May 20, 1998

The Honorable David P. Boergers
Acting Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: California Independent System Operator Corporation, Docket Nos. EC96-19-___ and ER96-1663-___

Amendment No. 8 to the ISO Operating Agreement and Tariff, including the ISO Protocols: Errata Pages

Dear Secretary Boergers:

Enclosed for filing please find errata pages to the transmittal letter accompanying Amendment No. 8 to the ISO Operating Agreement and Tariff, including the ISO Protocols, submitted yesterday by the California Independent System Operator Corporation in the above-referenced proceeding. The enclosed errata pages, which should be substituted for the respective original pages in the transmittal letter, correct inadvertent typographical errors. We apologize for any inconvenience.

Respectfully submitted,

Linda C. Ray
Counsel for the California
Independent System
Operator Corporation

For some time, the ISO has been concerned about the "thinness of Ancillary Services markets." While these markets had insufficient bids in a number of hours in early days of operation recently[1], the bids have been adequate for most of the hours in each day for all but Regulation. In nearly all of the hours for each operating day, the results of the Ancillary Services auction have left the ISO with insufficient Regulation, in the range of 60 to 100% deficient. This results in a significant reliability concern for the ISO. As the Commission is aware Regulation is a significant Ancillary Service that is essential to the reliability of the grid in every hour of operation. Unlike Spinning Reserve, Non-Spinning Reserve and Replacement Reserve which are usually only called upon for loss of a generator or a significant under forecasting of control area load. Regulation is called on every hour of the day to allow the ISO to meet the NERC control performance criteria (CPS1 and CPS2) for reliable control area operation.

The ISO experienced thin Ancillary Services bids during market demonstration testing that preceded the ISO Operations Date. Accordingly, the ISO developed, and has routinely implemented since the ISO Operations Date, a contingency plan in which shortfalls in Ancillary Services, including Regulation, are covered by calling on Reliability Must-Run ("RMR") Generating Units.

[1] The bids for Spinning Reserve have usually been 0-20% deficient in the hours of a day, the bids for Non-Spinning Reserves 0-10% deficient, the bids for Replacement Reserves 0-5% deficient.

A. Impact of Insufficient Regulation

As noted above, Regulation service is required to balance loads and generation on a continuous basis in every hour of operation. Without adequate Regulation, the reliability of the Control Area cannot be assured and the ISO's ability to satisfy Western Systems Coordinating Council ("WSCC") Minimum Operating Reliability Criteria ("MORC") and North American Electric Reliability Council ("NERC") Control Performance Standard ("CPS") will continue to be threatened.

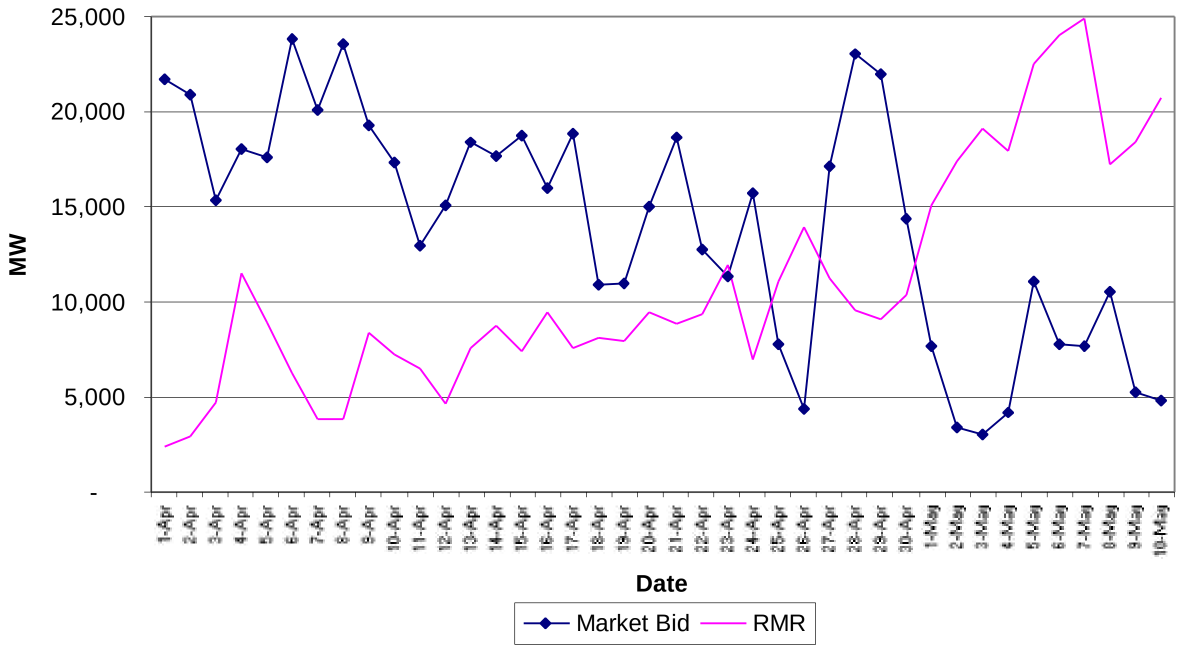
The WSCC's MORC requires that the ISO satisfy the NERC CPS. The NERC CPS is the measure against which all control areas are evaluated. A control area that does not comply with CPS is not adequately controlling its system and imposing burdens as its neighboring control areas. The NERC CPS is composed of two measures. The first measure (CPS1) is a statistical measure of Area Control Error (ACE) variability and its relationship to frequency error. The second measure (CPS2) is a statistical measure designed to limit unacceptably large net flows in or out of the Control Area.

The ISO triggers CPS2 violations typically during the morning and evening load ramps. The Control Area ramp in the heavy morning pull and in the evening drop-off has typically been between 40 and 70 MW per *minute*. In addition the market behavior creates large interchange ramps at least twice each day that only partially coincide with control area load increases. Regulating units need to be able to make sufficient room to allow these schedules to happen as scheduled by the market. For example: if at 6:00 AM the inbound ramp from neighboring control areas is 2000 MW and the load increase during the 20 minute ramp from 5:50 to 6:10 may only be 600 MW. The ISO must find 1400 MW of regulating units that can decrease output quickly (1400 MW in 20 minutes) to make room for the Energy coming in. During the additional time between 6:10 and 6:50 when the next ramp starts the control area load will increase and absorb the remaining 1400 MW of the 6:00 increase. At 6:50, the process repeats itself as it will each hour until the morning pull is over. The process reverses itself at night as the load falls between 9:00 PM and 1:00 AM. To follow these ramps effectively, the ISO must use fast-moving units (typically hydro) to regulate during the ramps. The RMR Units are, however, mostly slower-moving fossil units with ramp rates of between 2.5 and 7 MW per minute. These RMR units therefore do not provide sufficient regulation speed (ramp rate) to allow the ISO to follow the load without incurring violations of the CPS2 criteria.

The two graphs shown below clearly indicate the problems experienced by the ISO with respect to the Regulation market. The bottom line on Graph No. 1 indicates the absolute minimum Regulation requirements for the ISO during fairly smooth hours without heavy load ramps. The top line indicates the preferred level of Regulation capacity to allow the ISO to fully meet the CPS2 performance criteria including during heavy ramp hours. The middle line indicates the level of market bids for Regulation service plus the amount of capacity relied upon from RMR Generating Units for Regulation.

GRAPH 2

Regulation RMR is on an upward trend while market-provided capacity is trending downward.



B. Relationship between the Imbalance Energy in Market and Regulation

Graph No. 1 clearly indicates that there is a significant difference between the amount of Regulation capacity bid into the market (plus the RMR capacity) and the preferred level of regulating capacity. The ISO Imbalance Energy market is designed to provide a resource to provide or absorb energy to allow the ISO to follow load between Hourly Schedule changes, make up for load forecasting errors and make up for loss of generation. The Imbalance Energy market also is the resource for the ISO to use to attempt to return regulating units back to their preferred operating point to restore the full upward and downward regulating range of each unit. There are, however some communication and timing issues which impede full and timely utilization of the Imbalance Energy market to perform these functions. The sequence in real time occurs as follows. In order to instruct (increment or decrement) Generators that submit Supplemental Energy bids, the ISO will manually instruct by phone each Generator through its Scheduling Coordinator[2] unless the generator is on AGC. For example, in order to instruct IOU-owned Generating Units, the ISO must first call the PX (the Scheduling Coordinator for the IOUs), which then contacts the respective IOU's control center, which then contacts the Generator.

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[2] For a detailed operational timeline that may assist in understanding the examples set forth herein refer to ISO Scheduling Protocol sections 3, 9 and 11.

Completing this chain of communication can take as long as ten to fifteen minutes. During that time the ISO may see load swings of up to 600 MW. Thus the ISO cannot rely on the manual instruction of Generating Units in order to reliably match Generation and Load.

Another feature of the RMR units is that they are scheduled "outside" the market. The Balanced Day-Ahead Schedules submitted by Scheduling Coordinators do not include the RMR schedules. Each RMR unit placed on line for any reason creates the need for the ISO to turn to the Imbalance Energy market to exercise decremental bids ("decs") to make room for the Energy output of the RMR unit constrained on line. Thus, the more RMR units constrained on line, the more the need for decremental Supplemental Energy. This condition of being "outside" the market will continue until the PX is able to participate in the Hour-Ahead Market. When this happens, the ISO will require all SCs to include RMR dispatch in their Hour-
Ahead Schedules.

The balanced schedules submitted by Scheduling Coordinators include Adjustment Bids that the ISO may call to resolve congestion; but the ISO must exercise those bids in pairs, leaving a Scheduling Coordinator in "balance." Awarding Ancillary Services bids has no effect on the balance because they are capacity-only. The only opportunity for the ISO to call on generation without having to call on a Scheduling Coordinator for an offsetting amount of load is in real-time for Supplemental Energy.

A dec bid, if called, obligates the bidder to back down a unit (or increase a load). Without adequate dec bids in the BEEP stack, the ISO is even more dependent on Regulation when generation exceeds load, as it will when RMR units are injected after the Day-Ahead Schedules are final, since other than dec bids, Regulation is the only market tool available to the ISO to solve Overgeneration in real time. [3]

To Illustrate the pressure on the Imbalance Energy market consider the following example. A 300 MW unit may have the following constraints. Absolute minimum load may be 40 MW, AGC minimum load may be 70 MW. In order for the unit to be able to regulate in both the upward and downward directions, the unit may be loaded at 150 MW. If such a unit can move under regulation @ 3 MW/min and the ISO needs 60 MW/min regulation speed then 20 such units would be needed. If each unit were loaded at 150 MW to provide this service then 3000 MW of decremental bids would be needed to accommodate the Energy output of these units. This example further illustrates the need to get fast moving hydro units in the regulation market since they satisfy the need best since they have ramp rates of up to 50 MW/min.

C. Cost Implications of RMR *vs.* Regulation Bids

For example, the 300 MW Generating Unit referred to earlier may have a 150 MW Energy schedule and be selected to provide Regulation of 50 MW up

[3] This issue will be mitigated when the California Power Exchange ("PX") is able to accept hour-ahead market bids, because the ISO will then require the PX to include RMR units that are called in its hour-ahead schedule. The problem with be further reduced when the PX is able to submit revised bids after the ISO runs Congestion Management for the day-ahead market. That will allow the ISO to designate RMR units after the initial day-ahead schedules are set, but have the units included in the final day-ahead schedule of the PX – avoiding the need to displace other energy through decs in real-time.

and 50 MW down (at a price of $7/MW, for instance, taking into account cost caps) and, based on ramps and other system needs, could end up generating only 100 MWh for the hour. This is not at all an unlikely outcome given the significant needs for decremental Energy as explained earlier. The Scheduling Coordinator would be paid $700 for the Regulation capacity. If the Hourly Ex Post Price is $20/MWh, the Scheduling Coordinator would incur an Imbalance Energy charge of $1000. As a result, it costs the Scheduling Coordinator money to bid the resource into the ISO's Regulation auction. The potential for such outcomes creates disincentives for Scheduling Coordinators to bid their Generating Units into the ISO's Regulation reserve auction.

The capacity bid caps approved by the Commission also diminish incentives for Market Participants to bid. For example, when the PX Energy market price is expected to be higher than the approved bid cap, the Scheduling Coordinator will choose the PX Energy market since the ISO offers no incentives to bid the resource as Regulation but, instead, creates the possibility of the Scheduling Coordinator losing money based on the Hourly Ex Post Price. This is particularly true for Hydro units which have very low fuel cost. These are exactly the units most needed for regulation yet they are the units must likely to lose money in the “Decremental” situation in which the ISO now operates. If Market Participants were allowed to bid Ancillary Services at market prices, this problem could be

generator would receive $425 for the net energy of 25 MWh. (The upward adjustment of 100 MW for 30 minutes minus the 30 minute 50 MW downward adjustment.) The Generator would also receive a capacity reservation payment of $1,050, for a total of $1,475.

If the Generator were providing Spinning Reserve instead, the energy payments would be based upon the 10-minute incremental and decremental energy prices. If the prices during the hour were $30/MWh for incremental energy and $5/MWh for decremental energy, the Generator would receive $1,375: $1,500 for the incremental energy produced (50 MWh at $30/MWh) less $125 paid for the decremental energy (25 MWh at $5/MWh). The Generator would also receive its capacity reservation payment of $1,050, for a total of 2,425. By choosing to provide Spinning Reserve rather than Regulation, the Generator would receive an additional $950 for the hour under current ISO procedures.

With the REPA, the Generator would receive the capacity payment of $1,050 and be paid the same $425 for the net energy produced. The ISO would use the REPA formula to calculate an additional payment of $3,000 for providing a 150 MW range of Regulation, for a total of $4,475. (The amount in this example is based upon a 100 MW upward increment and a 50 MW decrement, each priced at $20/MWh. In the REPA formula, the Hourly Ex Post Price would apply if it were greater than $20/MWh.)

If the unit provided the full decremental capability as may happen in the present operational circumstances the payments would be 150 X $7 or

$1050 for Regulation capacity, 150 X $20 or $3000 for the Energy payment and pay the ISO back $50 X 17 for the deviation from Schedule. The net payment to the generator is still $3200 which should incent sufficient participation in the regulation market.

Even under the higher REPA approach, this is still a substantially less expensive means to provide Regulation than calling on RMR units, for which the ISO must make reliability payments of perhaps $60/MWh. Moreover, given the relatively small amount of Regulation required (5% of load) the ISO does not see a substantial risk of significant market dislocations even if the ISO determines based on the market response that the REPA would have been effective with the constant set initially at a more conservative number. Again, the ISO must err on the side of reliability to get matters under control, then it will look for ways to improve cost efficiency further.

The market will be closely monitored to determine the impact of the REPA payments on the number and price of Regulation bids received. The ISO believes, however, that the combination of the existing capacity reservation payment and the proposed REPA should provide sufficient economic incentives to attract more bids into the ISO Regulation market. Given the consistent and severe shortfall in Regulation reserves bids that the ISO has experienced since it commenced operations, the C factor is being set initially at 1, thus providing the most generous payment possible under the

CERTIFICATE OF SERVICE

I hereby certify I have this day served the foregoing submittal upon each person designated on the Official Service List compiled by the Secretary in Docket Nos. EC96-19-003 and ER96-1663-003, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.2010.

Dated at Washington, D.C., this 20th day of May, 1998.

Harry Dupre

Notice Suitable for Publication in the Federal Register

The California Independent System	)	Docket Nos. EC96-19-___
Operator Corporation	)	and ER96-1663-___

NOTICE OF FILING

Take notice that on May 20, 1998, the California Independent System Operator Corporation (ISO) filed errata pages, correcting typographical errors, to the transmittal letter accompanying Amendment No. 8 to the ISO Tariff, including the ISO Protocols, which was filed on May 19, 1998 in the above-referenced dockets.

The ISO states that the errata pages have been served upon each person designated on the official service list compiled by the Secretary in Docket Nos. EC96-19-003 and ER96-1663-003.