UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Mountain West Independent System Administrator	)))	**Docket No. ER99-3719-000**

ANSWER OF THE
CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION
TO MOTION FILED BY
SIERRA PACIFIC POWER COMPANY AND NEVADA POWER COMPANY
TO DISREGARD COMMENTS

Pursuant to Rule 213 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission"), 18 C.F.R. § 385.213, the California Independent System Operator Corporation ("CAISO") hereby submits this Answer to Sierra Pacific Power Company's and Nevada Power Company's ("Transmission Owners") motion to disregard the comments filed by the CAISO in this proceeding.[1] That motion was raised in the answer that the Transmission Owners filed on September 17, 1999.

The Transmission Owners claim that the CAISO's comments in this proceeding are motivated by CAISO's desire to be selected to perform the duties of the Mountain West Independent System Administrator in Nevada ("Mountain West") and hence should be disregarded. (Transmission Owner Answer at 3, 14-15.) The Transmission Owners misstate and miscomprehend the CAISO's comments in this proceeding. The main goal of the CAISO in this proceeding is

---

1 Rule 213 permits answers to motions, unless specifically prohibited. No such prohibition exists with regard to the Transmission Owners' motion to disregard the CAISO's comments. To the extent the Transmission Owners' request is not viewed as a motion, but as an answer, the CAISO requests permission to reply to that answer to provide additional information that is necessary to clarify the record. Good cause exists here for granting permission given the nature and complexity of this proceeding and the usefulness of this reply in ensuring the development of a complete record. *See, e.g.*, *Enron Corporation, et al.*, 78 FERC ¶ 61,179 at 61,733, 61,741 (1997); *El Paso Electric Company, et al.*, 68 FERC ¶ 61,181 at 61,899 & n.57 (1994).

to make certain that the Mountain West proposal is feasible so that Mountain West does not adversely affect reliability or the overall operation of the market in the West. The technical comments filed by the CAISO were directed at assuring that this goal is met and should, for the same reason, be closely considered by the Commission rather than being disregarded.

The comments filed by the CAISO in this proceeding made clear that the CAISO does not object to the proposed establishment of Mountain West. Although a part of the comments discussed the Mountain West proposal in light of the Commission's policies on RTOs (while openly and fully explaining the CAISO's interest in responding to the Mountain West RFP), the remainder of the comments raised and discussed technical concerns with Mountain West's proposal. The CAISO explained that the experience it has gained in operating in a contiguous control area with many market features similar to those proposed in the Mountain West filing made it aware of technical issues in Mountain West's proposal that needed to be resolved. The CAISO stated, and reemphasizes here, that regardless of the outcome of the Mountain West RFP, the CAISO, as a result of its obligation to operate a contiguous control area and in its role as one of the security coordinators of the Western Systems Coordinating Council, needs to assure that the details of the Mountain West proposal will allow Mountain West to operate reliably in coordination and conjunction with the California markets.

To that end, on September 14, 1999, the CAISO provided Mountain West with a more detailed description of the technical issues that the CAISO believes need to be resolved to assure Mountain West's operations can be performed reliably. These issues involve concerns relating to the following areas:

(1) Interaction between Mountain West and the Nevada Control Areas; (2) Scheduling Timeline: (3) Real Time Operation; (4) Ancillary Services Markets; and (5) Firm Transmission Rights. A copy of the description of those technical issues is attached to this Answer as Attachment A.

Accordingly, despite the Transmission Owners' allegations, the technical concerns the CAISO raised in its intervention have nothing to do with the CAISO's participation in Mountain West's RFP. Rather these technical concerns, which are further clarified in Attachment A to this Answer, must be considered by the Commission in order to assure that Mountain West will be able to maintain reliable operations while participating in the competitive market.

Wherefore, for the foregoing reasons, the CAISO respectfully requests that the Commission reject the Transmission Owners' request to disregard the CAISO's comments on the operations of Mountain West and instead act to assure that the technical issues and concerns raised by the CAISO are fully explored and resolved.

Respectfully submitted,

____
N. Beth Emery, Vice President
and General Counsel
Roger E. Smith, Senior Regulatory
Counsel
California Independent System
Operator Corporation
151 Blue Ravine Road
Folsom, CA 95630
Tel: 916-351-2207

____
Edward Berlin
Scott P. Klurfeld
David B. Rubin
Swidler Berlin Shereff Friedman,
LLP
3000 K Street, NW, Suite 300
Washington, D.C. 20007-5116
Tel: 202-424-7500
Fax: 202-424-7643

September 28, 1999

Counsel for the California Independent System Operator Corporation

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, DC, on this 28th day of September, 1999.

H. M. Mackey
Swidler Berlin Shereff Friedman, LLP
3000 K Street, NW, Suite 300
Washington, DC 20007
Tel: (202) 424-7500

ATTACHMENT A

LIST OF SPECIFIC ISSUES RELATED TO PROPOSED IMPLEMENTATION OF THE MOUNTAIN WEST INDEPENDENT SYSTEM ADMINISTRATOR

1. Interaction between the MWISA and the Nevada Control areas

The MWISA Tariff states that the ISA will not operate a control area. There are critical communications that must take place at certain times between the ISA Market Operators and the CAOs. These communications must be made in a timely fashion to address two critical elements:

1. Communicate all schedule changes in a manner acceptable to the Nevada CAOs and their neighboring CAOs. The MWISA Tariff states in Section B.2.9.a that the final schedules, operating plan, and merit order stacks for Balancing Energy will be sent by the MWISA to the CAOs 30 minutes prior to the start each Settlement Interval. CAISO is concerned that 30 minutes may not be adequate time for the CAOs to absorb the information, and plan and operate the system and the Balancing Energy market efficiently and reliably. CAISO's experience from the operation of the CA Imbalance Energy market indicates that there is considerable coordination that is required not only during but also prior to each Settlement Interval, particularly at times with high inter-tie ramps or operating reserve shortages. Balancing Energy bids across inter-ties or of inflexible resources may need to be called well ahead from the start of the Settlement Interval.

2. Maintain transparent market operations. The concern here is the role of the CAOs in determining ATC on each FTR interface, Load Forecast, operating the real time energy balancing market, and conducting intra-zonal congestion. The CAOs are the same entities as the TOs that are also market participants serving native load. ATC affects FTR capacity, and therefore FTR proceeds from the FTR auctions. Similarly, load forecasts affect Ancillary Services requirements. CAOs may be in a position of conflict of interest performing these calculations instead of an independent entity. Although the MWISA Tariff states in Section B.2.9.b that energy bid prices will not be revealed to the CAO operators, the merit order stack is already an indication of pricing, particularly when some bids in the stack belong to CAOs' resources. In that respect, the MWISA could be in violation of its Tariff Section B.4.

2. Scheduling Timeline

The proposed scheduling timeline for Nevada for both the day and hour markets represents a real concern both from a market and reliability perspective. The proposed closing of the day ahead market at 2pm PST and the hour ahead at 30 min prior to the beginning of real time pose a series of questions:

The 2pm PST time may be inconsistent with WSCC scheduling rules. Currently WSCC rules state that day ahead NERC Tags must be complete by 2pm in the eastern-most time zone involved in the transaction. Since Nevada operates on Pacific Time and trades with entities that operate on Mountain Time, the 2pm deadline in the eastern-most time zone would indicate a 1pm closing for Nevada. Transmission customers and market participants regularly argue that even a 1 PM Pacific Time publishing does not give them adequate time to complete this important reliability component.

It will be extremely difficult for the CAO (Control Area Operator) to manage the market with the 30 minutes between the receipt of final schedules considering the following:

a. Schedule changes due to RTR retractions and resource replacements.

b. Schedule changes due to NTR transactions.

c. Schedule changes due to intra-Control Area congestion management.

d. Existing contract (NCR) changes that happen up to t-20' and t-10'.

e. The need to call on intertie bids for Supplemental energy; the ISA timeline will only allow 10 minutes to make the call on intertie supplemental energy. WSCC cutoff time for intertie supplemental energy, including CAISO, is twenty minutes before the hour for schedule changes. Most market participants must commit to interchange schedules no later than 30 minutes to the hour. Any dispatch timeline set closer than 30 minutes prior to the hour will severely limit participation on the interties.

f. The quantity of refused or partially accepted supplemental energy bids.

g. The checkout with neighboring control areas, especially considering the historic difficulty of the Mead/Hoover and other tie points common to NV/CA.

With only one hour between the close of the HA market and the start of the Settlement Interval, it seems impossible for the ISA to complete all necessary actions in the first 30 minutes, i.e., close the market, finalize schedules, accept RTR adjustments, accept changes that flow from RTR adjustments, purchase needed A/S, and then turn control over to the CAO to accept all schedules, accept NCR changes, perform control area checkouts, and dispatch pre-hour imbalance, in the next 20 minutes, before the ramp starts. Splitting that last hour with its frantic activity between several different parties (the ISA and the CAOs) seems a formidable task. This may result in more out-of-market activity, more disputes, less efficient markets, and perhaps ACE regulation and reliability problems.

Scheduling problems may also appear due to inconsistencies between the scheduling timelines between CA and NV:

h. The final day-ahead schedules are published at 13:00 in CA, but 14:00 in NV. The last schedule submission in CA is at 12:00, whereas in NV, resource-specific schedules are submitted as late as 13:00. Any schedule changes at the CA-NV inter-ties after 12:00, e.g., due to NTR acquisition and scheduling, will not be reflected in the CA final day-ahead schedules. This could result in delays of the day ahead control area checkouts. Furthermore, these schedule changes may have financial implications since they may be priced at the hour-ahead energy price in CA, which could be significantly different than the day-ahead price. Similarly, adverse effects may exist in the Ancillary Services imported to CA from NV. Consider for example an RTR that is used to provide for transmission capacity for an A/S bid that is accepted in the CA A/S market. If this RTR is recalled by the ISA after 12:00, the original A/S provider may be forced to buy back it's A/S commitment in the hour-ahead market price at a significantly higher market clearing price.

i. The problems described above exist also in the hour-ahead markets. The final hour-ahead schedules in CA are published 2 hours prior to the Settlement interval. The deadline for hour-ahead schedules and bids in CA is 3 hours prior to the Settlement Interval, which is 2 hours prior to the closure of the hour-ahead market in NV. Any hour-ahead changes to CA-NV inter-tie schedules between 3 hours and 1 hour prior to the Settlement Interval will not be reflected in the final hour-ahead schedules in CA and will be considered as real time operational adjustments with certain financial consequences.

3. Real Time Operation

a. How will the CAO manage uninstructed deviations? The point here is that Nevada allows trading of imbalance energy deviations, but this will be done after the fact for settlement purposes and will not affect uninstructed deviations in real time. After the fact imbalance trading may not send the correct price signal for energy. Even if the hourly deviations cancel out by trading after the fact, the CAOs will still face considerable operational burden with large uninstructed deviations in real time, this will lead to out of stack dispatch by the CAO which necessitates the CAO to see all market participants bid data.

b. Large uninstructed deviations in NV may have an adverse financial impact on CA consumers. Inadvertent energy in CA is priced at the hourly average ex post price since it is equivalent to an uninstructed deviation, albeit from an unidentified source. The CAISO recovers the average cost of inadvertent energy (through the hours in a month) through the neutrality adjustment by the demand served in the CAISO control area. Inadvertent energy flowing from NV to CA at high price intervals and returned to NV at low price intervals will result in an out-of-market dollar flow from CA consumers to NV suppliers.

c. Who will manage intra-zonal congestion in real time and how will this action be accomplished?

d. Who will ensure that there are adequate units committed in the forward markets to maintain the integrity of the grid? What is the role of the CAO in the DA/HA markets from a resource adequacy standpoint?

e. How will the CAO manage emergency schedule changes when California prices are higher and suppliers that agreed to supply S/E to Nevada defect to higher-priced markets? This is especially important since price caps will be raised in CA and Nevada may face higher uninstructed deviations.

f. How will the CAO/ISA handle refusal to honor dispatch instructions when prices are unattractive?

g. How will the CAO dispatch base-loaded units in a 10-min energy market?

h. How will the ISA and CAOs work together to handle the inevitable decisions and compromises that are inherent in a real-time operating environment while trying to effectively balance market signals and reliability? This seems problematic when the CAOs and the ISA are separate entities. The CAOs may have many out-of-market actions that will reduce transparency in the market and create many settlement disputes.

4. Ancillary Service Markets

a. How will the MWISA validate that resources do not sell Ancillary Services in the CA and NV markets out of the same physical capacity?

b. The Ancillary Services auctions in NV are sequential. The sequence is in the order of higher to lower quality services. The California experience has been that this type of auction allows exercise of market power and leads to higher ancillary services costs.

c. Ancillary Services and Supplemental Energy bids are available to CAOs in real time operation and at the time of A/S procurement. These bids may be taken in merit order as needed. However, certain real time conditions may dictate divergence from the merit order. If the CAOs are also market participants, how can these selections be made without discrimination?

d. How does the ISA or CAO track, in real time, for non-performance for ancillary service awarded in the DA/HA? Is this an ISA or a CAO function? This is particularly important for regulation and load following services.

e. How does the auction deal with generating unit "dead band" or forbidden operating region?

f. How will the ISA deal with units providing operating reserve that perform uninstructed deviations to garner an attractive price in the real time energy market?

5. Firm Transmission Rights

a. The FTRs in CA are primarily financial rights whereas in NV they are physical rights. CAISO does not require possession of FTRs for scheduling on CA-NV inter-ties, but the MWISA does. The CAISO scheduling system cannot validate CA-NV inter-tie schedules for TR ownership in NV. This may result in inconsistent CA-NV inter-tie schedules. Consider for example a CA export into NV which is final after the closure of the day-ahead market in CA, but the required transmission right in NV is either not available or subsequently recalled.

b. The potential overscheduling of FTR in DA/HA could be problematic since there will be no validation of the secondary market with the timeline, we believe this could be a serious problem.

c. Nevada's proposal of FTRs as the only way to get transmission capacity (physical right) could be seen as a barrier to efficient transmission utilization because it includes the requirement that the user first obtain an FTR. In addition, this could result in less transmission availability in the day ahead market because unused FTRs may not be released until the hour ahead market. The un-scheduled FTR in the day-ahead market will be auctioned off as an RTR, which does not provide any price/schedule protection for the RTR owner, and it essentially becomes a non-firm product.

6. Overall Market Convergence

The CAISO believes that markets will evolve and eventually converge to a common market design. We realize that in order for a market to function properly, the role of the various ISOs and ISAs is to facilitate markets by providing accurate price signals. The CAISO has gained a tremendous amount of experience in the various markets in CA. The above list of questions and concerns should not be taken as a criticism but rather as constructive input from a neighboring control area that will without doubt benefit from a neighboring workable market.