UNITED STATES OF AMERICA
BFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company	)	**Docket Nos.**	**EL00-95-031**
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	)		
Investigation of Practices of the California Independent System Operator and the California Power Exchange	)))		**EL00-98-030** **EL00-98-033**
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Investigation of Wholesale Rates of Public Utility Sellers of Energy and Ancillary Services in the Western Systems Coordinating Council	))))		**EL01-68-000** **EL01-68-001**
	)		

COMMENTS OF CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION ON RECOMMENDATIONS OF CHIEF ADMINISTRATIVE LAW JUDGE TO THE COMMISSION

On June 9, 2001, at the conclusion of the recent settlement discussions conducted pursuant to the Commission's June 19 Order,[1] the Chief Administrative Law Judge ("the "Chief Judge") stated for the record the outlines of the recommendation he intended to make to the Commission regarding further proceedings. The Chief Judge invited the parties to comment on those recommendations by July 12 and stated that he would forward any comments to the Commission along with his recommendations. The California Independent System Operator Corporation (the "ISO") submits these comments in response to the Chief Judge's invitation.[2]

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[1] *Order On Rehearing Of Monitoring and Mitigation Plan For The California Wholesale Electric Markets, Establishing West-Wide Mitigation, And Establishing Settlement Conference*, 95 FERC ¶ 61, 418 (2001) ("June 19 Order").

[2] The ISO has also joined in the comments filed by the California Parties.

I. COMMENTS

A. Correcting for Economic and Physical Withholding

The Chief Judge has indicated that he intends to recommend, as a methodology to be used in determining refunds, retroactive application of the Commission's June 19 Order, with certain modifications. Tr. 698. It appears that one key modification being recommended by the Chief Judge is to use the actual heat rate of the marginal unit dispatched in the ISO imbalance energy market as the benchmark price for determining refunds. Id. 698-99. The ISO would urge that the methodology instead be based on the key principles of the June 19 Order, which include (1) the requirement that each generator make available to the ISO in the imbalance energy market all available and uncommitted capacity, and (2) bid price limits based directly on the actual incremental operating cost of each unit. In applying the June 19 Order retroactively, this would mean that the competitive baseline price would be determined by using the heat rate of the highest-cost thermal generating unit that was needed by the ISO to meet system demand in an hour, assuming economic dispatch of all available units. This mimics the "must-offer" and bid price mitigation features of the June 19 Order.

Dr. Hildebrandt of the ISO's Department of Market Analysis explained why retroactive use of the June 19 Order *with* the must-offer requirement and bid price mitigation included is the appropriate method. Essentially, this results in calculation of the competitive baseline price that would result in the absence of both types of withholding – economic and physical – that have been practiced in the imbalance energy market in the past. The method apparently favored by the Chief Judge, *i.e.*, the actual historical dispatch by the ISO, results in a benchmark price that is inflated by the fact that the ISO frequently had to dispatch higher cost units due to withholding of lower cost capacity by other suppliers – either through high bid prices and/or by failing to bid all available capacity into the market. Use of actual historical dispatch, as apparently the Chief Judge will recommend, would yield a higher baseline price than would occur in a truly competitive market: in a truly competitive market, no generator would practice economic or physical withholding, as the generator would realize no gain from it. Put another way, the Chief Judge's approach would *reward economic and physical withholding*, which was possible only because the generators had market power, and therefore would *reward the exercise of market power*. The very purpose of refunds, however, is to extract from the generators the fruits of their exercise of market power. *See* "Analysis of Payments in Excess of Competitive Market Levels in California's Wholesale Energy Market, May 2000-2001," dated July 9, 2001 (the "July 9 Analysis"), appearing after Tr. 667, at pages 2-3.

B. Refunds Prior to October 2, 2000

It appears that the Chief Judge intends to recommend that the Commission order refunds only from October 2, 2000 forward. The ISO urges that the Commission order refunds from May 2000 forward, as it was in May 2000 that the exercise of market power through economic and physical withholding became rampant. There is no bar to the Commission's ordering of refunds prior to October 2, 2000.

As the ISO has explained previously, the prohibition on retroactive rate making does not apply in the context of formula rates. *See* Application for Rehearing of the California Independent System Operator Corporation filed April 9, 2001 in Docket No. ER00-95-017, et al. at 34-37. The ISO stated:

> The wholesale sales of suppliers through the ISO's markets also constitute sales pursuant to formula rates. Since utilities collecting market-based rates for these wholesale sales do not file rate schedules at the Commission showing the specific rates they will charge, the normal prohibition on retroactive adjustments of amounts collected under "filed rates" accordingly should not apply. There is accordingly no legal basis for the Commission to limit the period during which, or

> the extent to which, it will scrutinize wholesale sales of electricity under its market-based rate authority.

Id. at 35. The ISO also noted that the Commission has recognized its authority to order refunds of market-based charges for wholesale transactions prior to October 2000. *See AES Southland, Inc. and Williams Energy Marketing and Trading Company*, 94 FERC ¶ 61,248 (2001).

The prohibition against retroactive rate adjustments does not apply when a public utility files a "formula rate" that permits the rate to fluctuate without prior Commission review. *See Connecticut Yankee Atomic Power Co.*, 40 FERC ¶ 63,009 (1987), at 65,012. Retroactive adjustments in such cases do not violate the rule against retroactive rate making because the Commission is not, in actuality, ordering a retroactive adjustment of the rate, but simply requiring the public utility to assess charges consistent with the formula as filed, which itself constitutes the rate. The Commission has the authority under section 309 of the Federal Power Act to review, ex post, the amounts charged by the utility under the formula rate without instituting a Section 206 proceeding.

Like formula rates, market-based rates permit the fluctuation of charges and revenues without prior Commission review, and charges under market-based rates are, like charges under formula rates, determined by variables that are not included in the rate itself (in the case of market-based rates, the competitive market price). In all significant respects, a grant of market-based rate authority is indistinguishable from a traditional formula rate. Recipients of the privilege of market-based rates have the freedom to "adjust" their allowed charges and revenues and thereby to reap the benefits of a workably competitive market. They can do so without any filing requirement or the imposition of any lag. It is not a violation of the filed rate doctrine or retroactive rate making doctrines for the Commission to order refunds of those amounts collected in excess of the amounts that would have been charged under competitive market conditions, because the seller's collection of such excess amounts is inconsistent with the market-based rate itself.

The underlying premise that justifies the privilege of market-based rates is availability of a workably competitive market that will determine the price charged. We know, from the analyses undertaken by the ISO's Department of Market Analysis and filed in these dockets, that the "formula" broke down at least as early as May, 2000. We know that at least beginning then, the generators began reaping monopoly rents in direct contravention of the essential predicate of their formula -- that they would collect no more than the revenues associated with a market that is workably competitive and free of market power abuse. Accordingly, as of that date, all revenues above those that would have been earned under competitive conditions are subject to being disgorged.

C. Incremental Heat Rates

Reliant and West Coast Power have questioned the accuracy of incremental heat rate numbers used by the ISO in calculating the marginal unit to be dispatched in determining the competitive baseline price. According to Mr. Stout of Reliant, "when we went back to examine those heat rate numbers, which were supposed to represent the highest actual incremental heat rate in the system for each hour between October and May, what we discovered is that 38 percent of those hours, we had unit operating that had substantially higher heat rates in operation at the time." (Tr. 600)

The heat rates calculated by the ISO referenced by Mr. Stout represent the highest incremental heat rate of all gas-fire units *dispatched in the ISO's real time imbalance market* during each hour. However, it is apparent that Mr. Stout has compared these results to the heat rates of all of Reliant's units *that happened to be in operation for any reason* during each hour.

The difference may be subtle to some, but is extremely significant. During many hours, units with higher heat rates are in operation and scheduled in the Hour Ahead market at partial load simply as a result of a unit's minimum operating level, in order to meet a bilateral or PX sale obligation, and/or so the unit may sell unloaded capacity into the ISO's Ancillary Services market. In fact, California's market design is explicitly designed to allow generators great flexibility in scheduling resources on a portfolio basis, so that they may "self-schedule" each unit in their portfolio in a way that reflects minimum operating constraints, maximizing the ability of certain units to sell "unloaded" capacity into the Ancillary Service market.

Other units with higher heat rates that may be in operation include units that are "constrained on" to meet reliability requirements through Reliability Must Run (RMR) contracts or "out-of-sequence" dispatches. However, generation needed for such reliability requirements is not used in assessing system marginal costs. This is embodied in the ISO Tariff, under which RMR dispatches and out-of-sequence dispatches are excluded from the calculation of the ex-post real time imbalance price.

Given the wide variety of different reasons noted above, we would expect units with heat rates above the heat rate of the marginal unit dispatched to meet system demand to be in operation a significant portion of the time. Thus, the statistics cited by Mr. Stout are both misleading and irrelevant with respect to the issue of whether the incremental costs of units dispatched in the ISO real time market are true system marginal costs.

Meanwhile, West Coast Power claims that it has determined that for 70 percent of the hours since October 2, 2000, "the ISO study understated the heat rate for West Coast units actually being dispatched." "Statement of the Undersigned Generators," at 4 (found after Tr. 662) Presumably, the statistics cited by Dynegy do not refer to the ISO's competitive baseline model, but instead refer to the calculation of the highest incremental heat rate of any unit dispatched for incremental generation by the ISO (or the lowest heat rate of units dispatched for decremental generation, when the ISO was decrementing generation in real time).

The ISO's ability to comment on West Coast Power's specific claims are limited due to the fact that no detailed information is provided about this alleged discrepancy. One possible explanation is that the calculations include out-of-market, out-of-sequence, and RMR dispatches – all of which, as explained above, involve special types of ISO "dispatches" which are not factored into the calculation of system or zonal market clearing prices due to dictates of both basic economic theory and ISO tariff protocols, as discussed above.

The methodology used to calculate the heat rates presumably referenced by Reliant and West Coast Power are provided in Appendix B of the July 9 Analysis which was submitted on the record. As noted in the description of methodology -- as well as by Dr. Hildebrandt in response to verbal questioning on the record on July 8 -- heat rates used in all the ISO studies are based on data provided by generators themselves pursuant to the Commission's April 26 Order.[3] As noted in the July 9 Analysis and in Dr. Hildebrandt's "Comments on Testimony of Dr. Richard Tabors," also submitted on the record on July 9, the corrected set of results distributed to conference participants reflects a correction in the heat rate initially reported by the plant operator of a single 25 MW cogeneration unit, which appeared as the marginal unit dispatched by the ISO 60% of the hours in the initial set of results. The fact that the ISO promptly recognized and corrected this error simply demonstrates the diligence of ISO staff in reviewing and refining key calculations.

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[3] *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 (2001) ("April 26 Order").

D. Price Caps

Reliant accuses the ISO of having selectively taken parts of the Commission's June 19 Order that "seemed to escalate the refund amount", while "discounting" other parts of the order that tend to "de-escalate" the refund amount. (Tr. 604). However, the only specific examples provided by Reliant of factors that would tend to reduce the refund involve how price caps for energy and ancillary services are set under the June 19 Order. In each of these cases, Reliant unabashedly argues that price caps that would result under the June 19 Order – representing *maximum* allowable price levels --- should be substituted for competitive or just and reasonable price levels as the basis for determining refunds. While the ISO's analysis bases refunds on competitive baseline prices that would result under competitive market conditions, Reliant argues that the ISO should have instead calculated refunds based on the price cap, or maximum allowable price, during each hour. This logic is inconsistent with the basic principle of using competitive market prices as a proxy for just and reasonable rates, and contradicts the fundamental objective of the June 19 Order: to mitigate market power and ensure competitive prices during all hours through *must-bid requirements* and *cost-based bid price mitigation*. Reliant's argument would take what was intended in the June 19 Order as a "safety net" to cap prices if the must-bid requirement for some reason failed adequately to mitigate prices, and turn it into an "umbrella" for generators allowing them to retain more revenues than would have resulted from just and reasonable, competitively determined rates in the past.

E. The ISO's Competitive Baseline Model

Contrary to the claims of Reliant and other generators that the ISO selected elements of the June 19 Order to maximize refunds, the ISO's competitive baseline analysis in fact contains a variety of key features that significantly *reduce* the amount of refunds that would result from this methodology.

First, the model accepts at face value all outages and partial unit derations (or "derates") reported by generators: that is, no effort was made to determine whether these represented examples of potential physical withholding. Given the very high outage rates reported by generators during the recent fall, winter and spring months, the impact of this unquestioning acceptance of outages and derates in terms of increasing the competitive baseline price is potentially very significant. As explained by Dr. Hildebrandt, the ISO's model "conservatively" accounts for physical withholding by simply assuming that all gas-fired capacity that was not declared unavailable was indeed available, even when all of the capacity was not bid into the market.

Second, the model calculates the competitive baseline energy price based on system demand for energy plus a 10% adder (representing demand for upward regulation and operating reserve). While this 10% adder actually represents total demand for capacity, the model assumes, in effect, that this full amount of capacity would be needed for energy, and calculates the competitive price of energy based on the full demand for energy plus capacity. Moreover, the ISO's approach ignores the fact that units actually providing ancillary services received the capacity payment *plus* an energy payment based on a separate bid price if actually dispatched for energy. Again, the effect of these assumptions is to increase the competitive baseline price.

Third, the model results used in the analysis also include a 10% adder on the supply side. The ISO does not agree that a 10% credit risk across all suppliers, in all markets, in all time periods of the study reflects actual or even competitive market conditions. However, the 10% adder was used precisely to ensure a conservative estimate of competitive market prices, that is, an estimate that was likely to be *higher* than might easily be justified with different but quite reasonable assumptions. Simply because the June 19 Order allows a 10% adder for sales in the real time market going forward, it does not follow that this adder should automatically be included in a calculation of prices that would result under competitive market conditions – particularly prior to the time when credit concerns existed. Moreover, while the 10% adder is only applied to the real time imbalance market under the June 19 Order, the ISO's analysis applies it to all markets.

F. Gas Prices

Numerous generators continue to argue for the use of daily spot market gas prices in place of the monthly bid week gas price index incorporated in the Commission's June 19 Order, and it appears the Chief Judge may do so as well. The problems inherent in using spot market gas prices as the basis for determining *just and reasonable* wholesale electric rates have been well documented by the ISO in these proceedings. Most importantly, perhaps, is the fact that the very spot market gas prices generators propose to use in calculating *just and reasonable rates* for wholesale electricity are the subject of a separate proceeding before the Chief Judge to determine if they are the product of price manipulation in the gas markets. Any use of these spot market gas prices in determining wholesale electric rates may simply pass on and magnify even further for wholesale electricity purchasers the effect of manipulation of spot market gas prices.

In addition, generators themselves acknowledge that a large portion – if not the bulk – of their gas purchases would be on month ahead or longer term basis. Thus, it is entirely inappropriate to use spot market gas prices as a benchmark for all time periods and all sales at question in these proceedings.

Moreover, the wholesale electric sales at question in these proceedings cover virtually the entire "net short" position of California's UDC's since May 2000. Due to the tight supply and demand conditions prevailing since May 2000, most -- if not virtually all – of these sales could be anticipated by suppliers based on simple assessment of supply and demand. The volume of sales above competitive market levels involved in these proceedings far exceeds the small portion of sales that may be characterized as unpredictable, "spot market" sales that prudent suppliers would procure on the spot market.

The ISO has directed suppliers to provide gas cost information for sales over the "soft cap" since December 8, 2000 under both Amendment 33 and its Market Monitoring Information Protocols (MMIP), but not one thermal generator has provided actual gas purchase data for examination by the ISO. Thus, absent a thorough accounting of actual gas spot market purchases and a thorough investigation of price manipulation in the spot gas markets, the Commission should continue to reject the use of spot market gas prices in any calculation of competitive market rates that might be used as a proxy for just and reasonable rates.

II. INFORMATION REQUESTED BY THE CHIEF JUDGE

During the proceedings, the Chief Judge asked that the ISO provide him and his staff information concerning the corrected heat rates used in the calculation of the competitive benchmark price, as well as data on the breakdown of the total energy market by type of transaction. The ISO has provided that information to the Chief Judge, and understands that the Chief Judge will include it in the record of these dockets.

III. CONCLUSION

The ISO trusts that the Commission will consider these comments as it reviews and acts on the recommendations of the Chief Judge. The ISO wishes to express its appreciation to the Chief Judge and his staff for their tireless efforts during the settlement conference.

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