January 25, 2002

The Honorable Linwood A. Watson, Jr.
Acting Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator Corporation and the California Power Exchange, Docket Nos. EL00-95-001, *et seq.;*

Investigation of Practices of the California Independent System Operator and the California Power Exchange, Docket Nos. EL00-98-001, *et seq.;*

Public Meeting in San Diego, California, Docket No. EL00-107-002; Reliant Energy Power Generation, Inc., Dynegy Power Marketing, Inc., and Southern Energy California, L.L.C. v. California Independent System Operator Corporation, Docket No. EL00-97-001;

California Electricity Oversight Board v. All Sellers of Energy and Ancillary Services Into the Energy and Ancillary Services Markets Operated by the California Independent System Operator Corporation and the California Power Exchange, Docket No. EL00-104-001;

California Municipal Utilities Association v. All Jurisdictional Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator Corporation and the California Power Exchange, Docket No. EL01-1-001;

Californians for Renewable Energy, Inc. (CARE) v. Independent Energy Producers, Inc., and All Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator Corporation and the California Power Exchange; All Scheduling Coordinators Acting on Behalf of the Above Sellers; California Independent System Operator Corporation; and California Power Exchange Corporation, Docket Nos. EL01-2-001; *et al.;*

Investigation of Wholesale Rates of Public Utility Sellers of Energy and Ancillary Services in the Western System Coordinating Council, Docket No. EL01-68-000

Dear Secretary Watson:

The California Independent System Operator Corporation ("ISO")[1] respectfully submits six copies of this filing in compliance with the Commission's December 19, 2001 "Order Accepting In Part And Rejecting In Part Compliance Filings," 97 FERC ¶ 61, 293 (2001) ("December 19 Compliance Order"); the December 19, 2001 "Order On Clarification and Rehearing," 97 FERC ¶ 61, 275 (2001) ("December 19 Rehearing Order"); and the December 19, 2001 "Order Temporarily Modifying The West-Wide Price Mitigation Methodology," 97 FERC ¶61, 294 (2001) ("December 19 Winter Price Order") in the above-captioned dockets. On January 17, 2002, in the above-referenced dockets, the ISO filed a Motion For Extension Of Time, seeking an extension of the compliance filing date from January 18 to January 25, 2002.

I. BACKGROUND

In its December 15, 2000, order[2] the Commission found that the market structures and rules for wholesale markets in California were seriously flawed and that these structures and rules, in conjunction with an imbalance of supply

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[1] Capitalized terms not otherwise defined herein are used in the sense given in the Master Definitions Supplement, Appendix A to the ISO Tariff.

and Demand in California, had created the opportunity for suppliers of electricity to exercise market power and to charge unjust and unreasonable rates. The December 15 Order mandated various remedies to address these circumstances, that included: (1) the elimination of the mandatory California Power Exchange ("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 Order[3] 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 in response to the December 19 Order ("January 2 Compliance Filing").

On April 26, 2001, the Commission issued its "Order Establishing Prospective Mitigation and Monitoring Plan for the California Wholesale Electric Markets and Establishing an Investigation of Public Utility Rates in Wholesale

[2] 93 FERC ¶61,294 (2000) ("December 15 Order").
[3] 95 FERC ¶ 61,121 (2000) ("November 1 Order").

Western Energy Markets" in the above-captioned dockets ("April 26 Order").[4] In the April 26 Order, the Commission reaffirmed its previous findings that there is a potential for the exercise of market power in the California wholesale markets under certain conditions and mandated that a replacement mitigation plan be put into place. The primary elements of the April 26 Order's mitigation plan included: (1) increased coordination, control and reporting of outages by the ISO; (2) a requirement that all sellers, including non-public utilities, that voluntarily make sales through the ISO's market or use the ISO's interstate transmission grid, to offer all of their available power in real time during all hours; (3) a provision for refund liability and conditions on public utility sellers' market-based rate authority to prevent anti-competitive bidding behavior; and (4) a price mitigation mechanism for the ISO's real time Energy Market during System Emergencies. In compliance with the April 26 Order, the ISO filed, on May 11, 2001, Tariff revisions that included: (1) proxy price calculation, reporting and cost-justification provisions; (2) data requirements for the ISO's implementation of generators' must-offer obligation; and (3) expanded outage coordination procedures ("May 11 Compliance Filing").

On rehearing of the April 26 Order, the Commission issued an order on

[4] 95 FERC ¶61,115 (2001).

June 19, 2001,[5] in which, in explicit recognition that the Western region is "a single market which is at once inextricably interrelated, yet characterized by important differences" the Commission prescribed price mitigation for wholesale spot markets throughout the Western Systems Coordinating Council ("WSCC").[6] Among its provisions, the June 19 Order: (1) modified the formula for determining the marginal cost-based proxy price for sales in the ISO's spot markets in operating reserve deficiency hours in California; (2) established a mitigated-reserve deficiency Market Clearing Price ("MCP") in the ISO's spot markets in operating reserve deficiency hours in California; (3) established a mitigated non-reserve deficiency 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 ISO-declared Stage 1 System Emergency was in effect; (4) instructed bidders to invoice the ISO directly for the cost to comply with emissions requirements and for start-up fuel costs; and (5) required all utilities who own or control generation in California to offer power in the ISO's spot markets.

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[5] *San Diego Gas & Electric Company, et.al,* 95 FERC ¶61,418(2001) ("June 19 Order").

[6] June 19 Order, slip op. at 2. References to the WSCC are limited to that portion of the WSCC in the United States and the terms "spot markets" and "spot market sales" are defined to mean sales that are 24 hours or less and that are entered into the day of or day prior to delivery.

The June 19 Order also allowed sellers other than marketers to justify prices higher than the market clearing price, subject to review and refund; and restricted marketers from bidding above the market clearing price. On July 10, 2001, the ISO submitted a compliance filing and proposed Tariff revisions, as directed by the June 19 Order ("July 10 Compliance Filing"). In addition to submitting revised Tariff sheets in response to the June 19 Order, the ISO also included in its July 10 Compliance Filing, a revised Tariff sheet to reflect the Commission's rejection of Amendment No. 31 in Docket No.ER00-3673-000, in response to the November 1 Order. The Commission, in the December 19 Compliance Order, accepted the revised Tariff sheet rejecting Amendment No. 31. On July 30, 2001, the ISO filed, as an errata amendment to its May 11 and July 10 Compliance Filings, revised Tariff sheets that substituted Hourly Ex Post Price for mitigated reserve deficiency MCP for Ancillary Service Prices during System Emergencies.

The ISO hereby submits, in compliance with the December 19 Compliance Order and the December 19 Rehearing Order proposed revisions to the ISO Tariff. All Tariff revisions proposed in the instant filing are black-lined against the Tariff language submitted in the January 2, May 11, July 10 or July 30 Compliance Filings, or conformed Tariff, as appropriate.

II. January Compliance Filing: Underscheduling Load Penalty

The December 19 Compliance Order accepted the proposed Tariff revisions in the ISO's January 2 Compliance Filing, with the exception of the proposed amendment related to the underscheduling Load penalty. The December 19 Rehearing Order also discussed the underscheduling Load penalty and noted that the suspension of operation of the PX Day-Ahead and Hour-Ahead markets, and the slow development of markets to fill this void, has limited the ability and flexibility of Loads to fulfill their requirements for Energy in the Day- Ahead and Hour-Ahead time frames. December 19 Rehearing Order, slip op. at 115. Concluding that the Commission "does not wish to penalize market participants for underscheduling when markets may not have been available to fulfill their needs" and because there is a "vast improvement in the reduction in underscheduling by loads, especially in summer months" the Commission ordered the underscheduling penalty be eliminated and thus, mooted Amendment No. 38, filed in Docket Nos. ER01-1579-000 and –001. *Id.* The Commission expressly noted, however, that it would not hesitate to prospectively impose a similar penalty if chronic Load underscheduling again creates a reliability problem. *Id.*

The ISO has revised Tariff Section 2.2.13.2.3, as needed, to eliminate the underscheduling penalty.

III. Must-Offer Obligation

A. Background

The Commission established the must-offer obligation in its April 26 Order by imposing the obligation on all Generating Units under ISO Participating Generator Agreements ("PGAs"). Specifically, the April 26 Order provides that "[s]ellers with PGAs should be required to offer all of their available capacity to the ISO in real-time if it is available and not scheduled to run." Slip op. at 4. In its June 19 Order the Commission affirmed the April 26 Order regarding the must-offer obligation in nearly identical language. Slip op. at 12.

The ISO has implemented the must-offer obligation as set forth in its May 11 Compliance Filing responsive to the April 26 Order; Status Reports on implementation of the April 26 Order, filed with the Commission on May 18 and 25, 2001; a June 6, 2001, ISO answer to comments and protests to the ISO's May 11 Compliance Filing; a July 10 Compliance Filing to the June 19 Order; an ISO July 19, 2001, Motion for Clarification and Request for Rehearing of the June 19 Order; ISO August 20, 2001, comments on the June 19 Order; quarterly reports, as required by the April 26 Order, on September 14 and December 14, 2001; ISO Market Notices on July 20 and August 8, 2001, detailing interim procedures for the must-offer obligation and a December 4, 2001 Status Report detailing revisions to the ISO's interim implementation procedures set forth in the above-listed filings and Market Notices.

In the December 19 Compliance Order, the Commission directs 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." Slip op. at 8. The Commission provides that the costs for running at minimum load should be directly invoiced to the ISO and the ISO should recover the costs consistent with the methodology used to recover costs associated with the reimbursement of emissions and start-up fuel costs incurred by generators operating in compliance with the must-offer obligation. *Id.* The opportunity for compensation of minimum load costs is effective on May 29, 2001.

The Commission directs 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 . . to determine the fuel payment . . . .." *Id.* The ISO interprets the minimum point to the average heat rate if the unit was operating at minimum load. The ISO uses a similar calculation to determine generating unit Proxy Prices, though the ISO uses the incremental heat rate to determine Proxy Prices but uses the average heat rate for calculation of fuel costs for minimum load cost recovery.[7] Generators who do not provide heat and emission rates to the ISO are not eligible for the recovery of costs incurred by running at minimum load.

In the instant filing, the ISO sets forth how it will compensate suppliers for minimum load costs and start-ups and the process it will use to grant temporary waivers from compliance with the must-offer obligation. In the following discussion, the ISO employs the following terms and concepts:

1. Generating Unit Operating Constraints: The feasible scheduling of a generating unit over a time period taking into account operating constraints, including but not limited to:

a. availability: A unit is available if it is not on a planned or forced outage.

b. start-up time: The time required for a unit to start-up.

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[7] The April 26 Order, slip op. at 15, directed the ISO to calculate a Proxy Price based on marginal (*i.e.,* incremental) cost, a provision subsequently affirmed in the June 19 Order, slip op. at 28, because marginal cost reflects the cost of the next MW of production. Average heat rate, not incremental heat rate, should be used for quantification of minimum load costs because average heat rate reflects the costs of the Energy already produced.

c. minimum up time: The minimum time that a unit must stay on-line after a start-up.

d. minimum load: The minimum power output for a unit while on-line.

e. shut-down time: The time required for a unit to shutdown.

f. minimum down time: The minimum time a unit must stay off-line after shut-down, including shut-down time and start-up time.

2. Generating Unit Costs: The costs associated with operating constraints including but not limited to:

a. start-up costs

b. minimum load costs

c. incremental costs

3. Unit Commitment Status: The state for a generating unit for a given time period. A unit is not committed (off) when it is off-line or in the process of start-up or shut-down. A unit is committed (on) when it is on-line and synchronized with the transmission grid. Unit commitment status can be further distinguished as:

a. self-commitment: A generating unit is self-committed (on) in any hour in which it participates in the ISO Day-Ahead or Hour-Ahead Energy or Ancillary Services Markets as demonstrated by submission of bids or schedules into one or more of these markets and any additional hours consistent with the unit's Minimum Up and Minimum Down Times.

b. waiver: When a generating unit is not committed (off) because of an ISO-explicit or ISO-implicit waiver to a generating unit from compliance with the must-offer obligation during a specific time period that is exclusive of such unit's self-commitment period(s), if any.

c. waiver denial: When a generating unit is committed (on) during all time periods in which a generating unit is denied an explicit or implicit wavier from the must-offer obligation.

B. Minimum Load Cost Recovery

In the instant filing, the ISO seeks to reconcile the Commission's direction that: (1) generators are to invoice the ISO for their actual costs during each hour and (2) the ISO is to use a heat rate calculation for calculation of the fuel costs for units running at their minimum load. Specifically, the ISO proposes to use the heat rate calculation "to determine the fuel payment for each hour that a generating unit is in minimum load status." *Id.* Allocation of minimum load costs will be allocated in the same way as start-up costs. Generating units required to run at minimum load in compliance with the must-offer obligation during a Waiver Denial Period will be reimbursed for their minimum load costs incurred during the Waiver Denial Period and, as detailed *infra*, for start-up costs. The ISO will compensate generating units for unrecovered minimum load costs, *i.e.,* that portion of such costs not recovered from profits realized through participation in the ISO markets during the Waiver Denial Period. Profits are calculated as the positive difference between market revenues and operating costs of the unit. Market revenues include settlement for Imbalance Energy (uninstructed and instructed, including out-of-sequence and out-of-market). Operating cost is derived using the average cost of Minimum Load Costs and instructed Energy output. The ISO will pay for the unit's Energy output at the Instructed Imbalance Energy price, then will net profits from all hours of the Waiver Denial Period against all above-MCP payments for Minimum Load Costs. To the extent that the unit's Minimum Load Costs incurred during the Waiver Denial Period still remain unpaid, the ISO will pay the generating unit the unpaid Minimum Load Costs using funds collected in the same way that the ISO collects for start-up and emissions costs.[8]

[8] The June 19 Order directed the ISO to establish a charge for emissions and start-up costs that would be billed to Scheduling Coordinators serving Load in the ISO Control Area and

The ISO has developed a standard invoice for generators to use to provide their records of the time periods generating units were running at minimum load in compliance with the must-offer obligation. The ISO will use the lesser of time periods indicated in the ISO's records or generator invoices for determining the time period for reimbursement.

B. Exemption From The Must-Offer Obligation

Finding the ISO's proposal to grant exemption from the must-offer obligation under certain conditions to be reasonable, the Commission directed the ISO to incorporate into its Tariff, in sufficient specificity, procedures for granting such exemptions, effective July 20, 2001. *Id.*

The ISO has developed a waiver process that provides for the ISO to determine which generating units will be needed by the ISO to be on-line and running at minimum load to be available for Dispatch in real time beyond the hours such units are self-committed. All other units, with either explicit (*i.e.,* formal requests to the ISO for a waiver) or implicit (*i.e.,* failing to submit a schedule) requests for waivers, shall be considered potentially eligible to go off-

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serving Demand in California outside of the ISO Control Area. In its December 19 Order, the Commission directed the ISO to allocate a charge for Minimum Load Costs in a similar manner. The ISO, lacking a means to accurately calculate a similar flat rate for recovery of Minimum Load Costs, in order to comply with the Commission's intent to assess this charge to all California load served on the ISO system, proposes to allocate Minimum Load Costs to Scheduling Coordinators each hour based on the proportion of each Scheduling Coordinator's Load and Export serving California Demand outside the ISO Control Area to total ISO Load and Exports serving California line. The ISO will deny waivers only to those units it determines are needed to run at minimum load. Thus, the ISO will: (1) contact only those specific units being denied waivers and (2) direct the units to be at minimum load for a period not less than the minimum number of hours necessary to reflect each unit's minimum up time, incorporating any Self-Commitment already in place when the waiver is denied.

For all units denied a waiver, the ISO will pay Minimum Load Costs as set forth above. If any such unit, during any hour of the Waiver Denial Period or a period beyond the Waiver Denial Period that is within the end of the last self-committed period preceding the Waiver Denial Period plus the unit's minimum down time: (1) submits an Hour-Ahead Energy Schedule; (2) self-provides or is awarded Hour- Ahead Ancillary Services Capacity; or (3) engages in uninstructed deviations over a entire operating hour that is outside a tolerance band equal to the greater of plus or minus 5 MW or 3% of the unit's maximum operating output, then any such unit shall be denied minimum load cost compensation for all hours of the Waiver Denial Period. All other units running at minimum load for their respective Waiver Denial Period shall be reimbursed for all unrecovered Minimum Load Costs incurred during the Waiver Denial Period.

Demand outside the ISO Control Area in that hour.

C. Start-Up Cost Recovery

In its December 19 Order, the Commission adopted the ISO's proposed Tariff revisions providing for the calculation, invoicing and assessment of charges associated with start-up costs. The ISO now clarifies that it will reimburse generating unit start-up costs for all instances when the generating unit is required to start-up in response to a waiver denial or ISO Dispatch instruction and otherwise would not start-up in response to self-commitment.

D. Economic and Operational Considerations In Granting Waivers

The December 19 Order expressly noted that the ISO should "make reasoned decisions about its generation requirements in order to maximize economic and reliable operations. . .". Slip op. at 8. Specifically, the ISO, will grant waivers in a non-discriminatory manner that will attempt to minimize, with due respect for locational reliability requirements, the collective costs to Market Participants for reimbursement for start-up fuel costs, emission fees, and minimum load operating costs as are incurred to meet the ISO's requirements to meet residual unscheduled load and reserve requirements over each operating day. Reserve requirements may include capacity necessary to ensure a competitive supply in the ISO Real-Time Energy Market.

Physical operating constraints including but not limited to, start-up time, minimum up and minimum down time and shut down time shall also be factored into the ISO's determination of which units shall be granted waivers from compliance with the must-offer obligation.

Lastly, the ISO respectfully notes that the Commission directive to pay Minimum Load Costs inadvertently may create a gaming opportunity by providing suppliers with a disincentive to schedule in the Day-Ahead market. Suppliers may withhold schedules they would otherwise submit to the Day-Ahead market in order to have the ISO subsidize their Minimum Load Costs during a Waiver Denial Period. Although the ISO has proposed a mechanism to minimize such potential gaming behavior, the ISO notes that it will monitor closely the patterns of bidding and will seek appropriate remedy before the Commission should such unintended consequences result.

The ISO includes proposed revisions to Sections 5.11.6 and the Master Definitions Supplement, Appendix A as needed to implement the above-discussed provisions. Given the Commission's determination that the ISO should reimbursement generating units for Minimum Load Costs effective May 29, 2001, the ISO is in the process of identifying which units are eligible for such compensation and calculating the compensation amounts. The ISO expects this effort to be completed in approximately eight weeks and will file a subsequent compliance report at that time.

IV. Recalculation of the Market Clearing Price

A. West-Wide Winter Season Methodology

In its December 19 Winter Price Order the Commission suspended the methodology adopted in its June 19 Order, effective December 20, 2001 through April 30, 2002, and substituted a winter season methodology. As a starting point for the winter season formula the Commission set a price level at $108/MWh, which is the actual mitigated price set using the prior methodology during the last ISO Stage 1 System Emergency on May 31, 2001, based on a proxy figure for natural gas costs of $6.641/MMBtu, a generating unit with a heat rate of approximately 15,360 Btu/MWh and $6.00/MWh for the variable O & M adder. December 19 Compliance Order, slip op. at 8. The new winter season methodology supersedes the prior price mitigation methodology (which established a price limit of approximately $92/MWh effective June 21, 2001), which was set at eighty-five percent of the originally calculated $108/MWh price limit for application during non-reserve deficiency hours.

Under the winter season formula, the mitigated price will be recalculated when the average of the mid-point for the monthly bid-week index prices reported for SoCalGas (Large packages), Malin and PG&E Citygate price points rises by a minimum factor of 10 percent (*e.g.,* for the first recalculation, to $7.305/MMBtu) effective for the following Trade Day. The winter formula also will track subsequent cumulative changes of at least 10 percent, but cannot drop below a floor of $108/MWh. Effective on May 1, 2002, the prior price calculation (*i.e.,* the "summer methodology") will be reinstated along with an initial price limit of approximately $92/MWh for non-reserve deficiency periods. December 19 Compliance Order, slip op. at 8-9.

The ISO has proposed revisions to Sections 2.5.23.3.1.1, 2.5.23.3.1.2, 2.5.23.3.1.3, 2.5.23.3.5 and the Master Definitions Supplement, Appendix A, as needed, to modify calculation of the mitigated price for the period December 20, 2001 through April 30, 2002, to implement the west-wide winter season methodology. Given the Commission's direction that this revision is to be effective for the period December 20, 2001, through April 30, 2002, the ISO is in the process of recalculating the applicable prices. The ISO expects this effort to be completed in approximately eight weeks and will file a subsequent compliance report at that time.

B. Definition of System Emergency and Recalculation of the Mitigated Price After April 30, 2002

In its December 19 Compliance Order, slip op. at 9, the Commission directs 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." *Id.*

The December 19 Compliance Order notes that, even though the commentors variously noted that the Commission appears to have used the declaration of a Stage 1 System Emergency or a System Emergency interchangeably with a seven percent operating reserve deficiency, that it is the reserve deficiency that creates a risk that prices might exceed those prices determined in a competitive market. *Id.*

The Commission states that "establishing a specific percentage is appropriate and reasonable because it enhances market certainty during the mitigated period." *Id.* Additionally, the Commission finds that continuing to permit the ISO discretion to declare a system emergency is "no longer warranted, and further, such discretion could provide the appearance of manipulation of the market by the ISO." *Id.*

In its Motion for Clarification and Request for Rehearing of the December 19 Rehearing Order and its Motion for Clarification and Request for Rehearing of the December 19 Compliance Order, filed on January 18, 2002, in the above-referenced dockets, the ISO respectfully notes that System Emergencies are defined by FERC-approved Western System Coordinating Council ("WSCC") reliability criteria. The ISO is committed to comply with the WSCC reliability criteria, from which operating reserves are calculated and System Emergencies defined, by virtue of: (1) the ISO's contract with the WSCC; [9] (2) the provisions of the ISO Tariff; [10] and (3) California state law.[11] Moreover, the WSCC Minimum Operating Reserve Criteria ("MORC") (the underlying standards with which the

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[9] The ISO agreement is designated by the Commission as WSCC Rate Schedule No. 5.

[10] Section 2.3.1.1.6 of the ISO Tariff states that the ISO should be the WSCC security coordinator for the ISO Controlled Grid. Under Section 2.3.1.3.1, the ISO is to exercise Operational Control over the ISO Controlled Grid "to meet planning and Operating Reserve Criteria no less stringent than those established by WSSC and NERC as those standards may be modified from time to time . . . ." *See also* Section 2.1 of the Dispatch Protocol of the ISO Tariff which provides:

> The ISO shall exercise Operational Control over the ISO Controlled Grid in compliance with all Applicable Reliability Criteria. Applicable Reliability Criteria are defined as the standards established by NERC, WSCC and Local Reliability Criteria and include the requirements of the Nuclear Regulatory Commission (NRC).

[11] Chapter 345 of Assembly Bill 1890 provides:

> "The Independent System Operator shall ensure efficient use and reliable operation of the transmission grid consistent with achievement of planning and operating reserve criteria no less stringent than those established by the Western Systems Coordinating Council and the North American Electric Reliability Council."

ISO must comply pursuant to the WSCC's Reliability Management System contract) requires the ISO maintain Spinning Reserves and Non-Spinning Reserves equal to the sum of five percent of the load responsibility served by hydroelectric generation and seven percent of the load responsibility served by thermal generation.[12] The Commission's direction to use a seven percent reserve margin does not comport with the WSCC MORC definition of a Stage 1 System Emergency.

In the two ISO Motions for Clarification and Requests for Rehearing to the December 19 Compliance and Rehearing Orders, discussed *supra*, the ISO explains that based on the five percent of Load served by hydroelectric Generating Units and the seven percent of Load served by thermal Generating Units, the ISO's average Operating Reserve requirement was not seven percent, but 6.2 percent, based on the simple average of the monthly Operating Reserve obligation in 2001. If the ISO were to operate using a seven percent Operating Reserve threshold for the duration of the price mitigation period (until September 30, 2002), the ISO will incur a significant additional cost, which must be passed through to Market Participants, for the procurement of unnecessary Operating

[12] WSCC Rate Schedule No. 1 First Revised Sheet No. 27.

Reserves above the MORC requirements. The ISO does not believe that the Commission intended this consequence.

Given that it is not reasonable to think that the Commission intends that the ISO maintain excessive operating reserves and noting the Commission clearly intends that it is a reserve deficiency that creates the risk that prices will exceed those charges in a competitive market should be the trigger to recalculate mitigated prices, the ISO proposes in the instant filing a new Tariff term, "Price Mitigation Deficiency Reserve," defined as "Any clock hour in which the ISO's maximum actual reserve margin is below seven (7) percent." Consistent with the several December 19 orders, the Non-Emergency Clearing Price Limit will be reset whenever a Price Mitigation Reserve Deficiency occurs.

The ISO's proposed approach is consistent with the Commission's finding that a specific percentage is appropriate and reasonable because it enhances market certainty during the mitigated price period even while avoiding a temporary redefinition of a Stage 1 System Emergency that would conflict with the ISO's operation of the ISO Control Area and ISO's compliance with the WSCC MORC.

As detailed in the two Motions for Clarification and Requests for Rehearings, detailed *supra*, and in the instant filing, the ISO requests the

Commission modify its directives to the ISO to adopt the proposed Price Mitigation Reserve Deficiency. While, in the instant filing the ISO proposes to set the Price Mitigation Reserve Deficiency at seven percent, in compliance with the December 19 Compliance Order, the ISO believes a more appropriate level is 6.2 percent. This represents the ISO's historical Operating Reserve requirement determined by the WSCC MORC.

The ISO has proposed revisions to Sections 2.5.22.4.2, 2.5.23.3.1.1, 2.5.23.3.1.2, 2.5.23.3.2, 2.5.23.3.5, 2.5.23.3.8, 2.5.27.7.1, 2.5.27.7.2., 5.11.5, and the Master Definition Supplement, Appendix A to implement this directive. Given the Commission's determination that revision is to be effective May 29, 2001, the ISO is in the process of identifying when operating reserves dropped below seven percent and thus triggered a revision to the Non-Emergency Clearing Price Limit. The ISO expects this effort to be completed in approximately eight weeks and will file a subsequent compliance report at that time.

V. Use of Proxy Price Only To Establish the Mitigated Reserve Deficiency Market Clearing Price

In its December 19 Compliance Order the Commission rejected the ISO's proposed calculation of the mitigated reserve deficiency MCP as 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. Specifically, the Commission directed the ISO “to modify the price mitigation sections of its Tariff to use the highest price unit dispatched during a system reserve deficiency using the proxy price to determine the mitigated reserve deficiency MCP, effective May 20, 2001” and, effective June 21, 2001, “to calculate the non-reserve deficiency MCP” the same way. December 19 Compliance Order, slip op. at 11.

The proposed revision to Section 2.5.23.3.1.1 implements this requirement. Given the Commission’s determination that revision is to be effective May 20, 2001, for reserve deficiency hours, and effective June 21, 2001, for non-reserve deficiency hours, the ISO is in the process of recalculating the relevant prices. The ISO expects this effort to be completed in approximately eight weeks and will file a subsequent compliance report at that time.

VI. Justification for Bids Above the Mitigated Market Clearing Prices

In its December 19 Compliance Order, the Commission found the ISO’s proposal to require cost justification for bids that are above the mitigated MCP but which are not accepted to be unnecessary and not supported by prior Commission orders. Slip op. at 11. The Commission stated that sellers should only be required to submit cost justification to the ISO in cases where bids above the mitigated MCP are accepted, effective May 29, 2001.

The ISO notes that it has filed, on January 18, 2002, a Motion for Clarification and Request for Rehearing, in the above-reference dockets, seeking reconsideration of the Commission's recession of this requirement. In compliance with the December 19 Compliance Order, however, the ISO has proposed revisions to Section 2.5.23.3.5 to provide that, effective May 29, 2001, only bids which are above the mitigated MCP and accepted by the ISO must be cost-justified.

VII. Penalty For Failure to Respond to ISO Dispatch Instructions

The Commission has concluded that, during the period that the must-offer obligation is in place, it is appropriate to modify the ISO Tariff provision, accepted in Amendment No. 33, imposing a penalty for failure to report a forced outage and for failure to comply with emergency Dispatch instructions. The removal of such penalties is to be effective June 21, 2001, through September 30, 2002.

Proposed Tariff revisions modify Section 5.6.3.2.1 to provide that, effective June 20, 2001, and continuing through September 30, 2002, (corresponding to the end of the must-offer obligation), the ISO will not levy penalties against Market Participants for either a failure to report forced outages or to respond to Dispatch instructions. The ISO is in the process of removing from billing and settlement records all such penalties for the past period beginning on June 20, 2002 and continuing to date. The ISO expects this effort to be completed in approximately eight weeks and will file a subsequent compliance report at that time.

VIII. Calculating the Market Clearing Price for Ancillary Services

The Commission directs the ISO to modify its Tariff to provide that the price limits for Ancillary Services should be established as of the time the transactions are entered into as opposed to when delivery actually occurs. December 19 Compliance Order, slip op. at 16, December 19 Rehearing Order, slip op 92-96. This modification is prospective only and effective December 20, 2001 forward.

The ISO has proposed Tariff revisions to Sections 2.5.27.7.1 and 2.5.27.7.2 to implement this requirement.

IX. Requirements for Resources To Set Market Clearing Prices

In the December 19 Compliance Order the Commission determined it will not require that a Participating Generator Agreement (“PGA”) be signed in order for a resource to set the mitigated MCP or for such a resource to be eligible to justify bids above the mitigated MCP. Slip op. at 17. Specifically, the Commission found in its June 19 Order that:

> "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." Slip op. at 18.

Moreover, the Commission clarified that "gas costs for these generators will be [the] 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 in California." Slip op. at 18. See also December 19 Rehearing Order, slip op. at 70.

The Commission also held that units dispatched under out-of-market calls and Regulatory Must-Run units are not eligible to set the mitigated reserve deficiency MCP, and that only units dispatched through the Imbalance Energy market are eligible to set the mitigated reserve deficiency MCP. December 19 Compliance Order, slip op. at 18.

The ISO has revised Sections 2.5.23.3.8 and 2.5.27.7.4 to remove the requirement that these out-of-Control Area resources need to execute a PGA in order to be eligible to set the MCP.

In order to validate the eligibility of a specific generating unit to set the MCP, the ISO must be able to confirm that: (1) such a unit is capable of performing to its bid and (2) the unit has changed its output in response to a specific Dispatch instruction, as opposed to running under a bilateral agreement. In the alternative, such a unit must at least be able to demonstrate to the ISO that it was operating at the relevant time at a level from which it could meet the ISO's Dispatch instructions. Therefore, to implement the Commission's direction to use meter and interchange data, the ISO is proposing to require generating units that do not operate under a signed PGA with the ISO, to have real-time visibility to permit the ISO to validate those resources' bids so as to prevent resources that can not respond to a Dispatch instruction from setting the MCP.

X. Emissions and Start-Up Fuel

The Commission clarified that sellers need not submit their entire gas supply portfolio, including the gas supplies of affiliates, in order to justify actual start-up fuel costs. Specifically, the Commission instead directed 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 in Gas Daily for three spot markets reported for California." December 19 Compliance Order, slip op. at 21. Moreover, the Commission stated that if sellers sought to recover costs above this gas price for start-up costs, sellers must submit their entire gas portfolio to the Commission and the ISO as justification." *Id.*

In response to comments on the July 10 Compliance Filing, the ISO agreed to a clarification proposed by Pacific Gas and Electric Company regarding allocation of emission and start-up costs on a gross load basis. In the December 19 Compliance Order, the Commission agreed with the ISO that gross load is the most appropriate basis for assessing emissions and start-up fuel costs because this assessment is consistent with the ISO's Real Time Imbalance Energy Market performing a reliability function. December 19 Compliance Order, slip op. at 22.

Proposed revisions to Sections 2.5.23.3.6.3, 2.5.23.3.7.3, 2.5.23.3.7.6 and the Master Definitions Supplement, Appendix A are included to provide for the required clarification that, effective December 20, 2001, sellers need not submit cost data for their entire gas portfolio and that total gross load is the basis for assessment of emissions and start-up fuel costs.

XI. Credit Risk Adder

The December 19 Compliance Order accepted the ISO's July 10 Compliance Filing proposed Tariff revisions to apply a ten percent credit adder "on the charges and payments for all sales in the ISO Markets at the mitigated Market Clearing Prices for those markets." Slip op. at 22. In conjunction with findings in the December 19 Rehearing Order, the Commission now requires "[I]n addition to the use of a ten percent surcharge adder to the mitigated Market Clearing Prices and Ancillary Services 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." December 19 Compliance Order, slip op. at FN 36. This additional application of the ten percent credit adder is effective December 20, 2001.

The ISO has proposed revisions to Section 11.2.12 to clarify the applicability of the ten percent credit adder.

XII. Termination Date For Market Mitigation Measures

In the December 19 Compliance Filing the Commission reaffirmed its intent to terminate the price mitigation plan after September 30, 2002. The Commission required the ISO to file revised Tariff sheets incorporating this termination date for the price mitigation plan.

The ISO includes herein a new Section 31, specifying the September 30, 2002, sunset date for the price mitigation methodology.

XIII. Price Takers Must Bid $0/MWh in the Real Time Markets

In the December 19 Rehearing Order, the Commission affirmed that the June 19 Order provision prohibiting marketers from bidding a price higher than the mitigated reserve deficiency MCP was to prevent megawatt laundering. Slip op. at 46 and FN 125. The Commission now clarified:

> "that the mechanism to make marketers price takers is to require marketers that do not resell in other bilateral markets and choose to participate in the real-time spot market to bid at $0/MWh, not at the mitigated Market Clearing Prices. The marketer will then be paid the market clearing price, up to the mitigated Market Clearing Prices. The same mechanism will apply to LSEs [Load Serving Entities] that choose to participate in the real-time spot markets by reselling excess energy that they themselves did not generate."
> *Id.* at 47.

The Commission also provides that it "will continue to preclude marketers from submitting justification for transactions above the mitigated Market Clearing Prices." *Id.* Finally, the Commission clarified that marketing affiliates of generators are required to be price takers and that marketer-to-marketer transactions in the bilateral spot markets are subject to price mitigation and marketers selling outside of the ISO's single price auction will receive the price up to the mitigated Market Clearing Price." *Id.*

As set forth in the ISO's Motion for Clarification and Request for Rehearing of the December 19 Rehearing Order, filed in the above-referenced dockets on January 18, 2001, the ISO strongly urges the Commission to modify the requirement that marketers bid at $0/MWh. The ISO agrees such entities properly should be price-takers, but nonetheless must have the ability to submit actual bids to provide for merit order Dispatch, to allow suppliers a reasonable opportunity to earn their bid price, and to contribute to a real, as opposed to artificially-repressed MCP that may result from a preponderance of $0/MWh bids.

In this compliance filing, the ISO is proposing revisions to Section 2.5.23.3.8.1, as needed to modify the Tariff to provide, effective December 20, 2001, that marketers and marketing affiliates of generators are price takers and must bid $0/MWh in the ISO real-time spot markets.

XIV. Hydroelectric Generators

In the December 19 Rehearing Order, the Commission affirmed that the June 19 Order provision that “[d]ue to their multi-purpose limitations, hydroelectric generators are not subject to the must-offer obligation” but such resources “are price takers during the hours in which they choose to participate in the spot market.” Slip op. at 46. Unlike marketers, the Commission declined to require hydroelectric generation units to bid at $0/MWh in the real-time spot markets. *Id.* at 46-47. Because the Commission did not distinguish between hydroelectric generation units within the ISO Control Area and those in other Control Areas in its requirement that all such units are price takers, the ISO must revise the Tariff to prevent hydroelectric units within the ISO Control Area from being eligible to set the MCP during non-reserve deficiency periods, as they currently may so do. Moreover, if the ISO Dispatches a bid from a hydroelectric generating unit that is above the last bid eligible to set the MCP, the ISO will deem the dispatched hydroelectric generating unit's bid to be equal to the last eligible bid setting the MCP. This requirement is effective on December 20, 2001.

The proposed revisions to Section 2.5.23.3.8 implement this change.

XV. Implementation Costs and Schedule

In light of concerns about the ISO's costs raised by other parties in the Commission's ongoing ISO Grid Management Charge proceedings, the ISO notes that it estimates that the new costs and retroactive application of certain new settlement formulae ordered by the Commission and set forth in this compliance filing will require changes to the ISO's scheduling and settlements software systems costing at least $850,000 and taking a minimum of eight weeks to design, test and implement. Moreover, the ISO's compliance with these new requirements is likely to force the ISO to seek greater revenues through appropriate mechanisms.

XVI. Reservation of Rights

This filing represents the ISO's best effort at complying with the price mitigation aspects of the three complex orders issued by the Commission on December 19, 2001, in the time permitted. The ISO already has identified a number of issues arising from or related to the December 19 orders which the ISO believes require clarification or modification. The ISO has addressed these issues in three separate motions for clarification and request for rehearing, filed on January 18, 2002.

XVII. Supporting Documents

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

Attachment A: Revised Tariff Sheets, incorporating the compliance changes;

Attachment B: Black-lined Tariff provisions showing revisions related to current Tariff sheets.

Attachment C: A notice of filing, suitable for publication in the Federal Register (also provided in electronic format).

Two additional copies of this filing are enclosed to be date-stamped and returned to our messenger. If there are questions concerning this filing, please contact the undersigned.

Respectfully submitted,

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Dated: January 25, 2002