97 FERC – 61, 293
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Pat Wood, III, Chairman;
William L. Massey, Linda Breathitt,
and Nora Mead Brownell.

San Diego Gas & Electric Company, Complainant, v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange, Respondents.

Docket Nos. EL00-95-034, EL00-95-040, EL00-95-008

Investigation of Practices of the California Independent System Operator and the California Power Exchange

Docket Nos. EL00-98-038, EL00-98-033, EL00-98-009

ORDER ACCEPTING IN PART AND REJECTING IN PART
COMPLIANCE FILINGS

(Issued December 19, 2001)

In this order, we accept in part and reject in part the California Independent System Operator's (ISO) January 2, May 11, and July 10, 2001 compliance filings. This acceptance in part and rejection in part reflects the appropriate implementation of our previous findings regarding the California markets and will promote a more efficient operation of the wholesale electricity markets in California to the benefit of all customers.

Background

A. January 2, 2001 Compliance Filing

On December 15, 2000, the Commission issued an order that established certain remedies to alleviate the extremely high prices being borne by Californians.[1] Specifically, the Commission instituted remedies that included: (1) the elimination of the mandatory PX Buy-Sell requirement; (2) the adoption of an advisory benchmark for assessing long-term bilateral contract prices; (3) the establishment of penalties for underscheduling with the ISO; and (4) the requirement that the ISO stakeholder governing board resign and be replaced by a board independent of market participants. In addition, the Commission established an interim modification of the single price auction as proposed in its November 1, 2001 Order[2] and reporting requirements for transactions and/or bids over $150/MWh.

On January 2, 2001, the ISO submitted a compliance filing and proposed Tariff revisions (January 2 Compliance Filing), as directed in the December 15 Order. The proposed Tariff revisions reflect the ISO’s implementation of the Commission’s directives regarding, among other things, the elimination of chronic underscheduling in the forward markets and the establishment of an interim "soft" price cap of $150/MWh for the Imbalance Energy Market and Ancillary Services Market with reporting requirements for transactions or bids in excess of the "soft" price cap. The changes to the ISO’s Tariff are proposed to be effective on January 1, 2001.

B. May 11, 2001 Compliance Filing

On April 26, 2001, the Commission issued an order[3] establishing a prospective mitigation and monitoring plan for wholesale spot markets operated by the ISO and instituting an investigation into whether a price mitigation plan should be implemented in the Western Systems Coordinating Council (WSCC). Elements of the April 26 Order’s mitigation plan include: increased coordination, control and reporting of outages by the ISO; a requirement for all sellers, including non-public utilities, that voluntarily make sales through the ISO’s markets or use the ISO’s interstate transmission grid, to offer all of their available power in real time during all hours; a provision for refund liability and conditions on public utility sellers’

[1] San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Service Into Markets Operated by the California Independent System Operator and the California Power Exchange, et al., 93 FERC − 61,294 (2000), reh'g pending on some issues (December 15 Order).

[2] San Diego Gas & Electric Co., et al., 93 FERC − 61,121 (2000) (November 1 Order).

[3] San Diego Gas & Electric Co., et al., 95 FERC − 61,115 (2001), order on reh'g, 95 FERC − 61,418 (2001), reh'g pending (April 26 Order).

market-based rate authority to prevent anti-competitive bidding behavior; and a price mitigation mechanism for the ISO's real-time energy market during system emergencies.[4]

On May 11, 2001, the ISO submitted a compliance filing and proposed Tariff revisions (May 11 Compliance Filing), as directed in the April 26 Order. The proposed Tariff revisions provide for the ISO's implementation of the Commission's directives regarding: (1) increased coordination, control, and reporting of outages to the ISO;[5] (2) a requirement for all sellers that own or control generation in California to offer all of their available power in the ISO's real-time energy market; (3) and a price mitigation mechanism for the ISO's real-time energy market during system emergencies. The changes to the ISO's Tariff are proposed to be effective on May 29, 2001, consistent with the effective date established in the Commission's April 26 Order.

C. July 10, 2001 Compliance Filing

On rehearing of the April 26 Order, the Commission issued an order on June 19, 2001,[6] modifying and expanding the mitigation plan and extending price mitigation to wholesale spot markets throughout the WSCC. Among its provisions, the June 19 Order modified the formula for determining the marginal cost-based proxy price for sales in the ISO's spot markets in reserve deficiency hours in California; established a mitigated reserve deficiency Market Clearing Price (mitigated reserve deficiency MCP)[7] in the ISO's spot markets in reserve deficiency hours in California; established a mitigated non-reserve deficiency Market Clearing Price (mitigated non-reserve MCP) for spot market sales in all non-reserve deficiency hours that is 85 percent of the highest ISO mitigated reserve deficiency MCP established during the hours when the last Stage 1 alert was in effect; instructed

[4] The April 26 Order is discussed more extensively in a separate order in Docket No. EL00-95-001, et al., (Rehearing Order) that is being issued concurrently with this order.

[5] On October 23, 2001, the Commission issued an order on the ISO's outage coordination portion of its May 11, 2001 Compliance Filing. San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Service Into Markets Operated by the California Independent System Operator and the California Power Exchange, et al., 97 FERC − 61,068 (2001).

[6] San Diego Gas & Electric Co., et al., 95 FERC − 61,418 (2001), reh'g pending on some issues (June 19 Order).

[7] The mitigated reserve deficiency MCP is the marginal cost of the last unit dispatched to serve the last increment of load during a period of reserve deficiency.

bidders to invoice the ISO directly for the cost to comply with emissions requirements and for start-up fuel costs; and required all utilities who own or control generation in California to offer power in the ISO's spot markets.[8]

On July 10, 2001, the ISO submitted a compliance filing and proposed Tariff revisions (July 10 Compliance Filing), as directed in the June 19 Order. The compliance filing provides for the ISO's implementation procedures for the modified market mitigation plan established by the June 19 Order, including: (1) facilitation of the must- offer obligation; (2) development of proxy prices (Proxy Price)[9] and mitigated Market Clearing Prices[10]; and (3) the processes for justification of bids and the collection of charges for and payment of emissions and start-up costs. In addition, the July 10 Compliance Filing includes minor Tariff revisions to comply with earlier Commission orders related to the monitoring and mitigation plan for California wholesale electricity markets.[11] The majority of the Tariff revisions to the ISO's Tariff are proposed to be effective June 21, 2001, consistent with the effective date established in the June 19 Order.

D. July 30, 2001 Amendment to Compliance Filings

On July 30, 2001, the ISO filed, as an amendment to its May 11 and July 10 Compliance Filings, revised tariff sheets that primarily substitute Hourly Ex Post Price for mitigated reserve deficiency MCP for Ancillary Service Prices during system emergencies. The ISO states that this modification is appropriate because the mitigated reserve deficiency MCP is a ten-minute price that should not be used for Ancillary Service Markets, which are hourly markets. The ISO submitted two sets of amended Tariff sheets; the first set of revised sheets is

[8] The June 19 Order is discussed more extensively in the Rehearing Order that is being issued concurrently with this order.

[9] Proxy Price as defined in this order is the price or the marginal cost of each unit calculated by the ISO based on the Commission prescribed inputs as set forth in the April 26 Order, as modified in the June 19 Order.

[10] The term mitigated Market Clearing Prices as used in this order includes the market clearing price established for both reserve deficiency and non-reserve deficiency periods.

[11] Specifically, the ISO has included revised sheets to conform with the findings in the Commission's Order issued May 25, 2001, 95 FERC − 61,275, reh'g pending, 96 FERC − 61,051 (2001) (May 25 Order), and the Commission's November 1 Order.

proposed to be effective from May 29, 2001 to June 20, 2001, and the second set of revised tariff sheets is proposed to be effective June 21, 2001.

Notice of Filings and Interventions

Notice of the January 2 Compliance Filing was published in the Federal Register, 66 Fed. Reg. 2897 (2001), with motions to intervene and protests due on or before January 23, 2001. None were filed.

Notice of the May 11 Compliance Filing was published in the Federal Register, 66 Fed. Reg. 27,954 (2001), with motions to intervene and protests due on or before May 22, 2001. Numerous parties filed motions to intervene, requests for clarification, comments and protests.

Notice of the July 10 Compliance Filing was published in the Federal Register, 66 Fed. Reg. 37,954 (2001), with motions to intervene and protests due on or before August 9, 2001. Numerous parties filed motions to intervene, requests for clarification, comments and protests.

Notice of the amendment to the May 11 and July 10 Compliance Filing was published in the Federal Register, 66 Fed. Reg. 42,527 (2001), with motions to intervene and protests due on or before August 20, 2001. None were filed.

On June 6, 2001, the ISO filed an answer to the motions to intervene, comments and protests of the May 11 Compliance Filing. On August 24, 2001, the ISO filed an answer (August 24 Answer) to the motions to intervene and protests and a commitment to a future modification of its Tariff regarding the assessment of Emission and Start-Up Fuel Costs. Subsequently, the Cogeneration Association of California and the Energy Producers and Users Coalition (CAC/EPUC) filed a motion to reject the ISO's proposed Tariff amendments. Sacramento Municipal Utility District (SMUD) filed a response in support of CAC/EPUC's motion, whereas Modesto Irrigation District (MID) filed a response opposing CAC/EPUC's motion. On September 7, 2001, Duke Energy North America, LLC and Duke Energy Trading and Marketing, LLC (Duke) filed an emergency motion for a cease and desist order against the ISO's implementation of a waiver policy instituted to comply with the must offer obligation set forth in the April 26 and June 19 Orders. On September 14, 2001, Southern California Edison Company (SoCal Edison) filed a response to Duke's emergency motion for a cease and desist order and Reliant Energy Power Generation, Inc. and Reliant Energy Services, Inc.'s (Reliant) supplemental protest. On September 21, 2001, the ISO filed an answer to Duke's motion for a cease and desist order.

Discussion

A. Procedural Matters

Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. 385.214 (2001), the timely, unopposed motions to intervene of Sunrise Power Company, LLC and Harbour Cogeneration Company serve to make them parties to this proceeding.[12]

Late-filed comments were submitted in Docket No. EL00-95-034 by the Western Power Trading Forum, SMUD, and AES Southland (AES) and in Docket No. EL00-95-040, late-filed protests were submitted by CAC/EPUC, SMUD, and SoCal Edison, and Reliant. We will accept the late-filed comments because they are not opposed and they assist us in our understanding and resolution of the issues in this proceeding.

Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. 213(a)(2) (2001) prohibits answers to protests unless otherwise permitted by the decisional authority. We find that good cause exists to allow the ISO's and SoCal Edison's answers because they have assisted us in our decision-making process.

B. January 2 Compliance Filing

Our preliminary analysis of the ISO's January 2 Compliance Filing indicates that the proposed Tariff modifications, with the exception of the underscheduling penalty, are consistent with the December 15 order and will be accepted for filing. As discussed in the Rehearing Order issued concurrently with this order, we are eliminating the ISO's proposed underscheduling penalty. Accordingly, the ISO's proposed tariff sheets reflecting this underscheduling penalty are rejected, effective January 1, 2001, consistent with our findings in the Commission's Rehearing Order.

C. Issues Common to May 11 and July 10 Compliance Filings

1. Must-Offer Obligation

On the issue of the institution of the must-offer obligation, the protests mirror the issues raised on rehearing. Generators with long start-up times and high minimum load requirements protest the ISO's implementation of the must-offer obligation, stating that it changes the must-offer obligation into a must-run obligation. They argue that the must-offer

[12] Numerous other parties filed motions to intervene in Docket No. EL00-95-034 and/or Docket No. EL00-95-040 who were already intervenors by virtue of their timely, unopposed motions to intervene filed at earlier stages of this proceeding. We need not address these motions.

obligation requires these generators to remain on-line with no guarantee of recovering their emissions, start-up, and other costs incurred to maintain minimum load status. Duke states that the ISO's July 10 Compliance Filing requires units with long start-up times to operate at or near their minimum loads during all hours, including off-peak periods when market prices may not cover operating costs, in order that they may be "available" for dispatch.

On July 20, 2001 the ISO, through a Market Notice, established an interim operating procedure whereby generators may request a temporary exemption from the must-offer obligation. Duke and Reliant protest the ISO's interim operating procedures under which exemptions of the must-offer obligation may be requested. Specifically, Reliant argues that the ISO's interim operating procedures are an unauthorized implementation of the Commission's must-offer obligation. Additionally, Duke argues that under these interim operating procedures, the ISO has arbitrarily denied and rescinded Duke's exemption requests for units with long start-up times.

In answering Duke's motion, the ISO concurs with Duke that the Commission should clarify whether the must-offer obligation applies to generators with long start-up times. In response to Duke's contention of arbitrary denial of exemptions, the ISO states that: (1) the ISO has implemented the must-offer obligation as instructed in the June 19 Order; (2) the ISO has voluntarily implemented the procedure for exemption of the must-offer obligation in order to assist generators with long start-up times; and (3) requesting an exemption is voluntary on the part of generators, and the granting and revoking of exemptions are discretionary on the part of the ISO.

Commission Response

The Commission grants clarification that generators subject to the must-offer obligation should have the ability to recover their costs for complying with the ISO's instructions to keep their units on-line at minimum load status in order to be available for dispatch instructions issued by the ISO. Accordingly, the Commission finds that a generator must be compensated for its actual costs during each hour when that generator is: (1) not scheduled to run under a bilateral agreement; (2) not on a planned or forced outage; and (3) running in compliance with the must-offer obligation but not dispatched by the ISO. These costs should be directly invoiced to the ISO and the ISO should recover these costs consistent with the methodology utilized for the recovery of emissions and start-up fuel costs. This procedure will allow the ISO to make reasoned decisions about its generation requirements in order to maximize economic and reliable operations, while keeping the generators whole for the costs they actually incur. This clarification is effective May 29, 2001, the effective date established by the Commission's April 26 Order for the Commission's mitigation and monitoring plan.

For the purpose of determining the fuel costs for units running at their minimum load, we direct the ISO to multiply the minimum point on the unit's heat rate curve by the average of the mid-point of the monthly bid-week gas prices for the three spot markets reported by Gas Daily for California[13] (i.e., the gas costs used to determined proxy prices) to determine the fuel payment for each hour that a generating unit is in minimum load status. Generators who refuse to provide heat and emission rates to the ISO are not eligible for the recovery of costs to maintain minimum load status.

We also find that the ISO's proposal to grant exemption of the must-offer obligation under certain conditions is reasonable. As proposed by the ISO under its interim operating procedures, generators must submit to the ISO a request for an exemption from the must-offer obligation. If the exemption of the must-offer obligation is granted, the generator will not qualify for minimum load costs during the period the exemption is in effect.

In accordance with our decision to permit the ISO to use its exemption procedure for the must-offer obligation, we will deny Duke's motion to cease and desist. However, we agree with Duke that the ISO's exemption policy regarding the must-offer obligation affects the rates and charges for wholesale energy in California. Accordingly, we direct the ISO to make a compliance filing, incorporating into its tariff the provision for exempting generators from the must-offer obligation, effective July 20, 2001. Furthermore, the ISO should include enough specificity to ensure that these procedures are non-discriminatory and transparent to market participants and the Commission.

2. Definition of System Emergency

Comments on both the May 11 and July 10 Compliance Filings state that the Commission used the declaration of a Stage 1 Emergency or System Emergency interchangeably with a 7 percent reserve deficiency but that the Commission made clear that it is the reserve deficiency that creates a risk that prices might exceed those charged in a competitive market. Intervenors state that the ISO should not be allowed the discretion to declare a system emergency and thereby manipulate prices in the market. Intervenors argue that the ISO's Tariff should be modified to reflect that the mitigated reserve deficiency MCP is only to be recalculated during periods when reserves fall below 7 percent.

[13] June 19 Order at 62,561.

In its answer, the ISO states that System Emergencies, especially Stage 1 Emergencies, are not fixed events that automatically occur upon reserves dropping to a specific percentage. The ISO notes that the Commission has granted the ISO flexibility by approving Tariff provisions that allow discretion for the ISO in declaring System Emergencies based upon forecast conditions, as well as other factors. Therefore, the ISO submitted to the Commission an implementation scheme wherein the trigger for resetting the mitigated reserve deficiency MCP is defined by an ISO declared System Emergency and not a 7 percent reserve percentage alone.

Commission Response

Consistent with our April 26 Order, our June 19 Order, and the Rehearing Order being issued concurrently with this order, we will require the ISO to modify its Tariff to make recalculation of the mitigated prices triggered when reserves in California fall below 7 percent.[14] We find that establishing a specific percentage is appropriate and reasonable because it enhances market certainty during the mitigated period. Prior to the April 26 Order, when we granted the ISO the discretion to declare system emergencies based on forecast conditions and other factors, the declaration of a system emergency did not trigger new prices through the mitigation plan. We find that during the duration of the mitigation plan, this discretion is no longer warranted and, further, such discretion could provide the appearance of manipulation of the market by the ISO.

Consequently, we direct the ISO to amend its Tariff regarding the declaration of system emergencies to reflect a definition of a Stage 1 system emergency to occur when reserves fall below 7 percent, and thus, a new mitigated reserve deficiency MCP must be calculated. This change is to be , effective May 29, 2001.

3. Establishment of the Mitigated Reserve Deficiency MCP through the Lesser of the Proxy Price or Actual Bid

Parties in both the May 11 and July 10 Compliance Filings object to the ISO's proposal to use as the mitigated reserve deficiency MCP the lesser of the Proxy Price or the actual bid for the gas-fired generating unit with the highest calculated Proxy Price dispatched by the ISO during a system emergency. Intervenors argue that the ISO's price mitigation proposal is inconsistent with the April 26 and June 19 Orders, which established the mitigated reserve deficiency MCP as solely the Proxy Price of the highest priced unit dispatched during a reserve deficiency. Intervenors state that the ISO's proposed

[14] See April 26 Order at 61,361-62; June 19 Order at 62,556.

tariff provision would allow the ISO to manipulate the merit order stack of real-time energy bids to lower energy prices. On the other hand, the Public Utilities Commission of the State of California (California Commission) argues that using the Proxy Price of the marginal unit to set the mitigated reserve deficiency MCP during a period of reserve deficiency, even when the bid for that unit is below the Proxy Price, would deprive purchasers of whatever efficiencies the market is providing.

The ISO answers that the objecting parties have not explained how the acceptance of submitted bids constitutes manipulation. The ISO argues that the objecting parties only favor market-based outcomes when they result in increased electricity prices, not when such outcomes might lower electricity prices. The ISO argues that it would be inconsistent with the April 26 Order's intent to achieve mitigation by emulating a competitive marketplace to prevent bids less than the unit's calculated Proxy Price from establishing the mitigated reserve deficiency MCP.

Commission Response

In our April 26 and June 19 Orders (collectively, Mitigation Orders),[15] we prescribed a specific method for calculating the mitigated reserve deficiency MCP during periods of reserve deficiency. That method retained the use of a single market clearing price with must-offer and marginal cost bidding requirements.[16] We set marginal costs using a Proxy Price and required that "[a]ll generators would be paid a single market clearing price reflecting the last unit dispatched calculated using the proxy prices."[17] We specifically rejected requests to use alternative methods, such as a generator's actual costs, to set the mitigated reserve deficiency MCP concluding that "[t]he Commission's mitigation plan is designed to establish a generators' bids and market prices up-front."[18] In imposing mitigation, we are no longer relying on the market. Instead, the mitigation substitutes a prescribed method for computing the mitigated reserve deficiency MCP during periods of reserve deficiency so as to replicate a competitive market by using an identified and consistent set of cost data. The ISO's use of alternative data violates our prescribed methodology and is therefore rejected.

15 See April 26 Order at 61,359; June 19 Order at 62,560.

16 June 19 Order at 62,548.

17 June 19 Order at 62,560.

18 June 19 Order at 62,560.

Accordingly, we direct the ISO to modify the price mitigation sections of its Tariff to use the highest priced unit dispatched during a system reserve deficiency using the proxy price to determine the mitigated reserve deficiency MCP, effective May 29, 2001. The ISO should also calculate the non-reserve deficiency MCP consistent with this finding, effective June 21, 2001.

4. Justification for Bids Above the Mitigated Market Clearing Prices

Duke, Mirant Americas Energy Marketing, LP, Mirant California, LLC, Mirant Delta, LLC, and Mirant Potrero, LLC (collectively, Mirant), Williams Energy Marketing & Trading Company (Williams) and others object to proposed provisions of the Tariff requiring sellers to submit justification for bids above the mitigated Market Clearing Prices when their bids are not accepted. In support of this position, Duke and others argue that requiring sellers to submit justification for bids which are not accepted unnecessarily increases the risk that confidential, proprietary information will be disclosed. They also argue that the submission of this information was not required by the June 19 Order.

In its answer, the ISO states that if generators were free to submit any bids without supporting data to document the reasonableness of such bids, generators would be free to engage in abusive bidding practices which would effectively gut the provisions of the must-offer obligation and market mitigation plan. In addition, the ISO notes that cost justification for all bids above the mitigated Market Clearing Prices is necessary if the Commission and the ISO are to monitor the prohibition on anti-competitive bidding.

Commission Response

We find the requirement to submit cost justification for bids that are above the mitigated Market Clearing Prices but are not accepted is unnecessary and not supported by the April 26 and June 19 Orders allowing for cost justification. These Orders require sellers to justify each transaction, not each bid, above the mitigated price. Thus, we find that sellers should only be required to submit cost justification to the ISO in cases where bids above the mitigated Market Clearing Prices are accepted. Accordingly, we direct the ISO to file revised tariff provisions that remove the requirement for sellers to submit cost justification for bids not selected. These revised tariff provisions are effective May 29, 2001, consistent with the findings in our April 26 and June 19 Orders.

With regard to the ISO's concerns with the opportunity for market manipulation given the ability of sellers to bid above their Proxy Price without submitting justification, we note that the ISO is required to provide to the Commission all bid data on a weekly basis, including bids for energy that were never accepted. We direct the ISO to identify and explain any inappropriate bidding that it has identified in its weekly reports to the Commission.

D. Issues Raised in the May 11 Compliance Filing

1. Sanction Authority

Dynegy and AES protest existing Tariff provisions that give the ISO the authority to impose sanctions on transmission owners or generators for operation or maintenance practices that either prolong the response time or contribute to the outage during a reserve deficiency. These parties argue that the Commission has instituted investigations of outages and should have the sole authority to sanction generators. The ISO answers that it did not propose to reduce or expand the provisions on its sanction authority.

Commission Response

Because Dynegy Power Marketing, Inc., El Segundo Power LLC, Long Beach Generation LLC, Cabrillo Power I LLC, and Cabrillo Power II LLC (jointly, Dynegy) and AES complain about existing provisions of the ISO’s Tariff that we did not direct the ISO to modify in either of our Mitigation Orders, these protests are denied as being beyond the scope of this compliance proceeding.

2. Confidentiality of Data

A number of parties request that the ISO’s Tariff be modified to provide for the automatic confidentiality of cost-justification data submitted to the ISO rather than maintaining the existing requirement to submit a request for confidential treatment.

Commission Response

The Commission’s June 19 Order clarified, out of an abundance of caution, that the ISO must treat all cost data in a confidential manner. Therefore, protests on this issue are dismissed as moot.

E. Issues Raised in the July 10 Compliance Filing

1. Calculation of Non-Reserve Deficiency MCP Based on Last Stage 1 Emergency

In the June 19 Order, the Commission directed the ISO to establish a market clearing price for non-reserve deficiency

hours equal to "85 percent of the highest ISO hourly Market Clearing Price established during the hours when the last Stage 1 (not Stage 2 or Stage 3) was in effect."[19] The ISO proposes to adopt Tariff language that establishes the mitigated non-reserve deficiency MCP based on the highest average price during a full clock hour of a Stage 1 Emergency.

Several parties claim that the ISO's proposed method for determining when to reset the mitigated reserve deficiency MCP is an unreasonable interpretation of the June 19 Order. They note that the ISO's selection of the "full-hour, top of the hour" approach results in the fewest resettings of the mitigated reserve deficiency MCP and results in unreasonable limits on prices that do not accurately reflect market conditions. They suggest that the ISO use the highest 10-minute interval during any hour in which a Stage 1 Emergency arises to reset the mitigated reserve deficiency MCP.

In its answer, the ISO states that the June 19 Order clearly directed the ISO to establish the non-reserve deficiency MCP using an hourly market clearing price established during the hours when the last Stage 1 Emergency was in effect. The ISO also notes that it proposes a top of the hour, full clock hour approach due to operational limitations, e.g., the ISO is not able to reorder bids in mid-hour. As a result, the ISO states that it implemented its best interpretation of the order to try to ensure a reasonable and equitable procedure that preserves the intended market power mitigation aspects while avoiding skewing prices unnecessarily.

Commission Response

We find the protesters' arguments unpersuasive. They have not shown that the ISO's method would produce unreasonable results. The Commission made clear in the June 19 Order that the ISO was to use "the highest ISO hourly Market Clearing Price established during the hours when the last Stage 1 was in effect" to establish the Non-Reserve Deficiency MCP. Therefore, the use of an hourly clearing price, rather than a 10-minute interval as suggested by several parties, complies with our order. We also find that the ISO's use of "the top of the hour" is appropriate since reordering the merit stack order from the top of the hour is consistent with existing ISO practices and the ISO's method of establishing the mitigated reserve deficiency MCP.[20]

[19] June 19 Order at 62,548.

[20] But see Investigation of Wholesale Rates of Public Utility Sellers of Energy and Ancillary Services in the Western Systems Coordinating Council, 97 FERC (2001).

2. Penalty for Failure to Respond to ISO Dispatch Instruction

On December 8, 2000, the Commission accepted Amendment No. 33 to the ISO's Tariff.[21] Amendment No. 33 instituted, inter alia, a penalty provision for Participating Generators that fail to respond to ISO dispatch instructions during a reserve deficiency. Generators subject to the penalty pay an amount equal to twice the highest price that the ISO paid for energy for each hour in which the Participating Generator failed to respond. The penalty would not apply if the Participating Generator notified the ISO that its unit was physically unable to operate or would violate a legal restriction. However, in the June 19 Order, in response to various parties' requests for clarification, the Commission found that the must-offer obligation modified various market rules that existed when this penalty provision was accepted for filing and that during the period when the mitigation plan is in effect, these tariff provisions are now unjust and unreasonable. The Commission therefore ordered the ISO to modify its Tariff so that the only penalty for having a unit forced out of service would be the cost of replacement energy.

In its July 10 Compliance Filing, the ISO states that it appears that the Commission misunderstands the Tariff provisions governing forced outages and the application of penalties to a generating unit that goes offline due to a forced outage. The ISO states that its Tariff provides for a penalty of twice the cost of replacement energy only "if Instructed Energy is not delivered during a System Emergency and a Forced Outage is not reported within the hour to the ISO."[22] The ISO therefore claims that there is no penalty for forced outages if the ISO is notified within the hour of the outage but rather there is a penalty for failure to report forced outages.

Several parties[23] state that the ISO has failed to modify the penalty provisions in its Tariff as required by the June 19 Order by failing to propose modifications to the Tariff "so that the only penalty for having a unit forced out of service is the cost of replacement energy."[24] They note that the ISO was explicitly ordered to remove the penalties for forced outages,

[21] See California Independent System Operator Corporation, 93 FERC ¶ 61,239 (2000), reh'g pending.

[22] Section 5.6.3 of the ISO's Tariff.

[23] See, e.g., Mirant, Williams, Reliant, Dynegy, and Bonneville Power Administration (BPA).

[24] 95 FERC ¶ 61,418 at 62,553.

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and, in response, the ISO has not complied with this directive but rather has chosen to present arguments as to why the penalties are necessary. They also argue that the ISO dismisses the fact that with respect to prices in its real-time market, Instructed Energy is not paid the same as Uninstructed Energy. Therefore, they argue that the ISO also needs to modify its provisions for allocating the cost of replacement energy.

The ISO states in its August 24 Answer that the cost of replacement reserve is not a penalty but rather the cost of energy that the ISO must procure to maintain balance in real-time and the cost of additional replacement reserve purchased to ensure the ISO does not violate reliability criteria.

Commission Response

In light of the mitigation plan instituted in the April 26 Order, including the must-offer obligation, we find that there is no need for the ISO to impose any penalty either for a failure to report a forced outage or a failure to respond to a dispatch request. In fact, as discussed in this order, the ISO is now giving exemptions to certain must-offer units because, at certain times, there is more capacity available than what is currently needed in the market. Furthermore, the ISO has not presented any new evidence supporting the need for the continuation of these penalty provisions. Thus, we reaffirm our directive to the ISO to make a compliance filing to remove these penalty provisions, effective June 21, 2001. This removal will ensure that there are no penalties in place. Thus, generators under the must-offer obligation will receive payment for the unit's bid into the market equal to the cost of replacement energy so as to prevent any financial harm to generators whose units unexpectedly trip offline.

Regarding the request for a modification of the allocation method for replacement reserve, we find that the present method does not impose a penalty on generators with uninstructed deviations. Rather, the uninstructed deviations impose a replacement reserve cost on the ISO's system that is appropriately allocated under cost causation principles to the generators producing the uninstructed deviations. We therefore deny the request for modification of these provisions.

3. Ex Post Ancillary Service Prices

Reliant argues that the ISO incorrectly interpreted the Commission's order with respect to calculating the Market Clearing Price for Ancillary Services. Reliant notes that while the ISO is correct in applying the Commission's price mitigation measures to capacity Ancillary Service transactions, the best interpretation of that requirement is that the relevant hour, for purposes of establishing the price, is the hour the transaction

is entered into, not the hour of delivery. Thus, Reliant asserts, prices must be set according to the form of price mitigation in effect at the time the transaction is entered into and should not be reset later by changed conditions (i.e., a Stage 1 Emergency) in the hour of delivery of the ancillary service.

The ISO answers that its Tariff language is consistent with the language in the May 25 and June 19 Orders where the Commission intended an ex post mitigation of Ancillary Service prices based on "the average hourly mitigated Imbalance Energy price for [the applicable] hour."[25]

Commission Response

In the Rehearing Order issued concurrently with this order, we grant the request for rehearing on this issue. Reliant is correct that it was our intent that the price established for Ancillary Services should be as of the time the transaction was entered into and not the time that delivery actually occurs. Additionally, this procedure is consistent with the underlying bid protocol provisions that were in effect prior to the imposition of our mitigation plan. Accordingly, we direct the ISO to modify its Tariff to reflect this finding.

4. Provision for Setting the Mitigated Market Clearing Prices

Numerous parties protest the ISO's proposed Tariff provisions regarding how the mitigated reserve deficiency MCP and mitigated non-reserve deficiency MCP are set.[26] Specifically, they object to the ISO's proposal that allows only suppliers that have signed a Participating Generator Agreement (PGA) to: (1) set the mitigated Market Clearing Prices, and (2) to submit justification for prices above the mitigated Market Clearing Prices. Parties argue that the proposal is unreasonable and arbitrary and prevents recovery of generators' marginal costs simply because they have not signed a PGA. They note that the proposed Tariff language is directly contrary to the Commission's direction that generators out of the state of California could set the mitigated reserve deficiency MCP if they supplied their operating information to the ISO. The City of Vernon, California (Vernon), SMUD, and others disagree with the ISO that real-time visibility through telemetry is necessary to determine which generator should set the mitigated reserve deficiency MCP and

[25] May 25 Order at 61,971.

[26] See, e.g., Duke, CAC/EPUC, Allegheny Energy Supply Company, LLC (Allegheny Supply), SMUD, MID, Northern California Power Agency (NCPA), Williams, Mirant, and Dynegy.

state that the ISO would be able to calculate their output by subsequent meter readings and interchange settlements.

Parties also protest provisions in the proposed Tariff that provide that units dispatched through the imbalance energy market are the only units that can set the mitigated reserve deficiency MCP. They suggest that units dispatched under Out of Market (OOM) calls or Reliability Must-Run (RMR) calls should also be able to set the mitigated Market Clearing Prices.

In its response, the ISO states that in order for it to distinguish such "other sellers" from marketers, the generating units of these other sellers must be visible to the ISO's monitoring systems as separate resources and must meet the ISO's scheduling and metering standards which are consistent with the standards required of Participating Generators. According to the ISO, it is these operational realities that led it to limit the entities eligible to either set the mitigated Market Clearing Prices and to seek to justify prices above the mitigated Market Clearing Prices to those non-marketer suppliers that have signed a PGA.

Commission Response

We will not require that a PGA be signed in order to set the mitigated Market Clearing Prices or to be eligible to justify bids above the mitigated Market Clearing Prices. The capability exists to determine a unit's Proxy Price without having a signed PGA. In the June 19 Order, the Commission stated that, with the implementation of mitigation for the entire WSCC, out-of-state generators will be treated like in-state generators and that out-of-state generators that want to have their marginal costs included for use in calculating a Proxy Price that may establish the mitigated reserve deficiency MCP can submit the required heat rate and gas source for their units to the ISO. The ISO can calculate proxy prices for non-PGA generators with a heat rate curve for the generator, and meter or interchange data. As we clarify in the Rehearing Order to be issued concurrently with this order, gas costs for these generators will be same gas costs used by the ISO for the development of the proxy price, i. e., the average of the mid-point of the monthly bid-week prices reported by Gas Daily for three spot markets prices reported for California. Further, it was not the intent of the Commission to require that sellers cede control of their generating units as is required under a PGA in order to be allowed to recover their marginal costs under the mitigation plan. Such a requirement would be both burdensome and costly to the other sellers. Therefore, we direct the ISO to modify its Tariff to remove the requirement that a PGA must be signed in order to set the

mitigated Market Clearing Prices or to justify bids above the mitigated Market Clearing Prices.[27]

We will deny the request that units dispatched under OOM calls or RMR calls should also be eligible to set the mitigated reserve deficiency MCP. The Commission has consistently held that for the purposes of mitigating the California market, the

ISO must institute a mechanism that emulates a competitive market where the marginal cost of the highest cost unit dispatched sets the mitigated reserve deficiency MCP. We have identified units dispatched through the Imbalance Energy market as the marginal units and, thus, they are the only units that can set the mitigated reserve deficiency MCP.

5. Recovery of Emissions and Start-Up Fuel Costs

In its July 10 Compliance Filing, the ISO proposes formula rates for the payment of emissions and start-up costs incurred by generators under the must-offer obligation as a result of dispatch instructions from the ISO. The ISO proposes to assess the charges to each Scheduling Coordinator based upon its metered demand: (1) within the ISO Control Area; and (2) within California but outside the ISO Control Area which is served by exports from the ISO Control Area. Under the proposal, the rates for the recovery of these costs will be calculated based on an annual forecast of emissions and start-up fuel costs divided by metered demand, with monthly adjustments to reflect actual cost incurrence.

Several parties argue that the ISO's proposed Tariff fails to comply with the June 19 Order regarding the recovery of emissions and start-up fuel costs.[28] First, they claim that generators should be entitled to payment from the ISO for all of their emissions and start-up fuel costs regardless of whether they have been dispatched by the ISO or whether they are supplying under the must-offer obligation. Duke argues that the Commission should clarify that sellers in California's bilateral spot markets whose negotiated prices are subsequently mitigated, are able to directly invoice the purchaser for emissions costs up to the difference between the negotiated and mitigated price. Second, some parties argue that the ISO's assessment of these charges should be based on peak loads rather than on all metered

[27] This finding also applies to the ISO's tariff provision regarding the eligibility to establish the mitigated Market Clearing Prices for Ancillary Services.

[28] See, e.g., Duke, AES, NCPA, Pacific Gas and Electric Company (PG&E), Metropolitan Water District (Metropolitan), Mirant, Reliant, Dynegy, and the California Department of Water Resources (DWR).

loads. These parties argue that the use of peak load is particularly appropriate for emissions costs because peak periods are when the dirtiest units are running and when the vast majority of the emissions costs are incurred. However, Mirant argues for the assessment of these charges based on in-state load or, alternatively, on net metered demand to prevent an assessment of these charges for inadvertent deviations from generation schedules. Fourth, Dynegy argues that the ISO improperly proposes to blend all emissions costs together and, thus, pay suppliers on a pro rata basis of their total emission costs rather than on the basis of actual emissions costs incurred in providing must-offer service. Dynegy suggests a last-in, first-out approach to reflect emissions costs associated with the ISO's real-time imbalance energy market. Finally, PG&E requests clarification as to whether the ISO will assess the emissions and start-up costs on a gross or net load basis.

Duke also objects to the proposed provisions requiring sellers to submit their entire gas portfolios to the ISO in order to justify actual start-up fuel costs, stating that this is not a requirement imposed by the June 19 Order.[29]

The ISO responds that the compliance filing appropriately implements the June 19 Order by providing for payment of emissions and start-up fuel costs to only those generators that are subject to the must-offer obligation and required to run in accordance with ISO dispatch instructions. The ISO states that it should not have to compensate generators for such costs incurred as a result of spot bilateral transactions since a generator is not under any obligation to enter into such bilateral transactions. Further, if a generator is unable to recover these costs through bilateral transactions, the generator should not enter into such an agreement.

In response to PG&E's request for clarification regarding whether the ISO will assess the emissions and start-up costs on a gross or net load basis, the ISO commits to modify its Tariff to assess these charges to "all ISO Control Area Gross Load within the ISO's Control Area and to all Load exported from the ISO Control Area to another Control Area in California."

In response to the ISO's commitment to modify its Tariff regarding the use of gross load, several parties protest the ISO's commitment to use gross load: (1) on procedural grounds, i.e., it violates the Commission's rules regarding proper notice; and (2) because this is not the appropriate forum to resolve this issue because this issue has been raised in other pending proceedings before the Commission. Additionally, parties argue that the ISO's proposal violates the cost-causation principle by

[29] Duke at 25.

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allocating charges to customers who do not benefit from ISO-dispatched generation. SoCal Edison argues that the ISO has no ability to measure the Control Area Gross Load of certain entities, such as generators with behind-the-meter loads, and therefore, the use of gross load is inappropriate.

Commission Response

We reject parties' claims that they should be paid by the

ISO for all emissions and start-up costs including those costs associated with bilateral transactions. These parties are free to recover emissions and start-up fuel costs as part of bilateral transactions and thus, any recovery of emissions and start-up fuel costs from the ISO could result in a double recovery of such costs. However, we will grant Duke's requested clarification regarding the invoicing of purchasers for emissions costs when negotiated bilateral spot market prices are mitigated. We find that where a higher, negotiated bilateral spot market price is mitigated by the mitigated Market Clearing Prices, the seller should have the ability to invoice the purchaser for direct and verifiable emissions costs up to but not exceeding the original negotiated price. This will place sellers in the bilateral spot markets on equal footing with those sellers in imbalance energy markets who receive the mitigated Market Clearing Prices and the ability to invoice the ISO for direct and verifiable emission costs. Accordingly, we find that the ISO has complied with our June 19 Order to develop a charge to recover emissions and start-up fuel costs assessed against generators that are required to run in accordance with ISO dispatch instructions and the must-offer provisions.[30]

Regarding Dynegy's arguments concerning the ISO's proposal to allocate a share of emissions costs on a pro rata basis, our review indicates that the ISO's Tariff provides for Scheduling Coordinators, on behalf of generators under the must-run obligation, that incur emissions and start-up fuel costs as a direct result of an ISO dispatch instruction, to submit an invoice to the ISO for the recovery of these direct costs. Thus, the ISO's proposed tariff provisions appropriately allow for direct payment of emissions and start-up fuel costs when those costs are separately invoiced. Dynegy's protest of the ISO's purported blending of emissions costs and payment on a pro rata basis applies only in situations where a Must Run Generator's applicable air quality district invoice also includes emissions from operations not resulting from ISO dispatch instructions. In these cases, the payment is based on the emissions costs of the invoice multiplied by a ratio of the energy associated with ISO dispatch instruction to the total energy associated with the emissions costs. We find that the ISO's pro rata payment when

[30] June 19 Order at 62,562.

costs are not separately invoiced is appropriate and consistent with the intent of our June 19 Order. Dynegy's argument for a last-in, first-out approach is predicated on the unsubstantiated assumption that bilateral transactions would always occur before the ISO dispatch of the unit occurs and, therefore, Dynegy's protest is denied.

We find that Duke's objection regarding the ISO's proposed requirement for sellers to submit their entire gas portfolio, including those of affiliates, in order to justify actual start up fuel costs has merit. We did not direct the ISO to require the submission of gas portfolios in order to verify the start-up fuel costs. Therefore, we clarify that the appropriate gas price used in determining start-up costs should be the same gas price used to determine proxy prices in the real-time market, i.e., the average of the mid-point of the monthly bid-week gas prices reported by Gas Daily for three spot markets reported for California. We find that the consistent use of one gas price for both start-up and real-time proxy prices properly represents a reasonable proxy of the costs that generators will incur, since they can pre-buy their gas requirements for the month at this price. Should sellers seek to recover costs above this gas price for start-up costs, then they must submit their entire gas portfolios to the Commission and the ISO as justification.

Regarding the proper demands to be used for the assessment of emissions and start-up fuel costs, our June 19 Order directed the ISO to assess these charges against all in-state load served on the ISO's system. Therefore, for those parties that request that these emissions and start-up fuel costs be assessed on the basis of peak demands, we find that the cost recovery methodology is based on actual costs incurred and that these costs may be incurred in both on-peak or off-peak periods. Therefore, the use of peak demands is inappropriate.

We agree with the ISO that total gross load is the most appropriate method to assess these costs. As we stated in our December 15 Order[31], the ISO provides imbalance service needed for reliable transmission service. Additionally, on July 25, 2001, the Commission issued an order[32] which stated that ISO market purchases are made in order to procure the resources necessary to reliably operate the grid.[33] We have previously found that the use of gross load is the appropriate billing unit

[31] December 15 Order at 61,993.

[32] San Diego Gas & Electric Co., et al., 96 FERC − 61,120 (2001), reh'g pending. (July 25 Order).

[33] July 25 Order at 61,515.

for the ISO's open access transmission access charge.[34] Accordingly, the use of gross load as the basis for the assessment of emissions and start-up fuel costs is appropriate in that all users of the transmission grid will be assigned these costs consistent with the ISO's markets performing a reliability function.

6. Ten Percent Credit Risk Adder

Several parties note that the ISO's revised Tariff provisions are unclear as to what sales are and are not covered under the 10 percent credit adder.[35] Duke argues that the adder should not be limited to sales at the mitigated Market Clearing Prices but should also include sales in the market when a seller justifies its bid above the mitigated Market Clearing Prices. Dynegy contends that the adder should be applicable to congestion revenues which result from both incremental and decremental Adjustment Bids. Mirant states that generators should not be assessed the adder since generators are the only fully creditworthy parties in the California energy market. Other parties state that the 10 percent adder should not be included on charges for "Net Negative Uninstructed Deviations" and "Regulation Down" services.

In its answer, the ISO states that, consistent with the Commission's directive, it has assessed the 10 percent credit adder on the charges and payments for all sales in the ISO Markets at the mitigated Market Clearing Prices for those markets. Accordingly, the ISO states that to the extent Duke is contending that the ten percent credit adder should also be applied to sales in those markets that are above the mitigated Market Clearing Prices, the application of the credit adder is inconsistent with the June 19 Order which explicitly ties the ten percent adder to the mitigated Market Clearing Prices paid to generators. Responding to Dynegy, the ISO states that congestion revenues are not the result of sales into the ISO markets and therefore do not fall within the scope of prospective sales in the ISO's markets.

Commission Response

In the Rehearing Order being issued concurrently with this order, the Commission addresses the issue of a 10 percent credit risk adder for all transactions in the ISO's markets. Consistent with our findings in the Rehearing Order, the ISO's proposed tariff revisions reflecting the 10 percent credit risk adder are

[34] California System Operator Corporation, 91 FERC ‑ 61,205 (2000), reh'g pending.

[35] See, e.g., Duke, Mirant, Dynegy, and DWR.

accepted for filing, as modified by our findings in the Rehearing Order,[36] effective June 21, 2001.

7. Termination Date

NCPA notes that the Commission's Mitigation Plan is not intended to be a permanent fixture in the Western states, but rather is intended only to meet an emergency situation. NCPA argues that the ISO should insert a termination date of September

30, 2002, for Tariff amendments related to the mitigation plan to reflect the intention of the Commission to impose only temporary market mitigation measures.

Commission Response

The Commission stated in the June 19 Order that it would extend the price mitigation plan to September 30, 2002. Nowhere in the revised Tariff sheets submitted in the July 10, 2001 Compliance Filing has the ISO included language reflecting this termination date. The Commission therefore orders the ISO to file, in the compliance filing required by this order, revised Tariff sheets incorporating a termination date of September 30, 2002 for the price mitigation plan.

8. Other Issues

In addition to submitting revised Tariff sheets in response to the June 19 Order, the ISO also included a revised Tariff sheet to reflect the Commission's rejection of Amendment No. 31 in Docket No. ER00-3673-000. No parties protested this revision. We find this change consistent with the Commission's findings in its November 1, 2000 Order[37] and we accept these Tariff revisions, effective November 15, 2000.

The Commission orders:

[36] In addition to the use of a ten percent surcharge adder to the mitigated Market Clearing Prices and Ancillary Service prices, the Rehearing Order requires bids above the mitigated Market Clearing Prices that are selected and justified to also be paid the ten percent surcharge.

[37] San Diego Gas and Electric Co. v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange, et al., 93 FERC ¶ 61,122 (2000).

(A) The ISO's compliance filings submitted on May 11, 2001, as amended, and July 10, 2001, as amended, are hereby accepted in part and rejected in part, as discussed in the body of this order.

(B) The ISO is hereby directed to submit a compliance filing, as discussed in the body of this order, within thirty (30) days of the date of this order.

(C) Duke's emergency motion for a cease and desist order is hereby denied, as discussed in the body of this order.

(D) The ISO's January 2 Compliance Filing is hereby accepted, effective January 1, 2001, except for the provisions implementing the underscheduling penalty, as discussed in the body of this order.

(E) The ISO is hereby informed that rate schedule designations will be given in a future order. Consistent with our prior orders, the ISO is hereby directed to promptly post the tariff sheets as revised in this order on the Western Energy Network.

By the Commission.

(S E A L)

Linwood A. Watson, Jr.,
Acting Secretary.