UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company	**)**	**Docket Nos. EL00-95-012**
	)	**and EL00-98-000**

STATUS REPORT TO UPDATE THE COMMISSION ON THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION'S PROGRESS TOWARDS IMPLEMENTATION OF THE COMMISSION'S APRIL 26 ORDER

Pursuant to Rules 207 and 215 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission"), 18 C.F.R. §§ 385.207 and 385.215, the California Independent System Operator Corporation ("ISO") hereby updates the Commission regarding the ISO's progress towards implementation of the Commission's April 26, 2001 *Order Establishing Prospective Mitigation and Monitoring Plan for the California Wholesale Electric Markets and Establishing an Investigation of Public Utility Rates in Wholesale Western Energy Markets*, 95 FERC ¶ 61,115 ("April 26 Order") in this proceeding.

I. COMMUNICATIONS

Please address communications concerning this filing to the following persons:

Charles F. Robinson
Vice President and General Counsel
Roger E. Smith, Senior Regulatory Counsel
The California Independent System Operator Corporation
151 Blue Ravine Road
Folsom, CA 95630
Tel: (916) 608-7135
Fax: (916) 608-7296

Kenneth G. Jaffe
David B. Rubin
Swidler Berlin Shereff Friedman, LLP
3000 K Street, N.W., Suite 300
Washington, DC 20007
Tel: (202) 424-7500
Fax: (202) 424-7643

II. BACKGROUND

In its December 15, 2000, order in this proceeding,[1] the Commission found that the market structures and rules for wholesale sales of Energy in California were seriously flawed and that these structures and rules, in conjunction with an imbalance of supply and Demand in California, have 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, including establishing a $150/MWh (or $150/MW) "soft cap" or breakpoint in the ISO's Ancillary Services and real-time Imbalance Energy markets. Under this price mitigation mechanism, suppliers whose bids to provide Ancillary Services or Imbalance Energy are above the $150 breakpoint and are accepted by the ISO are paid "as bid" (*i.e.*, no bid above

[1] *San Diego Gas & Electric Company 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 ¶ 61,294 (2000) ("December 15 Order").

$150 in any hour can set the Market Clearing Price ("MCP") in the ISO's Ancillary Services and Imbalance Energy markets). Public utility[2] sellers bidding above the breakpoint are required to submit cost support data for these above-cap bids to the Commission and payment for all such bids accepted by the ISO is subject to refund. Pursuant to the December 15 Order, the soft cap mechanism went into effect on January 1, 2001 and remains in effect to date. The December 15 Order also required the development of a longer term mitigation plan to replace the interim breakpoint methodology.

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. As described in further detail below, the mitigation plan adopted in the April 26 Order includes:

- increased coordination, control and reporting of outages;
- a requirement for public utilities purchasing in the ISO's real-time Energy market to submit demand bids that indicate the price at which Load will be curtailed;
- a requirement for all sellers that own or control generation in California to offer all their available power in the ISO's real-time Energy market;
- certain general conditions on market based rate authority prohibiting anomalous bidding behavior; and
- a price mitigation mechanism for the ISO's real-time Energy market during System Emergencies.

[2] The ISO uses the term "public utility" in the sense defined under Section 201 of the Federal Power Act ("FPA"), 16 U.S.C. § 824 (1994). That is, a public utility under the FPA is any entity that owns or controls Commission-jurisdictional assets and engages in the sale for resale of electric energy or that transmits energy in interstate commerce.

The Commission directed the ISO to submit Tariff revisions to comply with the April 26 Order within fifteen days and to implement such measures by May 29, 2001.[3]

III. DISCUSSION

Despite serious concerns regarding the potential effectiveness of the April 26 Order to meet the statutory requirement of ensuring just and reasonable rates (which objections will be the subject of a petition for rehearing to be filed shortly), the ISO has made every effort to be in a position to implement the Commission's directives by the dates set forth in the Commission's order. These efforts have included: (1) securing Generating Unit operating characteristics from both affected public utility sellers and non-public utility sellers, and (2) designing, coding, and testing the market application software necessary to support the revised market rules prescribed by the April 26 Order. The following sections update the Commission on the ISO's progress towards fulfilling those objectives.

Information Requirements

In the April 26 Order, the Commission adopted a price mitigation plan in which:

> each gas-fired generator in California (both those signing PGAs and covered non-public utility gas-fired generators) will file with the Commission and the ISO (on a confidential basis) the heat rate and emission rate for each generating unit. These heat rates must reflect operational heat rates that do not include start-up and minimum load fuel costs because, in a declared emergency, the market clearing price should reflect the cost to generate at or near maximum outputs. The ISO will use these heat rates to calculate a marginal cost for each generator [the Generator's "Proxy Price"] by using a proxy for the gas costs, emission cost, and a $2.00 adder

3 The ISO filed its compliance tariff changes with the Commission on May 11, 2001.

for operation and maintenance expenses.

April 26 Order at 61,358-59. These Proxy Prices will form the basis for the April 26 Order's price mitigation plan. *Id.* at 61,358-60.

The April 26 Order required each entity that owns or controls gas-fired Generation in California to file with the Commission and the ISO (on a confidential basis) the heat rate (not including start-up and minimum load fuel costs) and emissions rate for each gas-fired Generating Unit in the State. The ISO issued two market notices providing a format for submission of this information. In these market notices, the ISO requested heat and emission rates for eleven different operating points with the first and last operating points representing the unit's minimum and maximum (or near maximum) operating level, respectively.[4] The ISO also requested the minimum operating level (Pmin), maximum operating level (Pmax), and ramp rate for non-PGA units. In accordance with the April 26 Order, the ISO will calculate the Proxy Prices for gas-fired Generating Units using this information.

In the April 26 Order, the Commission also established a requirement that all non-hydroelectric Generators in the State of California "offer the ISO all of their capacity in real time during all hours if it is available and not already scheduled to run through bilateral agreements." April 26 Order at 61,355. This

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4 By collecting heat rate information at eleven different operating points, the ISO will be able to approximate the actual incremental cost curve of each Generating Unit and thereby develop representative Proxy Prices for each unit throughout the unit's operating range. In addition, the ISO believes that real-time dispatch based on these will result in a more accurate determination of system marginal cost, as represented by the Marginal Proxy Clearing Price, and will thus approximate closely the outcome of a competitive market. As described more fully below, the ISO will utilize the average heat rates provided for each resource to calculate incremental heat rates at various points of operation. The incremental heat rate will be multiplied by the gas price to produce a proxy bid reflecting the marginal cost

requirement applies not only to Participating Generators, but to all "non-public utility sellers that own or control generators in California" as a condition for their participation in the ISO's markets or use of the ISO Controlled Grid. *Id.* at 61,356.

In its May 11 compliance filing ("Compliance Filing") the ISO proposed Tariff revisions to make it clear that the selling obligation established by the April 26 Order is applicable to all "Must-Offer Generators," defined as either a Participating Generator or an entity that owns or controls one or more non-hydroelectric Generating Units located in California[5] from which Energy or capacity is either: (i) sold through any market operated by the ISO, or (ii) transmitted over the ISO Controlled Grid.

As the ISO stated in the Compliance Filing, in order to implement and monitor compliance with this requirement, the ISO must have certain operating information (i.e., minimum and maximum operating levels, ramp rates, and outage information) from all Generators subject to the requirement. The ISO does not currently receive this information from non-Participating Generators and therefore proposed certain reporting requirements for Must-Offer Generators that are not Participating Generators. As noted in the ISO's Compliance Filing, the ISO issued a market notice on May 6, 2001, requesting such information from the affected Generators.[6]

However, as the ISO further explained in its Compliance Filing, the ISO

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of operation at each point of operation.

[5] This would include Generating Units in the other Control Areas in California.

[6] *See* ISO's May 11, 2001 Compliance Filing. Additional ISO market notices are provided in Attachment B to the present filing.

does not have a contractual relationship with all of these Must-Offer Generators, including Must-Offer Generators both within and outside of the ISO Control Area. That is, while many of these resources are located in California, they are either: (1) not located within the ISO's Control Area and are not required to execute PGAs (thus, the ISO does not receive from these resources the information required to be submitted by Participating Generators under Schedule 1 of the PGA and these resources are not required to comply with the scheduling, metering, and telemetry requirements of the ISO Tariff); or (2) are located within the ISO Control Area but are scheduled and dispatched according to agreements that pre-date ISO operations and therefore do not have to comply with the ISO Tariff. Therefore, the ISO's ability to validate and enforce the requirements of the April 26 Order is limited with respect to those Generators. At most, the ISO can advise the Commission if it appears that any such Generator has failed to comply with the April 26 Order's requirements so that the Commission may take such action as it deems appropriate.

As detailed in Attachment A to the present filing, the response to both market notices has been incomplete. To date, as detailed in Attachment A, the ISO received heat and emissions rate information from: (1) 126 conventional gas-fired generating resources, representing about 19,700 MW of installed capacity; and (2) from ten gas-fired Qualifying Facility ("QF") resources, representing another 1,100 MW of installed capacity.[7] As further detailed in

[7] Some generating resources as listed in Attachment A are scheduled as aggregations of Generating Units. Thus, the number of individual Generating Units reported herein is higher than the stated number. In cases where an aggregated resource includes both gas-fired and non-gas-fired Generating Units, it is classified for purposes of Attachment A based on the predominant fuel

Attachment A, the ISO has not yet received heat and emissions rate information from: (1) ten conventional gas-fired generating resources, representing about 260 MW of installed capacity; and (2) one-hundred and two gas-fired Qualifying Facility resources, representing another 4,230 MW of installed capacity. Moreover, twelve gas-fired Qualifying Facilities, representing 838 MW of installed capacity, have explicitly refused to supply the requisite information.[8] Finally, the ISO notes that none of the gas-fired resources located in California but outside of the ISO Control Area have provided any information to the ISO.

As explained further below, for Generating Units that (1) have failed to submit the requisite information or whose data the ISO believes to be inadequate (i.e., they only submitted data for one operating point) and (2) for which the ISO has a viable alternative source of such information (e.g., either current or pre-existing Reliability Must-Run Contracts), the ISO intends to use such information from the alternative source. In addition, the ISO has determined, as described in detail below, that it will treat Must-Offer Generators that do not provide the necessary information as price-takers, i.e., as if they had submitted a bid of $0/MWh. The ISO seeks confirmation from the Commission that such treatment is appropriate for suppliers who have failed to comply with the Commission's requirements for providing their Generating Unit-specific data. Absent provision of a bid or the ability to substitute bids as outlined above, the ISO will be unable to implement the Commission's directives or the ISO's implementation of the

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type represented by the aggregated resource.

[8] Obviously, many of the Qualifying Facilities identified in Attachment A currently operate under their existing Power Purchase Agreements ("PPAs") with their host Utility Distribution Company ("UDC") and therefore are currently Scheduled with the ISO by their UDC. For

Commission's mitigation methodology will be incomplete or inaccurate.

Software Design and Implementation

In order for the ISO to design and implement any changes to its markets, the ISO must undertake an intensive exercise to scope, define, code, test, and implement the necessary changes to the ISO's computer systems. This process requires the ISO to take the following steps and requires the specified timeframe for completion of each task:

Step 1: Scope and Functional Requirement Definition (1 week)

Step 2: Design (2 week)

Step 3: Coding and Development (4 weeks)

Step 4: Unit Testing (1 week)

Step 5: Integration Testing (1 week)

Step 6: Market Simulation (1 week)

Step 7: Release and Notice To Market (1-2 weeks)

Even with perfect clarity as to the proposed market design and under the best of circumstances, the ISO could not have an automated system that would meet the Commission's proposed implementation schedule. However, recognizing the gravity of the circumstances and the unfathomable prospect of not having any mitigation measures in place by early June, the ISO is making best effort to have, at a minimum, a manual mitigation process in place by May 29. Based on the current schedule, and without further delays, the ISO anticipates that it can have automated procedures in place by July 1.

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purposes of Attachment A, resources have been classified as Qualifying Facilities if they operate under a PGA that was submitted by their UDC.

Based on the need to immediately scope and define the software requirements for implementing the Commission's directives, the ISO has had to make certain assumptions about the Commission's intent, as expressed in the directives contained in the April 26 Order. Therefore, at this juncture in the implementation process, the ISO believes it must clarify to the Commission how the ISO plans to implement the directives contained in the April 26 Order. To the extent that the Commission believes that the ISO has misinterpreted the Commission's order or disagrees with any aspect of the ISO's planned approach, the ISO requests that the Commission notify the ISO immediately so that it can make the necessary modifications to its implementation plan; thereby minimizing any further delay in implementing a fully automated and tested system.

<u>The ISO's Implementation Plan</u>

As noted earlier, the mitigation plan adopted in the April 26 Order includes:

- increased coordination, control and reporting of outages;
- a requirement for public utilities purchasing in the ISO's real-time Energy market to submit demand bids that indicate the price at which Load will be curtailed;
- a requirement for all sellers that own or control generation in California to offer all their available power in the ISO's real-time Energy market;
- certain general conditions on market based rate authority prohibiting anomalous bidding behavior; and
- a price mitigation mechanism for the ISO's real-time Energy market during System Emergencies.

<u>Outage Coordination</u>

As outlined in the ISO's Compliance Filing, the ISO has developed and is prepared to implement the outage coordination procedures set forth in that filing.

The outage coordination procedures will not require any changes to the ISO's market software systems.

Selling Obligation

As the ISO explained earlier in this motion and in its Compliance Filing, the ISO has developed Tariff language regarding the must-bid or selling obligation contained in the April 26 Order. In addition, the ISO has proposed, as set forth in the proposed Tariff language, the information requirements the ISO believes are necessary to implement the directive. However, as the ISO explained, there are limitations on the ISO's ability to monitor compliance with the must-sell requirement. While many of these must-sell resources are located in California, they are either: (1) not located within the ISO's Control Area and are therefore not required to execute PGAs (consequently, the ISO does not receive the information required to be submitted by Participating Generators under Schedule 1 of the PGA and these resources are not required to comply with the scheduling, metering, and telemetry requirements of the ISO Tariff); or (2) are located within the ISO Control Area but are scheduled and dispatched according to agreements that pre-date ISO operations and therefore do not have to comply with the ISO Tariff.[9] Therefore, the ISO's ability to validate and enforce the requirements of the April 26 Order is limited with respect to those Generators. At most, the ISO can advise the Commission if it appears that any such Generator

[9] The ISO notes that with respect to QFs that are operating under their existing PPAs with their host UDC, the ISO does not believe that the Commission's must-sell obligation pertains to the capacity under such contracts. The ISO believes that such capacity is available to the UDCs for satisfying their own load and is therefore already being Scheduled with the ISO. With respect to QFs that are no longer under a PPAs with a UDC and that sell into the ISO's markets or utilize the ISO Controlled Grid, their capacity must be made available to the ISO.

has failed to comply with the April 26 Order's requirements so that the Commission may take such action as it deems appropriate.

While the ISO will provide the Commission with all available information with regard to the availability of Generating Units located in California, ultimate enforcement of this obligation must reside with the Commission. To the extent that all covered Generating Units continue in, or come into, compliance with the ISO's information, metering, telemetry, and scheduling requirements, the ISO will be able to monitor compliance with the Commission's requirement and no changes to the ISO's systems will be necessary.

As the ISO proposed in its Compliance Filing, the ISO intends to insert "substitute" bids into the ISO's Imbalance Energy merit order stack ("BEEP Stack") for any available capacity that is not bid into the ISO's real-time market from Generating Units that are obligated to make all of their capacity available to the ISO in real time.[10] The ISO proposes to substitute a "$0" bid for all other resources, including gas-fired resources that have not submitted bids. The ISO believes that such an approach will provide resources with an incentive to offer all their available capacity at a stated price or subject themselves to dispatch as a price taker. In addition, the ISO believes that such an approach will provide an incentive for Generating Units subject to the must-offer requirement to submit timely and accurate information regarding their availability and thereby potentially avoid penalties for failure to follow an ISO dispatch instruction.

10 The ISO's ability to substitute bids will of course depend on its ability to determine, in real time, a unit's available capacity. As explained earlier, the ISO has concerns over its ability to monitor a Generating Unit's compliance with the as-bid requirement if that unit is located in California but is either located outside of the ISO's Control Area or is part of an aggregated

In order to implement the selling obligation with respect to Generating Units located outside of the ISO's Control Area but inside California, the ISO proposes to assign specific interchange identifications ("I.D.s") to these resources and to direct these resources to Schedule Energy at pre-specified tie points. Assuming that the ISO is able to secure the necessary heat rate and other operating information, under the ISO's proposal, the ISO will be better able to track and monitor compliance with the must-sell obligation.

For those California resources that are located outside the ISO Control Area (for example, resources located within the Control Areas of the Los Angeles Department of Water and Power or the Imperial Irrigation District), the ISO will report to the Commission the amount and price of Supplemental Energy import bids into the ISO's markets from these other Control Areas. The total quantity bid from each Control Area should represent the balance of Energy available in the Control Area after native Load has been served, and reserve requirements met. This Energy should be bid into the market as Supplemental Energy for real-time delivery, in compliance with the April 26 Order. This bid information will support the Commission's enforcement of the must-sell obligation for resources located within those Control Areas.

Resources covered by existing agreements include QFs and resources owned or operated by municipal or other governmental entities. Those QFs that are obligated by their existing PPAs to sell all available Energy to the host UDC are not subject to the must-sell requirement, on the premise that the full capability of such resources will be scheduled in the forward markets against the

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schedule under an agreement that pre-dates ISO operations.

UDC's native Load. However, QFs that have excess Energy that is not obligated under an existing PPA are expected to make all unscheduled Energy available in the ISO's real-time Imbalance Energy Market. The ISO expects that QFs will make necessary arrangements with the UDC with which they have a PPA to assure that any such excess Energy is bid into the ISO's markets.[11] Such arrangements would include executing a PGA and abiding by the ISO Tariff for scheduling, metering, and telemetry. To the extent that such arrangements are not made, the ISO expects that QFs will still respond to the call for Energy in a System Emergency. QFs that have terminated their PPAs and executed PGAs, and have not elected to enter a bilateral agreement under which all available Energy is forward scheduled, are obligated to submit Supplemental Energy bids through their Scheduling Coordinator for any unscheduled Energy into the ISO's real-time Imbalance Energy Market.[12]

Resources owned or operated by municipal or governmental entities should bid into the ISO's markets using resource I.D.s that have been established for the purpose of their participation in ISO markets. The amount bid each hour should represent the balance of capacity available after native Load has been served and applicable Operating Reserve requirements satisfied. The ISO will provide available information on these bids to the Commission to verify that the must-sell obligation the Commission intended to assign these parties is

[11] Clarification is required regarding what obligation the UDC has to fill the role of Scheduling Coordinator and settlement agent for this excess capacity, recognizing the one Scheduling Coordinator per meter limitation.

[12] As provided in the Commission's May 16, 2001 order in Docket No. EL00-95-020, 95 FERC ¶ 61,226, QFs that choose the real-time market over a forward bilateral agreement are required to be price takers.

fulfilled. The ISO also intends to identify any resources on which available capacity appears to be available and for which no bids have been submitted.

General Conditions Prohibiting Anomalous Bidding Behavior

The general conditions imposed on suppliers market based rate authority do not require any changes to the ISO's market software systems. The ISO will address its concerns regarding the limited scope of the prohibited bidding strategies in its later rehearing request.

Price Mitigation

The ISO currently facilitates Day-ahead and Hour-ahead markets for certain Ancillary Services (Regulation Service, Spinning Reserve, and Non-Spinning Reserve), and for Replacement Reserves. The ISO also administers a real-time Energy market and manages Congestion through the use of Adjustment Bids submitted as part of the ISO's Day-ahead and Hour-ahead Scheduling process. The April 26 Order only imposed, under certain conditions, price mitigation measures for sales in the ISO's Imbalance Energy Market. In contrast, the ISO has previously, and continues to, advocate that price mitigation measures are necessarily and appropriately applied for sales in <u>all hours</u> and in <u>all of the ISO's markets</u>. That is, price mitigation should apply for all sales in the ISO's Imbalance Energy, Ancillary Services, and Congestion Management markets. While the ISO continues to believe that the Commission's proposed price mitigation measures are inadequate and fundamentally flawed, for purposes of implementing the Commission's proposed order,[13] and consistent

[13] Of course, the ISO preserves its rights to seek rehearing of those elements of the April 26 Order that the ISO believes are ill-advised, inappropriate, or patently contrary to law.

with the Tariff changes submitted as part of its Compliance Filing, the ISO will not apply price mitigation measures in the ISO's Ancillary Services Markets or for purposes of managing Congestion (i.e., the ISO will not impose a cap on Adjustment Bids).[14] However, in light of the potentially astronomical impact on California consumers from the exercise of market power in the uncapped Ancillary Service markets and on Adjustment Bids, the ISO requests that the Commission notify the ISO immediately if its interpretation of the April 26 Order is in error. Moreover, the ISO urges the Commission to immediately address these issues upon rehearing.

With respect to implementation of price mitigation measures in the ISO's Imbalance Energy Market, the ISO is striving to implement such measures consistent with the Commission's directives. As noted above, in the April 26 Order, the Commission adopted a price mitigation plan in which:

> each gas-fired generator in California (both those signing PGAs and covered non-public utility gas-fired generators) will file with the Commission and the ISO (on a confidential basis) the heat rate and emission rate for each generating unit. These heat rates must reflect operational heat rates that do not include start-up and minimum load fuel costs because, in a declared emergency, the market clearing price should reflect the cost to generate at or near maximum outputs. The ISO will use these heat rates to calculate a marginal cost for each generator [the Generator's "Proxy Price"] by using a proxy for the gas costs, emission cost, and a $2.00 adder for operation and maintenance expenses.

[14] As part of the Compliance Filing, the ISO included Tariff revisions to eliminate the $150 soft cap on Ancillary Services capacity. In addition, the ISO also proposed to eliminate of the $250 hard cap for Adjustment Bids currently in effect. However, consistent with the ISO's previously stated position, the ISO believes that price mitigation measures are appropriately applied in all timeframes and in all markets. As the ISO will further explain in its rehearing request on these issues, the ISO is fearful that uncapped Ancillary Service markets and Adjustment Bids will result in outrageously high prices for these services and further exacerbate the already dire financial condition of California's Investor Owned Utilities and adversely impact the public at large.

April 26 Order at 61,358-59. As outlined by the Commission, these Proxy Prices will form the basis for the price mitigation plan to be in effect during System Emergencies. During such System Emergencies, bids for Energy from gas-fired Generating Units may be submitted at their Proxy Price, and "[a]ll generators who elect the proxy will be paid a single market clearing price reflecting the highest priced unit dispatched calculated using the proxy prices." *Id.* at 61,359.[15] Bids for Energy from gas-fired Generating Units that are above the Proxy Price and are accepted by the ISO will be paid as-bid but are subject to refund if the Commission determines that a bid is not cost-justified, following its review of reports that such Generators must submit to the Commission and the ISO. *Id*. During System Emergencies, Energy from Generating Units that are not gas-fired and all other resources may be bid into the ISO's markets and, if dispatched, will be paid the Market Clearing Price determined by the ISO in accordance with this mitigation scheme (the "Marginal Proxy Clearing Price" as defined in the ISO's proposed compliance filing Tariff language). *Id*. Such other resources may also bid Energy above that Marginal Proxy Clearing Price, subject to cost justification before the Commission and refund liability. *Id*.

Based on the heat and emissions rate information submitted by Generating Units, as required by the Commission, the ISO proposes to calculate the Proxy Prices for gas-fired Generating Units using the following methodology: The ISO will use the provided heat rate data to calculate an incremental heat rate

[15] The ISO intends to seek clarification and rehearing on the question of whether gas-fired combustion turbines ("CTs") should be able to set the market clearing price. Since in general CTs are not flexible units and can not be dispatched at varying levels over their operating range, it may be more appropriate to allow only flexible gas-fired resources to set the market clearing

step function for each gas-fired Generating Unit; i.e., the ISO will construct a proxy "bid curve" over the unit's operating range instead of determining a single proxy price using a single operating "point." If a unit submitted heat and emissions rate information for only a single operating point, the ISO will construct a proxy bid curve by assuming the heat and emissions rate for that one point apply to the unit's entire range of operation. If a unit did not submit the required information to the ISO after the Commission's April 26 Order, but the ISO already has the required information from another reliable source (such as an existing or prior Reliability Must-Run contract), the ISO will construct the proxy bid curve using the information from that source. In addition, the ISO believes that it is appropriate to only permit resources that use natural gas as their *primary* fuel to set the price, assuming they are running on natural gas.[16] To determine the Proxy Price at each operating level, the ISO will calculate the incremental heat rate cost using the daily gas price index described in the April 26 Order, add the emission cost, and add a $2.00 adder for operation and maintenance expenses.[17]

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price and to pay dispatched CTs as-bid when their proxy prices are above the market clearing price.

[16] Certain units in California are capable of burning multiple types of fuel. For example, certain units can be operated using either natural gas or oil. Others resources are capable of burning diesel or natural gas.

[17] While the ISO will be prepared to determine the proxy price using the applicable emissions costs, the ISO believes that such costs are appropriately excluded from the proxy price determination. The ISO plans to address this issue in its rehearing request. In addition, in the April 26 Order, the Commission specified that the ISO was to use "an average of the daily prices published in *Gas Daily* for all California delivery points." April 26 Order at 61,359. Gas Daily cites five daily prices applicable to California delivery – Malin, PG&E CityGate, Southern California Border, SoCalGas large packages, and PG&E large packages. The two large package prices do not pertain to individual delivery points per se. In addition, while Malin is not in California it does represent a pricing point for delivery to California. Therefore, for purposes of implementation, the ISO intends to use a simple average of *Gas Daily* index prices for Malin, PG&E Citygate, and California Border (Kern River Station). Furthermore, the ISO notes that it may seek rehearing on use of the Commission's gas price index. The ISO believes that use of a blended or weighted (i.e., long-term, short-term, and spot) index may more appropriately represent a purchaser's total gas supply portfolio.

As the ISO explained in the Compliance Filing, the April 26 Order does not provide detailed guidance as to how the Market Clearing Price will be calculated during System Emergencies under the mitigation plan established by the April 26 Order. The ISO believes that the April 26 Order requires the ISO to use the highest Proxy Price calculated for a gas-fired Generating Unit dispatched in real time during a System Emergency to set the Market Clearing Price for that settlement interval, even if the bid for the Generating Unit in question is above that unit's Proxy Price. To the extent that the marginal unit selected by the ISO submits a bid below that unit's Proxy Price, however, that unit's actual bid can also set the Market Clearing Price. That is, for each settlement interval in which price mitigation applies, the ISO will both dispatch (i.e., establish the merit order stack) and determine the Marginal Proxy Clearing Price based on the lower of each gas-fired resource's actual bid or its applicable Proxy Price. The ISO believes that the approach outlined above is consistent with the Commission's order and results in an efficient dispatch of resources and an accurate marginal or market clearing price.[18]

The ISO is electing to construct a proxy bid curve over the operating range of the unit instead of using a single operating point to ensure the greatest possible accuracy when economically dispatching resources for Imbalance Energy and calculating the cost of the marginal unit. As a unit's output increases, its marginal cost increases, so its highest marginal cost occurs at maximum load.

[18] Calculation of the MCP is the most difficult aspect of the ISO's design and software development process. The ISO must create a merged energy bid curve from the submitted bids that are less than the proxy price for each resource or the proxy prices of each resource. For purposes of the manual procedures the ISO proposed to implement as of May 29, the

A Market Clearing Price based on marginal cost at a single point – assumed to be maximum load – will be too high if the unit dispatched to set that Market Clearing Price is not dispatched to its maximum load. Since the ISO must retain some operating reserve margin, even during a Stage 3 Emergency, the unit dispatched to set the Market Clearing Price may also be providing reserves and therefore cannot be dispatched to full load.

Demand-Side Bidding

The April 26 order also imposed a demand bidding requirement on public utility buyers in the ISO's real-time Energy market. Specifically, the April 26 Order stated that:

> Beginning on June 1, 2001, the Commission will require each public utility purchasing electricity in the ISO's real-time market to submit demand-side bids that will indicate the price at which load will be curtailed and will identify the load to be curtailed. The bids will indicate the maximum prices that the purchaser is willing to pay for specified amounts of electricity and the loads on its system that would be curtailed when the applicable real-time energy price exceeds its bid.

April 26 Order at 61,357. The Commission stated that "requiring demand side bidding will provide downward pressure on wholesale prices since sellers will recognize the ISO will not pay any price to obtain power." *Id.* at 61,358.

While the ISO supports the Commission's efforts in facilitating greater demand responsiveness in the ISO's markets, the Commission's demand bidding requirement is unclear in two important respects:

First, it is not clear whether the Commission is requiring public utilities to indicate the price at which they are willing to invoke *rotating block outages* or

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ISO will only utilize the proxy bids of each resource and will not utilize those bids that have simply requiring public utilities to submit demand bids for large users who are willing to *voluntarily* reduce their hourly consumption in response to real-time prices. If the Commission intended the former, as the ISO has previously explained, the ISO and the Investor Owned Utilities cannot selectively curtail service to specific loads or customers. When a Stage 3 Emergency is declared and involuntary curtailment of firm Load is required, the ISO must follow the applicable Load-shedding procedures that have previously been developed, approved by the CPUC and filed with this Commission along with the UDC Operating Agreements executed between the ISO and the UDCs. These procedures take into account the reliability requirements of the ISO Controlled Grid in implementing such blackouts. Under the procedures in place today, the ISO notifies the applicable UDCs of the amount of firm Load (in MW) that must be curtailed to maintain reliable system operation, and the UDC then curtails Load on its distribution system, by blocks, according to predetermined and pre-approved Electrical Emergency Plans.

The ISO does not believe the Commission intended for public utilities to indicate, through demand bids, the price at which they are willing to invoke rotating block outages. As the Commission itself noted in the April 26 Order, "the allocation of short supplies – through rolling blackouts – is arbitrary and inefficient." April 26 Order at 61,358. Similarly, requiring public utilities to state a price at which they would prefer rolling blackouts over purchasing energy would also be an arbitrary and inefficient exercise and would clearly impinge on matters

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been submitted below the resource's proxy bid.

affecting state policy and jurisdiction.[19] Finally, even if the Commission intended for the ISO and the UDCs to implement a price-triggered load shedding program, such a program would require drastic modification to the state's existing load-shedding procedures and could not be implemented before this summer.

Alternatively, if the Commission intended public utility purchasers to submit demand bids for large users who are willing to *voluntarily* reduce their hourly consumption in response to real-time prices, the ISO already has in place certain demand response programs designed to reduce real-time demand. As the ISO explained in its comments on the Commission's *Order Removing Obstacles to Increased Electric Generation and Natural Gas Supply In the Western United States and Requesting Comments On Further Actions to Increase Energy Supply and Decrease Energy Consumption*, the ISO has undertaken several demand-side initiatives to encourage demand response. The ISO's initiatives include: (1) facilitating price-responsive demand (e.g., the ISO Participating Load Ancillary Services Program and ISO Discretionary Load Curtailment Program), (2) conservation campaigns (e.g., public announcements and the PowerWatch communications initiative), and (3) demand curtailments under emergency conditions (e.g., the ISO Demand Relief Program and UDC interruptible load programs).[20] In particular, the ISO's Participating Load Ancillary

[19] The ISO notes that the San Diego Gas & Electric Company, in its Request for Rehearing and Comments filed on May 8, 2001, raises similar concerns with respect to the Commission's proposal.

[20] *See* Comments of the California Independent System Operator Corporation Concerning Order Removing Obstacles to Increased Electric Generation and Natural Gas Supply In the Western United States and Requesting Comments On Further Actions to Increase Energy Supply and Decrease Energy Consumption, Docket No. EL01-47-001 (Apr. 3, 2001), at 16-17.

Services Program provides certain loads with the opportunity to submit bids in the ISO's markets.

In addition, the ISO notes that California has underway a number of demand reduction efforts (e.g., the contemplated installation of interval meters to facilitate implementation of real-time pricing and thus true demand responsiveness). The California Legislature recently appropriated funding for real-time metering systems. Assembly Bill 29X allocates $35 million dollars for the installation of real-time metering systems for all bundled service customers with maximum demand greater than 200 kW. The California Energy Commission ("CEC") is currently working with public utilities to install as many of these meters as is possible for this summer. Additionally, the CEC, CPUC, and CDWR have efforts underway to implement a real-time pricing program for this summer. Though the ISO will not see these demand bids in its real-time market, the effect will be essentially the same. Under these programs, during periods when supply margins are tight and energy prices high, end-users will either be paid to curtail Demand or curtail Demand to avoid paying high prices, and the reduced Demand will translate into lower energy imbalances in the ISO's real-time Energy market. With a smaller amount of load being served in real-time, the real-time market should clear at a lower part of the supply curve and will result in a lower MCP, just as would be the case if the ISO actually had a price-responsive demand curve in its market.

Second, it is not clear how the Commission intended the MCP to be set during the hours in which price mitigation applies. The April 26 Order states, in relevant part, that the MCP will reflect the highest priced unit dispatched calculated using the proxy prices. April 26 Order at 61,359. However, the order also states that when the demand for energy exceeds the supply, a demand bid can set the price. *Id.* at 61,364 n.47. These statements appear to be in conflict. Moreover, the Commission's order also appears to contemplate a real-time market where the MCP is determined through the intersection of price elastic demand and supply curves and awarded bids (both demand and supply) are settled at the MCP. The ISO's real-time market does not operate this way. Under the ISO's current market design, curtailable demand bids are treated as a supply resource where demand indicates the price at which it is willing to curtail. Payments to supply and demand bids dispatched in the real-time markets are determined by reconciling each unit's schedule and dispatch instructions with the metered output of the Scheduling Coordinator's entire portfolio. The ISO believes this important difference in market design raises a serious gaming problem if demand bids are allowed to set the real-time price during mitigated hours.

The gaming problem arises from the fact that unlike a typical market where settlement is based on submitted bids (i.e., the former California Power Exchange Market), the ISO real-time market is settled by reconciling metered output with schedules and dispatch instructions. This distinction means that there is no risk for a market participant, who wishes to drive up the real-time price, to submit a fictitious demand bid for a very large amount of load at a very high price. If the bid is dispatched (i.e., curtailed) and sets a high MCP, the participant has accomplished his objective. If the bid is not dispatched (i.e., the MCP is below the demand bid), the market participant has no purchase obligation at that price since he has no real load behind that bid (i.e., his metered load is equal to his scheduled load, which could be zero). In a more conventional market (i.e., one where settlement is based on submitted bids), this game is mitigated by the fact that a participant would be responsible for any demand bids that clear the market. The ISO is very concerned that if it allows demand bids to set the price during mitigated hours that this gaming opportunity would simply undermine the proposed price mitigation.

A second consideration is that Load is generally not dispatchable on a 10-minute basis. Large commercial customers typically prefer more advance pricing notice in order to have adequate time to adjust their operations, reschedule employees, etc. Moreover, loads typically need to implement curtailments in blocks of hours and are either incapable of or not interested in varying their demand in response to 10-minute prices. This is why the ISO has focused its efforts in developing the Demand Relief Program and the Discretionary Load Curtailment Program as they involve dispatch across multiple hours, generally with substantially more advance notice than provided to resources in the Imbalance Energy Market.

The ISO understands that having a price-responsive demand curve in the real-time market during periods of true supply scarcity would provide an opportunity for the market clearing price to be set at the “marginal buyer’s reservation price” and thus provide an opportunity for a generator that is always on the margin to earn scarcity rents. Not having price-responsive demand in the ISO's real-time market will obviously not allow for this type of price determination. However, as the Commission pointed out, "Since bilateral contracts should be the principal means by which generators recover their total costs, generators should be willing to sell any residual real-time energy for any price at or higher than their marginal cost." April 26 Order at 61,364. Given (1) the ambiguity of the Order with respect to whether demand bids can set the market clearing price during mitigated hours, (2) the serious gaming opportunity that would arise if the ISO allowed such an approach, (3) the fact that marginal generation resources will have opportunities to recover their total costs from bilateral contracts, and (4) the many other viable opportunities for real-time demand price responsiveness, the ISO plans to set the real-time Market Clearing Price during *all* mitigated hours equal to the highest priced proxy bid dispatched.

IV. CONCLUSION

The ISO requests that the Commission consider the ISO's above stated comments and immediately advise the ISO of any necessary modifications to the ISO's proposed implementation plan. To the extent that the Commission does so advise the ISO, the ISO will keep the Commission apprised of any impact such direction may have on the ISO's implementation schedule.

Respectfully submitted,

Charles F. Robinson
Vice President and General Counsel
Roger E. Smith, Senior Regulatory Counsel
The California Independent System Operator Corporation
151 Blue Ravine Road
Folsom, CA 95630
Tel: (916) 608-7135

Kenneth G. Jaffe
David B. Rubin
Bradley R. Miliauskas
Swidler Berlin Shereff Friedman, LLP
3000 K Street, N.W., Suite 300
Washington, DC 20007
Tel: (202) 424-7500

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