows the increase in intra-zonal costs experienced by the ISO in 2001:

[7] Status reports were filed on March 30, 2001, July 31, 2001 and October 31, 2001.

[8] *Order Approving Stipulation and Consent Agreement,* 95 FERC 61,167

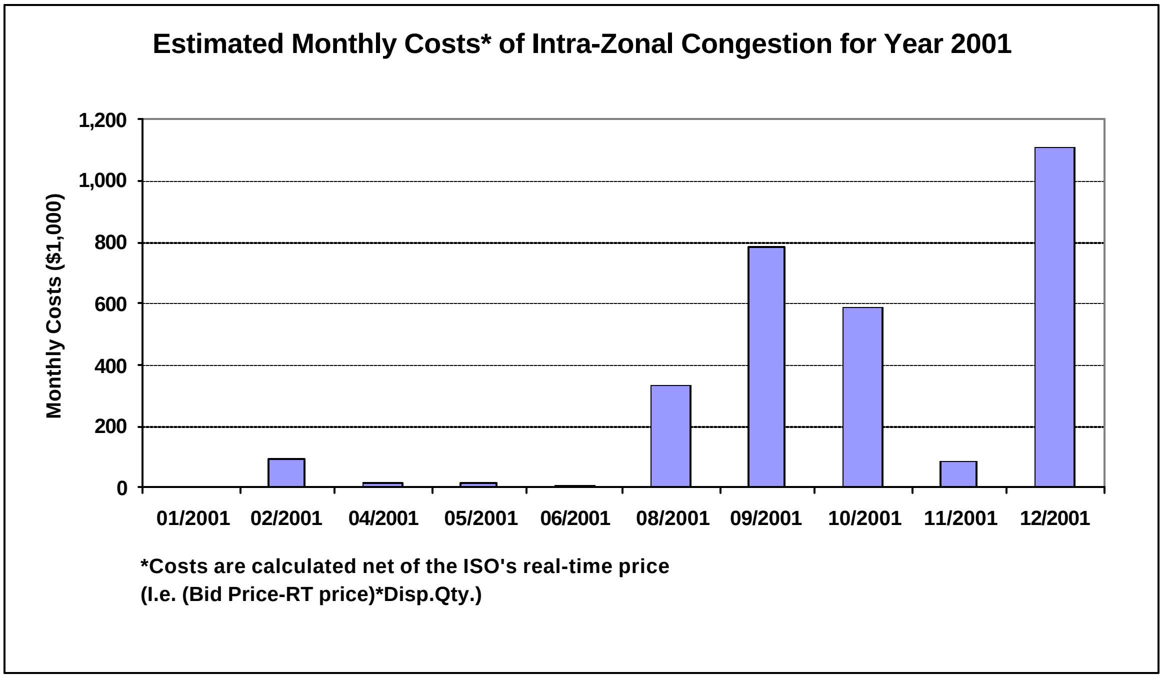

Figure 1

The ISO's Department of Market Analysis and the Commission's Market Oversight and Enforcement Staff have confronted generators playing the DEC game with negative DEC bids, sometimes successfully, but nothing in the ISO Tariff currently precludes generators from engaging in this behavior. Moreover, the ISO's inability to effectively deal with some intra-zonal congestion, including the DEC game, in the forward markets, results in an increasing burden for the ISO's real-time operations personnel. Though the ISO will comply with the Commission's requirement to submit a comprehensive plan for market redesign, including a congestion management redesign, by May 1, 2001, the ISO believes that certain actions must be in place before Summer 2002 to allow the ISO to deal effectively with this growing problem.

Moreover, the ISO is not alone in recognizing its urgent need for the ability to stop market gaming through use of negative DEC bids. The California Electricity Oversight Board ("CEOB"), in its January 15, 2002, "Complaint Requesting An Immediate Cease And Desist Order And Expansion Of 'Must-Offer' Requirement Or, In The Alternative, An Evidentiary Hearing With Fast-Track Processing,"[9] requested that the Commission require all suppliers with a Participating Generator Agreement and scheduled to run to submit to the ISO DEC bids based on avoided cost methodology.

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[9] Docket No. EL02-51-000 (2002) ("CEOB Complaint").

The CEOB Complaint specifically notes that:

> "[a]nti-competitive decremental bidding reflects continued efforts by suppliers to take advantage of California's dysfunctional market structures as well as infrastructure constraints. The presence of intra-zonal congestion facilitates the profitability of anti-competitive decremental bids. . . . . Unlike inter-zonal congestion, which refers to congestion across congestion zones, i.e., Path 15, the CAISO currently does not have a process to alleviate intra-zonal congestion in the forward market. [FN omitted]. Instead, the CAISO mitigated intra-zonal congestion in real-time and pay each supplier "as-bid." The limited geographic area of the congestion limits the number of responses capable of relieving the constraint. The result is local market power. The CAISO has observed an increase in "localized market power events" involving "large negative decremental energy bids" to reduce scheduled output. [FN omitted].
>
> The Commission has, therefore, left a gap open for gaming the CAISO's decremental energy market. Suppliers have taken advantage by exercising market power through anti-competitive, unjust and unreasonable negative decremental bids."

CEOB Complaint at 8-9.

Figure 2 below shows how the DEC game has grown through 2001:

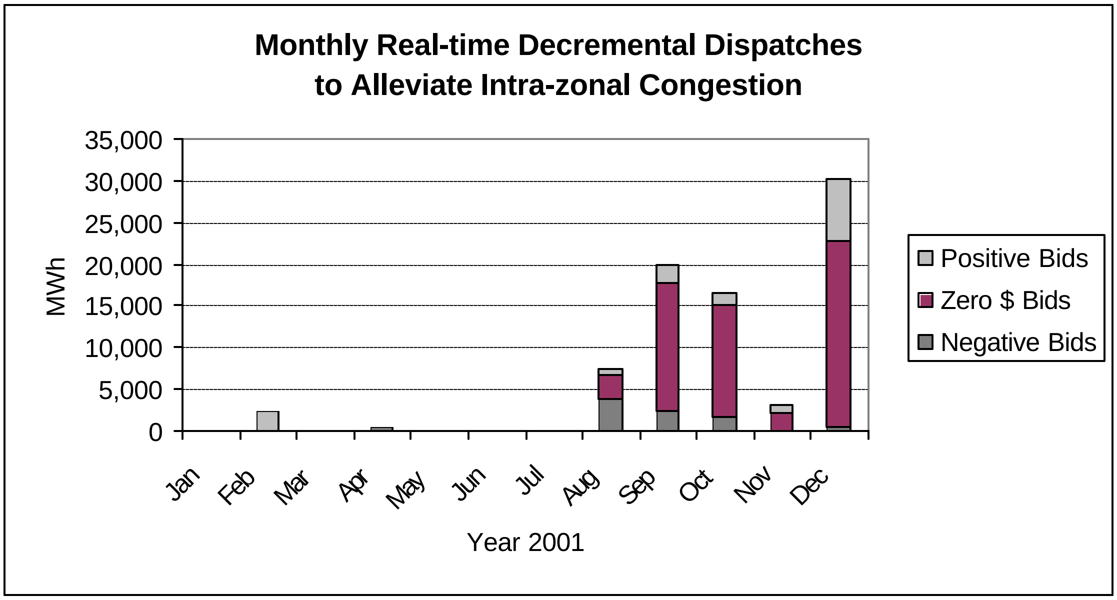

Figure 2

As noted *supra*, while efforts by ISO staff and Commission enforcement staff to discourage suppliers from submitting negative DEC bids have decreased the number of those bids, a $0/MWh DEC bid, which essentially constitutes an offer to not purchase Energy but merely take it from the ISO *for free*, thereby saving the cost of generating it instead, clearly represents the exercise of market power. It is an exercise of market power because a supplier reasonably would be expected to purchase Energy and avoid the cost of generating that Energy at a positive price just below the cost of generating that Energy themselves, and not at $0/MWh.

2. Proposed Modifications

The ISO proposes two actions. First, to eliminate the DEC game, the ISO proposes that the Commission grant to the ISO the ability to limit generators' Schedules in the forward market if the ISO determines that intra-zonal congestion would occur if generators' Schedules were not limited. Using the best information available, ISO staff will determine aggregate intra-zonal transfer limits two days before the operating day. The ISO will allocate these limits to those generators operating in this area, based on the generators' operating capability and cost.[10] The ISO then will publish those

[10] While the ISO would have preferred a market-based methodology for limiting those schedules, the ISO ultimately concluded that, since the DEC game flourishes in areas where there is a limited and, therefore, non-competitive pool of units, from which the ISO could solicit offers to limit schedules, that the ISO must limit schedules based on unit capacity and cost. Moreover, to fully extinguish the DEC game, a generator cannot somehow profit from

limits. If generators do not submit Schedules that adhere to those published limits, the ISO will adjust their Schedules with no compensation for the adjustment. This will ensure that generators cannot submit infeasible Schedules with which they could force the ISO to accept non-competitive DEC bids.

Second, to effectively mitigate congestion that may arise unpredictably in real-time while also preventing the exercise of local market power, the ISO seeks from the Commission authority to mitigate bids in real-time to the unit's cost-based proxy price if the ISO is required to use those bids to mitigate intra-zonal congestion. This authority that the ISO seeks is completely consistent with the authority already granted by the Commission to other Independent System Operators. The authority to cap bids when local congestion occurs clearly reflects the reality that local reliability problems give rise to market power for which there is no competitive solution – not in California, or in any other state.

The ISO notes that in June 2001, PJM filed a proposed amendment to its operating agreement and tariff that would extend PJM's existing authority to cost-cap must-run units beyond the day-ahead market to the real-time market as well. PJM stated that its experience over the last few years shows that it should also have the ability to cost-cap must-run units in real time, in order to prevent the exercise of market power if a transmission constraint should occur unexpectedly, so as to render, unexpectedly, a resource a must-run unit.[11]

The Commission approved this request on August 28, 2001, stating:

> "If, however, a transmission constraint occurs so as to make that unit a must-run resource, the generator could earn its high price, and that price would also become the LMP for the particular load pocket for that day. As PJM notes in its answer, this scenario has, in fact, occurred. PJM's MMU thus concluded that PJM should have the authority to cost-cap must-run units in real time in order to prevent the exercise of market power, and this proposal was approved by PJM's stakeholders. We find that PJM has persuasively demonstrated that, absent the authority to cost-cap in real time, consumers would be subject to the exercise of market power by generators, and that PJM

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the imposition of these limits, and so the ISO proposes to limit forward schedules without compensating generators for the adjustments required to adhere to the scheduling limits.

[11] PJM defines must-run units as "generation resources that…as a result of transmission constraints…must be run to ensure the reliability of service in the PJM control area". *PJM FERC Electric Tariff at 249.*

> requires authority to cost-cap must-run units in real time to prevent the exercise of market power in real time.
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> * * *
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> While no one (including PJM) can predict precisely when and where a transmission constraint may occur in real time, as stated above, a generator located within a load pocket can assume that a transmission constraint may occur so as to make its unit a must-run resource. Moreover, as described above, a generator need not predict with certainty that it will be designated a must-run resource in order to be able to exercise market power – it need only bid its generation into the market at an excessively high price, and over the course of time, it will, likely, at certain times, be designated a must-run resource. Thus, the fact that generators cannot predict exactly when they might be designated a must-run resource does not eliminate the need for PJM to be able to cost-cap units in real time so as to prevent must-run generators from exercising market power."

PJM Interconnection, L.L.C., 96 FERC ¶ 61,233, 61,936 (2001).

The findings in the Commission's order cited above and PJM's arguments hold regardless of whether congestion management is done on a nodal or zonal market structure. Since a competitive INC bid would reflect the cost of generation, an obvious mitigation measure for a unit that is already on-line is to set the mitigated INC bid to the higher of the unit's operating cost or the real time MCP (plus the 10% adder for the sale in the California market mandated by the Commission in it's June 19, 2001 order[12] as long as that provision is in effect). Similarly, the lower of a generating unit's operating cost or the real time MCP also would serve as an appropriately mitigated DEC bid since it would also represent the price at which a generator would be willing to reduce its output, avoid fuel and variable operating and maintenance costs, and instead purchase Energy from the ISO's Imbalance Energy Market.

The ISO is aware of certain shortcomings of its current zonal congestion management model and already has publicly announced its intention to move to a locational marginal pricing model that will address all grid congestion in the forward markets. On the other hand, the ISO believes that the problems discussed *supra* require it to seek immediate authority to limit Schedules in congested local areas to the physical limits of the System. Moreover, the authority to mitigate bids to eliminate locational market power is a feature of all market designs, including those of PJM and the New York

[12] 95 FERC ¶61,418 (2001).

Independent System Operator.[13] The Commission must not deny California the similar ability to mitigate bids that must be taken out of price merit order due to reliability needs.

D. Target Price

1. Background

Since inception, the ISO's Real Time Imbalance Energy Market has struggled with quantities of bids whose prices overlap (the "Price Overlap"). The Price Overlap is an unpredictable quantity of bids from Scheduling Coordinators who are willing to buy real-time Energy (i.e., reduce generator output) at prices higher than the prices at which other Scheduling Coordinators are willing to sell real-time energy (i.e., increase generator output). In a market with real-time trading opportunities, overlapping bids would become mutually beneficial trades between buyers and sellers and the Price Overlap would be eliminated by these trades. In the design of the ISO's Real Time Imbalance Market, however, there is no opportunity for Scheduling Coordinators to execute such trades, nor is the ISO permitted to execute trades on behalf of Scheduling Coordinators.

A Price Overlap is always possible even if it does not exist among the bids of any given Scheduling Coordinator. This is because, as shown in Figure 1 below, the total of the decremental and incremental Imbalance Energy bids offered into the ISO Imbalance Energy Market are submitted by multiple Scheduling Coordinators and are likely to overlap in price within the merit ordering of the BEEP stack.

The Price Overlap is an indication of profitable trade opportunity among Market Participants since Imbalance Energy can be exchanged (purchased from incremental bids and sold to decremental bids) at a mutually beneficial price. This price has been traditionally called "Target Price" and lies somewhere within the Price Overlap. Given the ISO's ten-minute interval market structure, the Price Overlap should be eliminated in order to produce a monotonically non-decreasing aggregate Imbalance Energy bid curve. Such a bid curve is essential to ensure that each of the ten-minute interval prices be consistent with and reflective of the Imbalance Energy requirements in each such interval. Without eliminating the Price Overlap, under the ISO's

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[13] Concerning the PJM market design, see *PJM Interconnection, L.L.C.*, 86 FERC ¶ 61,247 (1999); and *Atlantic City Electric Co., et al.*, 86 FERC ¶ 61,248 (1999), *clarified*, 86 FERC ¶ 61,310 (1999). Concerning the New York Independent System Operator market design, see *Central Hudson Gas & Electric Corp, et al.*, 89 FERC ¶ 61,196 (1999); and *Central Hudson Gas & Electric Corp, et al.*, 90 FERC ¶ 61,317 (2000), *clarified*, 91 FERC ¶ 61,154 (2000).

current one-sided Imbalance Energy auction mechanism,[14] the ten-minute interval price may alternate from low to high as the Imbalance Energy requirement changes sign from positive to negative across ten-minute intervals. Such alternations in price yield flawed economic signals that fail to provide proper incentives for real-time response. Figure 3 demonstrates that, absent elimination of the Price Overlap, for an Imbalance Energy requirement alternating between 10 MW and –10 MW, the price will alternate between \$30/MWh and \$200/MWh, with the high price at intervals of Energy surplus and the low price at intervals of Energy shortfall. Such price signals are confusing and create perverse incentives in the ISO markets.

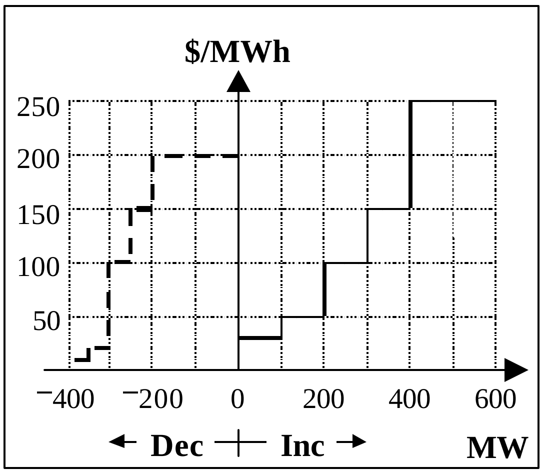
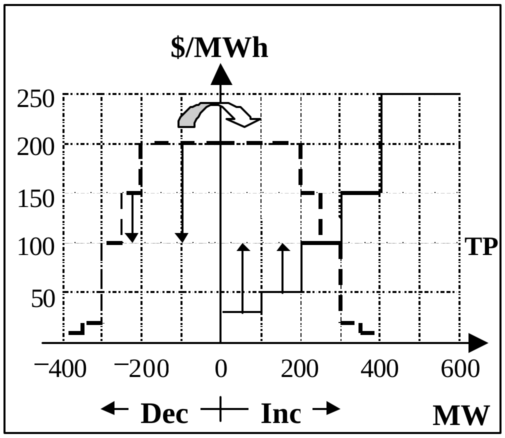


Figure 3. Price Overlap

To remove price confusion and instability, the ISO Real Time Market design eliminates the Price Overlap, by creating an aggregate Imbalance Energy merit order bid stack that is a monotonic non-decreasing bid curve. A Target Price replaces all bid prices that lie within the overlap. The original Target Price was the MCP that would result if the overlapping bids were matched and called in merit order. As shown in Figure 4, such a Target Price is calculated as the intersection between the incremental supply curve and the mirror image of the decremental supply curve over the price axis. All incremental bids lower than the Target Price are set equal (i.e. increased) to the Target Price, and all decremental bids higher than the Target Price are set equal (i.e. decreased) to the Target Price, with the result being a monotonic non-decreasing aggregate supply curve, as shown in Figure 4.

[14] The current Imbalance Energy procurement is based on selecting bids in merit order to meet the Imbalance Energy requirement, rather than a full economic dispatch.



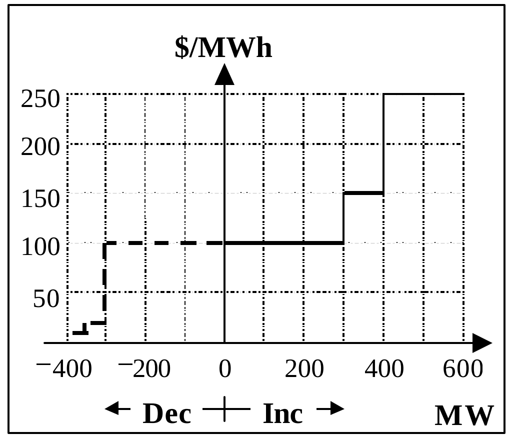


Figure 4. Price Overlap Elimination by Target Price

Stated otherwise, since inception of the ISO, the Target Price has been a problem because the ISO has not been permitted to take the economically rational action of "clearing the Price Overlap," by accepting all overlapping bids and requiring the bidders to actually buy and sell Energy at the resulting Target Price. The ISO's lack of ability to clear the Price Overlap has allowed Scheduling Coordinators to manipulate the Target Price when the ISO needed to procure Imbalance Energy by submitting unrealistically high offers to buy Energy, thereby artificially raising the Target Price, while at the same time obtaining Dispatch priority by submitting unrealistically low offers to sell Energy, knowing that the ISO could not Dispatch their decremental bids, but would pay their Dispatched incremental bids the elevated price.

In April 2000, the ISO tried to eliminate this gaming opportunity by changing its method for calculating the Target Price. This modification set the Target Price to be the greater of $0/MWh or the lowest price incremental bid. However, as market conditions changed during the Summer of 2001 the Target Price again became problematic. By submitting a $0/MWh incremental bid, even for a very small MW quantity, Scheduling Coordinators were able to set the Target Price to $0/MWh in periods in which the ISO needed no incremental Imbalance Energy, thus resetting all decremental bid prices to zero. This distorts the price signals and enables Market Participants to buy back Energy for free.

On September 1, 2000, the ISO changed its Real Time Energy Market to include ten-minute settlements. A component of the ten-minute settlements is the creation of two real-time prices: an incremental and a decremental price ("INCE price" and "DEC price," respectively). If the ISO Dispatches bids only in one direction, the INC price and the DEC price are the same. However, if in a ten-minute interval the Imbalance Energy requirements force the ISO to change from an incremental mode to a decremental mode, the ISO could have different INC and DEC prices. To the extent the INC and DEC prices are different, Uninstructed Energy is settled based on the unfavorable price. For example, positive Uninstructed Energy is paid the DEC price while positive Instructed Energy is paid the INC price. While the two-price system provided incentives not to deviate, many Market Participants complained about the complexity of the two-price system. Furthermore, the two-price settlement, in conjunction with the modified Target Price, reduced incentives to bid into the Regulation Up market since Regulation Energy was paid at the $0/MWh decremental MCP.

On October 29, 2001, the ISO reverted to the original single Target Price methodology, but limited its application to feasible bids and available proxy bids only. This reversion to the single Target Price was another attempt by the ISO to reduce the opportunities for gaming the Target Price. Now, after trying to solve the problem of gaming the Target Price with both one and two Target Prices, the ISO has determined that the best solution, rather than trying to craft a better Target Price formula, is to go to the root of the problem and eliminate the design constraint that prevents the ISO from dispatching overlapping bids. Therefore, as detailed below, the ISO proposes to eliminate use of Target Price.

Even while implementation of a single price system and elimination of the Target Price will produce significant benefits, including increased price transparency for Market Participants, the ISO notes that such a single price acts to increase frequency and quantities of uninstructed deviations. Table 1 shows that uninstructed deviations have increased in both the hourly and ten-minute Settlement regimes at the ISO. As a result, also as detailed below, the ISO also proposes Tariff modifications to provide for narrowly tailored explicit penalties to be levied against Scheduling Coordinators for uninstructed deviations that are beyond a tolerance band for generating unit performance.

Table 1. Average Monthly Positive and Negative Uninstructed Deviations

Period	Average Net Positive Deviation from Generation [15]	Average Net Negative Deviation from Generation
Jun – Aug 2000	**959.9 MW**	**557.0 MW**
June	895.0	632.8
July	882.8	564.4
August	1099.8	476.2
Sept – Nov 2000	**479.1**	**620.1**
September	569.3	591.1
October	362.5	609.8
November	509.6	659.6
Dec 2000 – Feb 2001	**659.9**	**829.7**
December	721.7	659.7
January	531.6	866.8
February	729.0	978.3
Mar – May 2001	**297.1**	**808.9**
March	298.4	720.2
April	287.8	859.7
May	304.7	848.7

[15] Net deviations are shown because Scheduling Coordinators are allowed to offset positive deviations from some of their resources with negative deviations from other resources, in real time. The net positive deviations are averaged for intervals in which individual Scheduling Coordinators have positive values, and net negative deviations are averaged for intervals in which individual Scheduling Coordinators have negative values. Because the output of resources that are providing Regulation will vary within a time period, the results reported here exclude resources for which Regulation bids have been accepted during the specific interval. Although generators that are providing Regulation are included in the overall calculation of uninstructed deviations for settlements purposes, Automatic Generation Control ("AGC") equipment will attempt to keep a generator's output within its regulating range, and will vary its output within the regulating range in response to system conditions. Thus, only deviations outside the regulating range would be truly uninstructed from an operational perspective, without a review of plant-specific operations. Such deviations have initially decreased since the implementation of ten-minute markets, but are small compared to the uninstructed deviations of generators that are not providing Regulation due to the effectiveness of AGC equipment, as shown in the following table (showing the sum of plant-specific uninstructed deviations rather than netting deviations across each Scheduling Coordinator's portfolio):

Month (Year 2000)	Average Positive Deviation Outside Regulating Range	Average Negative Deviations Outside Regulating Range
June	35.8 MW	44.7 MW
July	30.8	36.3
August	41.5	40.4
September	31.4	27.0
October	12.0	20.8
November	5.8	18.4

Jun – Aug 2001	**382.6**	**981.2**
June	549.9	1087.2
July	322.0	974.5
August	278.1	882.1

2. Proposed Modification For Clearing the Price Overlap

The ISO proposes to implement a procedure whereby it will issue Dispatch instructions to all overlapping bids, thus requiring bidders to actually buy Energy (*i.e.,* reduce generation) or sell Energy (*i.e.,* increase generation) at the applicable ten-minute price. Figure 5 illustrates the result of the ISO proposal: the specific creation of a monotonically non-decreasing aggregate supply curve where the Dispatched incremental bids become available as decremental offers and Dispatched decremental bids become available as incremental offers.

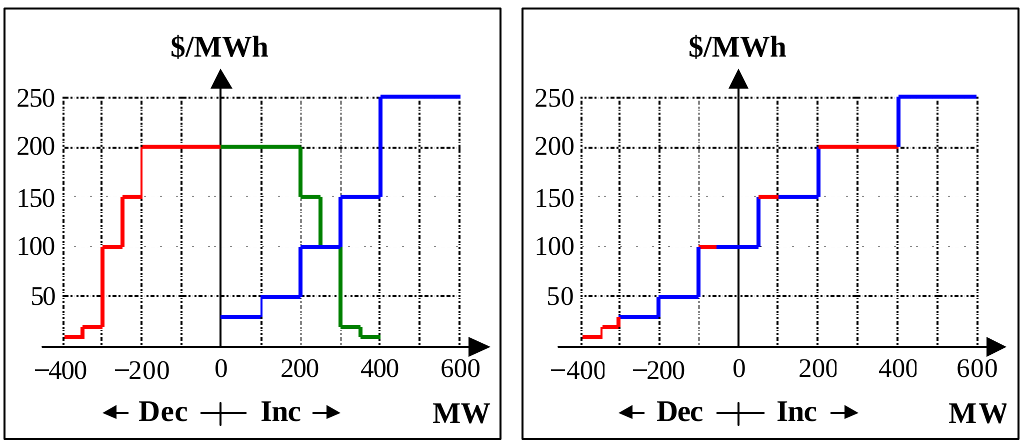


Figure 5. Elimination of the Price Overlap

Thus, by clearing the Price Overlap for each ten-minute interval, the separate INC and DEC prices converge to a single MCP. As a result, the proposed changes will simplify ISO real-time pricing by setting a single interval MCP.

3. Uninstructed Deviations

In developing the instant proposed modifications to the ISO Tariff, designed to deter unintended consequences of increased uninstructed deviations, the ISO seeks to balance operational requirements for maintaining System reliability with maximum operational flexibility for suppliers and accommodation of specific operating requirements of certain Market

Participants. The proposed modifications include penalties for certain uninstructed deviations, which the ISO carefully has designed to serve as a targeted and specific incentive mechanism for Market Participants to minimize uninstructed deviations and to be a fair penalty for those Market Participants that persist in deviating from submitted schedules and Dispatch instructions.

The ISO believes that some penalty beyond the replacement cost of energy must be imposed on a unit for failing to deliver according to a Dispatch instruction. A supplier with more than one generating unit could otherwise profit by increasing the MCP for all of its generating units by failing to deliver from that one unit. Since the ISO deems Dispatch instructions to be delivered, the unit that failed to deliver both is paid the MCP for the amount of Energy in its Dispatch instruction and charged the MCP for the amount of Energy it fails to deliver. Without a penalty, if the unit is dispatched but delivers nothing, the payments and charges completely offset each other. However, as a negative consequence, because the ISO still requires the Energy, it then is forced to call on the next bid in merit order in the BEEP stack, thereby raising the MCP. To provide an incentive for Scheduling Coordinators to comply with Dispatch instructions and specifically to discourage this market-manipulating behavior, the ISO proposes this modest penalty.

4. Proposed Modifications for Uninstructed Deviations

The proposed modifications specifically are designed to provide to Market Participants flexibility in complying with their Dispatch Operating Point[16] ("DOP") along with reasonable operational flexibility for generating resources. The ISO proposes to continue to issue unit-specific Dispatch instructions and to continue to settle on a unit-specific basis. However, Scheduling Coordinators could aggregate generators interconnected at a single ISO grid bus point for purposes of determination of the Uninstructed Deviation Penalty, thus effectively gaining the ability to net deviations from units located at a single point. The ISO also will allow for the net determination of penalties for other aggregations of generating units, as approved by the ISO on a case-specific basis.[17] Moreover, the ISO's proposed modifications will allow suppliers to have the flexibility to deviate from their DOP by a reasonable amount without incurring any penalties. The ISO believes that this latitude of compliance flexibility is sufficient to take into account unintentional deviations that occur as a result of unit operations while

[16] "Dispatch Operating Point" has been proposed as a defined term in the Master Definition section of the tariff.

[17] The ISO will develop a process to allow Market Participants to propose aggregations of generating units that are not at individual transmission bus points. Market Participants proposing unit aggregations will be required to demonstrate that the units aggregated are interchangable, function as a single entity, and will not affect grid reliability.

being sufficiently stringent enough to provide incentives to Scheduling Coordinators to maintain expected unit output. In addition to the flexibility provided to generating units, the instant proposed modifications will allow Metered Sub-System and self-serving Load Market Participants the ability to load-follow, with Uninstructed Deviation Penalties only applying to the net ISO-expected Energy deliveries. Finally, the ISO proposes that entities with limited control over their output, such as intermittent resources and units providing regulation, be exempted from the uninstructed deviation penalty provision.

The ISO notes for the Commission that the proposed Target Price methodology and uninstructed deviation tolerance and penalty provisions have been developed through a thorough and iterative stakeholder process. Specifically, the ISO held four focus sessions with stakeholders, and learned that, while there was little disagreement with the need to eliminate the Target Price, there was concern about the details of the penalties associated with the uninstructed deviations. As a result of those sessions, the ISO modified its proposal in significant ways. First, as discussed *supra*, the ISO proposes to permit some netting of uninstructed deviations so long as all of the resources whose Uninstructed Energy is netted are Scheduled by the same Scheduling Coordinator and also deliver all such Energy into the ISO Controlled Grid at the same point. This approach was a departure from the original proposal in which the ISO was recommending that the uninstructed deviation be applied strictly on a resource-specific basis.

The second significant accommodation was a change in the tolerance band for uninstructed deviations. The ISO's initial proposal to use a tolerance band of 3 MW or 3% of the instructed operating level. The ISO based this initial recommendation on empirical historical deviations, but many stakeholders felt it to be too restrictive and, given the penalty provision for positive deviations above the tolerance band, would encourage risk-adverse suppliers to bias generation downward. Accordingly, the ISO agreed to increase the tolerance band to be the greater of 5 MW or 3% of the maximum operating limit of the resource[18] (*i.e.,* Pmax).

The proposed penalties for positive uninstructed deviations will be the quantity of Uninstructed Imbalance Energy in excess of the tolerance band multiplied by a price that initially will be equal to 100% of the corresponding BEEP Interval Ex Post price. Thus the net effect of the uninstructed deviation penalty and the settlement for positive uninstructed deviations beyond the tolerance band will be that the supplier will not be paid for any such Energy. The uninstructed deviation penalty for negative uninstructed deviations will equal the amount of Uninstructed Imbalance Energy in excess of the

[18] "Resource" in this instance may be defined as the aggregated units, net expected generation for MSS, delivered Regulation range or scheduled load for PLA.

tolerance band multiplied by a price that will be set initially equal to 25% of the corresponding BEEP Interval Ex Post price. Thus the net effect of the uninstructed deviation penalties and uninstructed Imbalance Energy settlement will be that this energy will be charged at 125% of the corresponding BEEP Interval Ex Post price.

The ISO respectfully notes for the Commission that it is not alone is confronting the problem of uninstructed deviations in real-time markets. Other Independent System Operators across the country have a tolerance band for uninstructed deviations, ranging from ±1.5% on a net QSE basis for ERCOT to NYISO's ±3% on an individual resource basis. As summarized in Table 2 below, the ISO's proposed modifications regarding uninstructed deviations is fully consistent with other Independent System Operator practices, policies and authority as has been granted by the Commission.

	Dead-band for Energy	**Penalty within Dead-band**	**Over-generation Charges**	**Under-generation Charges**	**Notes**
Proposed CAISO	**Greater of 5 MW or +/- 3% of expected generation from MSS: greater of 5 MW or +/- 3% of bus generation or Unit P_{max}, as applicable**	**N/A**	**No Pay for deviations above dead-band**	**MCP + 25% of interval MCP for deviations below dead-band**	**SCs may nominate for non-bus-level aggregation of units**
ERCOT	±1.5% of QSE Schedules + instructions ±5.0 MW of expected interval generation	N/A	Graduated up to 100%, depending on system conditions	Graduated up to 100%, depending on system conditions	Dead-band may be reduced to ±1%, ±3% day ahead if ERCOT sees that "price chasing" exists.
PJM	No Dead-band	N/A	N/A for network service	N/A for network service	Penalty for schedules point-to-point MWh deviations, ±1.5% (±2 MW) band. Also, resources deviating beyond 10% of the instructed ("economic") base point are not eligible to set the price (LMP).
ISO – NE	(Under-generation only) 2.5% of claimed capacity or any deviation > 10 MW Also must be > 1 MW	N/A	Sanctions	Forfeit of all TMSR, TMNSR and TMOR payments for deviation period	Failure to provide services in real-time: Admin. Penalty = $1000/event; + Formula penalty = 50% of ECP

NYISO	Lesser of ±3% of unit upper operating limit or three times unit response rate	N/A Paid / Charged LBMP	100% (No payment for gen above dead-band. No charge during reserve deficiencies)	MCP_{rg} x under-generated MW	NYISO reserves the right to change dead-band as needed. Units that are off-dispatch can chase the real time price between their hour-ahead schedule and intersection of real-time MCP with their bid curve (with a 3% tolerance band).

Table 2. Uninstructed Generation Policies Among ISOs

In further elaboration, the ISO notes that PJM has the least amount of additional charge to discourage uninstructed deviations and that, for network service customers, there are no additional charges beyond the replacement cost of energy as is determined by the locational market-clearing price. All of the other Independent System Operators (*e.g.,* ERCOT, ISO-NE, and NYISO) assess some additional charges to generators undertaking uninstructed deviations. ERCOT measures deviations on the net Qualified Scheduling Entity (QSE) basis (which is similar to a Scheduling Coordinator at the ISO). ISO-NE and NYISO assess the uninstructed deviation charges on a resource specific basis. ERCOT attempts to only assess deviation charges when uninstructed deviations caused or contributed to problematic system conditions by looking at the aggregate deviation from schedule on the resources providing regulation. NYISO has adopted a similar process by relaxing positive deviation charges when it has a system reserve deficiency.

To better illustrate the operation and impact on Market Participants of the ISO's proposed uninstructed deviation penalty, two examples are set forth below. Example 1 illustrates the difference between implementing deviations on a unit-level v. bus-level of aggregation, while Example 2 represents the impact of penalties on Metering Sub-System Market Participants.

Example 1: Unit versus Bus-level Uninstructed Deviation Penalty Assessment

Assumptions:
- Participant Schedules Generation at unit-level
- Changes in net generation delivered to ISO system are subject to Uninstructed Deviation charges
- Participant can not net generation with other generation metered at different bus

Unit Level	Bus-level
Forward Schedule: Gen 1 = 140 MW of 160 MW Pmax Gen 2 = 140 MW of 160 MW Pmax Gen 3 = 120 MW of 180 MW Pmax **Real-time:** Gen. 1 increases 20 MW = 160 MW Gen. 2 decreases 20 MW = 120 MW **Result:** Gen. 1 deviation = +20 MW. No payment for 15 MW Gen. 2 deviation = -20 MW. Charged MCP for 20 MW + penalty of MCP*.25) for 15 MW	**Forward Schedule:** Gen 1 = 140 MW of 160 MW Pmax Gen 2 = 140 MW of 160 MW Pmax Gen 3 = 120 MW of 180 MW Pmax **Real-time:** Gen. 1 increases 20 MW = 160 MW Gen. 2 decreases 20 MW = 120 MW **Result:** Gen. 1 paid MCP * 20 MW Gen. 2 charged MCP * 20 MW No deviation charges or penalties applied

Example 2: MSS with Load and Generation Metered at Same Bus Uninstructed Deviation Penalty Assessment

Assumptions:
- MSS schedules Load and Generation
- MSS could load-follow without incurring Uninstructed Deviation Charges
- Increase generation in response to increase in own-load at same metered bus
- Decrease generation in response to decrease in own-load at same metered bus
- Changes in net generation delivered to ISO subject to Uninstructed Deviation charges

Forward Schedule: Load = 100 MW Gen. = 100 MW **Real-time:** Load increases 20 MW = 120 MW	**Forward Schedule:** Load = 100 MW Gen. = 100 MW **Real-time:** Load increases 20 MW = 120 MW

Gen. increases 20 MW = 120 MW **Result:** ➢ Increase in load offset by increase in generation ➢ Same net generation delivered to grid NO UNINSTRUCTED DEVIATION	Gen. Increases 10 MW = 110 MW **Result:** ➢ Increase in load only partially offset by increase in generation ➢ Net gen. delivered to grid decreases by 10 MW. Charged MCP for 10 MW + penalty of (MCP*.25) for 5 MW

II. EFFECTIVE DATE

The ISO respectfully requests that the Commission approve these Tariff revisions within the regular 60-day schedule, *i.e.,* April 1, 2002, consistent with the Commission's Rules of Practice and Procedure 18 C.F.R. § 35.3.

III. COMMUNICATIONS

Communications regarding this filing should be addressed to the following individuals, whose names should be placed on the official service list established by the Secretary with respect to this submittal:

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Fax:(916) 608-7296

IV. SERVICE

The ISO has served copies of this letter, and all attachments, on the Public Utilities Commission of the State of California, the California Energy Commission, the California Electricity Oversight Board, and on all parties with effective Scheduling Coordinator Service Agreements under the ISO Tariff. In addition, the ISO is posting this transmittal letter and all attachments on the ISO's Home Page.

V. ATTACHMENTS

The following documents, in addition to this letter, support this filing:

Attachment A	Revised Tariff Sheets
Attachment B	Black-lined Tariff provisions
Attachment C	Notice of this filing, suitable for publication in the Federal Register (also provided in electronic format).

Two extra copies of this filing are also enclosed. Please stamp these copies with the date and time filed and return them to the messenger.

Please feel free to contact the undersigned is you have any questions concerning this matter.

Yours truly,

Charles F. Robinson
Margaret A. Rostker
Counsel for The California Independent
System Operator Corporation

Enclosures