97 FERC ¶ 61,275

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company, Complainant, v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange, Respondents	Docket Nos. EL00-95-001 EL00-95-004 EL00-95-005 EL00-95-006 EL00-95-007 EL00-95-010 EL00-95-011 EL00-95-019 EL00-95-039 EL00-95-046 EL00-95-047
Investigation of Practices of the California Independent System Operator and the California Power Exchange	Docket Nos. EL00-98-001 EL00-98-004 EL00-98-005 EL00-98-006 EL00-98-008 EL00-98-010 EL00-98-011 EL00-98-018 EL00-98-037 EL00-98-043 EL00-98-044
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., Complainants, v. California Independent System Operator Corporation, Respondent	Docket No. EL00-97-001

California Electricity Oversight Board,
Complainant,
v.
All Sellers of Energy and Ancillary Services Into the Energy and Ancillary Services Markets Operated by the California Independent System Operator and the California Power Exchange,
Respondents

Docket No. EL00-104-001

California Municipal Utilities Association,
Complainant,
v.
All Jurisdictional Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange,
Respondents

Docket No. EL01-1-001

CAlifornians for Renewable Energy, Inc. (CARE),
Complainant,
v.
Independent Energy Producers, Inc., and All Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator 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,
Respondents

Docket No. EL01-2-001

Puget Sound Energy, Inc.,
Complainant,
v.
All Jurisdictional Sellers of Energy and/or Capacity at Wholesale Into Electric Energy and/or Capacity Markets in the Pacific Northwest, Including Parties to the Western Systems Power Pool Agreement,
Respondents

Docket No. EL01-10-001

California Independent System Operator Corporation	Docket Nos. ER01-607-000 ER01-607-001
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Investigation of Wholesale Rates of Public Utility Sellers of Energy and Ancillary Services in the Western Systems Coordinating Council	Docket Nos. EL01-68-002 EL01-68-008
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Arizona Public Service Company	Docket Nos. ER01-1444-001
Automated Power Exchange, Inc.	Docket Nos. ER01-1445-001
Avista Energy, Inc.	Docket Nos. ER01-1446-001
California Power Exchange Corporation	Docket Nos. ER01-1447-001
Duke Energy Trading and Marketing, LLC	Docket Nos. ER01-1448-002
Dynegy Power Marketing, Inc.	Docket Nos. ER01-1449-002
Nevada Power Company	Docket Nos. ER01-1450-001
Portland General Electric Company	Docket Nos. ER01-1451-002
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Reliant Energy Services, Inc.	Docket Nos. ER01-1453-001
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Issued: December 19, 2001

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ORDER ON CLARIFICATION AND REHEARING

(Issued December 19, 2001)

Introduction and Summary

In this order the Commission acts on petitions for rehearing of four interrelated orders issued in the above dockets to address mitigation of prices for power sold at wholesale through centralized, single price auction spot markets operated by the California Independent System Operator Corporation (ISO) and California Power Exchange Corporation (PX), as well as mitigation of prices for power sold at wholesale in bilateral (contractual) markets in the Western System Coordinating Council (WSCC). Since August 2000, the Commission has issued a series of orders (nearly 75), including the four orders addressed herein, dealing with various aspects of the recent electricity crisis in California. These orders have been aimed at correcting the market dysfunctions which contributed to the California crisis and which are within our jurisdiction to correct, and at stabilizing prices until the necessary corrections - - including correction of the supply-demand imbalance in California - - can be made. The four interrelated orders addressed herein, issued December 15, 2000, March 9, 2001, June 19, 2001, and July 25, 2001, represent the major steps taken by the Commission to modify the ISO market rules and adjust the pricing mechanisms used in California and the West, to ensure just and reasonable rates in Western markets.[1]

In exercising our responsibility under the Federal Power Act to ensure just and reasonable rates for wholesale sales of electric energy, the Commission has been faced with a very complex set of state and federal market rules affecting the California energy markets as well as a set of rapidly changing market conditions over the past year. The Commission has adopted a measured approach to provide for market corrections and

[1] In addition, this order acts on petitions for rehearing and/or clarification of four related orders issued on August 23, 2000, November 1, 2000, and two on December 8, 2000.

price mitigation, attempting to balance the need to protect customers from high prices in the short-term with the need to ensure that power continues to flow and that incentives are provided to bring much needed power supply on-line for the longer term. While some have argued in these proceedings that the Commission has failed to fulfill its statutory obligations by not returning to a system of cost-of-service rates, we conclude that such action was, and is, neither necessary nor appropriate to protect customers in either the short or the long-term, and that such action would deprive customers of the benefits that a competitive market will yield once the market dysfunctions are fully corrected and sufficient new supply is brought to fruition. Accordingly, today's order denies the petitions for rehearing on this fundamental issue and, on other issues, grants limited rehearing or clarification to ensure that the rate corrections ordered by the Commission yield just and reasonable rates.

Procedurally, the Commission's actions separate into two general time frames. The first is the period from October 2, 2000 until June 20, 2001 (with a minor exception).[2] For this time frame, the issue is whether refunds are owed by any sellers in the organized spot markets in California and, if so, how much. This issue is guided primarily by an order issued by the Commission on July 25, 2001.[3] There, the Commission prescribed a formula for determining the amount of any refunds and instituted evidentiary procedures before an administrative law judge to make findings of fact applying the formula. The formula is based substantially on the approach adopted for mitigation prospectively, described below. The Commission recently deferred temporarily the evidentiary procedures before the administrative law judge. In today's order, we direct the resumption of those procedures. When those procedures are completed, the administrative law judge will certify findings of fact for the Commission's consideration.

The second time frame is from June 21, 2001 until September 30, 2002 (with the same minor exception). For this time frame, the Commission adopted a prospective market monitoring and mitigation program to ensure that rates for spot sales throughout the Western United States remain just and reasonable. This program was prescribed in Commission orders issued on April 26 and June 19, 2001.[4]

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[2]See infra, n.163.

[3]San Diego Gas & Electric Co., et al., 96 FERC ¶ 61,120 (2001), reh'g pending on some issues (July 25 Order).

[4]San Diego Gas & Electric Co., et al., 95 FERC ¶ 61,115 (April 26 Order), order on reh'g, 95 FERC ¶ 61,418 (2001) (June 19 Order).

Elements of the plan previously adopted include:

- Enhancing the ability of the California Independent System Operator (ISO) to coordinate and control planned outages during all hours.

- Requiring sellers, including governmental entity[5] generators that voluntarily make sales into FERC-regulated markets or use FERC-regulated interstate transmission facilities (with the exception of hydroelectric power), to offer all their available power in real time during all hours.

- Establishing conditions, including refund liability, on public utility sellers' market-based rate authority to prevent anticompetitive bidding behavior in the real-time market during all hours.

- Establishing a mechanism for price mitigation for all sellers bidding into the ISO's real-time market during a reserve deficiency, i.e., when reserves in California fall below 7 percent. Under this mechanism, the Commission established a formula (based on gas-fired generation) that the ISO can use to establish the market clearing price when mitigation applies (mitigated reserve deficiency MCP).[6] Higher bids were permitted if they could be justified.

- Applying that clearing price as a maximum price for sales outside the ISO's single price auctions (bilateral sales in California and the rest of the WSCC), with sellers outside the single price auction receiving the prices they negotiate up to this maximum price.

- Using eighty-five percent of the highest ISO hourly mitigated reserve deficiency MCP established during the hours of the last Stage 1 alert for the mitigated non-reserve deficiency Market Clearing Price (mitigated non-reserve deficiency MCP) for subsequent non-reserve deficiency hours.

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[5]Our prior discussions regarding governmental entities imprecisely labeled them "non-public utilities." Use of that term is somewhat misleading, as many governmental entities fit within the definition of a "public utility." See FPA sections 201(e) and 3(7). Accordingly, our discussions regarding governmental entities will use the term "governmental entities" rather than "non-public utilities."

[6]The mitigated reserve deficiency MCP is the marginal cost of the last unit dispatched to serve the last increment of load during a period of reserve deficiency. The marginal cost of each unit calculated by the ISO based on Commission prescribed inputs is referred to as the "Proxy Price."

- Instructing bidders to invoice the ISO directly for the cost to comply with emissions requirements and for start-up fuel costs, which are too varied to be standardized in a single market clearing price.

- Allowing sellers other than marketers the opportunity to justify bids or prices above the maximum prices.

In today's order, we make only minor changes to this approach. For example, we now exclude governmental entities and cooperatives from price mitigation with respect to bilateral transactions outside of the ISO spot market, and with respect to the must-offer requirement outside of California. We also eliminate an "underscheduling" penalty imposed earlier. We state that marketers, load serving entities and hydroelectric generators may submit evidence that the refund method results in a total revenue shortfall in the organized California spot markets for their transactions during the refund period, after the conclusion of the refund hearing. These and other changes adopted today are described fully below. In all other respects, we affirm the approach adopted previously. In addition, we require the ISO to file a revised congestion management plan and a plan for the creation of a day-ahead energy market in California, both of which are to be filed by May 1, 2002.

Background

In May 2000, the costs of electric energy in California's wholesale market began to rise and the Commission instituted a nationwide investigation in July and an investigation on California matters in August. On November 1, 2000, the Commission released for public comment its staff's report on the reasons for the price increase. For the last year, the Commission has worked to correct the market dysfunction, and possible exercise of market power, that it believes are the cause of the price increases. As explained below, we have mitigated prices to ensure they are no higher than those that would result in a competitive market, i.e., at a price no higher than the cost of the least efficient generating unit needed to meet load, for the period October 2, 2000 through September 30, 2002, when we predict conditions to be adequate to revert to pricing based on market prices without regulatory price intervention.

We have used our experience and expertise to fashion, and modify as appropriate, our remedy to ensure that rates are just and reasonable under the limitations which Congress has enacted. While the past 18 months have caused many to question the wisdom of setting rates based on market forces, we continue to believe that market forces can ensure that wholesale rates remain just and reasonable, with proper regulatory oversight. The experience in the natural gas industry continues to convince us that our initial and subsequent decisions to authorize market-based rates in situations in which sellers lack market power is appropriate and in the long-term interests of customers.

We have recently taken steps to ensure that sellers lack market power, or cannot benefit from any market power they may temporarily possess. Besides the West-wide temporary price mitigation we have ordered and confirm today, as modified, we are in the process of: (1) completing the work of separating operation of transmission and generating facilities; (2) ensuring that sellers with market-based rates cannot benefit from engaging in anticompetitive behavior; and (3) standardizing wholesale market rules. We believe these steps will ensure that wholesale rates for the sale of electric energy in interstate commerce remain just and reasonable under the changing conditions we confront in the electric utility industry.

A. August 23 Order

On August 2, 2000, in response to significant increases in prices for energy and Ancillary Services in California, San Diego Gas & Electric Company (SDG&E) filed a complaint in Docket No. EL00-95-000. This complaint, filed against all sellers of energy and Ancillary Services into the ISO and PX markets subject to the Commission's jurisdiction, requested that the Commission impose a $250 price cap for sales into those markets. The Commission denied this request in an order issued August 23, 2000, on the grounds that SDG&E had not provided sufficient evidence to support an immediate seller's price cap.[7] However, in that order, the Commission instituted formal hearing procedures under section 206 of the Federal Power Act (FPA) to investigate the justness and reasonableness of the rates of public utility sellers into the ISO and PX markets, and also to investigate whether the tariffs, contracts, institutional structures and bylaws of the ISO and PX were adversely affecting the wholesale power markets in California. The Commission established a refund effective date of 60 days after publication of notice in the Federal Register of the Commission's intent to institute a proceeding.[8]

In the order, the Commission also directed the ISO to immediately institute a more forward approach to procuring its resources. In response, the ISO filed on September 1, 2000 proposed Tariff Amendment No. 30 to provide it with the authority to forward contract.

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[7]San Diego Gas & Electric Company, et al., 92 FERC ¶ 61,172 at 61,606 (2000) (August 23 Order).

[8]Id. at 61,608.

Southern California Edison Company (SoCal Edison) and Pacific Gas and Electric Company (PG&E) sought rehearing of the August 23 Order arguing that the Commission should have established an earlier refund effective date, October 2, 2000, which was 60 days following SDG&E's complaint filing. The utilities also sought immediate action by the Commission on the complaint, and argued for refunds prior to the refund effective date. Dynegy Power Marketing, Inc., El Segundo Power, LLC, Long Beach Generation LLC, Cabrillo Power I LLC, and Cabrillo Power II LLC (Dynegy) and Duke Energy North America LLC, Duke Energy Trading and Marketing, LLC, and Duke Energy Merchants, LLC (Duke) filed answers to the rehearing requests.

B. November 1 Order

The Commission issued an order on November 1, 2000 proposing measures to remedy problems identified in the ISO and PX markets.[9] In the November 1 Order, the Commission proposed remedies intended to reduce over-reliance on spot markets in California, and attempted "to balance, on the one hand, holding overall rates to levels that approximate competitive market levels for the benefit of consumers, with, on the other hand, inducing sufficient investment in capacity to ensure adequate service for the benefit of consumers."[10] The order proposed, effective 60 days after the date of the order, to: (1) eliminate the requirement that the investor-owned utilities (IOUs) must buy and sell power through the PX, (2) require market participants to schedule 95 percent of their transactions in the Day-Ahead markets or be subjected to a penalty charge; (3) replace the existing PX and ISO stakeholder boards with independent non-stakeholder boards; and (4) require the filing of generator interconnection procedures.

The order also identified longer-term structural reforms of ISO and PX markets that must be addressed, and urged state officials to take certain actions within their exclusive jurisdiction. Also, to ensure reasonable prices while various market reforms were being put in place, the order proposed additional temporary measures to mitigate prices, including modification of the single price auction so that bids above $150/MWh could not set the market clearing price that is paid to all bidders and imposition of certain reporting and monitoring requirements for transactions and bids above the $150/MWh breakpoint, as well as the retention of a refund obligation for sales into the ISO and PX markets for the period October 2, 2000 through December 31, 2002. The Commission explained that a paper hearing would be adequate to resolve the matters before it, established a period for the submission of comments and supporting evidence, and

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[9] San Diego Gas & Electric Company, et al., 93 FERC ¶ 61,121 (2000) (November 1 Order).

[10] Id.

announced its intent to issue a final order adopting and directing remedies for California's markets before the end of the calendar year.

The November 1 Order granted rehearing in part of the August 23 order by changing the refund effective date from 60 days after publication of notice in the Federal Register (October 29, 2000) to 60 days after the date of SDG&E's complaint (October 2, 2000). Finally, the Commission rejected proposed tariff amendments filed by the PX and the ISO in Docket Nos. ER00-3461-000 and ER00-3673-000, respectively, requesting or extending price caps for their markets.

Numerous parties sought rehearing of the November 1 Order, primarily objecting to certain proposed remedies or the proposed timing of their implementation, or the lack of other measures that were not included in the order. Parties also raised arguments about procedural aspects of the November 1 Order, including that the Commission should exercise its discretion to order refunds for periods prior to October 2, 2000, and requested various clarifications. The California Commission and the Oversight Board objected to the rejection of the ISO and PX price cap proposals.

C. Amendment No. 33 Order (December 8, 2000)

Beginning in mid-November, the ISO experienced numerous occasions of insufficient reserve margins and emergency conditions forcing it to serve increasingly large portions of its total Control Area load through its real-time Imbalance Energy market. On December 8, 2000, the Commission accepted for filing Amendment No. 33 to the ISO Tariff, which the ISO had submitted earlier that same day in Docket No. ER01-607-000.[11] Amendment No. 33 made three changes to the ISO Tariff. First, the existing $250/MWh purchase price cap on bids in the ISO's real-time Imbalance Energy Market was converted into a $250/MWh breakpoint, similar to the one described in the November 1 Order. Second, generators who failed to comply with an ISO emergency dispatch order became subject to a penalty. Third, a Scheduling Coordinator with unscheduled demand or undelivered generation became liable for the cost the ISO incurred to obtain electricity through bids above the $250/MWh breakpoint or through out-of-market dispatches.

After issuance of the Amendment No. 33 Order, numerous entities filed motions to intervene along with various requests for clarification, modification, or rehearing; entities seeking intervention are listed in Appendix B. Several parties complain that the

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[11] California Independent System Operator Corporation, 93 FERC ¶ 61,239 (2000) (Amendment No. 33 Order).

Commission violated due process by not affording the public any notice or opportunity to comment on Amendment No. 33. With regard to the $250/MWh breakpoint, the California Commission, PG&E, and SDG&E state that the Commission should not have allowed the ISO to remove the purchase cap. PG&E argues that the $250/MWh breakpoint was too high; Dynegy argues that it was too low. Several parties state that the $250/MWh breakpoint in the ISO market had unintended consequences in the PX markets. Dynegy states that it is unfair to impose penalties on generators who fail to respond to ISO emergency dispatch orders and offers several arguments to support that statement. With regard to the assessment of costs for unscheduled load and undelivered generation, PG&E claims that assessing costs for underscheduled demand will give sellers unfair leverage. Dynegy argues that the ISO has failed to offer adequate justification for assessing costs for undelivered generation.

D. Qualifying Facilities (QF) Order (December 8, 2000)

Also on December 8, 2000, the Commission issued an order waiving certain efficiency and fuel use regulations pertaining to QFs, effective for the period December 8 through December 31, 2000.[12] The waiver allowed certain QFs to sell their excess production to load located in California through negotiated bilateral contracts to supplement the inadequate generation resources in California.

SoCal Edison filed a request for immediate modification of the order, claiming that permitting sales of excess production interfered with existing contractual relationships, created uncertainty between the parties, and was unworkable given the short time period for the waiver (less than a month). SoCal Edison requests that the Commission limit its order to waiving efficiency and fuel use standards, and that the Commission allow the parties to determine how the waiver would impact their contractual rights and obligations, including whether a contract amendment should be negotiated.

E. December 15 Order

The Commission adopted many of the proposed remedies presented in the November 1 Order in an order issued December 15, 2000.[13] The December 15 Order focused on the need to reduce reliance on spot markets while balancing the need for

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[12] San Diego Gas & Electric Co., et al., 93 FERC ¶ 61,238 (2000) (December QF Order).

[13] San Diego Gas & Electric Co., et al., 93 FERC ¶ 61,294 (2000), reh'g pending on some issues (December 15 Order).

incentives for sellers to sell into California and for investment in generation and transmission facilities, with the overall goal of alleviating the extreme high prices being borne by Californians. The specific remedial measures adopted included: (1) eliminating the requirement that the IOUs sell all of their generation into and buy all their energy needs from the PX so as to terminate the over reliance on spot markets (which in turn required termination of the PX's wholesale rate schedules, as of the close of the April 30, 2001 trading day); (2) adopting an advisory benchmark for assessing prices of long-term electric supply contracts in order to provide guidance for market participants to evaluate the reasonableness of long-term prices; (3) requiring market participants to preschedule 95 percent of their load prior to real time and penalizing those who do not, so as to eliminate market participants' chronic underscheduling with the ISO; (4) establishing an interim modification of the single price auction as proposed in the November 1 Order and reporting requirements for transactions and/or bids over $150/MWh; and (5) requiring the ISO stakeholder governing board to resign and be replaced by a board independent of market participants. The order provided that, unless the Commission issued written notification to a seller that a transaction above the $150 breakpoint was still under review, refund potential on that transaction would close after 60 days.

Other actions taken in the order included: (1) extending the waiver of certain QF regulations granted in the December QF Order through April 30, 2001; (2) accepting for filing the ISO's tariff Amendment No. 30 (Docket Nos. EL00-95-002 and EL00-98-002); (3) rejecting the complaints filed in Docket Nos. EL00-97-000, EL00-104-000, EL01-1-000, EL01-2-000, and EL01-10-000; and (4) requiring the ISO, PX and IOUs to submit compliance filings.

SoCal Edison and PG&E filed emergency requests for rehearing on December 18 and 20, 2000, respectively. The companies detailed their weakening financial situations. According to SoCal Edison, between May and November 2000, it paid a total of $5.69 billion for wholesale electricity but collected billions less from its customers. Unless the California Commission ended its retail rate freeze, allowing recovery of wholesale costs in retail rates, and this Commission ordered a return to cost-based rates, SoCal Edison explained, it would not be able to meet its January financial obligations. The companies also warned that without immediate relief on their rehearing requests, they would seek action in federal courts.[14]

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[14]SoCal Edison later filed a petition for writ of mandamus. The D.C. Circuit denied the petition. In re: Southern California Edison Co., No. 00-1543 (D.C. Circuit filed January 5, 2001).

The PX filed a request for rehearing and emergency motion for stay of the December 15 Order on December 26, 2000. The PX requested that the Commission stay three aspects of the order: (1) the prohibition against the IOUs selling into the PX's spot markets and forward markets, allowing instead voluntary participation; (2) the termination of its block forward markets rate schedule; and (3) implementation of the $150/MWh breakpoint, which the PX stated was impossible to accomplish by January 1, 2001. The PX also sought rehearing of these aspects of the order, and in addition challenged the termination of its tariff governing its core markets. The PX cited the chilling effect of the December 15 Order on forward contracts calling for delivery after April 30, 2001, and stated that the order threatened to destroy it.[15]

Many other parties subsequently filed rehearing requests. Generally, generators and marketers argue that the Commission erred in finding rates were not just and reasonable during certain periods, that the Commission should eliminate or modify the $150/MWH breakpoint, and that the Commission erred in determining that opportunity costs could not be used to justify bids over the breakpoint. Others (e.g., municipals, IOUs, state government entities) ask for reconsideration of cost-based regulation and favor regional price mitigation, offering various proposals on how to implement both of these goals, and urge prompt determination of past overcharges and provision of refunds. Rehearing is sought in each of the related complaint dockets that were rejected, and regarding ISO Tariff Amendment Nos. 30 and 33.

F. Proceedings Concerning the Underscheduling Penalty

In the December 15 Order, the Commission adopted a penalty for any utility that underscheduled its load. This penalty was necessary since utilities' underscheduling of load jeopardized reliable system operations by forcing the ISO to satisfy far more load in real time than the market was intended to supply (i.e., approximately five percent). Therefore, the December 15 Order required all market participants to preschedule their load and imposed penalties when real-time load exceeded more than five percent of an entity's scheduled load.

Following the downgrade of SoCal Edison's and PG&E's credit and debt ratings in January 2001 and the PX's notification to the Commission that it had suspended the operation of its core markets, SoCal Edison and PG&E filed a request in Docket No. EL01-34-000 for immediate suspension of the underscheduling penalty. These utilities

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[15] The PX later filed a petition for writ of mandamus, which the Ninth Circuit denied. In re: California Power Exchange Corp., No. 01-70031 (9th Cir. filed April 11, 2001).

argued that the PX's suspension of the operation of certain markets and their credit and supply problems made it impossible for them to expand their forward purchases. SoCal Edison and PG&E maintained that, given these circumstances, the underscheduling penalty would not provide an incentive to their procurement strategy and instead amounts to an additional tax on their already expensive energy purchases. The Commission explained, however, that it needed further information on the market situation prior to considering whether to grant the utilities' request. Accordingly, on April 6, 2001, the Commission deferred action on the utilities' request to suspend the underscheduling penalty, pending the receipt of market information from the ISO.[16] The ISO filed the requested data on April 23, 2001.

Subsequently, the ISO filed Tariff Amendment No. 38 in Docket No. ER01-1579-000, proposing, in pertinent part, tariff amendments that would suspend the underscheduling penalty effective from January 1, 2001 through May 31, 2001. The Commission rejected the ISO's proposal due to its ongoing consideration of the issue in Docket No. EL01-34-000.[17] The Oversight Board and SoCal Edison filed requests for rehearing arguing that the Commission erred in rejecting the ISO's filing, which, they contend, was shown to be just and reasonable. In addition, SoCal Edison asserts that the Commission must make a finding on the merits of the filing, and moved to consolidate the docket with Docket No. EL01-34-000.

G. Subsequent Proceedings Arising from December 15 Order

As required by the December 15 Order, staff convened a technical conference on January 23, 2001 to explore options for a prospective mitigation and monitoring plan to be in place in May 2001. Staff issued its recommended plan on March 9, 2001, and sought comments from market participants.

H. March 9 Refund Order

Also on March 9, the Commission issued an order addressing above-breakpoint transactions that occurred in January, directing refunds from sellers for certain transactions, or alternatively, requiring sellers to submit additional cost or other

[16] Southern California Edison Co. and Pacific Gas and Electric Co., 95 FERC ¶ 61,025 (2001).

[17] California Independent System Operator Corp., 95 FERC ¶ 61,199 (2001).

justification for those transactions.[18] Numerous parties requested rehearing and/or clarification of the March 9 Order. These parties fell into three main categories: sellers of energy, California state entities, and the California IOUs. The principal issues the parties raise are the propriety of the Commission's adoption of a proxy price screen in place of either market-based or cost-based rates, the Commission's choice of factors in calculating the proxy price screen, the Commission's adoption of an as-bid option with refund liability, and the Commission's method in applying the refund liability. On May 24, 2001, PG&E and SoCal Edison filed a supplemental request for rehearing and motion to lodge the April 26 Order in the record for the March 9 proceeding.

I. Prospective Price Mitigation Orders (April 26 and June 19, 2001)

On April 26, 2001, the Commission issued a prospective mitigation and monitoring plan for wholesale sales through the organized real-time markets operated by the ISO,[19] and established an inquiry in Docket No. EL01-68-000 into whether a price mitigation plan should be implemented throughout the Western Systems Coordinating Council (WSCC). Elements of the plan included:

- Enhancing the ISO's ability to coordinate and control planned outages during all hours.

- Requiring sellers with Participating Generator Agreements (PGAs), as well as governmental entity generators located in California that voluntarily make sales through the ISO's markets or use the ISO's interstate transmission grid (with the exception of hydroelectric power), to offer all their available power in real time during all hours.

- Establishing conditions, including refund liability, on public utility sellers' market-based rate authority to prevent anticompetitive bidding behavior in the real-time market during all hours.

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[18] San Diego Gas & Electric Co., et al., 94 FERC ¶ 61,245 (2001) (March 9 Refund Order). The Director of the Office of Markets, Tariffs and Rates issued notices specifying similar transactions for the months of February, March, and April 2001 on March 16, April 16, and May 14, respectively.

[19] The April 26 Order also required the ISO to submit a compliance filing. The submission, filed on May 11, 2001 in Docket No. EL00-95-034, et al., is addressed in a separate order to be issued concurrently with this order.

- Establishing a mechanism for price mitigation for all sellers (excluding out-of-state generators) bidding into the ISO's real-time market during a reserve deficiency, i.e., when reserves fall below 7 percent. Under this mechanism, the Commission established a formula (based on gas-fired generation) that the ISO can use to establish the market clearing price when mitigation applies (mitigated reserve deficiency MCP).[20] Higher bids were permitted if they could be justified.

The Commission acted on requests for rehearing and clarification of the April 26 Order on June 19, 2001, modifying and expanding the mitigation plan in significant aspects. In the same order, the Commission instituted an investigation pursuant to section 206 of the FPA into public utility rates for spot markets sales in the WSCC.[21] Key elements of the mitigation plan, to be in effect from June 21, 2001 through September 30, 2002, include:

- Retaining the use of a single market clearing price with must-offer and marginal cost bidding requirements for sales in the ISO's spot markets in reserve deficiency hours (i.e.,when reserves fall below 7 percent).

- Applying that clearing price as a maximum price for sales outside the ISO's single price auctions (bilateral sales in California and the rest of the WSCC), with sellers outside the single price auction receiving the prices they negotiate up to this maximum price.

- Using eighty-five percent of the highest ISO hourly mitigated reserve deficiency MCP established during the hours of the last Stage 1 alert for the mitigated non-reserve deficiency Market Clearing Price (mitigated non-reserve deficiency MCP) for subsequent non-reserve deficiency hours.

- Instructing bidders to invoice the ISO directly for the cost to comply with emissions requirements and for start-up fuel costs, which are too varied to be standardized in a single market clearing price.

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[20]The mitigated reserve deficiency MCP is the marginal cost of the last unit dispatched to serve the last increment of load during a period of reserve deficiency. The marginal cost of each unit calculated by the ISO based on Commission prescribed inputs is referred to as the "Proxy Price."

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

- Allowing sellers other than marketers the opportunity to justify bids or prices above the maximum prices.

- Requiring all utilities who own or control generation in California to offer power in the ISO's spot markets, and requiring all utilities in the remainder of the WSCC to offer in the spot market of their choosing any non-hydroelectric resource to the extent its output is not already committed ("must-offer requirement").

Finally, the Commission announced that it would establish a settlement conference before an Administrative Law Judge in order to resolve refund issues for sales through the ISO and PX spot markets for past periods, among other things.[22]

Among other issues, parties sought rehearing and/or clarification of the California must-offer and price mitigation revisions, the extension of price mitigation to all hours, the bid justification provisions, the revised emissions cost collection procedures, the creditworthiness adder, and the scope, price mitigation and must-offer provisions under the West-wide investigation.

The Commission's Chief Judge convened a settlement conference as directed in the June 19 Order, and issued a report and recommendation regarding a refund methodology on July 12, 2001.[23]

J. July 25 Refund Order

On July 25, 2001, the Commission issued an order establishing the scope of and methodology for calculating refunds related to transactions in the spot markets operated by the ISO and the PX. The Commission found that transactions subject to refund are limited to the period October 2, 2000 through June 20, 2001, but include sales by all sellers into the spot markets operated by the ISO and the PX. The Commission further found that the refund requirements apply to ISO OOM purchases, but not to spot purchases by DWR or ISO purchases made pursuant to DOE orders.

The refund methodology adopted most of the criteria of the June 19 price mitigation plan, modified as to be appropriate for a past, rather than a future, period.

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[22] In addition, the order required the ISO to submit a compliance filing. The submission, filed on July 10, 2001 in Docket No. EL00-95-040, et al., is addressed in a separate order to be issued concurrently with this order.

[23] San Diego Gas & Electric Co., et al., 96 FERC ¶ 63,007 (2001) (Chief Judge's Report).

Under the methodology, refunds would be determined by the difference between prices charged and a competitive market base-line calculated for each hour of the refund period. Hourly mitigated prices would be developed using the marginal costs of the last unit dispatched to meet load in the ISO's real-time market using:

- Northern and Southern California zone specific spot gas prices, based on a composite of published market prices;
- a $6.00 per MWh adder for non-fuel O&M costs;
- a 10 percent creditworthiness adder for transactions after January 5, 2001;
- interest to be assessed on both refunds and receivables past due.

In addition, suppliers may net demonstrable emissions costs from their refund liability.

The order also established an evidentiary hearing proceeding in order to further develop the factual record so that refunds could be calculated. In addition, the order granted rehearing in part and denied rehearing in part of limited portions of earlier orders.

Finally, the order established a preliminary evidentiary proceeding to explore whether there may have been unjust and unreasonable charges for spot market sales in the Pacific Northwest and to determine the calculation of any refunds associated with such charges. An administrative law judge presided over the proceeding and issued recommendations and proposed findings of fact on September 24, 2001.

Parties seek rehearing of each aspect of the scope and calculation of refunds. They also challenge the adequacy and appropriateness of the evidentiary hearing proceeding and the preliminary evidentiary hearing in the Puget Sound proceeding in Docket No. EL01-10-000. On September 20, 2001, PG&E filed a motion to submit newly obtained evidence in support of its rehearing request. California Generators filed an answer in opposition to the motion on October 5, 2001, and PG&E subsequently responded.

K. July 25 Order Granting Emergency Motion for Clarification

On July 25, 2001, the Commission granted Mirant's emergency motion for clarification of the April 26 and June 19 Orders. The Commission found that Mirant presented an adequate showing under those Orders to excuse Mirant from the requirement that it offer all of its available capacity from certain of its units located at the Potrero Power Plant, because doing so would violate environmental operating limitations set forth in Mirant's permit. The Commission also provided guidance to other suppliers that may be concerned about penalties or damages resulting from citizen suits if they exceed operating limitations in order to comply with the must-offer requirement.

NCPA sought rehearing of the July 25 Clarification Order, claiming that the Commission's guidance does not provide viable alternatives.

Discussion

A. Procedural Matters

A number of entities filed late motions to intervene in this proceeding. The Commission ordinarily does not permit late interventions after an order has been issued, particularly for the purpose of requesting rehearing.[24] However, over the course of the SDG&E proceeding, the Commission has expanded the scope of its focus from just California to include the entire Western interconnect and also to implicate wholesale spot market transactions of governmental entities and cooperatives and bilateral spot market transactions. We find good cause, therefore, to grant the untimely, unopposed motions to intervene in Docket No. EL00-95-000 filed by Nevada Independent Energy Cooperative and Cogeneration Coalition of Washington (jointly) (Nevada IEC/CC Washington) and Tri-State Generation and Transmission Association that were both filed on May 17, 2001, and the untimely, unopposed motions to intervene of Public Utility District No. 1 of Chelan County, Washington (Chelan County), RAMCO, Deseret Generation and Transmission Cooperative (Deseret), Truckee Donner Public Utility District (Truckee Donner), Utah Associated Municipal Power System (Utah AMPS), Public Utility Commission of Oregon and Oregon Office of Energy (jointly), and Sunrise Power Company LLC and Harbor Cogeneration Company (jointly) (Sunrise and Harbor), which were filed on July 19 or July 20, 2001.[25]

These intervenors must accept the record as it had developed as of the date of their intervention, and their participation in this proceeding is limited to the issues that arose after the date each requested to participate in these proceedings. Thus, the requests for rehearing of the June 19 Order filed by Chelan County, Deseret, RAMCO, Sunrise and

[24] See, e.g., Southern Company Services, Inc., 92 FERC ¶ 61,167 (2000); Consolidated Edison, Inc. and Northeast Utilities, 92 FERC ¶ 61,014 (2000), order denying reh'g, 94 FERC ¶ 61,079 (2001).

[25] Arizona Electric Power Cooperative, Inc. (AEPCO) filed a motion to intervene out-of-time on August 24, 2001. AEPCO is already a party in this proceeding by virtue of its intervention request granted by Chief Judge Wagner; therefore, we need not address its subsequent motion to intervene.

Harbor, Truckee Donner, and Utah AMPS will be dismissed because they were not parties as of the date that order was issued. The July 25 Order granted the intervention of Attorney General of California as of July 17, 2001 (the date it requested intervention). Therefore its request for rehearing of the June 19 Order will likewise be dismissed, as it was not a party on June 19, 2001. Similarly, APPA's request for rehearing of the March 9 Refund Order will be dismissed because it had not requested intervention prior to the date that order was issued.

On November 23, 2001, the Institute for Legal Reform of the Chamber of Commerce of the United States (Institute) moved to intervene for the limited purpose of filing a brief concerning developments in California state court proceedings involving allegations of state antitrust violations that could purportedly affect the implementation of the Commission's market mitigation plan. The Institute states that the issues can be resolved on the existing record, that there will be no prejudice to or burden on other parties, and that its proposed relief will not require any delay in the proceeding. The People of the State of California, ex rel. Bill Lockyer (Attorney General of California) and the City of Tacoma, Washington and the Port of Seattle, Washington oppose the Institute's intervention on the grounds that its intervention will disrupt the proceeding and that the interests the Institute represents are already adequately represented. We find, contrary to the Attorney General's assertions, that the Institute's late intervention for the purpose of filing its brief will not prejudice or place additional burdens upon the existing parties, that it will not disrupt the proceeding, and that the Institute's interest is not adequately represented by other parties in the proceeding. Therefore, we will grant the Institute's untimely motion to intervene. We find, however, that the Institute's arguments need not be resolved here; we will address this pleading in a future order.

Section 313(a) of the FPA requires an aggrieved party to file a request for rehearing within thirty days after the issuance of the Commission's order, in the case of the June 19 Order, by July 19, 2001. Because the 30-day deadline for requesting rehearing is statutorily based, it cannot be extended, and the requests for rehearing of Truckee Donner, and Utah AMPS filed on July 20, 2001 (dismissed above because they lacked party status) are also dismissed as untimely.[26] Further, requests for rehearing of the July 25 Order were required to be filed by August 24, 2001, and, therefore,

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[26]We will, however, grant these parties' late motions to intervene, as of the dates their motions were filed, because of lack of procedural clarity about the deadline for interventions. Further, we will treat comments submitted without a formal motion to intervene as intervention requests, because of the potentially confusing procedural stance of Docket No. EL01-68-000. Thus, Avista Utilities is a party in this proceeding as of the date its comments were filed, May 7, 2001.

TransAlta's request for rehearing filed on August 27, 2001 (dismissed above because it lacked party status) is also dismissed as untimely.

Portland General and the City of Seattle seek clarification of their party status in Docket No. EL01-68-000. Both had timely intervened in Docket No. EL00-95-000, et al., but had not intervened separately in Docket No. EL01-68-000. We will clarify that these two entities, and any others who intervened in Docket No. EL00-95-000, et al., are entitled to full party status in Docket No. EL01-68-000, regardless of whether they filed a motion to intervene. Likewise, for the same reasons, any entities who have intervened in Docket No. EL01-68-000 are entitled to full party status in Docket No. EL00-95-000, et al., as of the date of their intervention requests in Docket No. EL01-68-000.[27]

Cities/M-S-R seek to correct the Appendices to the June 19 Order, which listed "M-S-R Public Power Agency, et al." as the entity seeking rehearing of the April 26 Order, to reflect that the Cities of Santa Clara and Redding, California also sought rehearing, and to reflect correctly which entities had filed comments and intervened in Docket No. EL01-68-000. We acknowledge that Santa Clara and Redding requested rehearing of the April 26 Order jointly with M-S-R. The relief provided above permitting all intervenors in Docket No. EL00-95-000, et al., to have party status in Docket No. EL01-68-000 should resolve Cities/M-S-R's other concerns.

On May 24, 2001, SoCal Edison and PG&E filed a supplement to their request for rehearing of the March 9 Order, or alternatively a motion to lodge the April 26 Order in that rehearing proceeding. We will reject these companies' request to supplement their requests for rehearing as we have no authority to accept materials in support of rehearing if such materials are filed after the 30-day statutory deadline for submitting materials in support of rehearing.[28] Further, the Commission is already fully considering the April 26 Order and its effect on prior orders. Accordingly, we deny the alternative motion.

On September 30, 2001, PG&E filed a motion to submit newly obtained evidence in support of its request for rehearing of the July 25 Order. We will reject this request to supplement PG&E's request for rehearing because we have no authority to accept materials in support of rehearing if such materials are filed after the 30-day statutory

[27] Thus, Chelan County has intervenor status in Docket No. EL00-95-000 by virtue of its motion to intervene in Docket No. EL01-68-000 filed on July 19, 2001, and its request for rehearing of the July 25 Order will therefore be accepted.

[28] See, e.g., Southern Company Services, Inc., 57 FERC ¶ 61,093 at 61,344 and n.79 (1991); and Public Service Company of New Hampshire, 65 FERC ¶ 61,105 at 61,403 and n.16 (1991).

deadline for submitting materials in support of rehearing.[29] We will also reject California Generators' filing in opposition to the motion, and PG&E's response.

Pursuant to Rule 713 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.713, answers to requests for rehearing normally are prohibited. Accordingly, we will reject Dynegy's and Duke's answers to the rehearing requests of the August 23 Order, the ISO's answer to rehearing requests of the July 25 Order, and Powerex's answer to the Oversight Board's request for rehearing of the July 25 Order.

In view of the early stage of the proceeding in Docket No. EL01-34-000 and the absence of any undue prejudice or delay, we will grant the motion to intervene out-of-time of Dynegy Power Marketing, Inc., El Segundo Power LLC, Long Beach Generation, LLC, Cabrillo Power I LLC and Cabrillo Power II LLC (collectively, Dynegy). As the Commission is considering both Docket No. ER01-1579-000 and Docket No. EL01-34-000 in this order, and the proceedings are not being set for hearing, there is no need to consolidate the dockets; thus, we will deny Dynegy's motion to consolidate. Similarly, we will deny Dynegy's motion to lodge its motion to intervene and protest that was filed in Docket No. ER01-1579-000 in the record for Docket No. EL01-34-000.

While, for organizational purposes, we may address the issues raised on rehearing of different orders in separate sections of this order, our discussions and holding in any section regarding a specific issue also raised on rehearing of another order or orders apply to all rehearings on that specific issue.

B. Rehearing of Issues Surrounding Level and Scope of Mitigated Prices

1. Scope of Transactions Subject to Mitigation and Refund

a. Applicability to Sales by Governmental Entities

Requests for Rehearing

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[29] See id. and CMS Midland, Inc., 56 FERC ¶ 61,177 at 61,623 (1991) (rejecting pleadings even when filed in support of timely-filed requests for rehearing).

Several governmental entities[30] contend that the Commission erred in ordering them to make refunds regarding their sales in the FERC-regulated ISO and PX markets. They argue that: the Commission's rate and refund authority under FPA sections 205 and 206 applies only to "public utilities;" that FPA section 201(f) expressly exempts governmental entities from FERC jurisdiction unless the statute specifically provides otherwise; the Commission does not have subject matter jurisdiction over governmental entities' sales into the FERC-regulated PX and ISO markets because section 201(f) overrides the more general statutory provision in section 201(b); the refund holding here nullifies FPA section 201(f); and FPA subject matter jurisdiction is determined solely by whether the seller is subject to jurisdiction under the FPA.

Governmental entities further assert that: the Commission cannot indirectly exercise jurisdiction over governmental entities because it cannot directly do so; the public interest cannot override FPA jurisdictional limitations; the finding that the underlying goals of the FPA are promoted by placing all sellers in these markets on the same footing for refund purposes is inapposite and unconvincing; if the Commission has jurisdiction here, governmental entities would have been subject to full jurisdiction under the FPA merely by using public utilities' transmission systems to make sales for resale; governmental entities will be forced to choose between subjecting themselves to FERC regulation or not selling into certain markets, rendering FPA 201(f) superfluous; any regulatory gap that exists regarding governmental entities was intentional on Congress' part; and no regulatory gap exists because the rates for power sold by governmental entities are regulated by local authorities.

Moreover, governmental entities argue that: ordering governmental entities to make refunds is contrary to Commission and court precedent; the Commission changed its policy regarding governmental entities without providing a reasonable basis for doing so; they did not and could not waive the Commission's lack of subject matter jurisdiction when they made sales in the FERC-regulated ISO and PX markets; basing the Commission's jurisdictional finding on the ISO and PX tariffs and certain agreements executed by governmental entities violated the filed rate doctrine because those documents do not expressly require governmental entities to make refunds; they had no

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[30] See, e.g., Requests for Rehearing of Bonneville Power Administration (Bonneville) at 2-18, DSI Companies (adopting Bonneville's arguments), NCPA at 9-17, APPA at 2-9, Turlock at 5-20, Burbank (virtually identical to Turlock), Imperial (virtually identical to Turlock), LADWP at 5-7, 10-12, Southern Cities at 3-12, Pasadena at 3-7, PUD No. 2 (virtually identical to Southern Cities), Metropolitan at 4-13, Cities/M-S-R at 6-10, Modesto (adopting the arguments raised by Cities/M-S-R), CMUA at 3-15 and AEPCO at 3, 7-14.

notice that their power sales in the FERC-regulated ISO and PX markets were subject to refund; and the Commission cannot create jurisdiction by placing parties on notice that it intends to exercise jurisdiction or by approving a particular market structure.

Additionally, governmental entities assert that: most governmental entities did not execute the pro-forma scheduling coordination agreements; the Commission failed to provide adequate notice that sales of electricity by governmental entities in the ISO or PX would be subject to refund, violating due process (i.e., the right to notice and a meaningful opportunity to be heard); the refund holding regarding governmental entities is inconsistent with the holding regarding refunds for the period prior to October 2, 2000; even if the Commission could condition governmental entities' sales into these FERC-regulated markets on their agreement to assume refund liability, no such condition was imposed; and the equities do not support refunds on sales by certain governmental entities.

Salt River agrees with the refund result of the July 25 Order, but disagrees with the order's rationale for the same reasons given by the governmental entities that oppose the refund order. Salt River suggests that the Commission should focus more narrowly on the specific terms and conditions of the FERC-regulated PX and ISO Tariffs that governmental entities voluntarily and explicitly agreed to abide by, including provisions that authorize the recalculation and issuance of revised settlement statements.

Commission Response

i. Statutory Framework

It is undisputed that the Commission has personal jurisdiction over the PX and ISO, and that they operate pursuant to FERC-approved tariffs and wholesale rate schedules.[31] Moreover, the PX and ISO are public utilities under FPA section 201(e).[32] The Commission's subject matter jurisdiction includes wholesale sales (defined as "sale[s] of electric energy to any person for resale"[33]) of electric energy in interstate

[31] FPA § 201(b).

[32] In re California Power Exchange Corporation, 245 F.3d 1110, 1114 (2001); Pacific Gas & Electric Co., 77 FERC ¶ 61,204 (1996), reh'g denied, 81 FERC ¶ 61,122 (1997).

[33] FPA § 201(d).

commerce.[34] As all of the electric energy sales into the FERC-regulated PX or ISO spot markets are wholesale sales of electricity in interstate commerce, they all fall within the Commission's subject matter jurisdiction.[35]

The exemption for governmental entities in FPA section 201(f)[36] does not require a different result regarding sales by governmental entities in the PX and ISO spot markets. While that provision exempts governmental entities generally from Commission jurisdiction under Part II of the FPA, it does not do so under the specific circumstances here. Here, governmental entities and others sold energy in a centralized, single clearing price auction market under which all sellers received the same price for a given sale, pursuant to market rules set by this Commission and administered by public utilities (the California PX and ISO) subject to this Commission's jurisdiction. The involvement of the PX and ISO, whose roles are central in these California spot markets, along with the nature of the interstate wholesale sales, give us subject matter jurisdiction entirely independent of the jurisdictional nature of the entities selling into the markets at issue.[37] Thus, FPA section 201(f) does not change the analysis or the result in determining whether we have subject matter jurisdiction over the sales at issue.[38]

Moreover, governmental entities that made sales in the PX and ISO spot markets waived any exemption they otherwise may have had from the Commission's personal jurisdiction regarding those sales.[39] Because the markets did not exist prior to FERC authorization and operate according to FERC rules, all those who participated in them reasonably had to recognize the controlling weight of FERC authority. The PX and ISO operated under FERC-approved tariffs, which set forth all rates, charges, classifications,

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[34]July 25 Order, 96 FERC at 61,511 (citing FPA § 201(b)).

[35]FPA § 201(b).

[36]FPA § 201(f) provides that "[n]o provision in this Part [of the FPA] shall apply to, or be deemed to include, the United States, a State or any political subdivision of a state, or any agency, authority or instrumentality of any one or more of the foregoing . . . unless such provision makes specific reference thereto."

[37]United Distribution Companies v. FERC, 88 F.3d 1105 (D.C. Cir. 1996) (UDC).

[38]As the Commission can directly regulate the sales at issue regardless of who made the sales, this is not a case of the Commission indirectly exercising jurisdiction over governmental entities when it cannot do so directly.

[39]See Burger King Corp. v. Rudzewicz, 471 U.S. 462, 473 n.14 (1985).

practices, rules, regulations or contracts for or in connection with all sales made in their markets.[40] The tariffs established spot market auction mechanisms that made clear that all sellers, including governmental entities, would receive the same FERC-regulated market clearing price for any given sale. That price, under the FPA, could not exceed the just and reasonable rate. All sellers were on notice that those clearing prices, and the market rules that set the clearing prices, were subject to change and refund if they were found to be unjust and unreasonable.

We made clear in our order authorizing establishment of the PX and the ISO that, "[o]nce filed, the rate schedules and related contracts, rules and protocols will be subject to the exclusive jurisdiction of the Commission under sections 205 and 206 of the FPA, 16 U.S.C. sections 824d, 824e (1994)."[41] Thus, all sellers in the PX and ISO markets, including governmental entities, were on notice that if they participated in those markets, they would do so subject to the terms of the ISO and PX tariffs and concomitant FERC jurisdiction. Our order authorizing the PX and ISO to operate provided further notice that the same rules and obligations applied to all sellers and sales made in the PX and ISO spot markets. For example, the order established that all PX and ISO rules, protocols, procedures and standards applied to all entities selling energy in the PX and ISO markets.[42] Furthermore, the December 15 Order discussed refunds as applying to "all sellers into the markets operated by the ISO and the PX."[43]

Governmental entities or their agents entered into various arrangements that explicitly acknowledged the Commission's jurisdiction regarding their sales in the PX and the ISO. For example, many governmental entities[44] accepted a FERC-approved pro-forma Scheduling Coordinator Agreement that explicitly acknowledges their obligation "to comply with the terms and conditions of the ISO Tariff and ISO

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[40]See FPA § 205(c); 18 C.F.R. §§ 35.1(a) and (e), 35.2(a) and (b) and n.1; Pacific Gas & Electric Co., 77 FERC ¶ 61,204 at 61,804 (1996).

[41] Pacific Gas & Electric Co., 77 FERC at 61,804.

[42]Pacific Gas & Electric Co., 81 FERC ¶ 61,122 at 61,580-87 (1997).

[43]December 15 Order, 93 FERC at 62,011. The Commission's deviation from this in the November 1 Order, by using the term "public utility sellers" in the title of the section discussing potential refund liability, does not negate that governmental entities had notice that their sales in the PX and ISO spot markets could be subject to refunds.

[44]These sellers included the Cities of Anaheim and Riverside and DWR.

Protocols."[45] Moreover, numerous governmental entities[46] executed the FERC-approved pro-forma PX Participation Agreement, which "establishes the basis and terms upon which entities shall receive service through the PX, in accordance with the PX Tariff and Protocols."[47] In approving the pro-forma PX Participation Agreement, we found that it and "the services provided under the PX Tariff are jurisdictional" and needed to be filed with the Commission in accordance with FPA section 205(c).[48]

We reiterate our finding that, by participating in the FERC-regulated centralized PX and ISO spot markets, all sellers, including governmental entities, agreed to accept the same clearing price for any given sale under the single price auction mechanism approved by FERC. We further reiterate that all entities, including governmental, that sold in the PX and ISO spot markets were on notice that they were subject to,[49] and are in fact subject to, FERC jurisdiction regarding the rates to be received for those sales, including FERC rate and refund orders. In the July 25 Order, we acted appropriately pursuant to our authority under FPA section 206 to fix the just and reasonable rate by revising the method for calculating the FERC-regulated PX and ISO spot market clearing prices as of October 2, 2000. In doing so, we simply revised the market clearing prices that all market participants previously agreed to accept for their sales, and ordered refunds to effectuate that revision. Thus, we deny rehearing of the claims that we erred in ordering governmental entities to make refunds regarding their sales in the FERC-regulated ISO and PX markets.

Our refund order does not violate the filed rate doctrine. As our refund authority derives from the FPA, the filed rate doctrine does not require that the ISO and PX tariffs

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[45] See Pacific Gas and Electric Co., 82 FERC ¶ 61,326 at 62,283 (1998).

[46] Those entities include the Arizona Electric Power Cooperative (AEPCO), Bonneville, DWR, the Cities of Anaheim and Riverside, LADWP, Modesto, and NCPA. See PX January 25, 2001 letter filing, Docket No. ER98-2095-000 (index of parties who executed the Participation Agreement as of December 31, 2000).

[47] California Power Exchange Corp., 83 FERC ¶ 61,186 at 61,770 (1998).

[48] Id. at 61,771.

[49] The March 9 Order at 7 incorrectly indicated that we have no authority to order governmental entities to make refunds here. That statement has no bearing on governmental entities' general notice regarding their sales being subject to FERC jurisdiction under the FPA's just and reasonable standard, including the potential for refund liability.

or the agreements executed by governmental entities include an express refund provision. Moreover, because authority for the refund order derives from the Commission's FPA subject matter jurisdiction over the sales themselves, the Commission was not required to condition governmental entities' sales into the FERC-regulated PX and ISO spot markets on their agreement to assume refund liability. The only filed rates in this case consisted of the ISO and PX tariffs, both of which were subject to the SDG&E complaint and the Commission's section 206 investigation instituted on August 23, 2000, and thus subject to our refund authority.

We are not relying on the public interest to "override" FPA jurisdictional limitations and thus doing indirectly that which we cannot do directly. Rather, the subject matter of the sales here provides us with jurisdiction.[50] As a separate matter, by selling in the PX and ISO spot markets, the governmental entities waived any personal jurisdictional limitations.

ii. Precedent

Including governmental entities in our refund order is not contrary to Commission precedent. Our determination that all sellers, including governmental entities, in the PX and ISO spot markets are liable for refunds is limited to the specific circumstances before us in this case: sales made in FERC-jurisdictional (PX and ISO) spot markets in which all sellers received the same prices for sales of electric energy for resale in interstate commerce determined by FERC-jurisdictional entities under a single price auction format. None of the cases cited as contravening our holding here presented similar circumstances.

Rather, the cited cases involve much broader factual scenarios, and stand for the unexceptional proposition that FPA section 201(f) generally exempts governmental entities from our jurisdiction.[51] For example, in New West, a governmental entity sought

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[50]The legislative history indicates that Congress never contemplated a market scenario such as the one here. See, e.g., To Provide for the Control in the Public Interest of Public Utility Holding Companies Using the Mails and the Facilities of Interstate Commerce, to Regulate the Transmission and Sale of Electric Energy and Natural Gas in Interstate and Foreign Commerce, and for Other Purposes, 1935: Hearings on H.R. 5423 Before the House of Representatives Committee on Interstate and Foreign Commerce, 74th Cong. 2160 (1935) (statement of Mr. DeVane, Solicitor of the Federal Power Commission).

[51]E.g., Prairieland Energy, Inc., 92 FERC ¶ 61,139 (2000); Mid-Continent Area

(continued...)

general Commission authorization under FPA section 205 to engage in wholesale electric sales at market-based rates as a power marketer. We rejected the request, finding that the governmental entity was exempt from Commission FPA section 205 rate regulation by virtue of FPA section 201(f). New West is inapposite to our holding here, as that order did not involve a centralized market or single price auction for the sale of electric energy in interstate commerce operated by a public utility subject to our exclusive rate jurisdiction, but rather addressed only the much broader issue of whether the Commission can assert jurisdiction over a governmental entity's interstate wholesale sales as a general matter, regardless of the circumstances under which those sales are made.[52]

Other Commission precedent cited by those seeking rehearing supports our refund holding here. For example, in Order No. 888,[53] we required governmental entities that receive open access transmission service from a public utility to offer comparable service in return. We explained that:

> While we do not have the authority to require non-public utilities to make their systems generally available, we do have the ability, and the obligation, to ensure that open access transmission is as widely available as possible and that this Rule does not result in a competitive disadvantage to public utilities. . . . [W]e will not permit [non-public utilities] open access to

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[51](...continued)
Power Pool, 92 FERC ¶ 61,229 (2000); New West Energy Corp., 83 FERC ¶ 61,004 (1998); Sacramento Municipal Utility District v. Pacific Gas and Electric Co., 37 FERC ¶ 61,323 (1986).

[52]It also should be noted that we also did not analyze the jurisdictional issues in the cited cases in light of UDC. Similarly, the court precedent cited by those requesting rehearing neither involved the limited specific circumstances present here nor considered the jurisdictional matters at issue in light of UDC.

[53]Promoting Wholesale Competition Through Open Access Nondiscriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,760-62 and 31,857, 61 Fed. Reg. 21,540 (1996), clarified, 76 FERC ¶ 61,009 and 76 FERC ¶ 61,347 (1996), on reh'g, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, 62 Fed. Reg. 12,274, clarified, 79 FERC ¶ 61,182 (1997), on reh'g, Order No. 888-B, 81 FERC ¶ 61,248, 62 Fed. Reg. 64,688 (1997), on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998), aff'd sub nom. Transmission Access Policy Study Group v. FERC, 225 F.3d 667 (D.C. Cir. 2000), cert. denied in pertinent part, 69 U.S.L.W. 3574 (U.S. Feb. 26, 2001).

> jurisdictional transmission without offering comparable service in return.[[54]]

In City of Vernon, California,[55] we held that "the Commission does have the authority to evaluate non-jurisdictional activities to the extent they affect the Commission's jurisdictional activities." In that case, we required modification of certain rates of a governmental entity that wanted to become a participating transmission owner in the FERC-jurisdictional California ISO. We reviewed the governmental entity's proposed rates "as a means of ensuring that the costs ultimately charged by the ISO are just and reasonable. The Federal Power Act requires us to ensure the justness and reasonableness of the ISO's rates, and we cannot reach this result if we absolve from our review the portion of the ISO's costs incurred with respect to "this governmental entity."[56] The same reasoning applies to the sales at issue here. As here, "the approach we took [in City of Vernon] properly balances our duty to ensure the justness and reasonableness of the ISO's rates with the fact that [the governmental entity] itself [may not be] jurisdictional for purposes of FPA Section 205 [or 206]."[57]

In short, we have been consistent in our approach regarding the activities of governmental entities as they affect matters subject to our jurisdiction, and have applied it to the specific limited factual scenario presented here.

Our refund holding regarding governmental entities is not inconsistent with our holding regarding refunds for the period prior to October 2, 2000. The subject matter of the sales, in the specific circumstances presented,[58] makes all sellers in the PX and ISO spot markets subject to refunds in accordance with FPA section 206. All sellers in those markets reasonably were on notice that their sales were subject to refund, and that, in accordance with FPA section 206, their refund liability would begin no "earlier than the date 60 days after the filing" of a complaint. Sellers were not reasonably on notice that

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[54]Order No. 888 at 31,761-62.

[55]93 FERC ¶ 61,103 at 61,285(2000), reh'g denied, 94 FERC ¶ 61,148 (2001).

[56]94 FERC at 61,564.

[57]Id.

[58]Sales made in FERC-jurisdictional (PX and ISO) spot markets in which all sellers received the same prices for sales of electric energy for resale in interstate commerce determined by FERC-jurisdictional entities under a single price auction format.

their refund liability would begin prior to October 2, 2000, the date we previously determined would be the refund effective date.[59]

Our interpretation of UDC and our action here does not eviscerate the section 201(f) exemption. We reiterate that our ruling here is limited to the specific circumstances presented during a past time period in the California PX and ISO spot markets during which all sellers received the same price for a given transaction. That price was determined by FERC-jurisdictional entities (the PX and ISO) in FERC-jurisdictional markets under a single price auction format, as originally set and later modified by FERC, for sales of electric energy for resale in interstate commerce.

The sales that fall within the scope of the July 25 Order amount to a small fraction of all sales made by governmental entities. The Commission has not scrutinized any non-spot market sales by those entities and does not intend to start such scrutiny now. Similarly, governmental entities have not been, and will not now be, subject to filing and other requirements unrelated to the PX and ISO spot markets that attach to non-exempt public utilities. Thus, the Commission is not seeking to expand its jurisdiction to include entities exempted by FPA section 201(f). Rather, in the limited circumstances involved in the California PX and ISO spot markets, the Commission is using its subject matter jurisdiction over those sales to assure compliance by all sellers in those markets with the regulatory regime established by FERC to assure just and reasonable rates for those sales.

Several governmental entities argue that, even if the Commission has jurisdiction to order refunds from them, it should not do so for what they term "policy or 'fundamental fairness' considerations."[60] Among the arguments raised are: governmental entities, as purchasers, had to pay higher electricity prices which negated any benefit of their sales to the ISO or PX spot markets;[61] that they are price takers, not price gougers,

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[59]It is true that the Commission's authority to institute investigations of rates, terms or conditions of jurisdictional service under section 206 applies only to public utilities. However, the ISO and PX are two of the public utilities whose rates were made subject to investigation in our August 23 Order, and because the ISO and PX set a single market clearing price for all sellers, both governmental and non-govermental, that sold through their markets, all sellers' rates accordingly were made subject to potential refund as of the October 2, 2000 refund effective date.

[60]AEPCO at 13.

[61] CMUA at 14-15; AEPCO at 14-15 (but also recognizing the potential for refund recovery under the Commission refund proposal).

and thus could not cause unjust and unreasonable rates;[62] the Commission should focus on those who have misused the system and limit refunds to divestiture of "ill-gotten gains";[63] and, ordering refunds creates hardships for governmental entities and their customers.[64]

The FPA grants the Commission discretion in ordering refunds.[65] The Commission's practice has been to order full refunds of any amounts collected above the just and reasonable level, absent contrary equitable considerations.[66] Refunds are restitutionary, rather than punitive, relief.[67] Because the statutory goal of refunds is customer restitution, the Commission does not set refund levels based on a degree of culpability regarding overcollections. Rather, our refund task in this and other cases is to determine objectively the amount of overcollections that should be returned to customers. Here, that means resetting the auction prices to just and reasonable levels that apply to all sellers in that single price auction market. Accordingly, we decline the governmental entities' invitation to determine refunds based on some unidentified measure of blameworthiness.

iii. Reliance on UDC

Some parties challenge the Commission's reliance on UDC[68] as providing guidance on whether governmental entities could be included in the refund plan for the California PX and ISO spot markets. Among the arguments raised by those parties is that such reliance ignores the fact that the Natural Gas Act (NGA), at issue in UDC,

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[62] APPA at 8-9; NCPA at 15-16.

[63] NCPA at 15.

[64] AEPCO at 14; CMUA at 15; APPA at 9.

[65] Both FPA § 205(e), 16 U.S.C. § 824d(e) and FPA § 206(b), 16 U.S.C. § 824e(b), indicate the Commission "may"order refunds. See also FPA § 309, 16 U.S.C. § 825h.

[66] E.g., Western Resources, Inc. v. FERC, 9 F.3d 1568, 1581 (D.C.Cir. 1993).

[67] Towns of Concord, et al. v. FERC, 955 F.2d 67, 75-76 (D.C.Cir. 1992).

[68] 88 F.3d 1105.

"includes no equivalent to FPA section 201(f)."[69] Another argument contends that as UDC dealt with FERC authority over transportation, it offers no guidance as to the Commission's authority to regulate rates.[70]

Parties also contend that the result here was driven by a policy decision to fill in a gap without regard to the statutory limitations on the Commission's authority.[71] On a related point, several parties point to our prior orders disclaiming jurisdiction over governmental entities as demonstrating that the July 25 Order breaks with decades of prior practice in implementing the FPA.[72]

We have given careful consideration to all the arguments raised concerning the alleged inapplicability of the approach taken in UDC to the instant situation. In our view, that approach does apply here and is consistent with the FPA's statutory plan, and with controlling precedent. Under the specific circumstances presented by the California PX and ISO spot markets in the time period at issue, our decision to make all sellers liable for possible refunds for their sales fulfills our statutory obligation. Accordingly, we deny all requests for rehearing on this point.

Several parties seek to distinguish the applicability of UDC on grounds that it "involved terms and conditions of jurisdictional pipelines' transportation service, not non-jurisdictional sales of gas."[73] In UDC, however, the court was asked to deal only with the clause in NGA section 1(b) addressing transportation of natural gas in interstate commerce.[74] Thus, the limitation in the UDC litigation to the transportation clause resulted from its factual context, not from a statutory restriction. Nothing in UDC suggests that the court would have reached a different conclusion had the issue related to

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[69]See Requests for Rehearing of Bonneville at 6; Turlock at 18; Southern Cities at 7; MWD at 7; LADWP at 11; M-S-R at 6.

[70]See Requests for Rehearing of Bonneville at 6; Metropolitan at 8-9; LADWP at 9.

[71]See, e.g., Requests for Rehearing of Bonneville at 12-13; AEPCO at 9; Southern Cities at 11-12.

[72]See, e.g., Request for Rehearing of Southern Cites at 11.

[73]See, e.g., Request for Rehearing of LADPW at 9 (emphasis in original).

[74]88 F.3d at 1151.

jurisdictional sales of gas.[75] As the very next clause of NGA section 1(b) addresses the sale of natural gas for resale in interstate commerce, it seems impossible that the court would not have found such sales to fall within the Commission's subject matter jurisdiction, just as interstate transportation does.

As the July 25 Order stated, the court ruled "the Commission's jurisdiction attaches to the subject of the capacity release transaction: interstate transportation rights," regardless of whether the Commission had jurisdiction over the particular participants in the transactions.[76] The comparable provision to NGA section 1(b) is FPA section 201(b)(1), which defines FERC jurisdiction as extending "to the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce."

Here, the subject of the California PX and ISO spot market transactions, the sale of electric energy at wholesale in interstate commerce, is likewise a matter explicitly within the Commission's jurisdiction under FPA section 201(b)(1). Accordingly, the Commission can act to assure that the just and reasonable standard is applied to the market clearing prices for all transactions in those markets, as such protection lies at the heart of the Commission's ratemaking responsibilities under the FPA. Under UDC, all sellers, including governmental entities, into those markets were subject to and had to abide by FERC regulation of those prices (as well as all other aspects of the rates and conditions affecting them) because the sales are within our FPA jurisdiction.

The payment of refunds cannot be differentiated analytically from other rate conditions that limited the manner in which all sellers could transact sales in those markets. Refunds, under FPA section 206(b), are, like other rate conditions, a means to limit the prices that can be charged consistent with the just and reasonable standard. All rate conditions imposed by the Commission in the California spot markets limited the amount of money that any seller could retain from a sale into those markets.[77] All sellers

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[75]The Commission disagrees with LADWP's characterization of the sales in the instant matter as non-jurisdictional.

[76]96 FERC at 61,512 (citing 88 F.3d at 1152).

[77]For example, the markets originally used a single price auction system under which the highest price bid and accepted set the clearing price for all sellers. The Commission then instituted a $150/MW breakpoint above which any sales would not set a market clearing price. "The $150 breakpoint thus represents a limitation on the single price auction format of the CalPX spot markets." California Power Exchange Corp., 345

(continued...)

in those markets, both governmental and non-governmental, accepted without challenge other rate conditions, as originally established and subsequently modified, that limited the terms under which those sales could be made. It follows that all sellers in those markets must comply with our refund conditions.

Parties try to distinguish UDC on grounds that "the NGA does not have a specific, express exemption for municipalities like that in Section 201(f) of the FPA."[78] Others suggest that our prior rulings finding governmental agencies not subject to our jurisdiction preclude reliance on UDC. Again, we find no support for these views in that case. The court in UDC accepted the municipalities' statement that they "are exempt from the Commission's jurisdiction under the NGA."[79] In addition, the court recognized that the Commission had "twice rejected the suggestion that it should invoke its transportation jurisdiction over municipalities."[80] Thus, as presented, the underlying issue in UDC is essentially identical to the issue presented here despite the difference in statutory language.

As the court stated, "notwithstanding" the statutory exemption and prior agency decisions to the contrary, "FERC may, consistent with the NGA, require municipalities to comply with the capacity release regulations."[81] The key factor again was that "FERC's transportation jurisdiction extends as a separate matter over capacity release given the involvement of interstate pipelines."[82] Likewise, here, the involvement of jurisdictional public utilities (the PX and ISO), whose role, like the pipelines' role in UDC, "is absolutely central, and the transaction itself controls access" to the interstate wholesale sale of electric energy in the California spot markets at issue, gives us subject matter jurisdiction "entirely independent of the jurisdictional nature" of the entities selling into

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[77](...continued)
F.3d 1110, 1118 (9th Cir. 2001).

[78]See, e.g., Request for Rehearing of Bonneville at 18; see also Request for Rehearing of M-S-R at 6 (same).

[79]88 F.3d at 1153 (emphasis added).

[80]Id.

[81]88 F.3d at 1154.

[82]Id. (first emphasis added; second in original).

the markets at issue.[83] Thus, the presence of FPA section 201(f) does not change the analysis or the result in addressing whether we have subject matter jurisdiction over all sales involved.

It is asserted that the "issue in this case is the Commission's rate authority under sections 205 and 206 of the FPA," not jurisdictional issues as was true in UDC.[84] But this fails to acknowledge the importance of a threshold jurisdictional ruling. If we lack jurisdiction under FPA section 201(b)(1), then the issue of the Commission's rate authority under sections 205 and 206 never arises. In any event, the substantive statutory provision in the UDC case, like that in this case, concerned the Commission's ratemaking authority.[85]

It is also asserted that reliance on UDC is nothing more than an effort to avoid a regulatory gap[86] or to effectuate policy based on equitable considerations. In this respect, it is charged that avoiding a regulatory gap "is a subject for Congress, and not the Commission . . . to address," and that policy determinations are irrelevant to the statutory question at hand.[87] That is not the teaching of the case law, which "counsels inquiry into the necessary consequences of [whether otherwise nonjurisdictional sales should be subject to the federal plan] in terms of the scope of federal and state regulatory authority in the premises."[88]

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[83] Id.

[84] See Request for Rehearing of Bonneville at 5-6.

[85] See UDC, 88 F.3d at 1154 n. 65 ("in instituting the capacity release program, the Commission legitimately invoked its authority under NGA section 5," which is the counterpart of FPA section 206).

[86] In this respect, we wish to clear up a potentially confusing statement in the July 25 Order, 96 FERC at 61,512, where it was stated that California "declined to regulate California non-public utilities' sales in the California centralized ISO and PX spot markets." California is, of course, free to regulate or not to regulate sales within its jurisdiction. The sales at issue, however, are sales for resale in interstate commerce via a single price auction that is implemented by public utilities pursuant to tariffs within this Commission's exclusive jurisdiction.

[87] See Requests for Rehearing of AEPCO at 9; Southern Cities at 11.

[88] FPC v. Louisiana Power & Light Co., 406 U.S. 621, 632 (1972). See also, e.g.,

(continued...)

iv. Retroactivity

With regard to the July 25 Order's discussion of retroactivity, various parties challenge the relevance of the retroactivity principle to the instant situation, as well as the Commission's application of the five-part test for determining whether an adjudicatory ruling should be applied retroactively.[89]

As stated in the July 25 Order, under the retroactivity principle, adjudications are to be given retroactive effect for similarly situated parties.[90] It is argued that the principle is irrelevant here because similarly situated parties are not involved. According to Bonneville, the retroactivity principle would apply if in one case, the Commission announced a new rule of law that a "governmental seller" must pay a refund, then in another pending case, that new rule could be applied to a different "governmental seller."[91] But, here, "there is no particular litigant before the Commission," and thus the principle does not apply.[92] That analysis ignores a basic point we have repeatedly made: sales through the markets operated by the jurisdictional ISO and PX, not parties, are the subject matter of this proceeding.

In the July 25 Order, the Commission found that all sales priced above certain levels in the ISO and PX spot markets were unjust and unreasonable, and ordered refunds to remedy receipt of amounts above the just and reasonable level. Viewed from

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[88](...continued)
West v. Gibson, 527 U.S. 212, 218 (1999)("Words in statutes can enlarge or contract their scope as other changes, in the law or in the world, require their application.").

[89]See, e.g., Requests for Rehearing of AEPCO at 10-13; LADWP at 12-15; Bonneville at 18-20.

[90]96 FERC at 61,513 (citing Harper v. Va. Dept. of Taxation, 509 U.S. 86, 94-95 (1993) ("the fundamental rule of retrospective operation that has governed judicial decisions for near a thousand years")). See James B. Beam Distilling Co. v. Georgia, 501 U.S. 529, 537 (1991) ("selective prospectivity also breaches the principle that litigants in similar situations should be treated the same"); see also Nat'l Fuel Gas Supply Corp. v. FERC, 59 F.3d 1781, 1789 (D.C. Cir. 1995)(same).

[91]Request for Rehearing of Bonneville at 20.

[92]Id. at 21. Bonneville also claims the proceeding "partakes more of rulemaking than adjudication," and thus can be applied only prospectively. Id. As was discussed in the July 25 Order, 96 FERC at 61,513-14, and again below, this case is an adjudication.

this perspective, all sales for resale in the California PX and ISO spot markets are similarly situated, regardless of whether they were made by governmental or non-governmental sellers. Under the single price auction method, where all sellers received the highest price bid and accepted, it would be impossible to reach any other conclusion. In some cases, we assume that the price received by all sellers under the auction format resulted because a non-governmental seller bid the highest price accepted. In other cases, we assume the price received by all sellers resulted because a governmental seller bid the highest price accepted. In other words, the amount of the highest bid accepted, not the identity of the bidder, controlled the price received by all sellers.

In those circumstances, all sales are similarly situated, as are all sellers with regard to what price they received in any individual sales transaction.[93] Given this similarity, there is no reason for selective prospectivity with governmental sellers being free from refund obligations related to sales for which they received the exact same prices as did non-governmental sellers when those prices have been determined, as here, to be unjust and unreasonable. Accordingly, the retroactivity principle counsels that refund obligations apply to all sellers.

Another set of challenges contends that under a test for determining if retroactivity is appropriate that retroactive application to governmental entities fails on all five counts.[94] Those challenges largely hinge on whether the situation presents a case of first impression, as found in the July 25 Order.

The challengers claim this is not a case of first impression, resting on a view that "Congress decided the matter in 1935,"[95] or that the Commission "overlooks a history of

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[93] Bonneville's example might be apt if there were two markets operating. In one, only governmental sellers participated, while in the other only non-governmental sellers participated, and the two markets showed wholly different pricing patterns. In that hypothetical, a finding that prices in the non-governmental market were unlawful might not be immediately applicable to the governmental market. But the California PX and ISO spot markets did not consist of separate markets for governmental and non-governmental sellers; rather, both types of sellers transacted under the same set of rules and received the same price for a particular sale.

[94] See, e.g., Request for Rehearing of LADWP at 12. See Williams Natural Gas Co. v. FERC, 3 F.3d 1544, 1553-55 (D.C.Cir. 1993).

[95] See Request for Rehearing of LADWP at 13.

more than 50 years,"[96] or a history of "over thirty years,"[97] during which the Commission did not assert jurisdiction over governmental entities. To reiterate, the July 25 Order asserts jurisdiction over sales for resale in interstate commerce that occurred during the relevant time period in the California PX and ISO spot markets, not over governmental entities. But that aside, the challenges reflect a view that the FPA is static and rigid, rather than dynamic and flexible, in the face of new factual circumstances. That is not the law.

The July 25 Order found this to be a case of first impression because "the Commission had never dealt with market-wide refunds in a single price auction for widespread centralized spot purchases of wholesale electricity in interstate commerce."[98] The challengers' assertion that this situation did "not suddenly convert this question into one of first impression,"[99] ignores the teaching from the earliest cases that agencies must be able "within the ambit of their statutory authority, to make the pragmatic adjustments which may be called for by particular circumstances."[100] Thus, the particular circumstances present here are critical to determining how the FPA should be applied.

Defining the appropriate regulatory response cannot be divorced from the particular circumstances facing the Commission.[101] More recently, the Ninth Circuit looked at the particular circumstances facing the Commission in the California markets to find that while "FERC's termination of CalPX's rate schedules was perhaps unprecedented, we are not convinced that FERC lacks authority under section 206(a) of the FPA to address the structural flaws of a market-based rate regime through the

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[96] See Request for Rehearing of Bonneville at 21.

[97] See Request for Rehearing of AEPCO at 11.

[98] 96 FERC at 61,514.

[99] See Request for Rehearing of Bonneville at 21.

[100] FPC v. Natural Gas Pipeline Co., 315 U.S. 575, 586 (1942)(emphasis added).

[101] See, e.g., Permian Basin Area Rate Cases, 390 U.S. 747, 774-77 (1968) (rejecting challenges that adoption of area rates exceeded the Commission's NGA authority, was inconsistent with the statutory language, and prior Court decisions on grounds that Congress gave adequate authority "to achieve with reasonable effectiveness the purposes" underlying the statutory grant).

termination of a public utility's wholesale tariff and rate schedules in circumstances such as these."[102]

Thus, the FPA cannot be interpreted in a vacuum, but must be adapted to fulfill its purposes as specific circumstances require. As the Commission has never interpreted how the FPA should be adapted to fulfill its purposes in the particular circumstances here, which reflect a new ratemaking paradigm, this case is one of first impression.

On the second criterion, the challengers claim that the July 25 Order represents an abrupt departure from well-settled law, rather than an effort to fill a void in an unsettled area of law.[103] But, as noted above, the Commission has never addressed the legal question of how refunds should apply in these particular circumstances, and thus the ruling is properly seen as an effort to fill a void in an unsettled area. All challengers point to our March 9 Order, which stated, "[t]he Commission has no authority to order [governmental] sellers to make refunds" as well as to the acknowledgment in the July 25 Order of similar statements. In the context of this case, the March 9 Order does not constitute well-settled law. Not only was the Order subject to numerous rehearing requests, but also it was in place for only four months before issuance of the July 25 Order, which, upon further analysis and consideration, changed many other aspects of the March 9 Order's refund proposal.

The challengers place the remaining criteria together to claim that they reasonably relied on "sixty-six plus years of unbroken precedent,"[104] and that they were "not subject to Commission regulation."[105] But, again, the Commission is not asserting jurisdiction over them, but only over the interstate sales for resale that they made in the California PX and ISO spot markets, which were established and regulated entirely under Commission FPA authority. As early as the August 23 Order responding to complaints that sales in those markets might exceed the just and reasonable standard, and well before the October 2 refund effective date, governmental and non-governmental sellers were aware that possible remedies for all sales violating that standard in those markets included refund liability.

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[102]California Power Exchange, 245 F.3d at 1122 (emphasis added).

[103]See, e.g., Request for Rehearing of LADWP at 13.

[104]See Request for Rehearing of LADWP at 14.

[105]See Request for Rehearing of Bonneville at 23.

We see no reason that reliance on generalized statements related to wholly different situations should prevail over a clear indication of what our course would be in the particular circumstances at issue. Likewise, it is not an undue burden for governmental sellers to refund amounts received over and above the just and reasonable prices allowed by the Commission for these sales. Under the single price auction format, governmental sellers could expect no higher price than what all other sellers received for the same transactions, and under the FPA, that price could not exceed the just and reasonable standard. Selective prospectivity, as the challengers propose, flies in the face of the FPA's primary statutory interest of preventing exploitation of consumers. Accordingly, retroactive application of refund obligations for all sellers is favored here.

vi. Adjudication v. Rulemaking

Several governmental entities contend that this proceeding, as it relates to governmental entities, is more of a rulemaking than adjudication.[106] For example, NCPA argues that the July 25 Order represented a significant departure from an established policy. NCPA asserts that such a shift in policy, without notice or opportunity for affected parties (e.g., municipals) to comment, violated the rulemaking requirements of the Administrative Procedure Act. It contends that the jurisdictional expansion constitutes a rulemaking under 5 U.S.C. section 551(a), because it is an agency statement of general applicability and future effect designed to implement, interpret, or prescribe law or policy relating to future rates, valuations, and costs. NCPA also contends that the July 25 Order violates municipalities' procedural due process rights.

This case involves the extent to which refunds are owed for sales made in the California PX and ISO spot markets for a defined past period. In view of this, the case involves an adjudication, consistent with the terms of 5 U.S.C. § 551(6) and (7). The 1947 Attorney General's Manual on the Administrative Procedure Act (at 14) states that "adjudication is concerned with the determination of past and present rights and liabilities." Clearly, that is what is involved here.

In addition, our ruling here is based on specific past events in the California ISO and PX spot markets. It is highly unlikely that those same circumstances will be repeated or, if they are, that they will reoccur on a widespread basis. Accordingly, there is no reason for the Commission to formulate a policy to cover that eventuality. Nor do we see any due process problems with the approach that we have taken. The July 25 Order explained in detail the reasons for our decision. Parties have addressed those reasons in

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[106] See, e.g., Requests for Rehearing of NCPA, Bonneville, APPA.

their rehearing requests and presented their countervailing arguments. Those arguments have been fully considered and addressed in this order. No further procedure is needed to ventilate these issues.

Accordingly, the requests for rehearing based on claims that the issues presented must be resolved through rulemaking are denied.

b. Applicability to QFs

On rehearing of the June 19 Order, QFs oppose application of the price mitigation plan to QFs because it purportedly violates their statutory protections.[107] Nevada IEC/CC Washington maintain that the must-offer requirement conflicts with PURPA which established contracts governing the QF output sales, conflicts with prior Commission decisions which exempted QFs from regulation under section 206 of the FPA, conflicts with delivery obligations under QF purchase agreements with UDCs, and conflicts with QF obligations to thermal hosts.[108]

Several parties contend on rehearing of the June 19 Order that the must-offer requirement should not apply to QF capacity committed under a contract to a utility and that the requirement should not obligate a QF to breach its delivery obligations under an existing power purchase agreement.[109] Oversight Board also requests that the Commission clarify that a QF will be subject to the must-offer requirement only to the extent the QF's contract permits third-party sales.

On rehearing of the July 25 Order, NIEP and CCW argue that PURPA and the Commission's regulations implementing it reflect a legislative intent that QFs will be regulated through avoided cost rates and contracts approved by state commissions and not through traditional ratemaking regulation under section 206. Further, they contend that applying the mitigation plan to QFs would confuse or interfere with the QF's delivery obligation under power purchase agreements with their utility distribution company (UDC). NIEP and CCW argue that the June 19 Order was targeted at those generators who can decide when to generate, to whom to sell and at what price. They contend that those decisions are preempted in the case of QFs by their agreements with their thermal host and with their UDC. Assuming that QFs are covered by the June 19

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[107] See, e.g., Request for Rehearing of Nevada IEC/CC Washington.

[108] See Request for Rehearing of Nevada IEC/CC Washington. See also Request for Rehearing of Oversight Board.

[109] See, e.g., Requests for Rehearing of Calpine Corporation and Oversight Board.

Order, NIEP and CCW maintain that the price mitigation directive in the July 25 Order would require a review of QFs' costs, which is contrary to Order No. 69 in which the Commission rejected cost-of-service regulation of QFs. They also argue that it would be contrary to PURPA, 16 U.S.C. § 824a-3. They assert that although a QF may voluntarily accept some rate other than its avoided cost, if the QF is compelled to sell rather than voluntarily offer, the QF is entitled to full avoided costs.

CAC reasserts the same arguments it made on rehearing of the April 25 Order.

Commission Response

As part of the Commission's efforts to alleviate the severe electric energy shortages facing California and the West, the Commission took a number of actions, including several related to QFs. Among them, the Commission granted temporary waiver of the technical regulations relating to QF status through April 30, 2002.[110] The waivers were intended to facilitate the sale of "excess QF power."[111] Sales pursuant to the waivers were to be pursuant to negotiated bilateral contracts[112] and were to be made

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[110] See December QF Order at 61,773; December 15 Order at 62,018; and Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States, 94 FERC ¶ 61,272 at 61,970-71 (2001) (March 14 Order); Further Order Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States, 95 FERC ¶ 61,225 (2001).

[111] "Excess QF power" was defined as power above what has been historically sold from a facility to the purchasing utility. A facility's seasonal average output during the two most recent years of operation will define historical output. See December QF Order. See also Order Granting Motions for Emergency Relief in Part and Deferring Action on Other Aspects of Motions and Proposed Order Under Section 201(d) Directing Interconnections with Qualifying Facilities and Establishing Further Procedures, 95 FERC ¶ 61,226 at 61,782-83 (2001) (May 16 QF Order).

[112] December QF Order at 61,773.

if consistent with the contractual obligations to purchasing electric utilities[113] and to thermal hosts.[114] Our July 19 and July 25 Orders were issued in this context.

There is no merit to the QF-related arguments made on rehearing. First, as to the arguments that QFs are being compelled to make sales inconsistent with their obligations to either purchasers of their electric or thermal output, the July 19 Order explicitly stated that the Commission was not ordering QFs to make sales that were inconsistent with contractual obligations, whether the contractual obligations were to electric utilities or to thermal hosts. Thus, the order presents no conflict with delivery obligations either to utilities or thermal hosts. We will, however, modify the previous waivers of the Commission's technical requirements (18 C.F.R. §§ 292.204 and 292.205 (2001)) to extend the waivers from April 30, 2002, until the end of that calendar year, i.e., until December 31, 2002. We do this because, under our regulations, compliance with the technical requirements for QF status is measured on a calendar year basis, and the extension of the waiver will thus make the waiver consistent with how compliance with our regulations is measured. The extension removes any doubt that a QF, which makes sales prior to April 30, 2002 pursuant to the waiver already granted, will maintain QF status without having to alter operations to bring their operations into compliance with the technical requirements for QF status for the calendar year.

Regarding the argument that our orders are inconsistent with the exemption granted to QFs from certain requirements of the FPA, as we noted in the June 19 Order, QFs are public utilities that are subject to the Commission's jurisdiction. Pursuant to PURPA, they have been exempted from many of the requirements of the FPA and other federal and state legislation. When we imposed the must-offer requirement, we chose not to extend the exemptions already granted to QFs to this new requirement and thus did not exempt the QFs from the must-offer requirement. We did this because of the need for uniformity among sellers and the great need for additional power supplies. No arguments have been raised on rehearing that would cause us to reach a different result.

Regarding arguments that our orders will compel sales at prices inconsistent with PURPA, we disagree. QFs that operate under this regimen will not be compelled to make sales inconsistent with the pricing provisions of PURPA. The QFs' primary sales

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[113] May 16 QF Order at 61,788 & n.18 (where a purchasing utility and a QF do not agree that there is "excess QF capacity" the issue is to be determined by a state court and may require permission of the bankruptcy court).

[114] June 19 Order at 62,553 (the must-offer requirement applies to energy that is available from generation that is not already contractually committed and would not violate its contractual obligation to its thermal host).

remain sales pursuant to contracts with purchasing utilities with either negotiated rates or rates set by a state commission. Those rates are consistent with our regulations implementing PURPA.[115] The vast majority of the remaining sales will take place pursuant to negotiated bilateral contracts, which are also consistent with the Commission's regulations under PURPA.[116] Any remaining sale (where a QF, which was not relying on the waivers to make a sale and thus was not required to enter into a bilateral contract to make such sales, but was contractually free to make a sale and thus subject to the must-offer requirement) would take place at the price the purchasing utilities are paying other sellers for similarly available electric energy (i.e., the purchasing utilities' avoided cost); those sales would also be consistent with the Commission's regulations under PURPA.[117]

c. Applicability to Marketers

i. June 19 Order

On rehearing of the June 19 Order, marketers strongly oppose the requirement that they be price takers. For example, Enron argues that precluding cost justification filings based on marketers' own costs is arbitrary, potentially confiscatory and unsound policy and will prevent marketers from participating in WSCC spot markets, thereby degrading liquidity and reliability, and leading to increased costs for the consumer.[118]

Allegheny contends on rehearing that the mitigation plan prevents marketers from bidding and prohibits reasonably incurred costs from being included in such justification;[119] that the June 19 Order has a discriminatory impact on power

[115] See 18 C.F.R. §§ 292.301- 292.304 (2001).

[116] See 18 C.F.R. § 292.301 (b) (2001).

[117] See 18 C.F.R. § 292.101(b)(6) (Avoided costs means the incremental costs to an electric utility of electric energy . . . but for the purchase from the qualifying facility or qualifying facilities, such utility would . . . purchase from another source).

[118] See also Requests for Rehearing of Idacorp, Mirant, IEP, PPL, and Sempra Trading.

[119] See also Requests for Rehearing of Avista Energy, BP Energy, El Paso.

marketers;[120] and that there is no evidentiary support for making all marketers become price takers in spot markets and allowing only generators to submit cost support.[121] El Paso asserts that this requirement is inappropriate where the Commission did not find evidence that power marketers had or exercised market power. BP Energy contends on rehearing that if a marketer purchases power in a bilateral transaction that is not a spot market transaction, then the purchase price is not mitigated but the sales price is mitigated. EPSA contends that the requirement that marketers be price takers disregards the benefits power marketers provide.

Allegheny and Avista Energy request clarification of the June 19 Order that any entity that owns or controls generation and engages in marketing through a portfolio of physical and contractual resources should be governed by the same rules applicable to generators.[122] Calpine seeks clarification that marketing affiliates of generators are not price takers and that marketer-to-marketer transactions (i.e., those transactions not involving an LSE or the ISO, the costs of which may be passed through to ratepayers) are exempt from the requirement to be price takers.

Duke requests clarification that marketers as price takers can receive their bid price up to the mitigated Market Clearing Prices,[123] stating that the ISO has taken the view that marketers are not only prohibited from bidding above the mitigated Market Clearing Prices but are also prohibited from setting the market clearing price when the market clears at a level below the mitigated Market Clearing Prices. Mirant requests on rehearing of the June 19 Order that the Commission allow marketers and other sellers to justify prices above the mitigated price based on the cost of purchased power, subject to Commission oversight for potential affiliate abuse.

El Paso states that the June 19 Order creates uncertainty as to whether or not marketers whose bids during reserve deficiency hours are subsequently determined to be above the mitigated reserve deficiency MCP will be required to consummate the sale at the reduced price.

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[120] See also Request for Rehearing of Avista Energy.

[121] See also Request for Rehearing of El Paso.

[122] See also Request for Rehearing of Calpine.

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

Enron requests clarification that marketers that fulfill functions normally provided by a Scheduling Coordinator for a specific generator, or otherwise act as the generator's agent, or as a toller,[124] will not be treated as marketers and should be allowed to file justification to recover costs incurred in excess of the mitigated Market Clearing Prices.

Southern Cities requests clarification that LSEs who resell excess energy under long-term contracts entered into prior to June 19, 2001 will not be treated as marketers and therefore will not be required to sell this excess energy at prices less than their costs to acquire such energy.

PG&E requests clarification that marketers are price takers in all hours in which they sell into the spot market. PG&E also requests clarification that hydroelectric generation, like sales by marketers, will be price takers in all hours. According to PG&E, the June 19 Order provides that marketers must bid as price takers, but then provides that marketers cannot bid higher than the mitigated Market Clearing Prices. PG&E requests that the Commission fix this ambiguity so that sellers with higher cost units will still be able to bid or demand prices that reflect their running costs, but marketers will not be able to increase those prices further.

Commission Response

To prevent the use of megawatt laundering[125] as a strategy for evading potential mitigation, the June 19 Order prohibited marketers from bidding a price higher than the mitigated reserve deficiency MCP. Thus, marketers were required to be price takers. The Commission reasoned that "[t]his will still provide marketers with an opportunity to earn a reasonable return on purchased energy, since the mitigated price is established by the marginal costs of the last unit dispatched and this price will be above the costs of the generators from which the marketers obtain their portfolio of energy."[126] Due to their multi-purpose limitations, hydroelectric generators are not subject to the must-offer

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[124]Enron defines tollers as entities that provide the fuel to a generator in exchange for some or all of the power output from the generator.

[125]As explained in the June 19 Order, megawatt laundering occurs where a generator sells power to an out-of-state marketer who then reimports that power to avoid a mitigated price.

[126]June 19 Order at 62,564.

obligation.[127]. Hydroelectric generators, however, are price takers during the hours in which they choose to participate in the spot market.

The Commission now clarifies 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 that choose to participate in the real-time spot markets by reselling excess energy that they themselves did not generate.

Due to the difficulty of tracing energy back to the generating source to determine the heat rate and gas prices of the source, especially if multiple sources are used, the June 19 Order precluded marketers from justifying costs above the mitigated reserve deficiency MCP. This restriction was imposed to prevent marketers from circumventing the Commission's price mitigation measures. The Commission will continue to preclude marketers from submitting justification for transactions above the mitigated Market Clearing Prices.

The Commission rejects marketers' contention that requiring them to be price takers will prevent them from recovering reasonably incurred costs. Under the mitigation plan, marketers are not subject to the must-offer requirement and therefore are not required to bid into the real-time spot markets if they believe they will not recover their purchased power or other costs. The real-time market is the last opportunity to resell energy and the only alternative is to allow the resource to be unused with no revenue recovery.

The Commission denies clarification that marketers that own or control generation and engage in marketing through a portfolio of resources, or that perform scheduling or tolling functions on behalf of generators, will be treated as generators; they must be price takers. By contrast, entities that are able to trace a transaction to a specific generating unit will be treated as generators. With respect toCalpine's request for clarification, the Commission will require marketing affiliates of generators to be price takers. Furthermore, marketer-to-marketer transactions in the bilateral spot market 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.

[127]See April 26 Order at 61,357.

We deny Southern Cities' request for clarification that LSEs that resell excess energy under long-term contracts entered into prior to June 19, 2001 into the real-time spot markets will not be treated as marketers. LSEs that choose to resell excess energy acquired under long-term contracts into the real-time spot markets will be price takers.

We will not address the argument that sellers of hydroelectric power should be permitted to recover opportunity costs, because hydroelectric power is not subject to the must-offer requirement. If these sellers do not believe that they will recover their costs during any particular time period, because they prefer to save their resources to maximize the value of the hydroelectric power, they need not offer their power for sale. However, if they do offer their power for spot market sales, they are subject to price mitigation.

ii. July 25 Order

Marketers object to the holding in the July 25 Order that they, as price takers, may not justify transaction prices above the mitigated Market Clearing Prices. Mirant asserts that, applied on a retroactive basis, the prohibition is illogical (punishing marketers for behavior that enhances market liquidity), potentially confiscatory, and unjustifiably discriminatory as between generators and marketers. Portland General also objects to the discrimination that results from requiring non-generators to "take" a fictional price while permitting other market participants to justify their actual price.

On rehearing of the July 25 Order, EPSA raises marketers' concerns that ordering refunds from them based on a Proxy Price set by a generator is inappropriate, noting that marketers' costs have nothing to do with the operating costs of particular generating units. Because marketers manage their operations on a portfolio basis, EPSA argues that it is not reasonable to consider each specific transaction when determining whether a marketer made sales above prices that a competitive market would yield. Finally, EPSA asserts that, although marketers may be able to change their future decisions based on the Commission directives, "power markets do not provide an opportunity to retroactively change completed transactions."[128]

The Marketer Group contends on rehearing of the July 25 Order that the Commission erred when it refused to consider evidence that refunds of marketers' charges that exceed generators' operating costs will yield rates that are confiscatory. The Marketer Group continues that, while marketers accept the risk of not making a profit for certain transactions, "they should not be required to accept the risk of unlawful

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[128]Request for Rehearing of EPSA at 29.

regulatory confiscation after-the-fact."[129] Avista does not dispute the Commission's imposition of refund liability on marketers, but contends that the Commission erred in applying a Proxy Price developed for generators that failed to account for the "unique cost issues" facing power marketers.

The Marketer Group also challenges the failure of the Commission in the July 25 Order to consider the characteristics of sellers of hydroelectric power, i.e., not accounting for the opportunity costs involved in hydro generation. The Marketer Group explains that hydroelectric generators offer their resources at the expected summer price, and asserts that marketers with hydro-based portfolios will follow the same pricing strategy.

Commission Response

While it is true that marketers have not yet been provided an opportunity to justify bids above the mitigated Market Clearing Prices for transactions that occurred during the refund period, or to submit evidence that the refunds are confiscatory, this is true for all sellers. Thus, the policy does not discriminate against marketers. The July 25 Order established an evidentiary hearing limited to the collection of data needed to apply the refund methodology. During the hearing, parties do not have an opportunity to submit additional evidence. However, as explained further below,[130] the Commission will provide an opportunity after the conclusion of the refund hearing for marketers to submit cost evidence on the impact of the refund methodology on their overall revenues over the refund period. For the Commission to consider any adjustments, marketers will have to demonstrate that the refund methodology results in a total revenue shortfall for all jurisdictional transactions during the refund period. The Commission will consider such submissions in light of the regulatory principle that sellers are guaranteed only an opportunity to make a profit. To the extent we stated in the July 25 Order that we would not allow such a showing regarding sellers' purchased power costs,[131] we grant rehearing. We will also allow sellers of hydroelectric power to demonstrate the impact of the refund methodology.

This modification should satisfy marketers' concerns. Marketers are not being treated differently from generators. They will have an opportunity to offer evidence that

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[129] Request for Rehearing of Marketer Group at 27.

[130] See infra, section F.

[131] See July 25 Order at 61,518.

their revenues are less than their total costs.[132] Demonstrations related to those reselling purchased power or selling hydroelectric power must also show the impact on all transactions from all sources during the refund period.

d. Applicability to DWR and OOM Transactions

Several parties argue that DWR's spot market purchases should be included in refund determinations.[133] They argue that DWR's spot market purchases were made in the same dysfunctional market in which ISO out-of-market (OOM) purchases were made and like ISO OOM purchases were made at extremely high prices that are unjust and unreasonable. Since the Commission determined that ISO OOM purchases are subject to refund, they argue that there is no rational basis to treat DWR's purchases differently. Further, they contend that DWR did not voluntarily enter into transactions outside the ISO because the Commission terminated the PX Tariff and imposed a penalty on underscheduled load and sellers refused to offer supply through the ISO's real-time market. Thus, they assert that the sellers and DWR had unequal bargaining positions. They argue that it was unlawful for the Commission to find that an imbalance of supply and demand provides sellers with market power and attempt to force customers to purchase 95 percent of their electricity in the forward market[134] – while refusing to mitigate sales in the forward market or to provide refunds for such sales when they are clearly unjust and unreasonable.

With regard to DWR's access to the ISO's control room, California Parties contend that, when DWR became the only creditworthy California purchaser, it was not unreasonable for DWR to need and obtain access to the ISO's trading floor. Further, they assert that this proceeding concerns rates charged by sellers, but the ISO and DWR are customers and would be entitled to just and reasonable rates even if the Commission believed that they had engaged in improper conduct.

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[132] In keeping with EPSA's comment that it is not reasonable to consider each specific transaction, the Commission will consider the impact on a marketers' entire portfolio of transactions over the duration of the refund period.

[133] See, e.g., Requests for Rehearing of California Parties, ISO, PG&E, Oversight Board.

[134] Forward markets are defined as markets with transactions with a future delivery that are entered into more than 24 hours before commencement of service. See June 19 Order at 62,546, n.9.

PG&E argues that this proceeding has not been limited to the centralized ISO and PX markets. Rather, PG&E argues that the Commission has been addressing all transactions in California wholesale markets.[135]

Puget/Avista object to the Commission making ISO OOM spot market purchases subject to refund because the decision is not supported by the record and is inconsistent with the treatment of DWR bilateral transactions. Others argue that these sales should not be subject to refund because OOM sales do not involve sales into either the ISO's or PX's markets; rather, they are bilateral transactions that arise out of a separate authorization under the ISO's tariff for the purpose of assuring grid reliability.[136] Portland General also points out differences between the ISO's centralized auction market, where the price is set by the highest bid dispatched, and its OOM transactions, which are freely negotiated. Portland General asserts that OOM transactions are much more like DWR's, which the Commission determined are not subject to refund, and states that the Commission made no specific findings that rates for OOM transactions were unjust and unreasonable.

The Marketer Group also argues that, to the extent that OOM sales were made subject to refund, it was not pursuant to the August 23 or November 1 Orders; rather, it could only have been pursuant to the April 26 Order which established a refund effective date of July 2, 2001 for all sales in the WSCC generally. Thus, the Marketer Group argues that the determination in the July 25 Order to make OOM purchases subject to the October 2, 2000 refund effective date violated section 206 of the FPA.

On August 30, 2001, as corrected on November 13, 2001, CARE filed a motion seeking an order canceling or suspending DWR's long-term energy contracts and associated IOU rate schedules on the basis that they were not properly filed by DWR pursuant to the FPA. CARE bases its motion on the contention that DWR is acting as a "designated representative" as described in 18 C.F.R. § 35.1(a), because of actions that DWR has taken before the California Commission. Mirant filed an answer in response to the motion asserting that the DWR contracts to which it is a counterparty need not have

[135]As an example, PG&E cites the November 1 Order, 93 FERC at 61,370 ("if the Commission finds that the wholesale markets in California are unable to produce competitive, just and reasonable prices, or that market power or other individual seller conduct is exercised to produce an unjust and unreasonable rate, we may require refunds for sales made during the refund effective period.").

[136]See, e.g., Requests for Rehearing of Marketer Group, Nevada IEC/CC Washington, CAC.

been filed because Mirant, as a power marketer with no generating assets, is not required to file service agreements.

Commission Response

The Commission disagrees with the arguments for extending refund liability to include DWR transactions. DWR transactions are negotiated bilateral contracts for the procurement of energy on behalf of California IOUs, and are distinctly beyond the realm of ISO and PX centralized market operations that have been the subject of this proceeding since its inception. Whether or not DWR could have conducted its transactions through the ISO is immaterial. In addition, although some of DWR's contracts may have been in the spot market, most were not; indeed, the intent of DWR's involvement in the market was to enter into longer-term contracts. PG&E's selection of a single reference to "California wholesale markets" not specifically limited to spot markets operated by the ISO and PX ignores the dozens of other references prior to, subsequent to, and within, the November 1 Order that acknowledge the limited scope of the proceeding. For example, on the first page of the November 1 Order, the Commission indicated its finding that the California electric market structures and market rules, "in conjunction with an imbalance of supply and demand in California, have caused, and continue to have the potential to cause, unjust and unreasonable rates for short-term energy (Day-Ahead, Day-of, Ancillary Services and real-time energy sales) under certain conditions."[137] No party could reasonably have believed that the Commission intended the proceeding to be broader. As the Commission noted in the July 25 Order, if DWR or another party believes that any of its contracts are unjust and unreasonable, it may file a complaint under FPA section 206 to seek modification of those contracts, assuming the seller is a public utility.

ISO OOM transactions, on the other hand, are purchases for the purpose of maintaining reliability on the ISO-controlled grid and are necessarily purchases of short-term energy. They are contemplated in the ISO Tariff as a backstop to the ISO's auction markets. It is only when the ISO market produces insufficient resources that the ISO must resort to out of market purchases. It follows that if the price in these markets is subject to refund, then the price for the OOM transaction (which is a purchase of last resort in lieu of a market purchase) is subject to refund also. Relatively early in this proceeding, parties sought clarification that OOM transactions would be subject to the reporting and cost justification requirements of the December 15 Order,[138] and the

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[137]November 1 Order, 93 FERC at 61,349, emphasis added.

[138]See, e.g., Requests for Rehearing of the December 15 Order of ISO, PPL. See (continued...)

Commission included OOM transactions when identifying those which were above the monthly proxy market clearing price in the March 9 Refund Order and subsequent notices. The July 25 Order did not expand the scope of the proceeding but merely clarified that the OOM transactions are within suppliers' refund liability. Thus, the appropriate refund effective date for ISO OOM transactions is October 2, 2000, the same date as for all ISO and PX spot market transactions.

In the July 25 Order, we noted the competitive advantage DWR had by virtue of its access to the ISO's control room and trading floor information as a further reason why refund liability should not attach to its transactions. We cannot agree with California Parties that DWR had any legitimate reason to position its employees in the ISO's control room.[139] California Parties fail to demonstrate why it was necessary to grant one market participant -- DWR -- preferential treatment over all other power market participants in order for the ISO to meet its obligations and responsibilities over the transmission grid. DWR is not involved in the operation of the transmission grid and does not need the same information that the ISO needs. As the Commission recently held in a separate proceeding, preferential disclosure to DWR of confidential market information is unacceptable.[140] We also disagree that DWR is merely a customer in these markets; it has an interest in recovering the costs of its purchases from end users.

With respect to CARE's motion seeking suspension of DWR's contracts, we disagree that DWR is a "designated representative" as defined in the Commission's regulations. Section 35.1(a) of the Commission's regulations states that, where two or more public utilities are parties to the same rate schedule, each one must file the rate schedule. An exception to that rule, relied on by CARE, is that "[i]n cases where two or more public utilities are required to file rate schedules . . . such public utilities may authorize a designated representative to file upon behalf of all parties if upon written request such parties have been granted Commission authorization therefor." Initially, we note that DWR's actions in proceedings before the California Commission have no

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[138](...continued)
also comments of Reliant in Docket No. EL01-23-000 at 8 (filed soon after issuance of the December 15 Order, noting that prices for OOM transactions are subject to the Commission's review under the existing price mitigation scheme).

[139]In a status report filed on October 12, 2001, in Docket No. ER01-889-000, the ISO informed the Commission that DWR no longer had access to its control room as of September 1, 2001.

[140]Reliant Energy Power Generation, Inc., et al. v. California Independent System Operator Corp., 97 FERC ¶ 61,215 (2001).

impact on its status here. More fundamentally, a discretionary arrangement between public utilities permitted by the Commission's regulations has no bearing on DWR's status. CARE presents no basis for canceling or suspending DWR's contracts. Accordingly, we will deny CARE's motion.[141]

e. Applicability to Other Transactions

The ISO argues that the exclusion of spot purchases made by the ISO pursuant to DOE orders is at odds with DOE regulations that govern DOE Orders which presume that the ensuing charges will be in conformity with existing Commission standards. The ISO states that 10 C.F.R. § 205.376 explains how rates and charges for services provided under section 202(c)) of the FPA are to be determined, i.e., services provided under section 202(c)) are to be settled in accordance with established Commission formula rates. The ISO asserts that it relied on the rate regime that the Commission had in place at the time, i.e., the $150/MWh breakpoint. PSColorado seeks clarification that out-of-market sales transacted pursuant to DOE orders are not subject to refund. It contends that these transactions are indistinguishable from other OOM transactions with the ISO.

San Francisco and Port of Oakland argue that short-term bilateral contracts should be made subject to refund. They argue that the prices in those contracts were as high and, thus, unjust and unreasonable, as spot market transactions made subject to refund.[142] They also argue that, since the Commission forced market participants to engage in short-term bilateral transactions, equity requires that the Commission make those transactions subject to refund. Port of Oakland also argues that the July 25 Order erroneously focused on the type of contract rather than the level of the rate in determining whether prices are unjust and unreasonable. It argues that the FPA does not make a spot market/bilateral contract distinction, but instead requires that all wholesale power sales be at just and reasonable rates. Port of Oakland also contends that the spot and bilateral markets are part of an integrated California market and should not be treated separately for purposes of refunds. It contends that trading counterparties rely upon spot market indices to determine the prices under bilateral contracts, and if spot market prices are unjust and unreasonable, the basis for bilateral contracts, in turn, is also unjust and unreasonable.

Commission Response

[141] Mirant correctly concludes that its contracts with DWR were not required to have been filed.

[142] See also Request for Rehearing of California Parties at 5-6, describing sellers' purported market power in bilateral markets.

The ISO states that it relied on DOE regulations when entering into transactions pursuant to DOE section 202(c)) orders. However, the FPA itself is the primary authority for determining rates for those transactions, and section 202(c)) provides:

> If the parties affected by such order fail to agree upon the terms of any arrangement between them in carrying out such order, the Commission, after hearing held either before or after such order takes effect, may prescribe by supplemental order such terms as it finds to be just and reasonable, including the compensation or reimbursement which should be paid to or by any such party.

The statute provides no role for the Commission in the event the parties agree on the rates that will apply to the transactions. In the case of the sales at issue here, the parties agreed on the terms and rates for the sales. Thus, the statute provides for no further adjustments. The fact that DOE regulations offered guidance referencing Commission decisions does not change the statutory provisions. Nothing the ISO argues convinces us that these transactions are to be brought within the scope of this proceeding.

We clarify for PSColorado that OOM sales transacted pursuant to DOE orders are similarly not subject to refund. Although the ISO negotiated directly with parties to obtain both types of OOM sales, parties should be able to distinguish between them because of the way they were procured by the ISO. After issuance of an order from DOE for a particular day, the ISO notified specific market participants whose resources were needed the following day to meet forecasted system demand pursuant to the DOE order. Ensuing negotiations would thus have been informed by that notification.

We are not convinced that any other short-term bilateral contracts may be made subject to refund under the July 25 Order. As discussed above, bilateral transactions are beyond the scope of the SDG&E proceeding. SDG&E's initial complaint targeted only sales of energy and Ancillary Services into markets operated by the ISO and the PX, not bilateral sales. Although the Commission found it appropriate after the DOE section 202(c)) order to apply prospective price mitigation to bilateral spot markets in the WSCC, including California,[143] this action was taken as part of the section 206 investigation of the WSCC markets. Imposing refund liability on bilateral transactions in the SDG&E proceeding is not permitted.

f. The October 2, 2000 Refund Effective Date

[143] See June 19 Order at 62,556.

Some parties oppose the establishment of October 2, 2000 as the refund effective date.[144] For example, the Marketer Group argues that the Commission has not addressed EPSA's argument, raised on rehearing of the November 1 Order, that, because the Commission dismissed the remedy sought by SDG&E and initiated a broader investigation, the case was an investigation created by the Commission on its own motion and that the refund effective date should be October 29, 2000, which was 60 days from the date of Federal Register publication of the August 23 Order initiating the broader investigation. According to the Marketer Group, this conclusion flows from the purpose of the 60-day prior notice requirement, which involves giving targets of an investigation reasonable notice. It argues that, for a complaint, the complainant must serve a copy of the complaint on the defendant contemporaneously with the filing of the complaint; thus, it makes sense for the refund effective date to be 60 days from the date the complaint is filed. By contrast, Marketer Group argues that when the Commission initiates a proceeding, it does not serve the potential defendants. Instead, the Commission publishes notice in the Federal Register; thus, the refund effective date is 60 days after Federal Register publication. In either case, Marketer Group argues, the point is to have the 60 days start running on the day the defendant can reasonably be expected to have notice of the magnitude of the charges against it.

Portland General and Reliant argue that refunds for transactions that already have been reported and that did not receive notification of potential refunds within the 60-day review period established in the December 15 Order should be excluded from the refund hearing. Portland General seeks clarification on this issue.

PG&E maintains that the Commission is able to order refunds for the pre-October 2000 period if it determines that it committed legal error in the August 23 Order when it denied SDG&E's request for a price cap. It requests refunds going back to May 2000, or at least back to August 2000.

Commission Response

We deny rehearing concerning the establishment of October 2, 2000 as the refund effective date, as discussed below.

EPSA's argument that the August 23 Order is a rejection of SDG&E's complaint and Marketer Groups' argument concerning notice of the initiation of the Commission's investigation are not persuasive. In denying SDG&E's request for an immediate price cap on all sellers into the ISO and PX markets, the August 23 Order did not dismiss

[144] See, e.g., Requests for Rehearing of Marketer Group, Dynegy.

SDG&E's complaint in Docket No. EL00-95-000. Although the August 23 Order denied SDG&E's request for summary disposition (i.e., the immediate imposition of a price cap) as too narrowly focused on seller conduct and unsupported, based on the facts then available, the August 23 Order nonetheless set the issue of the justness and reasonableness of sellers' rates in the ISO and PX markets for investigation.[145] Further, the investigation initiated in Docket No. EL00-98-000 concerned whether market rules or institutional factors embodied in the ISO's and PX's tariffs and agreements contributed to the unusually high rates and needed to be modified.[146] Thus, the investigation in Docket No. EL00-98-000 did not supersede the rate investigation in the complaint docket; it complemented the rate investigation. The August 23 Order thus established two separate, but related, investigations -- Docket No. EL00-95-000 concerning sellers' rates in the ISO and PX markets and Docket No. EL00-98-000 concerning whether the ISO and PX market rules or institutional factors were flawed and required modification -- and consolidated them for purposes of hearing and decision in view of their common issues of law and fact.

Section 206 of the FPA requires the Commission to establish a refund effective date "whenever the Commission institutes a proceeding under this section."[147] In a complaint proceeding, the Commission may establish the refund effective date anywhere from 60 days after the filing of the complaint to five months from the expiration of the 60-day period. In an investigation initiated on its own motion, the Commission may establish a refund effective date anywhere from 60 days after publication of notice of its intent to initiate a proceeding to five months after the expiration of the 60-day period. The Commission's policy is to establish the earliest refund effective date allowed in order to give maximum protection to consumers.[148] The SDG&E complaint docket involves all sellers' rates in the ISO and PX markets. All sellers receive the market clearing price (unless they successfully justify a bid higher than the mitigated Market Clearing Prices), and all three of the IOUs were required to make their wholesale purchases through the

[145] August 23 Order, 92 FERC at 61,609, Ordering Paragraph (B) (ordering a public hearing in Docket Nos. EL00-95-000 and EL00-98-000) and Ordering Paragraph (D) (consolidating Docket Nos. EL00-95-000 and EL00-98-000 for purposes of hearing and decision).

[146] 92 FERC at 61,605-06.

[147] 16 U.S.C. § 824e(b) (1994).

[148] See, e.g., Indiana Municipal Power Agency v. PSI Energy, Inc., 85 FERC ¶ 61,073 (1998); Canal Electric Co., 46 FERC ¶ 61,153, reh'g denied, 47 FERC ¶ 61,275 (1989).

ISO and PX from October 2, 2000 through January 1, 2001. Any refunds applicable to SDG&E thus would apply to PG&E and SoCal Edison as well. The earliest permissible refund effective date, which afforded maximum protection to consumers, was October 2, 2000.

Marketer Group's argument concerning notice to affected parties of section 206 proceedings rests on the premise that the August 23 Order rejected SDG&E's complaint and that the investigation in Docket No. EL00-98-000 superseded the complaint proceeding. That was not the case, as discussed above. Thus, Marketer Group's argument is not persuasive. Further, the cases cited by EPSA are distinguishable. In Sierra Pacific Power Co.,[149] the Commission addressed two different proceedings – a section 205 filing of one agreement and requests for rehearing of an order accepting another agreement. On rehearing, the Commission reconsidered and determined that the previously accepted agreement should be set for hearing. However, it could not suspend a previously-accepted rate schedule, i.e., it could not, on rehearing, reverse its original decision not to suspend the rates. Rather, it had to set the matter for hearing under section 206 and establish a refund effective date. With respect to EPSA's argument that the Commission did not base the refund effective date upon the date of the protests, we note that the Commission has determined that it will not treat protests as complaints. That has no bearing on this case, however, because SDG&E filed the complaint in this case.[150] Further, although the Commission may not, on rehearing, reverse a decision not to suspend a rate filing, it may change the refund effective date on rehearing of an order establishing the refund effective date. The order establishing the refund effective date was not a final order, as rehearing of that order was available.[151] Requests for rehearing

[149] 86 FERC ¶ 61,198 (1999).

[150] EPSA also cites PacifiCorp, 74 FERC ¶ 61,163 (1996), for the proposition that the Commission established one refund effective date based upon the date of the complaint by customers concerning excessive rates but 60 days after notice of the Commission's further investigation for those rates not otherwise the subject of the complaints filed. That case is not persuasive. As noted above, the SDG&E complaint involves all sellers' rates in the ISO and PX markets. EPSA also cites Vermont Yankee Nuclear Power Co., 91 FERC ¶ 61,235 (2000), in which the Commission initiated a section 206 proceeding from rate concerns raised in a section 203 proceeding. No such facts are presented here. As noted above, the instant proceeding was initiated, in pertinent part, by SDG&E's complaint, which the Commission expressly set for hearing.

[151] See, e.g., Florida Power Corp., 65 FERC ¶ 61,040 at 61,412-13 (1993) ("[J]ust as the decision to suspend a rate increase for five months rather than one day must be

(continued...)

of the August 23 Order raising the refund effective date issue were timely filed. Thus, any reliance by sellers on the October 29 refund effective date prior to issuance of a final order was at their own risk.

PG&E's contention that the Commission has authority under the FPA to order refunds for the period prior to October 2, 2000 relies on our authority to set just and reasonable rates, but the issue here concerns retroactive refunds of unjust and unreasonable rates. These are two separate issues, each with its own governing principles.

Our authority under FPA section 206 to set new rates is prospective only; if we find that rates no longer meet the just and reasonable standard, we are authorized only to fix a new rate or to fix practices "to be thereafter observed."[152] As a separate matter, FPA section 206 provides us with limited refund authority. While section 206 as originally enacted did not provide for refunds, Congress amended the provision to permit us to order refunds effective no earlier than 60 days after the date that a complaint is filed or the Commission initiates an investigation.[153] Therefore, section 206 does not permit retroactive refund relief for rates covering periods prior to the refund effective date established on complaint or the initiation of a Commission investigation, even if the Commission determines that such past rates were unjust and unreasonable.

PG&E's reliance on a "legal error" theory to circumvent the statutory limitation on refunds is flawed. The Commission did not commit legal error regarding its oversight of the California markets, as PG&E asserts.[154] In any event, the legal error theory is wholly

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[151](...continued)
challenged at the beginning of the proceeding, when that decision is made, so the decision to select an RFA refund effective date must be challenged at the time that decision is made (when the Commission establishes the period for which refunds can be ordered)."), reh'g rejected and reconsideration denied, 66 FERC ¶ 61,200 (1994).

[152]16 U. S.C. § 824e(a) (1994).

[153]Regulatory Fairness Act of 1988 (RFA). S. Rep. No. 491, 100th Cong., 2d Sess. 3-4 (1988), reprinted in 1988 U.S.C.C.A.N. 2685.

[154]PG&E Rehearing Request at 19-20 and n.38 ("The Commission has the ability to order refunds for the pre-October period if it acknowledges that allowing the California markets to operate unhindered initially was legal error," citing the Commission's August 23, 2000 Order, 92 FERC ¶ 61,172, denying SDG&E's request for (continued...)

inapplicable. That theory may permit the Commission to order refunds as a remedy to correct legal errors found by an appellate court upon judicial review.[155] No such finding has been made here.

g. Duration of Price Mitigation

A number of parties request rehearing of the termination date established in the June 19 Order as unsupported by substantial evidence that the market will operate effectively by that date, or clarification that the Commission will review conditions in California and the WSCC before it terminates the mitigation plan.[156] Conversely, Tucson and Mirant contend on rehearing of the June 19 Order that the Commission failed to justify extending the termination date past the April 2002 date specified in the April 26 order. Duke requests clarification of the June 19 Order that the Commission may further modify the mitigation plan prior to the commencement of the summer season in 2002, depending upon market conditions at the time of the March 2002 compliance filing.

PG&E requests clarification that the refund methodology established in the July 25 Order was not intended to supersede the $150 breakpoint methodology that was established in the December 15 Order, as it applied to the markets operating from January 1, 2001 to May 28, 2001. Absent such clarification, PG&E seeks rehearing.

PG&E states that, in informal discussions, some sellers have suggested that the July 25 Order applies only to non-emergency hours, but does not apply to hours that were addressed in the March 9 Order. PG&E requests clarification that the July 25 Order's

[154](...continued)
a $250/MWh price cap on all sales into the ISO and PX markets).

[155] See United Gas v. Callery Properties, 382 U.S. 223, 229 (1965) (while the Commission has no power to make reparation orders, its power to fix rates being prospective only, it is not so restricted where its order, which never became final, has been overturned by a reviewing court); Reynolds Metals Co. v. FERC, 777 F.2d 760, 763 (D.C. Cir. 1985); Public Utilities Commission of the State of California v. FERC, 988 F.2d 154, 161-162 (1993) (allowing pipeline to seek retroactive recovery of costs based on court reversal of FERC order, citing "general principle of agency authority to implement judicial reversal").

[156] See, e.g., Requests for Clarification and Rehearing of Attorney General of Washington/City of Tacoma, Washington and Port of Seattle, Washington, ISO, Metropolitan, and Washington Attorney General.

refund methodology applies to all hours from January 1, 2001 to May 28, 2001, including the emergency hours that were previously capped using the proxy price methodology adopted in the March 9 Order.[157] Absent such clarification, PG&E seeks rehearing. PG&E contends that the July 25 Order's methodology corrects deficiencies in the March 9 Order's methodology.

Commission Response

We deny these requests for rehearing. In the June 19 Order, we cited our requirement that the ISO file a report on market conditions by March 26, 2002 that addresses, among other things: a list of all new generating resources that the State of California has announced would be on line by summer 2002 and which of those facilities are on line;[158] and the continued progress in executing long-term contracts and reducing reliance on the spot market.[159] Further, the June 19 Order continued the April 26 Order's requirement that the ISO file quarterly reports, beginning on September 14, 2001, analyzing how the mitigation plan is operating and the progress that has been made in developing new generation and demand response.[160] In a recent Commission order, the Commission explained that if there is not a sufficient Commission-approved superseding mitigation plan in place after September 30, 2002, all sellers into the ISO market will need to undergo review of their market-based rate authority based on the Supply Margin Assessment screen or such other Commission-approved market power analysis in place

[157] We interpret PG&E's request to be in the alternative to its request for clarification concerning the $150 breakpoint methodology, discussed above.

[158] The April 26 Order and the June 19 Order noted that the State committed itself to increasing in-state generation and that the State projected that new generation totaling 4,168 MW would be on line by the end of August 2001 and that there could be as much as 6,879 MW on line for the summer of 2002. See June 19 Order, 96 FERC at 62,567 & n.85. According to the ISO's web site: 2,231 MW of generation capacity was added to the ISO control area as of September 2001; another 1,612 MW of new capacity is expected to become operational by the end of 2001; and during 2002, an additional 6,490 MW of new capacity is expected to be added based on currently announced plans. (See ISO Web Site, 2001/02 Winter Assessment Report, pp. 5-6, 10 (Oct. 8, 2001).)

[159] 95 FERC at 62,567.

[160] Id.; see also April 26 Order, 95 FERC at 61,365. The Commission will review comments on the ISO's reports and determine whether any element of the mitigation plan warrants adjustment.

at that time.[161] We also note that the April 26 Order conditioned sellers' continuing market-based rate authority on their not engaging in certain anticompetitive behavior, with violators' market-based rates being made subject to refund.[162]

In response to the parties who oppose extending price mitigation to September 30, 2002, as noted above, the June 19 Order identified getting new generation on line as one of the key elements of having markets perform properly. Further, the State has targeted the summer of 2002 for bringing much of that new generation on line. Therefore, it is appropriate to extend price mitigation through the summer of 2002 (i.e., through September 30, 2002) in order to help ensure that an imbalance of supply and demand is not continuing to hamper proper performance of the markets before price mitigation ends.

With respect to PG&E's requests for clarification, we clarify that the July 25 refund methodology applies to all hours from October 2, 2000 through May 28, 2001. Thus, the refund methodology established in the July 25 Order supersedes the $150 breakpoint methodology for that period. For the period from May 29, 2001 through June 20, 2001, the April 26 price mitigation measures will apply to reserve deficiency hours;[163] the mitigated price for non-reserve deficiency hours will be calculated in the refund hearing before Judge Birchman.[164] This approach reflects the July 25 Order's adoption, with modifications therein, of the recommendation of the Chief Judge in the

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[161] Huntington Beach Development, L.L.C., 96 FERC ¶ 61,212, reh'g denied, 97 FERC ¶ 61,256 (2001).

[162] We further note that the Commission recently issued an order pursuant to section 206 of the Federal Power Act proposing to revise all existing market-based rate tariffs and authorizations to include a provision prohibiting the seller from engaging in anticompetitive behavior or the exercise of market power. Order Establishing Refund Effective Date and Proposing to Revise Market-based Rate Tariffs and Authorizations, 97 FERC ¶ 61,220 (2001).

[163] The July 25 Order noted that there was a gap from May 29 through June 20, 2001, when price mitigation only applied to periods of reserve deficiencies. In order to maintain a consistent approach during all periods of time, the July 25 Order required application of the refund calculation discussed therein to the non-reserve deficiency hours from May 29 through June 20, 2001. Transactions that occurred during reserve deficiency hours in that period, already mitigated as a result of the April 26 Order, were not affected. The June 19 Order mitigates prices in all hours, effective June 21, 2001.

[164] 96 FERC at 61,517, 61,520.

settlement proceeding that the Commission should apply a consistent methodology to the entire refund period.

2. Calculation of Mitigated Prices

a. Use of Marginal Cost of Last Unit Dispatched

i. June 19 Order

On rehearing of the June 19 Order, APPA argues that the Commission's mitigated market clearing price methodology fails to establish separate and distinct prices based on the costs of production for each major zone within the ISO and for regional market hubs within the WSCC and that it likewise fails to pay sellers based on the marginal prices within each such zone. According to APPA, a single price approach will produce unreasonable results and may allow the exercise of market power whenever interregional transmission constraints limit imports into California, or on Path 15 between northern and southern California. Therefore, APPA considers the Commission's approach reasonable only on an interim basis.

Enron and Reliant request clarification of the June 19 Order that the mitigated Market Clearing Prices be known at the time a sale is confirmed. They contend that the current mitigated Market Clearing Prices, which can change hourly and without notice, do not provide the certainty the Commission supports. They request clarification that the mitigated Market Clearing Prices in effect at the time the deal is transacted, rather than the mitigated Market Clearing Prices in effect when delivery takes place, will apply to the transaction.

Dynegy requests clarification of the June 19 Order that the mitigated reserve deficiency MCP will be based on the marginal cost of the least efficient unit serving load in the ISO spot markets and should not be based solely on the last unit dispatched in the ISO's BEEP stack. Dynegy claims that the BEEP stack is limited to supplemental energy bids and the energy portion of Ancillary Services bids, which should be limited to no more than 5 percent of the market, and excludes other ISO spot market energy sales. Furthermore, Dynegy claims that the ISO can too easily disqualify units from setting the mitigated reserve deficiency MCP by labeling them "out of market" or "out of sequence" if the mitigated reserve deficiency MCP is based solely on BEEP stack transactions.

Reliant requests clarification of the June 19 Order that the mitigated reserve deficiency MCP is to be set by the proxy price of the last unit dispatched, not the lower of the marginal costs or the actual bid of the marginal unit.[165] According to Reliant, the June 19 Order fails to correct the ISO's misapplication of the April 26 Order's requirement to set the mitigated reserve deficiency MCP based on the highest cost dispatched gas-fired generator. However, Reliant complains that the ISO has proposed in its May 11, 2001 compliance filing to establish the mitigated reserve deficiency MCP at the lower of the actual bid or the marginal costs of the last unit dispatched, as calculated according to the June 19 Order.

Commission Response

In the June 19 Order, the Commission found it appropriate to mitigate all sales in the WSCC spot markets based on the ISO mitigated Market Clearing Prices. The Commission found it critical to treat all sellers alike to remove the incentive to sell in one area versus another. Furthermore, the Commission pointed out that since there is no centralized clearing house for spot market sales in the WSCC other than the ISO, there is no ability to develop a separate market clearing price for sales outside the ISO. Therefore, we deny APPA's requested modification.

Dynegy's request for clarification that the mitigated reserve deficiency MCP will be based on the marginal cost of the least efficient unit serving load in the ISO spot markets and should not be based solely on the last unit dispatched in the ISO's real time Imbalance Energy market pertains to the ISO's July 11 compliance filing; that filing will be addressed in a separate order to be issued concurrently with this order. In that order, we explain that units dispatched through the Imbalance Energy market are the marginal units and thus are the only units that can set the mitigated reserve deficiency MCP.

With respect to Reliant's request for clarification that the mitigated reserve deficiency MCP is to be set by the Proxy Price of the last unit dispatched, rather than the lower of the Proxy Price or the actual bid of that marginal unit, we clarify that the proxy price alone should set the market clearing price. As explained in our order on compliance to be issued concurrently with this order, we specifically rejected requests to use alternative methods, such as a generator's actual costs, to set the mitigated reserve deficiency MCP, concluding that "[t]he Commission's mitigation plan is designed to establish a generators' bid and market prices up-front."[166] In imposing mitigation, we are no longer relying on the market. Instead, the mitigation substitutes a prescribed method for computing the mitigated reserve deficiency MCP during periods of reserve

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[165] Request for Expedited Clarification of Reliant Energy Power Corp. and Reliant Energy Services, Inc.

[166] June 19 Order at 62,560.

deficiency so as to replicate a competitive market by using an identified and consistent set of cost data. The ISO's use of alternative data violates our prescribed methodology and is therefore rejected.

ii. July 25 Order

PSColorado argues on rehearing of the July 25 Order that relying on actual heat rate data requires the assumption that imports into California markets would have remained at the same volume even if those suppliers outside of California faced the prospect of much lower prices (i.e., the resulting mitigated Market Clearing Prices). However, the company asserts, a reduction in prices would have led to fewer imports and a corresponding increase in intra-California generation and thus a higher heat rate for the marginal unit. Thus, the argument follows, use of the actual heat rates substantially understates the marginal costs under mitigated prices, and PSColorado argues that the Commission should instead set a mitigated market clearing price that accurately reflects the actual market conditions affecting California during the refund period, specifically, by keying refunds to a generic proxy price based on a relatively inefficient unit. AEPCO raises the same issue but suggests taking into account the heat rates of out-of-California sellers that exceed the highest California heat rate. Dynegy seeks rehearing of the Commission's implicit decision that only in-state generators may set the mitigated reserve deficiency MCP.

Parties representing purchasers argue the opposite, that utilizing the heat rate of the actual unit dispatched increases the mitigated reserve deficiency MCP.[167] These parties believe that, by withholding capacity, generators forced the ISO to dispatch less efficient units. They conclude that the marginal cost of the last unit dispatched did not represent a competitive market price, and suggest instead determining the highest heat rate of all units that were not, but could have been, dispatched as if these units were dispatched in economic merit order. PG&E asserts that least cost dispatch should be used, and that parties should be permitted to argue for such at the hearing before Judge Birchman, if the Commission finds a pattern of improper withholding.

Indicated California Generators request rehearing of the method of determining the highest marginal cost unit dispatched in real time. The companies assert that the Commission's approach mistakenly focuses on identifying the unit with the highest heat rate and instead "should apply the 'North' gas cost index to the unit in the North with the highest heat rate, and apply the 'South' gas cost index to the unit in the South with the

[167] See, e.g., Requests for Rehearing of California Parties, PG&E, ISO.

highest heat rate. Whichever unit has the highest total costs should serve as the system-wide marginal, market clearing unit."[168]

Duke notes that the Commission has imposed refunds on all transactions in a variety of ISO and PX markets, yet allows units operating in only one market -- the ISO's real-time market -- to set the mitigated Market Clearing Prices for them all. Dynegy similarly argues that any generating unit used to sell into any of these markets should be able to set the mitigated price. Duke alleges that market dynamics in some other markets are quite different from those in the ISO real-time market, and charges that the Commission erred by not allowing suppliers the opportunity to present evidence on an appropriate methodology for setting different mitigated prices for the various markets.

Commission Response

We are not persuaded by PSColorado's arguments that the volume of imports would have changed considerably if different heat rate data were used to calculate the mitigated reserve deficiency MCP, or that imports would have significantly affected the resulting Proxy Prices. It is the Commission's understanding that, for technical reasons, out-of-state generators' participation in the ISO's real-time market is minimal.[169] Thus, we do not believe that the proxy price is understated. Moreover, any effort to implement PSColorado's premise would be extremely speculative. Indeed, the Commission selected a remedy with theoretical underpinnings that, at the same time, could be reasonably implemented.[170]

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[168]Request for Rehearing of Indicated California Generators at 3. See also Requests for Rehearing of Dynegy, Reliant, Portland General.

[169]See, e.g., California Independent System Operator Corporation, 91 FERC ¶ 61,324 at 62,115-16 and 62,118 (2000), reh'g pending (Amendment No. 29 Order).

[170]The Commission has freedom, "within the ambit of [its] statutory authority, to make the pragmatic adjustments which may be called for by particular circumstances. "FPC v. Natural Gas Pipeline Co., 315 U.S. 575, 586 (1942); In re California Power Exchange Corp., 245 F.3d 1110, 1120 (9th Cir. 2001). FPA section 309, 16 U.S.C. § 825h (1994), gives the Commission the necessary flexibility to take unusual remedial action in appropriate circumstances. See Permian Basin Area Rate Cases, 390 U.S. 747, 776 (1968) (applying NGA section 16, the counterpart of FPA section 309, the Court held that "the Commission's broad responsibilities . . . demand a generous construction of its statutory authority."); FPC v. Louisiana Power & Light Co., 406 U.S. 621, 642 (1972) (same).

We are also not persuaded that the marginal costs are overstated. The ISO and other parties raised the same arguments in response to the Chief Judge's Recommendation, and the July 25 Order discussed at length why this approach (a simulation of the must-offer requirement, or "assumed economic dispatch") would not be appropriate. In the July 25 Order, the Commission explained that we did not institute the must-offer requirement or the marginal bidding requirement until May 29, 2001, and that it was unreasonable to require that the markets be recreated to, in effect, apply those requirements to the refund period. In addition, the Commission noted that generators actually dispatched had specific marginal costs that are reasonably recovered. The Commission concluded that the end result of using an assumed economic dispatch would be to unfairly lower prices below the actual marginal costs of the last generator dispatched.

On rehearing, California Parties and others focus on purportedly "unrefuted evidence that sellers exercised withholding" and argue that the Commission's approach allows the sellers to retain the fruits of their acts. The "unrefuted evidence" of withholding cited by parties consists of analyses of bidding behavior that, through economic inference, conclude that sellers' bidding strategies resulted in market clearing prices rising above competitive levels. Any firm evidence of strategic withholding will be pursued seriously by the Commission; however, these studies do not rise to that level because they are simply based on assumptions. They do not persuade us to impose an assumed economic dispatch, a hypothetical dispatch, for past periods. We believe our refund methodology ensures just and reasonable rates as required by the FPA; we are under no obligation to make, or recreate, a perfect market based on a hypothetical dispatch of resources.

We will clarify for Dynegy and AEPCO that we will permit prospectively out-of-state generators to set the mitigated reserve deficiency MCP. The June 19 Order specified that out-of-state generators that want to have their marginal costs included in calculating the mitigated reserve deficiency MCP can provide the required heat rate and gas source data to the ISO.

We will grant Indicated California Generators' rehearing request. They correctly describe the appropriate method for determining the mitigated reserve deficiency MCP using separate gas cost indices for northern and southern California, which will lead to the best approximation of the marginal costs of the last unit dispatched. Therefore, we will direct the ISO to recalculate the mitigated reserve deficiency MCP for each hour of the refund period in the manner prescribed in our orders, as modified by the Indicated California Generators, and to provide the data to Judge Birchman for use in the refund hearing. We will permit Judge Birchman to revise the hearing schedule as needed to accommodate these additional calculations.

The arguments of Duke and Dynegy regarding mitigated prices in other ISO markets are similar to those addressed in the section on the treatment of Ancillary Services.[171] As we explain there, it is appropriate to have separate market clearing prices for each Ancillary Service, capped by the Imbalance Energy mitigated reserve deficiency MCP.

b. Gas Costs

i. June 19 Order

Many generators seek rehearing of the Commission's revision to the gas cost formula in the June 19 Order.[172] They argue that the proxy gas price based on the Commission formula bears no relationship to the gas prices actually incurred by generators.[173] They also argue that the gas cost methodology will impede suppliers' recovery of operating costs while subject to a must-offer requirement;[174] that it understates gas costs by directing the ISO to average the mid-point of the monthly bid-week prices reported for three spot market prices for California;[175] that it fails to account for the in-state costs of natural gas transportation;[176] and that it ignores the fact that gas is purchased at different locations in California depending on the location of the generating unit.[177]

Mirant contends that the gas cost formula is inconsistent with the rationale underlying the Commission's price mitigation scheme. Mirant states that in the April 26 Order the Commission excluded a fixed cost adder because the single-price auction mechanism allows most generators to recover some contribution to their capital costs. However, Mirant asserts, the June 19 Order departed from the concept of a single price auction by revising the gas cost formula to reflect average monthly gas costs and

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[171] See supra, section B.2.g.

[172] See e.g., Requests for Rehearing of Calpine, Duke, Dynegy, EPSA, Enron, Idaho Power, IEP, Mirant and Reliant.

[173] See, e.g., Request for Rehearing of Calpine.

[174] See, e.g., Request for Rehearing of Duke.

[175] See, e.g., Request for Rehearing of EPSA.

[176] See, e.g., Requests for Rehearing of EPSA and Reliant.

[177] See, e.g., Request for Rehearing of EPSA.

excluding emissions costs. Mirant contends that this change has significantly expanded the number of generators who will not be able to recover their variable costs and who will therefore not obtain a contribution to their fixed costs through the mitigated reserve deficiency MCP.

Generators recommend: (1) terminating the averaging of gas costs;[178] (2) using separate prices for deliveries in northern and southern California;[179] (3) including intrastate transportation charges and other gas costs in the mitigated reserve deficiency MCP;[180] (4) providing for gas imbalance penalties as an uplift charge;[181] and/or (5) using daily rather than monthly gas costs based on published indices and hubs that are actually used by traders to secure gas for California generating plants.[182]

Reliant and Duke request clarification of the June 19 Order as to how the use of "gas source" data for out of state generators is to be applied. Idaho Power recommends that the mitigated reserve deficiency MCP for sales in the Pacific Northwest (i.e., the states of Washington, Oregon, Idaho, Montana, Wyoming and Utah) should be based on the published spot gas prices for Northwest Pipeline Corporation's Canadian Border (Sumas, WA) and Rocky Mountain (Opal, WY) delivery points.

Commission Response

We find that the gas cost methodology established in the June 19 Order will not impede suppliers' recovery of operating costs and should be maintained. While both the Chief Judge and the Commission recognized in the July 25 Refund Order that, over the prior period, generators procured gas on a spot basis to support spot electric sales,[183] the Commission determined in the June 19 Order that it is appropriate for the prospective period to require the use of monthly gas costs to address and influence purchasing decisions for prospective sales. As the Commission explained in the June 19 Order, the

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[178] See, e.g., Request for Rehearing of Dynegy.

[179] See, e.g., Request for Rehearing of Calpine.

[180] See, e.g., Request for Rehearing of Dynegy.

[181] See, e.g., Request for Rehearing of Dynegy.

[182] See, e.g., Requests for Rehearing of Enron and Mirant.

[183] Report and Recommendation of the Chief Judge and Certification of Record, 96 FERC ¶ 63,007 (2001); July 25 order at 61,517-18.

mitigation plan is designed to establish generators' bids and market prices ahead of time. The Commission found that the average pricing formula "represents a reasonable proxy for the marginal costs that generators will incur, since they can pre-buy their gas requirements for the month at this price."[184] The Commission determined that it is inappropriate in the context of prospective mitigation to use actual costs because that approach would not provide price transparency and because it would require burdensome post hoc reviews of generator bids.[185]

Suppliers complain that the averaging of the mid-point of the monthly bid-week prices reported for three spot market prices for California will under-compensate generators located in higher gas cost areas in Southern California. They also contend that there is no compensation for intrastate gas transmission costs. In the June 19 Order the Commission recognized that there are intrastate gas transmission constraints in Southern California and other factors that have led to higher reported prices in that region. However, the Commission identified concerns regarding the reliability of the reported gas prices in southern California as a predictor of actual prices paid by generators in that region.[186]

Furthermore the Commission pointed out that suppliers have two alternatives if they find they are not fairly compensated for these costs.[187] First, individual generators may justify bids above the mitigated Market Clearing Prices so long as they can show their entire gas portfolio justifies such a bid. Alternatively, they may file under cost of service rates as to their portfolios. Under either approach, suppliers are assured that they will be compensated for their gas costs.

Finally, we disagree with Mirant's argument that the gas cost formula is inconsistent with the Commission's premise that the proxy price should be based on the least efficient generator. In the context of prospective mitigation, as noted above, generators should be able to purchase gas at the prices used in the mitigation formula.

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[184] June 19 Order at 62,561.

[185] Id.

[186] Among other things, the Commission explained in the June 19 Order that it is unclear what volume of gas moves at the prices reported by Gas Daily and other reporting services, and that the higher prices reported for Southern California may not necessarily be paid by generators who may hedge their gas costs or buy on a forward basis.

[187] June 19 Order at 62,564.

We decline to set prices based on the higher costs of those who forego this opportunity. Accordingly, we continue to believe, that for the prospective price mitigation covered by the June 19 Order, the average gas cost method achieves an equitable balance of our concerns regarding the reasonableness of pricing gas costs based on reported prices in Southern California, providing prospective price transparency, and ensuring that generators are compensated for their gas costs.

In response to Reliant's and Duke's requests for clarification, we clarify that out-of-California generators are to use the same gas source data as is used for generators in California. While we recognize that these generators do not purchase gas at the California source points, gas prices have been higher in California during the summer months relative to the remainder of the West. Therefore, we expect that out-of-state generators will be fully compensated for their gas costs during the summer. Gas pricing for the period following the summer of 2001 is the subject of an inquiry in Docket No. EL01-68-000 and is addressed in an order issued concurrently with this order.[188]

ii. July 25 Order

The Commission held in the July 25 Order that gas costs for past periods should be determined by using the daily spot market price for gas, rather than the monthly bid-week prices used in the June 19 Order. The Commission also separated the state's gas market into northern and southern zones, applying a northern and southern gas cost depending on whether the marginal unit is located in northern or southern California. The Commission supported the use of daily prices based on: (1) evidence presented before Judge Wagner that generators purchased gas at spot prices for generating electricity for sales into spot markets; (2) Commission precedent using spot purchases to calculate the replacement cost of fuel; and (3) the fact that the June 19 approach intended to address and influence purchasing decisions for prospective sales, while the refund methodology applied to past periods.[189]

The Oversight Board, California Parties, City of San Diego and PG&E object to the use of daily spot gas prices, arguing that there was insufficient evidence in the record to determine that generators purchased gas at spot prices. They point out that the

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[188] This inquiry relates to the technical conference which staff conducted on October 29, 2001 regarding West-wide price mitigation for the winter season. See Investigation of Wholesale Rates of Public Utility Sellers of Energy and Ancillary Services in the Western Systems Coordinating Council, Docket No. EL00-68-000, 97 FERC ¶ _____ (2001).

[189] July 25 Order, 96 FERC at 61,517-18.

evidence before Judge Wagner consisted of testimony of a single generator and that other parties had no opportunity to cross-examine the witness or to present conflicting evidence. They also contend that the Commission punishes California customers by not "recreating" gas purchasing behavior, asserting that the use of actual cost data, or the approach adopted in the June 19 Order, would be more accurate, and they charge that the higher spot prices may have resulted from manipulation in the gas market. Many of these parties also assert that the Commission should allow for further adjustments to gas prices based on a final decision in Public Utilities Commission of the State of California v. El Paso Gas Co., et al., 94 FERC ¶ 61,338, order on reh'g, 95 FERC ¶ 61,368 (2001) (El Paso), investigating manipulation of gas prices in California.[190]

PG&E challenged the Chief Judge's recommendation previously, and in the July 25 Order, the Commission responded that the PG&E had not refuted the evidence relied on by the Chief Judge. On rehearing, PG&E states that "evidence concerning sellers' gas purchasing has never been made available in discovery, or through any other means."[191] Therefore, PG&E asserts that the Commission should return to the June 19 Order's approach or it should provide additional data gathering process.[192] San Diego points out that disputes about the proper gas price can be eliminated by using the marginal generator's actual gas costs.

Mirant challenges the use of gas prices at both Malin and PG&E Citygate hubs for calculating the proxy price for Northern California transactions because gas prices at Malin are irrelevant to a determination of a Bay Area supplier's actual gas costs, and urges the use of only PG&E Citygate.

Commission Response

While the purchasing practices of a single generator cannot be assumed to apply to the entire industry, we historically have used spot prices to calculate the replacement cost of fuel. We find it appropriate to apply that policy here. Because gas fired generators

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[190]See, e.g., Requests for Rehearing of ISO, San Diego, PG&E and California Parties.

[191]Request for Rehearing of PG&E at 7.

[192]On September 20, 2001, PG&E filed a motion to submit newly obtained evidence in support of its rehearing request consisting of data obtained in response to discovery requests in the refund hearing that it alleges refutes the evidence relied upon by the Chief Judge. This order rejects the motion as an untimely supplemental rehearing request. See supra, section A.

have not been considered core customers on the local gas distribution systems in California, they have had no rights to firm transportation capacity on either LDCs or upstream pipelines, and thus, have had to rely on gas spot markets. Accordingly, we believe that using daily spot prices for the refund methodology is most likely to capture the costs that units actually paid. Thus, no additional process is required. Use of actual gas costs is not appropriate because they would not be transparent or readily verifiable, unlike spot market prices.

We will not decide here what adjustments, if any, are appropriate in the event refunds are ordered in the El Paso proceeding. The presiding judge issued an Initial Decision on October 9, 2001, finding that El Paso did not manipulate gas prices and recommending that refunds not be ordered.[193] In an order being issued concurrently we are requiring a limited reopening of the record to obtain additional evidence. We will resolve the question raised in this proceeding when we take final action in the El Paso proceeding.

The Commission addressed Mirant's issue in the July 25 Order, stating that if Mirant did not believe the gas prices used sufficiently covered its costs, it could file cost-based rates covering all of its units in the WSCC. Mirant raises no new arguments on rehearing to change our determination. The index price for northern California applies to all units throughout the northern part of the state; as an average of two prices, it will not represent the exact costs paid by any one generator, but will reasonably approximate what will be spent by the last unit dispatched for purposes of calculating the proxy price in northern California. Thus, use of this average is reasonable.

c. Emissions Costs

i. June 19 Order

A number of parties object to the Commission's directive in the June 19 Order that the ISO pass on to all users of the ISO grid emissions and start-up fuel costs through an uplift charge.[194] They argue that:

[193] Public Utilities Commission of the State of California v. El Paso Gas Co., et al., 97 FERC ¶ 63,004 (2001).

[194] See, e.g., Requests for Rehearing of APPA, DWR, ISO, Southern Cities, City of Vernon, Cities/M-S-R, Metropolitan, Modesto, NCPA, and City of Redding.

- Such costs should be allocated only to those loads that are responsible for the spot market energy and Ancillary Services procured by the ISO and DWR on behalf of ISO loads;[195]
- Forcing ISO transmission customers to subsidize combustion turbine generators' billed (not necessarily incurred) costs for air pollution and start-up fuel violates principles of cost-causation, Order 888/2000 unbundling, and nondiscrimination, and requires cost of service payment without cost of service regulatory oversight;[196]
- The uplift charges for emissions and start-up fuel costs should be charged to all users of the ISO controlled grid, including exports to control areas outside California;[197]
- The June 19 Order improperly requires load-serving entities to pay start-up and emissions costs associated with energy used to serve loads supplied by others;[198] and
- The emissions surcharge deprives communities that have planned carefully for their emissions liabilities and needs of the benefit of their planning and forces them to pay for both their own planned-for emissions plus the emissions on generation purchased for other California customers.[199]

Generators contend on rehearing of the June 19 Order that the Commission erred in failing to account for start-up and emissions costs for generators outside of California.[200] Dynegy claims that the emission cost recovery mechanism inappropriately exposes generators to substantial future costs for which recovery might not be available.

APX requests clarification of the June 19 Order as to how a neutral exchange, such as APX, which does not take title, may implement the June 19 Order. APX contends that it should be allowed to adjust the contract price to the mitigated price and that a seller in such a contract should then be allowed to apply to the Commission for an

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[195] See, e.g., Request for Rehearing of APPA.

[196] See, e.g., Request for Rehearing of DWR.

[197] See, e.g., Request for Rehearing of ISO.

[198] See, e.g., Requests for Rehearing of Southern Cities, City of Vernon, Cities/M-S-R, Metropolitan, Modesto, NCPA, and City of Redding..

[199] See, e.g., Request for Rehearing of NCPA.

[200] See, e.g., Requests for Rehearing of Pinnacle West and PPL.

additional payment of emissions and startup costs from the buyer with the total payment limited by the contract price.

NRECA requests clarification of the June 19 Order that cooperatives making mandatory sales within the WSCC but outside of California should be able to collect their emissions costs without exceeding the otherwise applicable maximum price imposed by the Commission.

In addition, generators request clarification of the June 19 Order that extraordinary emissions and maintenance costs should be recovered as an addition to the O&M adder;[201] and that all environmental compliance fees, including mitigation fees, that are required for operation in accordance with ISO dispatch orders and the must-offer provisions are to be invoiced to the ISO.[202]

Commission Response

We will deny the requests for rehearing. As we stated in the June 19 Order, we believe that generators should be permitted to recover the cost of mitigation fees assessed when they are required to run in accordance with ISO dispatch instructions and the must-offer requirement.[203] The must-offer requirement is designed to ensure adequate supplies, which benefits all customers in California. Therefore, the administrative charge should be assessed against all load served on the ISO's system. We will not allow generators to bill the ISO for capital improvements that may serve to reduce their emissions costs. Fixed costs associated with such improvements are not within the scope of the emissions allowance.

As noted above, the June 19 Order directed generators that are required to run in accordance with ISO dispatch instructions and the must-offer requirement to invoice the ISO directly for actually incurred emissions and start-up fuel costs.[204] APX misunderstands the price mitigation process. Pursuant to the June 19 Order, sellers selling through the ISO are subject to price mitigation. Therefore, when the seller's price is above the proxy price, the seller, not APX, must justify its bid. Furthermore, the seller will invoice the ISO directly for emissions costs for transactions scheduled through the

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[201] See, e.g., Request for Clarification of Duke.

[202] See, e.g., Requests for Clarification of Duke and Reliant.

[203] June 19 Order at 62,562.

[204] Id.

ISO pursuant to ISO dispatch instructions. We note that the Commission determined to leave the issue of APX's role in the hearing established in the July 25 Order, including APX's liability, if any, for refunds and APX's obligation, if any, to provide data, to the presiding administrative law judge in the first instance.

ii. July 25 Clarification Order

On rehearing of the July 25 Clarification Order, NCPA states that it is unclear how it is to implement the general guidance that the Commission offered for other parties facing the dilemma of conflicting obligations under the must-offer requirement and their respective Clean Air Act operating permits.[205]

NCPA asserts that neither of the alternatives suggested by the Commission for obtaining an exemption presents a viable option. According to NCPA, the alternative that it submit "an adequate Mirant-style presentation," places a severe and unfair burden on a party because it requires that the party demonstrate that it (1) had signed an agreement with the local air quality district, which would require both the payment of mitigation penalties and the admission that additional operations would violate its permit; and (2) been sued for signing such an agreement. NCPA contends that the other alternative allowed by the Commission, to obtain a declaratory order from an appropriate court, may be unavailable because it is unclear who would be the appropriate defendant or which court would grant such an order. NCPA believes that courts may consider a request for declaratory order to be unripe.

In an informational filing submitted to the Commission on August, 17, 2001, Duke states that two of the six turbines at its Duke Energy Oakland facility have already reached their hourly operating limits; that the entire facility has used 4,400 of its allowable 5,000 hours for the 12 month period ending December 31, 2001; that it has not entered into a Compliance and Mitigation Agreement with the Bay Area Air Quality Management District; and that the Duke Oakland units are distinguishable from the generators addressed in the July 25 clarification order because they are RMR Condition 2

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[205]In that order, the Commission stated:

> If a generator does not want to wait until it is sued to seek an exemption from the must offer requirement, it may instead obtain a declaratory order from an appropriate court finding that compliance with the must offer requirement will result in a violation of its permits. (San Diego Gas & Electric Co., et al., 96 FERC ¶ 61,117 (2001)).

units which operate only when dispatched by the ISO.[206] Duke states that when it exhausts its hourly limits under its permit, continued operation in excess of those limits would be contrary to its RMR Tariff and would also constitute a violation of its permit, which would expose it to civil penalties. Duke states that under those circumstances the conditions for exemption from the must-offer requirement under the July 25 Clarification Order would apply to Duke Energy Oakland.

Commission Response

We continue to believe that it is essential to promote maximization of generator output in California through the must-offer requirement (so long as sellers are being paid). Therefore, we require a generator to provide concrete evidence that it will be in violation of its permit before we will waive that requirement. However, as we observed in the July 25 Clarification Order, the Commission is not the appropriate forum for determining whether entities are in violation of their Clean Air permits. The guidance contained in the July 25 Clarification Order suggests two ways in which generators may satisfy the evidentiary requirement while respecting the jurisdictional limitations that preclude the Commission from engaging in interpretation of Clean Air Act permits. While NCPA argues that courts may not entertain requests for declaratory orders in these circumstances, NCPA's argument is speculative and does not require identification of additional procedures at this time.

Duke's informational filing does not seek a waiver of the must-offer requirement. We will consider such a request if and when one is filed by Duke.

iii. July 25 Order

The July 25 Order permitted generators to recover in full all of the demonstrable emissions costs incurred during the refund period. The order provided that sellers will submit their emissions costs during the refund hearing for subtraction from their respective refund liabilities. We also explained why it would not be appropriate to include these costs in the calculation of the mitigated Market Clearing Prices.

On rehearing of the July 25 Order, suppliers contend that the refund methodology should be revised to include environmental compliance costs (NOx costs and other

[206] According to Duke, under its RMR Agreement, the ISO may not request and Duke is not obligated to provide service from a unit where it would violate environmental limitations for the unit. We note that our orders are clear in that generators are not required to run if environmental limits will be broken.

environmental mitigation fees) in the calculation of mitigated Market Clearing Prices,[207] or that all such costs, and not just NOx credits, be offset against refund liabilities.[208] The Marketer Group charges that the Commission erred in allowing generators to recover the cost of NOx emission allowances but denying marketers the right to recover their costs for emissions allowances.[209] The Marketer Group asserts that the mitigated reserve deficiency MCP should be set to include recovery of the cost of these allowances. It asserts that the Commission's failure to recognize that marketers purchased power at market prices that included emission credit costs, but imposed reference prices that do not recover these costs, is unjust and unreasonable, and it suggests two possible methods for calculating the marginal cost of emissions credits that should be included in the reference price, one which could be used where emissions credits are traded, and another which could be used where there is no observable market price.

Commission Response

Consistent with the July 25 Order, we clarify that all demonstrable emissions costs, and not just NOx credits, are to be offset against refund liabilities. This includes credits required to comply with SOx emissions restrictions, and "actual and verifiable environmental compliance fees."[210] It does not include capital improvements that may serve to reduce generators' emissions costs, or other fixed costs associated with such improvements, as discussed above.

Reliant faults the order for not including environmental compliance costs in the mitigated reserve deficiency MCP, since they would not be recognized as part of the actual running costs of the marginal unit. For the reasons described in the July 25 Order, the Commission found that doing so would present an insurmountable burden. Parties have not challenged that finding. Reliant's concern is unwarranted because the order allows each generator to recover its environmental compliance costs for the entire refund period; the Commission has provided an alternative method for full recovery of the emissions costs. The costs need not be included in the mitigated reserve deficiency MCP for the generators to recover their costs.

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[207] See, e.g., Request for Rehearing of Reliant.

[208] See, e.g., Requests for Rehearing of Mirant.

[209] See also Requests for Rehearing of Nevada IEC/CC Washington and CAC.

[210] Request for Rehearing of Reliant at 11.

If a marketer believes that the inability to recover emissions costs through the refund methodology is confiscatory, it will have an opportunity to offer evidence that its revenues were less than its costs after the conclusion of the refund hearing, as discussed above.[211]

We do not believe either of the Marketer Group's proposals for recovery of emissions costs by marketers is workable because they are not verifiable, especially on a portfolio basis. Both proposals suffer from the same flaw that led the Commission to exclude emission costs from the Proxy Price: there is no certainty that the expense was incurred for the power purchased.

d. O&M Adder

The ISO, City of San Diego, and Southern California Water Company seek rehearing of the Commission's decision in the June 19 Order to increase the adder for operation and maintenance expenses from $2.00 to $6.00 per MWh. They claim that this increase is unsupported by evidence of actual costs, that it improperly subsidizes more efficient generation facilities, and that the $2.00 per MWh rate specified in the April 26 Order is more consistent with actual data. In addition, the ISO asserts that the Commission's justification was based on a five-year old analysis and lacks a detailed analysis of the relevancy of the dated DOE data to the current California fleet of generators.

The ISO states that the average O&M costs for 41 current or former RMR units in California, representing over 10,000 MW of in-state gas-fired generating capacity, is $1.5527/MWh, as agreed to in the RMR global settlement.[212]

On rehearing of the July 25 Order, parties again object to the $6.00 per MWh adder. San Francisco opposes any O&M adder, asserting that operation and maintenance expenses are generally treated as fixed costs. If any adder is used, San Francisco and California Parties prefer examination of actual, historical data, or adoption of a $2.00 per MWh adder that may be increased if justified based on the costs of the least efficient unit. PG&E argues that the Commission has not supported the higher figure, and the ISO states that six dollars is almost certainly substantially higher than sellers' actual O&M costs; they both support a $2.00 adder.

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[211] See id.

[212] The ISO points out that five older low-capacity units had average O&M costs over $30.00/MWh, but that these units run infrequently and the number of MWh over which the O&M costs were spread was small.

Commission Response

In the June 19 Order, the Commission found the California market primarily consists of older oil and gas-fired steam plants, which justifies using a long-term average of actual O&M expenses for the same kind of units currently in California. Based on a study conducted by the EIA,[213] the Commission found that a $6 adder for O&M expenses is appropriate. We do not believe that the O&M costs for RMR generators suggested by the California ISO is representative of O&M costs that should be allowed for purposes of the mitigated price allowance. The marginal unit from which the mitigated reserve deficiency MCP is determined is likely to be one of California's older generators, which would incur higher O&M costs. It is appropriate to average costs over a longer time period to obtain a more reliable average of costs for these older units. Furthermore, these generators have been required to run at extraordinary levels, which significantly increases their O&M costs. Based on these considerations, we believe that the Commission properly exercised its discretion in increasing the O&M adder to $6.00. We also disagree that the increased O&M adder improperly subsidizes more efficient generators. Since it is based on average actual O&M costs, it will compensate generators based on a reasonable estimate of costs and will encourage investment in more efficient generation units. These conclusions are equally applicable to the refund period.

We disagree with San Francisco that O&M costs should be treated as fixed costs. In our orders, the Commission sought to approximate the costs of the least efficient marginal unit dispatched in order to emulate the workings of a competitive market.[214] Thus, the inclusion of variable O&M expenses is consistent with the variable costs that would be incurred in a competitive market and, thus, the inclusion of these costs in the refund methodology is appropriate.

e. Creditworthiness Adder

i. June 19 Order

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[213] See http://www.eia.doe.gov/oiaf/issues/opctbl3.html. Oil and Gas Steam Plant Operations and Maintenance Costs, 1981-1987.

[214] We also note that, in the context of cost-of-service pricing, O&M expenses such as fuel and maintenance costs are treated as variable costs. See, e.g., Illinois Power Company, 15 FERC ¶ 61,050, reh'g denied, 17 FERC ¶ 61,063, reh'g granted in part, 19 FERC ¶ 61,073 (1981).

California Utilities and customers seek rehearing of the 10 percent credit adder,[215] provided in the June 19 Order, arguing that (1) it gives the ISO another vague accounting task that only increases the likelihood that tracking of cost-causation and repayment entitlements will not be accomplished; (2) it makes no sense to use regulatory intervention to single out generators for special cost recovery assistance when ISO customers are already overburdened; (3) the Commission has no basis for acting as collection agent on behalf of power sellers under investigation for excess charges;[216] (4) the credit adder is unjustified and unfairly raises the prices ultimately paid by electric consumers in California;[217] (5) the credit adder should not apply to entities that are neither slow to pay nor credit risks;[218] and (6) the credit adder does not adequately address the creditworthiness problems faced by California market participants.[219]

Attorney General of Nevada, Pinnacle West, Portland General, and Idaho Power also seek rehearing of the June 19 Order, contending that the credit adder could encourage sellers to choose the California market over other parts of the WSCC, and potentially interfere with reliability and supply in other WSCC markets if it is not applied to all sales in the WSCC.

Duke claims on rehearing of the June 19 Order that the Commission failed to justify limiting the credit premium to 10 percent.[220] Idacorp contends that if the Commission orders refunds that reflect an inadequate recognition of credit risk, most sellers will be driven away from the California market. Idacorp also states that any adder to compensate for credit impact should reflect actual conditions at the time of the sale,

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[215] See, e.g., Requests for Rehearing of DWR, Oversight Board, ISO, City of San Diego, City of Vernon, Metropolitan, NCPA, PG&E, SDG&E, Sierra Pacific Power and Nevada Power, and Southern California Water Company.

[216] See, e.g., Request for Rehearing of DWR.

[217] See, e.g., Request for Rehearing of City of San Diego and Southern California Water Company.

[218] See, e.g., Request for Rehearing of City of Vernon.

[219] See, e.g., Request for Rehearing of NCPA.

[220] See also Request for Rehearing of Williams, which states that given the extraordinarily high risk of doing business in California, 25 percent is a more commercially reasonable credit premium.

and is thus an issue of fact for hearing. Idacorp also recommends that the Commission allow cost-justifying sellers to include a profit margin that adequately reflects risk.

Reliant requests clarification of the June 19 Order that the mitigated Market Clearing Prices, for purposes of determining which bids must be justified, are to be calculated inclusive of the 10 percent credit adder.

Allegheny Energy requests clarification of the June 19 Order that the 10 percent adder applies to transactions conducted with and settled by the ISO.[221] Parties also request clarification of the conditions under which the Commission will no longer require the imposition of the 10 percent creditworthiness adder;[222] and that the 10 percent adder for credit risk is applicable for all power sellers in the California markets, whether the sales are made by generators or by wholesale power marketers.[223]

Commission Response

In the June 19 Order, the Commission instituted the 10 percent adder to recognize both the larger risk of nonpayment in California when compared with that in the larger West-Wide market, and the longer payment lag in the ISO spot markets when compared with that in the Western bilateral spot markets.[224] The Commission also pointed out that questionable business practices have sent negative signals to future supplies, credit rating agencies, and investors. The Commission has considered arguments that ISO customers are already over burdened and that it is unfair to apply a creditworthiness adder to entities that are not credit risks. However, despite our repeated instructions to the ISO to ensure that there is a creditworthy party backing up each and every transaction, we have continued to receive complaints that suppliers are not being paid. Under these circumstances, we continue to believe that the circumstances that justified institution of a creditworthiness adder have not abated. Until the risk of nonpayment by purchasers in California has been relieved, the adder is still justified. Accordingly, we will deny rehearing.

We will deny requests by generators to increase the level of the creditworthiness adder. Given the fact that generators will earn interest on amounts eventually paid, we

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[221]Request for Clarification of Allegheny Energy.

[222]Request for Clarification of APX.

[223]Request for Clarification of BP Energy.

[224]June 19 Order at 62,564.

believe that 10 percent is reasonable for the risk of certain amounts ultimately not being repaid at all.

We clarify that the mitigated Market Clearing Prices should not include the 10 percent creditworthiness adder, since these prices are applicable to all spot market sales in the WSCC, and the adder applies only within California. As explained in the June 19 Order, the Commission instructed the ISO to add 10 percent to the market clearing price paid to generators for all prospective sales in its markets to reflect credit uncertainty. Furthermore, generators whose bids above the mitigated price are accepted should not include the ten percent adder in their justification filings. As the Commission instructed in the June 19 Order, the ISO must add 10 percent to the price for all prospective sales. Therefore, generators who bid above the proxy price, will be paid their bid price, which is subject to justification and refund, plus a surcharge of 10 percent of their bid price. The adder is not a part of the bid that is to be justified.

We agree with Allegheny Energy that the 10 percent adder applies to transactions conducted with and settled by the ISO. We also confirm that the adder applies to all power sellers in the ISO markets, whether the sales are made by generators or by power marketers. Since the risk of nonpayment by purchasers is felt by all sellers, regardless of their source of supply, all power sellers in California markets are eligible to receive the adder.

The Commission is considering in separate proceedings other issues related to the ISO's obligation to ensure that a creditworthy party backs every transaction, and with contentions that even when dealing with a creditworthy party, sellers still have not been paid. The Commission addressed these issues in a separate order issued on November 7, 2001.[225]

ii. July 25 Order

Similar arguments emerge on rehearing of the July 25 Order. Several entities note that as of January 17, 2001, DWR was the purchaser of record, and, as an arm of the state, was a creditworthy buyer,[226] and they assert that SDG&E remained creditworthy at

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[225]See California Independent System Operator Corporation, 97 FERC ¶ 61,151 (2001) (addressing the ISO's proposed Tariff Amendment No. 40, Docket No. ER01-3013-000, and Motion of Indicated Generators filed in Docket No. ER01-889-008) (November Creditworthiness Order).

[226]See, e.g., Requests for Rehearing of San Francisco, Oversight Board, ISO.

all times.[227] They contend that application of such an adder to past periods bestows a windfall on sellers for no valid reason because its logic does not apply to transactions that have already occurred. California Parties and the ISO also contend that application of a creditworthiness adder and interest for the same transactions is redundant.

Suppliers, on the other hand, believe that the adder should be higher than 10 percent, more in line with common business practices.[228] They note the failure of the ISO and PX to pay for sales prior to January 5, 2001, and that the risk of default by SoCal Edison and PG&E preceded that date, arguing that the adder should apply to transactions prior to that date.

Commission Response

For the same reasons discussed in the context of prospective transactions, we will retain the creditworthiness adder for the refund period, and we will continue to add 10 percent rather than a higher amount. While the knowledge now that an adder will be available for a past period cannot affect the behavior of sellers for that period, we still believe that the adder should be retained. Beginning as of January 5, 2001, sellers bid into the ISO and PX markets with the certainty that a significant risk of non-payment existed. It was reasonable for these sellers to add a premium to their bids because of the risk. We are not willing at this time to require sellers to refund amounts that were reasonably included in their bidding strategies (although we are limiting the level of the premium to an amount we find is reasonable, i.e., 10 percent).

We recognize that some risk of non-payment may have existed prior to January 5; however, the extent and inception of the risk is unclear. There is no doubt about the importance of PG&E's and SoCal Edison's bonds being downgraded, and their losing the credit status required by the ISO's Tariff, both of which occurred on or about January 5. Therefore, it is appropriate that events of January 5, 2001 should trigger the commencement of the creditworthiness adder.

The fact that SDG&E has been creditworthy is not relevant because sellers transacting in the ISO's Imbalance Energy market receive payment from the ISO, regardless of the purchaser, and the ISO has not paid sellers for many months. The same is true for DWR.

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[227] See, e.g., Requests for Rehearing of San Diego, Oversight Board, ISO.

[228] See, e.g., Requests for Rehearing of Dynegy, Duke, Pinnacle West, Puget/Avista.

We disagree that receiving interest on amounts past due negates the need for a creditworthiness adder. Interest assures that parties receive the time value of the money they are owed. The adder offers financial security for the risk of transacting in California markets and not selling in other markets that is warranted in these circumstances.

f. Opportunity Costs, Scarcity Rents, Recovery of Fixed Costs and Justification of Higher Prices

i. June 19 Order

A number of generators argue on rehearing of the June 19 Order that the Commission erred in failing to allow suppliers to include various cost items in their price justification filings.[229] For example, Duke contends that the Commission has failed to demonstrate that its methodology, which omits opportunity costs, fixed costs, replacement costs, scarcity rent and other factors, represents a realistic competitive market outcome. Duke contends that suppliers should be permitted to make individualized showings of opportunity costs associated with environmental restrictions and to permit such demonstrated costs to be flowed through the administrative charge. Mirant argues that the Commission's refusal to allow suppliers to justify a price based on the cost of purchased power lacks any reasoned basis. Mirant recommends that the Commission allow marketers and other sellers to justify prices above the cap based on the cost of purchased power, subject to the Commission's oversight for potential affiliate abuse. LSEs also contend on rehearing that the Commission erred in denying the right to seek recovery of purchased power costs, arguing that the restriction is an unjustified departure from precedent approving rates based on purchased power costs, and would impermissibly require LSEs to offer excess energy for sale at non-compensatory prices.[230]

Other generators contend that the Commission should allow sellers to include in their justification filings amounts to allow recovery of: credit premiums from buyers outside of California having insufficient credit;[231] major expenditures that may be required to keep a generating unit in the market or to maintain a unit in compliance with

[229] See, e.g., Requests for Rehearing of Duke, Dynegy, Enron, Mirant, PPL, Reliant, and PSColorado.

[230] See, e.g., Requests for Rehearing of Pinnacle West, Portland General, PSNM, Salt River, Avista Utilities, and Tucson.

[231] See, e.g., Request for Rehearing of PPL.

environmental standards;[232] and start-up costs other than start-up fuel costs (such as the significant O&M costs that are involved with frequent requests to turn on older generators for short periods of time).[233]

Load serving entities claim on rehearing of the June 19 Order that treating them as marketers and precluding recovery of their purchased power costs fails to recognize the special native load service obligations of load serving utilities.[234] They argue that excluding such costs is an unjustified departure from precedent approving rates based on purchased power costs, and would impermissibly require LSEs to offer excess energy for sale at non-compensatory prices. They also argue that allowing inclusion of purchased power costs is consistent with encouraging forward contracts.

Salt River and PSNM request clarification that LSEs may justify sales above the mitigated Market Clearing Prices based on their cost of purchased power. Tucson argues that the Commission should allow load serving entities to settle spot market sales at prices above the mitigation cap level if justified based on long-term forward purchases that the load serving entity entered into prior to the issuance of the June 19 Order.

On the other hand, on rehearing of the June 19 Order, the Oversight Board opposes justification filings altogether, contending that permitting suppliers to justify each transaction above the mitigated price allows suppliers to manipulate their purported costs, and fails to ensure that wholesale electric prices are just and reasonable. PG&E states that the Commission should clarify its approach for evaluating individual seller justifications for pricing above the mitigated price cap to prevent gaming in fuel pricing (such as by matching highest cost gas with highest cost generation, rather than by justifying pricing based on the entire generation and fuel portfolio).

Dynegy claims on rehearing that it is impossible for generators to provide a complete cost justification, including a detailed breakdown of all of the component costs, within seven days of the end of the month. According to Dynegy, it does not receive a preliminary settlement statement from the ISO until 38 days after the end of the month. Dynegy also states that natural gas costs are not received until five days after the end of the month, leaving only two days to provide a breakdown on a portfolio basis.

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[232] See, e.g., Request for Rehearing of Reliant.

[233] See, e.g., Request for Rehearing of Tri-State.

[234] See, e.g., Requests for Rehearing of Pinnacle West, Portland General, PSNM, Salt River, Avista Utilities, Washington Utilities and Transportation Board and Tucson.

Therefore, Dynegy requests that the Commission adopt a longer timetable based on these considerations.

Commission Response

We decline to allow the additional cost items proposed by parties. As discussed in our prior orders, our mitigation plan is intended to replicate the price that would be paid in a competitive market, in which sellers have the incentive to bid their marginal costs. The mitigated reserve deficiency MCP is then based on a single price which is set by the marginal cost of the last unit produced, and all more efficient units receive the same price, which creates an incentive for firms to increase their efficiency.[235] Furthermore, opportunity costs are not appropriate because energy that is available in real time cannot be sold elsewhere.[236] We note that, during the latter half of this year, spot market sales in all of the major western trading hubs (Palo Verde, Mid Columbia and California-Oregon Border) have consistently been below \$40/MWh, which is well below the current mitigated non-reserve deficiency MCP of approximately \$92/MWh. To the extent generators find that the Proxy Price will not compensate them for their marginal costs, they are permitted to file cost based rates for their entire portfolio in the WSCC.

The Commission determined in the June 19 Order that marketers and load serving entities that choose to participate in real time spot markets must be price takers, because the Commission is unable to trace transactions that can span multiple entities back to the individual generators that supply these transactions. Furthermore, as we have discussed earlier in this order, as price takers, these entities must bid zero. We note that marketers are not subject to the must-offer requirement, and therefore need not bid if they believe that they will under recover their purchased power costs.

We deny requests to allow sellers to include in their justification filings amounts to allow recovery of credit premiums from buyers outside of California having insufficient credit. No party has indicated that there are non-creditworthy purchasers outside of California. Furthermore, in the bilateral market outside of California parties can and typically do include in their contracts appropriate contract provisions to ensure that they are dealing with a creditworthy party.

We decline to allow sellers to include in the justification filings environmental and start up costs. In the June 19 Order, the Commission allowed generators in California to invoice the ISO for their emissions and start-up fuel costs. Sellers will

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[235] June 19 Order at 62,560.

[236] Id. at 62,564.

receive these costs over and above the mitigated Market Clearing Prices. Therefore, these are not to be included. Similarly, start-up costs other than start-up fuel costs (such as the significant O&M costs that are involved with frequent requests to turn on older generators for short periods of time), should not be included. In the order on the ISO's compliance filings being issued concurrently with this order, we are requiring the ISO to compensate generators for start up and minimum load costs, to compensate generators for their actual costs during each hour that generators are not scheduled to run under a bilateral agreement, are not on a planned or forced outage, and are running in compliance with the must-offer obligation, but are not dispatched by the ISO. We also will not allow generators to include major expenditures that may be required to keep a generating unit in the market or to maintain a unit in compliance with environmental standards. Capital investment for pollution control equipment will increase the hours that a plant can operate which will increase the revenues from the Imbalance Energy market for the potential recovery of such costs. The proposed recovery of capital costs as a separate adder as is allowed for emissions costs is inappropriate because such investments are not subject to the volatility and changing circumstances as are present with the California emissions programs. Capital cost recovery would be appropriate in the context of cost-based rates. As we stated in the June 19 Order, sellers who desire cost-based rates may do so for their entire portfolio of resources.

We will not allow LSEs to justify sales above the mitigated Market Clearing Prices based on their cost of purchased power. Like marketers, LSEs purchase from many sources of supply, and it is in most instances not possible to trace the power to a particular generator. Furthermore, we note that LSEs purchase power in order to serve their native load obligations. To the extent that they have excess capacity to sell, the proceeds of such sales would reduce the sunk costs of that power that their customers otherwise would pay.

Mirant and Duke contend that the ISO should play no part in reviewing or gathering the bid justification data. We note that this was an issue that should have been, but was not, raised on rehearing of the April 26 Order in which we required submission of justification data to the ISO. Because the Commission did not reverse its findings on this issue in the June 19 Order, Mirant and Duke's contention is untimely.

We reject as untimely Dynegy's request for rehearing of the requirement to submit complete justification filings within seven days of the end of the month. In the April 26 Order, the Commission required that "[a]t the end of each month in which a generator submits a bid higher than the market clearing price, the generator must file with the Commission and the ISO, within seven days of the end of the month, its complete justification, including a detailed breakdown of all of its component costs for each transaction exceeding the market clearing price established by the proxy bid." Since the

June 19 Order restated, but did not alter, this requirement, Dynegy's request for rehearing after the June 19 order is untimely.

ii. July 25 Order

Suppliers raise most of these same issues and arguments on rehearing of the July 25 Order, pressing for the opportunity to justify prices above the mitigated Market Clearing Prices based on these additional factors, the ability to offset the costs against potential refunds, or their outright inclusion in the mitigated Market Clearing Prices.[237] In particular, they object to the prohibition on offsetting purchased power costs against potential refunds. BP notes that the Commission's rationale from the July 25 Order, that the purchased power costs of public utilities were sunk costs, does not apply to unaffiliated power marketers, which have no sunk costs. BP and others respond to the Commission's statement that they are not guaranteed recovery, just the opportunity to recover their costs, by explaining that marketers will have no opportunity to recover these costs under the retroactively imposed refund methodology. Portland General argues this is unlawful without a finding of market power or other abuse. Others explain that they had no ability to avoid purchasing and reselling high-cost power, and claim that the Commission's position results in a confiscatory rate.[238] Dynegy seeks clarification whether start-up fuel costs are recoverable in the same manner as in the June 19 Order.

Several suppliers call the Commission's departure from policy developed in orders prior to the July 25 Order arbitrary and capricious, particularly when utilization of bilateral forward contracts (prices for which they now seek to use as justification to exceed the mitigated Market Clearing Prices) had been encouraged in those orders. PSNM refers to specific assurances by the Commission concerning the use of purchased power costs as justification for sales prices above the mitigated prices, as well as a passage in the November 1 Order implying that sellers' refund liability would be limited "to no lower than the sellers' marginal costs or legitimate and verifiable opportunity

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[237] See, e.g., Request for Rehearing of Marketer Group, calling the Commission's decision to disregard marketers' costs confiscatory (at 25-27); Nevada IEC/CC Washington, warning that the methodology will discourage new generation and asserting that denying full compensation to suppliers constitutes an unconstitutional taking; LADWP, seeking recovery of transmission losses, embedded costs, and interest on debt; and Dynegy, arguing that scarcity rents and opportunity costs (at 4-7) and all elements of short-run marginal costs, such as intrastate gas transportation costs and certain ISO charges (at 11-13), should be included in the Proxy Price.

[238] See, e.g., Requests for Rehearing of Pinnacle West, PSNM, PSColorado.

costs,"[239] and asserts that it relied to its detriment on these statements. PSColorado cites Commission cases dealing with pricing structures for "off-system" sales and charges that the Commission made no findings that would support departing from them.[240]

LSEs contend that their unique circumstances (i.e., they must stand ready to serve peak native loads, and are expected to sell their more expensive surplus power on the wholesale market to help reduce cost of service to native load) warrant different treatment.[241] Nevada BCP seeks a specific exemption for LSEs that it represents from paying any refunds.

Several utilities outside of California claim that any refunds required to be paid will have to be passed on to their ratepayers, resulting in subsidization of California ratepayers.[242] Portland General contends that any such cost-shifting is per se arbitrary and capricious. Nevada BCP characterizes the situation thus: "California customers are guaranteed the mitigated price while utilities that incurred purchased power costs that, in most cases, if not all, are above the mitigated price, are left to subsidize mitigated prices for California purchasers."[243]

Dynegy and Mirant object to the Commission's invitation to submit cost-of-service rates for each generator's entire portfolio of units, noting that each of its affiliated subsidiaries are separate limited liability companies, and arguing that each should be entitled to file cost-based rates regardless of the others' decision to do so. AEPCO asserts that it would be inappropriate to force cooperatives to incur the substantial administrative burden associated with making such a cost-of service filing with the Commission.

Commission Response

[239] Request for Rehearing of PSNM at 57, quoting November 1 Order, 93 FERC at 61,370.

[240] See, e.g., Request for Rehearing of PSColorado at 10-11, citing Illinois Power Company, 57 FERC ¶ 61,213 (1991); Detroit Edison Company, 78 FERC ¶ 61,149 (1997).

[241] See, e.g., Requests for Rehearing of Puget/Avista, Portland General, PSNM.

[242] See, e.g., Requests for Rehearing of Portland General, Nevada BCP, PSColorado.

[243] Request for Rehearing of Nevada BCP at 10.

For the reasons discussed above, we will not allow any additional cost items to be included in the refund formula. To hold otherwise would be inconsistent with our marginal cost based approach. We recognize, however, that market participants were not basing their buying and selling decisions with specific knowledge of the mitigated Market Clearing Prices during the refund period, and that they may not have an opportunity to recover their costs (once refunds are ordered) because the refund methodology is being imposed retroactively. Therefore, as discussed elsewhere in this order, we will provide an opportunity after the conclusion of the refund hearing for marketers, those reselling purchased power, or those selling hydroelectric power to submit evidence that the impact of the refund methodology on their overall revenues over the refund period is inadequate. Such demonstrations must show the impact on all transactions from all sources during the refund period.

We do not agree that LSEs' circumstances warrant different treatment. As explained above, to the extent LSEs have excess capacity to sell, the proceeds of those sales serve to reduce the sunk costs of the purchased power costs their customers otherwise would pay. No other sellers are exempt from potential refunds for sales into the ISO and PX spot markets, and Nevada BCP has not justified such an exemption for LSEs. Nevertheless, as discussed elsewhere in this order, sellers, including LSEs, will have an opportunity to demonstrate that the refund methodology results in a total revenue shortfall (or, for marketers, imposes costs in excess of revenues) for all jurisdictional transactions over the duration of the refund period. We will continue to prohibit recovery of opportunity costs, as the Commission has indicated will be our approach since the December 15 Order.[244] We will also prohibit recovery of major expenditures associated with plant additions, since these should be capitalized, as discussed above. Parties' purported reliance on prior orders as to the recovery of purchased power costs was misplaced; neither the November 1 Order, December 15 Order, nor March 9 Order proposed or provided that such costs could be used to justify sales prices above the mitigated prices.

We are not persuaded that California ratepayers are being subsidized at the expense of ratepayers elsewhere in the West. California ratepayers have been exposed to some of the highest wholesale power prices anywhere, particularly before January 1, 2001, when California IOUs had been required to purchase all of their power in the spot markets. The Commission had to intervene and fix the excessive prices being charged in those markets. In any event, concerns about subsidization cannot justify the continuation of excessive rates.

[244] December 15 Order at 62,010.

Regarding Dynegy's request for clarification, we will not permit start-up fuel costs to be recovered under the refund methodology. It will be impossible to reconstruct and demonstrate what gas costs were incurred strictly for start-up that are not otherwise recoverable. For example, a unit may have incurred start-up costs in order to be available to provide spinning reserves (which is a capacity Ancillary Service). In this instance, it would be inappropriate to seek double recovery of those costs. Moreover, these start-up costs were allowed to be recovered in the June 19 Order because of the impact of the must-offer requirement, and that requirement was not in place during the refund period.

Dynegy and Mirant's objection to our requiring submission of an entire portfolio of units for cost-of-service rates is without merit. As a matter of policy and in an effort to avoid the gaming inherent in hybrid markets,[245] we will require that the entire portfolio choose to be under cost-of-service or under market-based rates.

We are also not persuaded by AEPCO's objection to the potential administrative burden for a cooperative to prepare cost-of-service justification. The City of Vernon, California provides an example of doing so without substantial difficulty.[246]

g. Treatment of Ancillary Services

The ISO argues on rehearing of the June 19 Order that the Ancillary Services price mitigation, as adopted, will result in Ancillary Services prices above just and reasonable rates and seeks to prohibit sellers from seeking or obtaining payments for Ancillary Services capacity bids above the applicable Market Clearing Prices. The ISO contends that an ex ante approach to Ancillary Services price mitigation is superior and that Ancillary Services price mitigation measures should be applied in all hours as of May 29, 2001, the effective date of the April 26 Order. PG&E contends that the Commission should distinguish between capacity and energy in Ancillary Services pricing, since capacity does not incur variable costs.

PG&E repeats this argument in the context of the refund methodology. As the July 25 Order did not address Ancillary Services pricing, PG&E seeks clarification that for capacity bids prior to June 20, 2001, gas prices and O&M charges should be subtracted from the hourly Ancillary Services market clearing price. Similarly, the ISO

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[245]See, e.g., AES Redondo Beach, L.L.C., et al., 85 FERC ¶ 61,123 (1998), order on rehg 87 FERC ¶ 61,208, order on further reh'g, 88 FERC ¶ 61,096 (1999), order on further reh'g, 90 FERC ¶ 61,036 (2000).

[246]See City of Vernon, California, 93 FERC ¶ 61,103 (2000), reh'g denied, 94 FERC ¶ 61,148 (2001).

and California Parties note that sellers who provide energy pursuant to a capacity bid under the ISO Tariff would be paid twice for expenses such as gas, start-up fuel and O&M, and argue that on rehearing the Commission should direct that the mitigated price for replacement reserves and Ancillary Services should not include these costs.

Enron and Reliant request clarification of the June 19 Order that the mitigated Market Clearing Prices be known at the time an Ancillary Service transaction is confirmed. They contend that the current mitigated Market Clearing Prices, which can change hourly and without notice, does not provide the certainty the Commission supports. They request clarification that the mitigated Market Clearing Prices in effect at the time the Ancillary Service deal is transacted, rather than the mitigated Market Clearing Prices in effect when delivery takes place, will apply to the transaction.

PG&E argues that the July 25 Order's refund methodology should also provide for refunds of the entirety of the amount spent on replacement reserves between October 2, 2000 and December 31, 2000. According to PG&E, the rationale for such refunds is essentially the same as that cited by the Commission for applying the refund methodology to spot market OOM transactions, that is, the replacement reserves were needed for the ISO to reliably operate the grid, and thus they should receive the same treatment. Because the ISO tariff allocated the entire cost of replacement reserves to the buyers that had failed to meet their demand in the PX markets, and sellers had not submitted bids in the auction with which buyers could service all their load, PG&E argues that the cost allocation effectively imposed an unwarranted penalty on buyers.

Commission Response

The Commission addressed issues of price mitigation for Ancillary Services in an order issued May 25, 2001, clarifying and providing preliminary guidance for implementing the April 26 Order.[247] The May 25 Clarification Order provided that the ISO should use the relevant hourly mitigated Imbalance Energy price to cap the other Ancillary Services markets. Thus:

> If the Ancillary Services markets clear below the average hourly mitigated Imbalance Energy price for that hour, then the ISO will pay the Ancillary Services clearing price for that market. If the Ancillary Services markets clear above the

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[247] San Diego Gas & Electric Company, et al., 95 FERC ¶ 61,275, reh'g denied, 96 FERC ¶ 61,051 (2001) (May 25 Clarification Order). On rehearing, the Commission indicated that the Ancillary Services issues should be raised on rehearing of the June 19 Order, so they are appropriately addressed in the instant order. See 96 FERC at 61,128.

> average hourly mitigated Imbalance Energy price, then the ISO will use that [Imbalance Energy] price to clear the market and will pay as-bid for all Ancillary Services that are needed above the mitigated price. Bids accepted above the mitigated price will be subject to refund and justification.

95 FERC at 61,971-72. It is in this context that the ISO and PG&E object to generators' ability to potentially justify Ancillary Services prices above the mitigated Market Clearing Prices.

The ISO Tariff provides that a supplier of capacity reserves will receive a capacity payment based on the market clearing price of the particular Ancillary Service in which its bid is accepted, and, if called upon to run, the supplier will also receive the Imbalance Energy market clearing price for its energy. In the case of replacement reserves, a supplier receives only an energy payment if its capacity is called upon. Parties here want spinning and non-spinning reserves treated the same as replacement reserves. This would require a change in the tariff provisions that is outside the scope of this proceeding. Capacity payments have been intended as a contribution toward a supplier's fixed costs, whereas suppliers' marginal costs are covered by the energy payment. The issue whether to continue payments toward suppliers' fixed costs is not before the Commission in this proceeding.

The appropriate level of compensation for supplying capacity may differ from the appropriate energy prices, because fixed costs differ from marginal costs. For this reason, it would not be appropriate to subtract certain variable costs from the Ancillary Services market clearing price, as PG&E suggests. To the extent Ancillary Service markets clear below the hourly Imbalance Energy clearing price, no further adjustment is necessary. However, these markets will be limited to the Imbalance Energy clearing price in recognition that there is a relationship between offering the capacity in lieu of providing energy in real time. Prior efforts to decouple these markets resulted in insufficiency in the capacity markets.[248]

The ISO, Enron and Reliant seek some type of ex ante pricing. The ISO proposes that prices in the Ancillary Services capacity markets in all hours including system emergency hours be limited to 85 percent of the most recently established mitigated reserve deficiency MCP, asserting that such an approach is more consistent with the Commission's intention to set prices before they are charged. While Enron and Reliant

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[248] See AES Redondo Beach, L.L.C., et al., 85 FERC ¶ 61,123 (1998), order on rehg 87 FERC ¶ 61,208, order on further reh'g, 88 FERC ¶ 61,096 (1999), order on further reh'g, 90 FERC ¶ 61,036 (2000).

also seek a price that is known before the price is charged and that will not change, that price would not be capped. This topic is addressed in the order on the ISO's compliance filings that is being issued concurrently with this order. As we explain in that order, changes in the mitigated reserve deficiency MCP for the Imbalance Energy market should have no effect on prices in the Ancillary Services markets. Thus, we agree with Enron and Reliant that the price for the hour a transaction is entered into, and not the hour of delivery, is relevant for establishing the market clearing price for Ancillary Services. We will grant rehearing of our prior orders on this point, to the extent needed to allow this modification. We will not adopt the ISO's proposal because, as discussed above, the Ancillary Services markets should not be capped at a level lower than the Imbalance Energy market.

We do not agree with PG&E that replacement reserves costs should be refunded in their entirety. As explained above, prices in each of the ISO's auctions will be subject to refund to the extent they exceed the mitigated Market Clearing Prices in the Imbalance Energy market. To require the entire amount the ISO spent on replacement reserves to be refunded would be inconsistent with the treatment of the other Ancillary Services, and PG&E has not justified why replacement reserves should be treated differently. Even in a functional, competitive market, the ISO would have had some replacement reserves expenses. Replacement reserves are directly assigned to Imbalance Energy service and are needed for reliability purposes.[249] This is a necessary link that PG&E has not provided any explanation for breaking. Furthermore, PG&E's rationale with respect to OOM transactions is flawed. We did not order complete refunds for OOM transactions but are merely subjecting them to the same mitigation formula as other ISO transactions. To the extent that PG&E's problem may lie with cost allocation, we find that issue to be outside the scope of this proceeding.

Regarding the period between May 29 and June 20, 2001, the July 25 Order provided that the refund methodology would apply to non-reserve deficiency hours for those days. Rather than applying price mitigation to the Ancillary Services markets for all hours for that period, we clarify that the refund methodology and procedures will apply to the non-reserve deficiency hours.

3. Other Refund Issues

a. The July 25 Refund Methodology was Properly Applied to All Sales at Issue

[249] See Amendment No. 33 Order, 93 FERC ¶ 61,239 (2000).

Many marketers and generators challenge the Commission's determination that prices charged were unjust and unreasonable. For example, EPSA and Williams argue that refunds are inappropriate because the Commission made no finding that any market participant exercised market power, never defined market power, and made no factual determination that warrants refunds in all hours. Others complain that the Commission made no findings that rates were unreasonably high or were increased above reasonable levels through market power.[250] Many assert that the Commission's findings violate section 206 of the FPA and the Administrative Procedure Act because there was no record evidence supporting those findings and because sellers were not afforded due process to address the issue on the record.[251] Williams and Reliant contend that the Commission erred by imposing refunds without substantial record evidence in support. As a result, these parties argue that imposing refunds violates the rule against retroactive ratemaking, the filed rate doctrine, and the Mobile Sierra doctrine.[252] In addition, they argue that the July 25 Order is contrary to long-standing precedent regarding retroactive rule changes and that the Commission erred in providing inadequate notice and explanation of changes in its policies.[253]

A number of parties argue that the filed rate doctrine forbids the Commission from ordering refunds with respect to transactions that were conducted in accordance with all Commission-approved rules (e.g., breakpoints, price caps or proxy prices) in effect at the time of the transactions.[254] They argue that the filed rate may be a formula rate and that a market-based rate is a formula rate, with the formula comprising the rules that govern the functioning of the market. With respect to the ISO and PX spot markets during the relevant periods, they argue that the rules that governed the functioning of the markets were the individual sellers' market-based rate authorizations, the Commission-approved ISO and PX tariffs, and the various Commission orders in effect at particular times. They argue that, if the Commission has never determined that an individual seller

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[250]See, e.g., Requests for Rehearing of Mirant, Nevada IEC/CC Washington, PSNM, Dynegy, Duke.

[251]See, e.g., Requests for Rehearing of Williams, Mirant, Nevada IEC/CC Washington, Marketer Group.

[252]See, e.g., Requests for Rehearing of BP, Duke, EPSA, Marketer Group, Nevada IEC/CC Washington, CAC.

[253]See, e.g., Requests for Rehearing of PacifiCorp, EPSA, PSNM. These issues are addressed elsewhere in this order.

[254]See, e.g., Requests for Rehearing of Marketer Group, PSNM, LADWP.

has not acted in accordance with its market-based tariff, the ISO and PX tariffs and the Commission's orders, there is no basis for the determination that the seller make refunds.

According to PSNM, just as purchasers must be on notice of the rates that they may be charged, the filed rate doctrine requires that sellers be on notice of the rules that will govern their rates. PSNM contends that the July 25 Order is at odds with this principle in two respects. First, PSNM cites the November 1 and December 15 Orders as informing sellers that their refund liability would be no lower than the seller's marginal costs or legitimate and verifiable opportunity costs and that the Commission assured sellers that to the extent their sales prices exceeded the relevant benchmark prices, they would be able to justify the prices based upon their cost of purchased power. Second, PSNM states that, under the December 15 Order mitigation plan that took effect on January 1, 2001, the refund potential for sellers would close within 60 days of the initial report unless the Commission notified the seller otherwise. PSNM asserts that it was not identified in the March 9 Order that its transactions were subject to refund, and, therefore, with respect to its sales into the ISO and PX markets beginning January 1, 2001, PSNM was not on notice of potential refund liability.[255]

Williams asserts that the order is at odds with principles of finality and certainty that the Commission cited in prior orders in this proceeding.

Marketer Group argues that each of the various price caps, breakpoints and proxy prices in effect since October 2 created a safe harbor below which sellers were assured that their charges would not be subject to refund. It contends that, if sales both above and below the price cap were equally subject to potential refunds under the refund effective date, then the price cap would have no meaning, nor could such an interpretation be harmonized with the Commission's determination that the market rules established the filed rate. Marketer Group argues that the Commission cannot reopen rates after they have become final and that the filed rate doctrine must be strictly enforced without regard to equitable considerations. It contends that the Commission is barred from retroactively adjusting the final rates in effect to reflect its later view of equitable prices under the mitigated Market Clearing Price mechanism announced in the June 19 Order.

Commission Response

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[255]Issues regarding 60 day refund notifications are addressed elsewhere in this order. See supra, section B.3.c.

We found in the November 1 Order that the "electric market structure and market rules for wholesale sales of electric energy in California were seriously flawed and that these structures and rules, in conjunction with an imbalance of supply and demand in California, have caused, and continue to have the potential to cause, unjust and unreasonable rates for short-term energy . . . under certain conditions."[256] In the December 15 Order we reaffirmed this finding, and explained that, "[w]hile high prices in and of themselves do not make a rate unjust and unreasonable (because, for instance, underlying production prices may be high), if over time rates do not behave as expected in a competitive market, the Commission must step in to correct the situation."[257] We continued by finding that:

> independent of any conclusive showing of a specific abuse of market power, a variety of factors have converged to drastically skew wholesale prices under certain conditions: significant over-reliance on spot markets . . .; significant increases in load combined with lack of new facilities as well as reduced availability of supply from out of state; chronic underscheduling; and lack of demand responsiveness to price. . . . [W]e have no assurance that rates will not be excessive relative to benchmarks of producer costs or competitive market prices, due to the circumstances listed above.[258]

Moreover, we specifically found that an abuse of market power is not required for a determination that rates are unjust and unreasonable. Rather, whether prices are just and reasonable depends on whether those prices fall within a "zone of reasonableness."[259]

We reaffirm those findings. Our determination regarding the justness and reasonableness of the rates here is based on systemic dysfunctions in the single clearing price auction markets that resulted in those rates. We determined that structural problems, which existed in all hours, had the potential to cause market prices to exceed that which one would expect in a competitive market. While our solution requires review for all hours, that does not mean that this will result in refunds for all hours.

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[256]November 1 Order at 61,349-50; see also December 15 Order at 61,998.

[257]December 15 Order at 61,998-99.

[258]Id.

[259]Id.

Individual seller analysis was not required to find the rates unjust and unreasonable here, particularly as a single market clearing price applied to any given sale. All sellers received the same price. These circumstances make it appropriate to analyze all sellers as a whole. While the December 15 Order devised a remedy allowing individual sellers to justify prices above the "breakpoint," the underlying problem was that the single price auction, in conjunction with other components of market structure and market rules, was no longer producing just and reasonable rates.

FPA section 206(b) explicitly permits us to order refunds of any amounts paid in excess of those which would have been allowed under the just and reasonable standard. Sellers were or should have been aware that this statutory provision governed the rates of the sales at issue here. Under the rapidly changing circumstances here, where proceedings regarding the justness and reasonableness of the rates in the PX and ISO markets were instituted in August, 2000, with a refund effective date in October 2000, the beneficial effects of rate certainty must yield to the Commission's statutory obligation to ensure that rates do not exceed the zone of reasonableness. As Commission orders are not final while subject to rehearing, and rehearing was requested of all orders in this proceeding, the mitigation measures and related procedures implemented in those orders were subject to adjustment or replacement. Sellers could not reasonably have expected therefore, that the mitigation measures and related procedures implemented in earlier orders in this proceeding would remain unchanged during the rehearing process.

Due process has been satisfied in this case. As the voluminous record in this case illustrates, parties were provided with a full opportunity to address refunds and all other issues in this case. We fully considered all proper submissions, and this record provides sufficient discussion of the issues so that we can appropriately decide all issues in this case on the resulting record.

b. Applicability of Refunds to APX

APX, a power exchange, argues that the Commission should not impose refunds on sellers that do not own generation. Specifically, APX contends that it had no ability to exercise market power since it only served as an intermediary between the generators and the PX.

Commission Response

By letter order issued on August 10, 2001, the Commission determined to leave the issue of APX's role in the hearing established in the July 25 Order, including APX's liability, if any, for refunds and APX's obligation, if any, to provide data, to the presiding administrative law judge in the first instance. We will address this issue, if necessary, after the judge addresses it in the refund proceeding.

c. Issues from December 15 Order

Several issues related to refunds remain from the December 15 Order. First, several suppliers oppose the December 15 Order's determination to adopt, over their objections, the November 1 Order's proposal to "condition market-based rates on sellers remaining subject to potential refund liability through December 31, 2002[260] in order to ensure just and reasonable rates during the period it takes to effectuate longer term remedies in the markets."[261] They renew their argument that it was beyond the Commission's authority under section 206(b) of the FPA to extend potential refund liability for more than 15 months from the refund effective date.[262] For example, Dynegy argues that: the general duty imposed by section 206(a) is to be implemented only in accordance with the substantive and procedural limitations of section 206(b); the opportunity to obtain refunds, as well as limitations on refund effective dates, are created by section 206(b) and are not mentioned in section 206(a); once a rate is accepted for filing and that rate is challenged by the Commission or another market participant under section 206, then the limitations of section 206 apply; Central Iowa Power Cooperative v. FERC[263] is distinguishable because, although the court held that the Commission had authority to amend the power pooling agreement pursuant to section 206, the court's decision did not concern the extent of the Commission's refund authority; although the courts have recognized that imposing a condition can be preferable to the alternatives of rejection or unconditional acceptance, the Commission has steadfastly refused to reject market-based rates, and the Commission approved Dynegy's market-based rate without suspension or hearing; the Trans Alaska case[264] is distinguishable because it was an Interstate Commerce Act (ICA) case, not an FPA case, the 15-month refund provision was recently added to the FPA and Trans Alaska involved the ICA equivalent of an FPA

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[260]The Commission subsequently provided for price mitigation, which includes potential refund liability, to run through September 30, 2002. See June 19 Order, 95 FERC at 62,567.

[261]See December 15 Order, 93 FERC at 62,010-11.

[262]See, e.g., Requests for Rehearing of Dynegy at 18-26, Enron at 9-10, PPL at 18-21, and Reliant at 16-18.

[263]606 F.2d 1156 (D.C. Cir. 1979) (Central Iowa).

[264]See Trans Alaska Pipeline Rate Cases, 436 U.S. 631 (1978).

section 205 rate approval rather than an FPA section 206 rate adjustment; the Yankee Atomic case[265] is distinguishable because there the Commission required amendment of the utilities' base rates to allow for refunds if a limited component, the return on equity component, of their formula rates exceeded a certain level; and section 206(a) does not provide an independent source of refund conditioning authority because it does not explicitly reference refunds, the Commission is attempting to do indirectly what the FPA does not permit it to do directly.[266]

Reliant argues that the refund condition is improper because the December 15 Order ordered the implementation of market structural remedies to assure just and reasonable rates going forward. Further, it contends that under section 206(b), once the Commission has put into place the conditions for just and reasonable rates "to be thereafter observed," the refund period is closed, and prospective refunds are precluded by the mechanics of the FPA. Further, it contends that the types of conditions placed on authorization of market-based rates relate not to the price charged but to the structure and restrictions of market interactions, such as the requirement that an applicant file and operate pursuant to an open-access tariff or file regular reports regarding contractual relationships with affiliates so that the Commission can insure that a party is not exercising market power. It also argues that the uncertainty of whether a certain price will meet an after-the-fact "just and reasonable" evaluation would discourage new investment in needed resources. If any refund obligation is retained, Reliant argues that it should apply only to transactions that occurred between October 2, 2000 and December 31, 2000, and transactions at prices above the $150/MWh breakpoint after December 31, 2000 that are evaluated by the Commission during the rolling sixty-day refund period.

PPL also objects to the imposition of refund liability as a condition on the market-based rate authority of sellers that the Commission did not find specifically to have exercised market power. The City of San Diego conversely asserts that ending refund liability at the end of December 2002, without evidence that rates being charged after that date would be just and reasonable, was improper. The California Commission and the County of San Diego allege that the 60-day window for above-breakpoint transactions, after which refund liability will end absent written notification from the Commission, improperly restricts sellers' refund obligations, and they complain that buyers will not have access to data in that time frame to be able to challenge the rates

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[265]See Yankee Atomic Electric Co., 40 FERC ¶ 61,372 (1987).

[266]Further, Dynegy argued that the need for prospective refunds should be reassessed based on the outcome of the conference on forward contracting in Docket No. PL01-2-000 that commenced in December 2000. However, the conference was suspended on January 10, 2001.

charged. The City of San Diego also argues that the Commission must either order refunds immediately or give a reasonable basis for the delay.

Commission Response

We deny rehearing on these issues. The parties' emphasis on section 206(b) is misplaced. As discussed in greater detail in the November 1 Order,[267] Congress passed the Regulatory Fairness Act (RFA), establishing the 15-month refund effective period, in order to give the Commission authority to order retroactive rate reductions in section 206 proceedings.[268] Nothing in the RFA or its legislative history suggests that Congress intended to address, much less limit, the Commission's pre-existing authority to order prospective relief. Since the RFA has no bearing on this issue, cases cited by the Commission concerning its prospective conditioning authority carry the same precedential weight regardless of whether they were decided before or after the enactment of the RFA. Therefore, section 206(b) does not limit the Commission's prospective conditioning authority. Further, the fact that Central Iowa did not specifically address refund conditions for market-based rates does not prevent the application of its broader holding - that the Commission may amend rates pursuant to section 206 -- to these facts. The fact that Yankee Atomic applied to one component of a formula rate is irrelevant; the Commission had authority to change the rate under section 206.

Further, Dynegy's argument that section 206(a) does not mention refunds is also misplaced, because section 206(a) authorizes the Commission to fix the just and reasonable rate, charge, classification, rule, regulation, practice or contract to be thereafter observed. Having found that "the California market structure and rules provide the opportunity for sellers to exercise market power when supply is tight"[269] and that long-term measures needed to be developed, the Commission could not lawfully

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[267]See 93 FERC at 61,379-80.

[268]Prior to enactment of the RFA, the Commission's authority under section 206 was limited to prospective relief. Congress took note of the fact that section 205 proceedings, in which proposed rate changes are subject to refund, took on the average of one year to complete, but section 206 proceedings, in which rate reductions could be ordered prospectively only, took on the average of two years to complete. It concluded that one probable reason for the difference was that public utilities had little incentive to settle meritorious section 206 complaints since any relief was prospective. See S. Rep. No. 100-491, 1988 U.S. Code & Cong. Ad. News 2684-85.

[269]Id. at 62,011.

ensure just and reasonable market-based rates in the ISO and PX markets in the interim period absent the imposition of a refund condition. Consequently, any refunds would be pursuant to the sellers' continuing market-based rate authorizations, not section 206(b). Since the December 15 Order instituted interim remedial measures, we reject Reliant's argument that the order's mitigation measures made a refund condition unnecessary.

Whether conditions on market-based rate authorization ordered previously in other cases included refund conditions does not affect our authority to impose refund conditions to ensure just and reasonable rates here. We find that the need for the refund condition here to address the dysfunctional markets outweighs the potential that refund uncertainty might dissuade some potential sellers from new investment in generation in California.

Even if we agreed with the view that the 15-month limitation on refunds under section 206(b) applied to prospective relief, and we do not, the argument concerning the December 15 Order's conditioning of suppliers' continued market-based rate authority on a refund obligation through December 31, 2002 has been rendered moot by subsequent Commission orders. The temporary price mitigation measures adopted in the December 15 Order were superseded, effective May 29, 2001, by the long-term price mitigation measures adopted in the April 26 Order and further modified in subsequent orders. The April 26 Order replaced the December 15 Order's market monitoring requirement for monthly reports filed by the ISO with a formula-based mitigated reserve deficiency MCP. The April 26 mitigation plan made sales above the mitigated price occurring in a given month subject to refund pending Commission review of sellers' cost justification filings for that month.[270] Thus, effective May 29, 2001, the date that the April 26 mitigation took effect, sellers' refund obligation was pursuant to the April 26 Order's cost justification filing requirement rather than pursuant to the December 15 Order's ongoing market monitoring.[271] Since the refund condition adopted in the December 15 Order remained in existence for only five months, it did not exceed the 15-month limit under FPA Section 206(b). Accordingly, arguments based on a premise that the limit was or would be exceeded are moot.

[270] The Commission also conditioned sellers' market-based rate authority on their not engaging in certain anticompetitive behavior, with violators' market-based rates being made subject to refund.

[271] Refunds for transactions occurring during non-reserve deficiency hours from May 29 through June 20, 2001 will be calculated in the refund hearing before Judge Birchman. See July 25 Order, 96 FERC at 61,517.

City of San Diego expresses concern that the December 15 Order does not ensure that sellers' rates would be just and reasonable after the termination of their potential refund liability. Its concern was premature in view of the interim nature of the December 15 Order. As noted above, even though the June 19 price mitigation is set to end on September 30, 2002,[272] quarterly reporting by the ISO will continue. If the quarterly reports reveal the potential to exercise market power, the Commission will determine any appropriate action to take.

We reject PPL's argument that we may not impose refund liability absent a finding that a specific seller exercised market power for the same reasons that we reject the same argument on rehearing of the July 25 Order.[273]

The parties' argument that the 60-day window for review of transactions above the mitigated price is too restrictive is moot.[274] In the June 19 Order, in response to similar concerns, we explained that the 60-day period for review of cost justifications was a self-imposed requirement to ensure that there is price certainty and that we have the authority to extend the period if necessary to finish processing the justifications.[275] To date, we have processed cost justification filings without extending the 60-day window of review.

With respect to City of San Diego's argument that we should have ordered refunds immediately, the record was not sufficiently developed at the time of the December 15 Order to take such action. As noted earlier in this order, the Commission established a refund hearing in this proceeding.

d. Issues from June 19 Order

APPA contends that limiting price mitigation to spot market sales of 24 hours or less unreasonably truncates the scope of potential refunds. The ISO claims that the June 19 Order fails to adequately address refunds for past overcharges by sellers.

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[272] June 19 Order, 95 FERC at 62,567.

[273] See supra section B.3.a.

[274] As noted above, the December 15 Order's provision for reporting transactions above the $150 breakpoint has been replaced with the requirement that sellers make cost justification filings for sales above the mitigated price.

[275] 95 FERC at 62,566.

BP Energy Company contends that the refund obligation is imposed on mutually agreed, bilateral sales transactions without required evidentiary findings that such sales are not just and reasonable. Idacorp and Williams request clarification that the June 19 methodology will not be applied retroactively. Idacorp requests, at least, clarification that the methodology will not be applied retroactively unless the Commission has further proceedings to develop a fact-based methodology. In addition, Idacorp requests clarification to reaffirm that rates may be justified by costs, and that sellers have the right to setoff against any refund amounts. PPL asks the Commission to abide by its commitment to notify sellers within 60 days of their reports if it may impose refund liability. Puget Sound requests confirmation that the refund effective date for sales outside of California is not prior to July 2, 2001. Sierra Pacific and Nevada Power request clarification that they should have no refund obligation for past sales into California.

AEPCO claims that there is no basis for applying provisions under the June 19 Order retroactively to out-of-California sellers that are not public utilities and forcing such sellers to undergo any sort of overcharge/refund inquiry.

Washington Attorney General and several other parties contend that the Commission should have established a refund effective date for West-wide refunds consistent with the refund effective date for California refunds. Washington Attorney General argues that (1) the original San Diego proceeding has always been, effectively, considered as a West-wide proceeding; (2) excluding Northwest utilities from potential refunds from October 2, 2000 would lead to refund anomalies that would be inconsistent with the FPA's policies against a seller giving preferential treatment to any purchaser and against any advantages to any person based on geographic locality; and (3) the Puget Sound proceeding provides a basis for an earlier refund effective date.[276]

Commission Response

We deny these requests for rehearing and grant or deny requests for clarification, as discussed below. In view of Commission determinations in the July 25 Order, some of these issues are either moot or subsumed within the discussion of requests for rehearing of the July 25 Order, which are discussed elsewhere in this order.[277]

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[276] See also Requests for Rehearing of Idaho Power, North Star Steel, Attorney General of Washington/City of Tacoma, Washington, and Port Seattle, Washington

[277] Regarding AEPCO's argument concerning bilateral transactions, this order (see sections B.1, E.10) affirms the determination to apply the refund methodology to

(continued...)

APPA contends that the Commission's investigation should encompass all public utility sales for resale at market-based rates and all transactions of less than one year. The spot markets were the only markets in which the Commission determined that rates may be unjust and unreasonable.[278] Therefore, it was appropriate to limit mitigation to those markets. Moreover, APPA provides no justification to extend the scope of our investigation or the mitigation to bilateral transactions other than those in spot markets.[279]

With respect to the ISO's arguments that the June 19 Order fails to adequately address refunds for past overcharges, we note that the July 25 Order established a methodology for calculating refunds from October 2, 2000 through June 20, 2001 and a hearing before Judge Birchman to develop the factual record in order to implement it.

We also provide the following clarifications. First, price mitigation, as modified by the July 25 Order, will be applied to the period from October 2, 2000 through June 20, 2001.[280] Second, for prospective price mitigation, all sellers in the ISO spot markets and all public utility sellers for bilateral spot market sales in the WSCC through September 30, 2002 seeking to charge prices in excess of the mitigated price may make cost justification filings pursuant to the procedures set forth in the April 26 and June 19 Orders and this order.[281] Third, the June 19 Order stated that the 60-day review period was self-imposed, and we reserved the right to take more time, if necessary to finish

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[277](...continued)
transactions by governmental entities and cooperatives in the ISO and PX markets, but grants rehearing and determines that those sellers are not required to make refunds for transactions outside of the ISO and PX markets.

[278]The spot markets are short-term (i.e., one day or less) energy markets (Day-Ahead, Day-of, Ancillary Services and real-time energy sales). See November 1 Order, 93 FERC at 61,349; June 19 Order, 95 FERC at 62,545, n.3).

[279]See 95 FERC at 62,556.

[280]As noted supra note 260, refunds for transactions occurring during non-reserve deficiency hours from May 29, 2001 through June 20, 2001 will be calculated in the refund hearing before Judge Birchman.

[281]The April 26 Order established the cost justification filing mechanism. The June 19 Order, among other things, modified the April 26 Order with respect to the types of costs that would be allowed.

processing the justification filings.[282] In any event, a self-imposed procedural deadline could not preclude us from ordering refunds where necessary to fulfill our duties under section 206.

Concerning Puget Sound's request for clarification that the refund effective date for sales outside of California is not prior to July 2, 2001, we note that the April 26 Order which initiated the West-wide investigation of sales in the WSCC established a refund effective date of July 2, 2001.[283] However, we further note that the July 25 Order established a separate proceeding (in response to Puget Sound's complaint) to address whether there may have been unjust and unreasonable charges for spot market bilateral sales in the Pacific Northwest for the period beginning December 25, 2000 through June 20, 2001. Puget Sound has filed a motion to withdraw its complaint in that proceeding. If the Commission denies Puget Sound’s motion to withdraw its complaint, then the Commission could establish a refund effective date as early as December 25, 2000, with respect to rates in the Pacific Northwest.[284] Thus, there remains the potential for some overlap, with respect to rates in the Pacific Northwest, between the Puget Sound complaint and the West-wide investigation. The complaint, and the motion to withdraw the complaint are pending. At present, the only operative refund effective date is July 2, 2001 with respect to the West-wide investigation.

We deny Sierra Pacific's and Nevada Power's request for clarification that they should have no refund obligation for past sales into California. In the July 25 Order, the Commission determined that refund liability should apply to all sellers of energy in the ISO and PX spot markets for the period beginning October 2, 2000.[285]

With respect to Washington Attorney General's argument that the refund effective date for West-wide refunds should be consistent with the refund effective date for California refunds, we note that the July 2, 2001 refund effective date established for the

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[282] See 95 FERC at 62,566.

[283] See June 19 Order, 95 FERC at 62,567-68, 62,570 (noting that the date 60 days after Federal Register publication of notice of the investigation initiated by the April 26 Order was July 2, 2001).

[284] See 96 FERC at 61,520-21 & n.75. December 25, 2000 is the earliest refund effective date the Commission could establish for Puget Sound's complaint regarding rates in the Pacific Northwest.

[285] See 96 FERC at 61,511.

West-wide investigation initiated in the April 26 Order was 60 days after Federal Register publication of notice of initiation of the investigation, which is the earliest refund effective date permitted under section 206(b) of the FPA.[286]

Further, we disagree that the original SDG&E complaint proceeding was effectively a West-wide proceeding. The SDG&E complaint concerned rates for SDG&E's purchases through the ISO and PX markets in California. The Commission did not establish a West-wide investigation until it issued its April 26 Order.

e. Issues from July 25 Order

The ISO seeks clarification that the July 25 Order does not require a full refund period netting approach for settlement of refunds. The ISO contends that by allowing sellers to net against refund amounts they owe past due payments and possibly refund amounts owed to them by sellers, without consideration of timing or parties involved, the Commission would be giving sellers who charged unjust and unreasonable rates first collection priority over refund amounts. Instead, the ISO asserts that the Commission should refer to the hearings on refunds the issue of how refund amounts should be calculated and paid, and must indicate that the resolution of the issue must not give sellers an unfair advantage.

Other clarifications sought include whether the refund amounts owed by suppliers are to be offset by the amounts due to suppliers,[287] whether any refunds need to be paid if a purchaser has failed to pay for its purchases,[288] and by what mechanism refunds should flow through to purchasers.[289]

Commission Response

The July 25 Order provides in pertinent part:[290]

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[286] Id. at 61,520 n.75.

[287] See, e.g., Request for Rehearing of Salt River.

[288] See, e.g., Request for Rehearing of Puget/Avista.

[289] See, e.g., Request for Rehearing of City of San Diego, Vernon.

[290] 96 FERC at 61,519.

> Once the ISO has calculated the hourly market clearing prices for the refund period, this data should be used by both the ISO and PX to rerun their settlement/billing processes and all penalties. These revised settlements should be submitted to the administrative law judge and parties should use this information to form the basis of any offsets (i.e. the amounts to be refunded against the payments past due). We direct the administrative law judge to certify this information, in its entirety, to the Commission.
>
> California Parties support the calculation of interest against refunds and maintain that Commission precedent requires an interest calculation. Sellers believe that if interest charges are assessed that they should be assessed symmetrically to refunded amounts and to amounts past due. We will direct the calculation of interest on both refunds and receivables past due, pursuant to the methodology for the calculation of interest under Section 35.19a of the Code of Federal Regulations.[[291]]

With respect to the requests for clarification or rehearing concerning offsets, and whether a seller must make refunds even when a purchaser has failed to pay for its purchases, we note that the July 25 Order provides for offsets of amounts to be refunded against payments past due, as discussed above. The July 25 Order balanced the interests of those who would receive refunds and those who would have to pay refunds by directing the calculation of interest on both refunds and receivables past due. The ISO does not explain, and we do not see, how this offset approach would give sellers who charge unjust and unreasonable rates first collection priority over refund amounts, as the ISO asserts, and the ISO has not persuaded us that this approach will not adequately protect the interests of those who will receive refunds.

The July 25 Order does not specify the mechanism by which refunds should flow to customers. We will address this issue when, after reviewing the judge's findings of fact in the refund hearing, we issue an order addressing refunds.

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[291] The July 25 Order also established an evidentiary hearing to further develop the factual record to enable the refund methodology prescribed in the order to be implemented, and it generally limited the scope of the evidentiary refund hearing to the collection of data needed to apply the refund methodology prescribed in the order. Id. at 61,520.

PG&E reiterates its argument that refunds should be ordered for the pre-October 2000 period. The July 25 Order denied PG&E's and others' requests for rehearing of the November 1 Order on that issue, and PG&E makes no new arguments that cause us to reconsider our determination that the Commission is not authorized to order refunds prior to the October 2 refund effective date.

C. Rehearing of Remaining Issues from December 15 and Earlier Orders

Many arguments regarding the proposed remedies in the November 1 Order were never ripe for rehearing. In the November 1 Order, the Commission merely proposed actions or tariff changes. Commission proposals do not trigger administrative review, and rehearing does not lie until the Commission issues a final decision or other final order.[292] In any event, the events and orders transpiring since the beginning of this proceeding have resolved or made moot many issues the parties have raised. For example, since deadlines that the Commission imposed in the November 1 Order for the implementation of various Commission directives have passed, and no consequences were imposed for not meeting those deadlines, the arguments concerning the impracticality of these deadlines are now moot. Furthermore, the market mitigation plan established in the April 26 and June 19 Orders has now superseded prior Commission directives, and the refund methodology adopted in the July 25 Order has now superseded the $150/MWh breakpoint approach of the December 15 Order. Thus, most of the issues raised on rehearing with respect to the mitigation and reporting requirements of the December 15 Order are moot.

1. Buy/Sell Requirement

The December 15 Order eliminated the requirement that the IOUs sell all of their generation into and buy all their generation from the PX ("buy/sell requirement"). In order to enforce this remedial measure, the Commission also terminated the PX's wholesale rate schedules, noting the California Commission's reluctance to remove its mandatory buy requirement, and finding that the Commission could not ensure just and reasonable rates in the presence of a mandatory power exchange in those circumstances. The Commission later clarified that only the PX's spot market rate schedules (core

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[292] See Rule 713 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.713 (2001).

markets) needed to terminate, and that the PX's forward markets (CTS Rate Schedules) could continue in a modified form.[293]

The PX contends that the Commission overstepped its statutory and Constitutional authority when it ordered the end to the PX's rate schedules. Specifically, the PX states that FPA section 206 authorizes the Commission to examine the justness and reasonableness of any wholesale rate schedule, and if it finds that a rate is unjust and unreasonable, the Commission shall prescribe substitute terms or conditions. The PX argues that the Commission has a statutory duty to allow a public utility to continue in business and to prescribe just and reasonable terms under which that can occur.

In stating that the Commission's cancellation of the PX's rate schedules is unconstitutional, the PX contends that it has a "fundamental right not to have its property taken without due process and just compensation," since "every public utility is entitled to an opportunity to recover its costs of doing business and a fair rate of return on its capital." Finally, the PX argues that the termination of the CTS Rate Schedule was unnecessary and that clarification is needed to distinguish between the mandatory PX core markets and the voluntary CTS Block Forward Markets.

In order to address some of its concerns, the PX requests that the Commission stay two actions taken in the December 15 Order. First, the PX requests that the Commission stay its action preventing the IOUs from continuing to sell power into the PX markets on a voluntary basis. Second, the PX asks that the Commission stay its termination of the CTS Block Forward Rate Schedule to prevent a chilling effect on long-term contracts.

The Oversight Board states that the termination of the PX tariff needlessly eliminates market opportunities for buyers and sellers, when, in the alternative, the Commission could have simply eliminated the mandatory buy/sell requirement.[294] The California Commission contends that the Commission erred in eliminating the PX's buy-sell requirement since this action violates the FPA, is arbitrary and capricious, is not the

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[293] See San Diego Gas & Electric Co., 94 FERC ¶ 61,005, reh'g dismissed, 94 FERC ¶ 61,243 (2001) (January 8, 2001 Order).

[294] In addition, the Oversight Board contends that the Commission's actions, in removing the utilities' supply from the PX spot markets, intrude upon the California Commission's jurisdiction over the manner in which the revenues associated with utilities' sales of energy are allocated. Specifically, the Oversight Board states that without utilities purchasing their own supply from the PX, the California Commission loses its exclusive jurisdiction over how the utilities' revenues are treated: either as benefits to a utility's shareholders or ratepayers.

product of reasoned decisionmaking, and is not based on substantial evidence. SMUD argues that, since the Commission's prohibition against the IOUs selling into the PX markets may be "undermined" if the PX's Motion to Stay this prohibition is granted by the 9th Circuit, it is an inadequate measure to ensure just and reasonable rates. Finally, SDG&E seeks clarification that the Commission intended to eliminate only the requirement that IOUs bid their resources into the PX market, thus permitting IOUs to rely on their own resources to serve their retail load, and not to forbid IOUs from selling into the PX market any surplus resources that are not needed to serve that load.

Commission Response

The Commission finds that its actions eliminating unjust and unreasonable rates through removal of the reliance on the buy/sell requirement lawfully followed the procedures dictated in FPA section 206. Under FPA section 206, the Commission can investigate existing rates, and, if it finds those existing rates unlawful, set new just and reasonable rates. In response to numerous formal and informal complaints, comments, and inquiries, and following the Commission’s paper hearing and an investigation of the serious economic impact that the existing wholesale market structure was having on California, the Commission determined that the buy/sell requirement created a dysfunctional wholesale spot market with considerable volatility. In light of this finding, the Commission concluded, pursuant to FPA section 206, that it was no longer just and reasonable to permit virtually all of the IOUs' needs to continue to be met in the wholesale spot market.

However, when faced with the California Commission's unwillingness to relinquish reliance on the buy/sell requirement, the Commission "conclude[d] that it is necessary to take the unusual step of terminating the PX's wholesale tariffs which . . . enable it to continue to operate as a mandatory exchange."[295] Thus, once the Commission determined, pursuant to FPA section 206, that the PX's mandatory exchange rates were unlawful, the Commission properly tailored relief to eliminate the problem through termination of the PX's wholesale tariffs. This relief action that the Commission contoured to address the identified harm, was a critical part of the comprehensive set of remedies for the serious flaws in the California market structure and rules that have caused and could have continued to cause unjust and unreasonable rates for short-term wholesale sales of electric energy in interstate commerce. Through the remedies ordered in the December 15 Order and orders issued thereafter, the Commission determined "the just and reasonable rate, charge, classification, rule, regulation, practice or contract" to

[295]December 15 Order at 61,999

replace the flawed structure and rules and "fix[ed] the same by order," as required by FPA section 206.

Furthermore, the Commission has not closed the PX for business, despite the PX's contention that the effect of the December 15 Order was to do so. In fact, in the December 15 Order, the Commission invited the PX "to reconstitute itself as an independent exchange with no regulatory mandated products and offer the services needed by market participants."[296] Also, in the January 8, 2001 Order, the Commission clarified "that our determination to terminate the PX's existing wholesale rate schedules was not intended to preclude the PX from engaging in bilateral forward contracting."[297] We went on to state that the "PX is free to revise its CTS tariffs to remove the spot market components of its existing rate schedules, and to file them" pursuant to FPA section 205.[298] In addition to demonstrating that the Commission has not closed the PX, these clarifications in the January 8, 2001 Order render moot the PX's request that the Commission stay its termination of the CTS Block Forwards Rate Schedule.

The Commission also must deny the PX's request that the IOUs be allowed to voluntarily sell power into the PX markets. In order to assure just and reasonable rates in the presence of the state-mandated requirement that the IOUs sell all of their generation into and buy all of their generation from the PX, and in light of the state's established policy favoring the use of the spot markets, the Commission found it necessary and continues to believe it necessary to terminate the PX's Core Markets rate schedules as clarified in the January 8 Order. To do otherwise would be to allow a state requirement to override the Commission's mandate to assure just and reasonable rates for sales within the Commission’s exclusive jurisdiction.[299]

The PX is also incorrect in stating that the Commission's action "is unconstitutional because it violates the PX's fundamental right not to have its property taken without due process and just compensation." In Jersey Central Light & Power Co.

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[296] Id. at 62,000, n.46.

[297] January 8, 2001 Order at 61,008.

[298] Id.

[299] While the PX argues that the "absolute prohibition contravenes the December 15 Order's stated objective of promoting forward trading opportunities," the Commission addressed this concern in the January 8 Order when it clarified that its action "was not intended to preclude the PX from engaging in bilateral forward contracting." 94 FERC at 61,008.

v. FERC, 810 F.2d 1168 at 1180-81 (D.C. Cir. 1987), the court stated that "a company that is unable to survive without charging exploitative rates has no entitlement to such rates." Since the PX's tariff led to unjust and unreasonable rates under certain conditions, it has no constitutional right to retain that tariff. Also, since the PX has recovered its $100 million startup costs and the opportunity was available to recover ongoing operating expenses through its tariff,[300] no takings issue exists.

Finally, we note that, in considering the PX's arguments in a petition for mandamus in this proceeding, the United States Court of Appeals for the Ninth Circuit stated that "[w]e are unconvinced that CalPX [PX] has presented a 'clear and certain' claim that FERC violated section 206(a) by terminating its tariff and rate schedules." California Power Exchange Corp. v. FERC, 245 F.3d 1110, 1121 (9th Cir. 2001). Indeed, the court found that terminating the PX's tariff and wholesale rate schedule "to prevent it from continuing to operate as a mandatory exclusive exchange," along with the other remedies in the December 15 Order "appear to be fully consistent with § 206(a). Id.

In our December 15 Order and subsequent orders, the Commission has established rates, regulations or practices which we believe result in just and reasonable rates.

2. Underscheduling

In the December 15 Order, the Commission adopted an underscheduling penalty to apply to market participants that met more than five percent of their load in the real-time markets. The California Commission, ISO, SMUD, the Oversight Board, and PG&E request rehearing of the underscheduling penalty, stating that the penalty should either account for good utility practice, apply symmetrically to generation not scheduled in forward markets, or should be eliminated. The California Commission states that the decision in the December 15 Order rests on internally inconsistent factual assertions and that the penalty will exacerbate the exercise of market power by the suppliers. Further, the California Commission opposes the distribution of proceeds from the underscheduling penalty to loads that schedule accurately because only those loads that are self-sufficient in generation will benefit due to the lack of adequate supply offered in the PX markets. The California Commission asserts that these self-sufficient loads have an incentive to withhold supply from the market to increase the revenues they receive from the underscheduling penalty. The Oversight Board argues that the penalty is unlikely to reduce underscheduling and may increase costs in the forward markets.

[300]See PX FERC Electric Tariff, Third Revised Volume No. 1, Schedule 1, Original Sheet Nos. 48-49.

SDG&E and PG&E contend that other aspects of the December 15 Order crippled the ability of suppliers to use short-run coordinated markets to balance supply and demand, and thus made it impossible for suppliers to avoid the underscheduling penalty. The two companies jointly filed a request in Docket No. EL01-34-000 seeking suspension of the underscheduling penalty. The Commission deferred action on the request and sought additional information from the ISO, which the ISO has since submitted.[301] The matter remains pending before the Commission.

On rehearing of the December 15 Order, the ISO expresses support for incentives, such as the underscheduling penalty, to move both load and generation into forward purchases, but suggests that the December 15 Order does not apply these incentives symmetrically, and should also include incentives to move generation out of real-time markets. The ISO also filed in Docket Nos. ER01-1579-000 and ER01-1579-001, Amendment No. 38 to temporarily suspend the penalty for underscheduled load because severe financial difficulties of PG&E and SoCal Edison prevented them from making bilateral purchases or accessing forward markets. The Commission, among other things, rejected the proposed tariff amendment on the basis that the matter was pending in Docket No. EL01-34-000.[302] Parties sought rehearing of the Commission's decision.

Commission Response

The Commission has long had penalties in Open Access Transmission Tariffs to encourage balanced schedules. In the December 15 Order, the Commission recognized that the lack of forward purchases and any resulting underscheduling of load threatened the reliability of the ISO controlled system by forcing over-reliance on the ISO's real-time imbalance markets to supply load. Therefore, the Commission adopted the penalty provision as one component of the market mitigation to encourage forward contracts and a more balanced supply. Subsequent to the issuance of the December 15 Order, the State of California and DWR began negotiating forward purchases on behalf of SoCal Edison and PG&E to cover their net short position (i.e., the load remaining to be served after the utilities had self-supplied generation).

We will grant rehearing on this issue and will eliminate the underscheduling penalty for load as of January 1, 2001, when it was to have been implemented pursuant to the December 15 Order. As noted by intervenors, the suspension of operation of the PX

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[301] See Southern California Edison Company and Pacific Gas & Electric Company, 95 FERC ¶ 61,025 (2001).

[302] See California Independent System Operator Corporation, 95 FERC ¶ 61,199 (2001), reh'g pending.

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 fill their requirements for energy in the day ahead and hour ahead time frames. The Commission does not wish to penalize market participants for underscheduling when markets may not have been available to fulfill their needs; it would be unreasonable to impose a penalty in a situation where that penalty could not be avoided. In any event, we have seen a vast improvement in the reduction of underscheduling by loads, especially in the summer months, when historically underscheduling has been most noticeable. There do not appear to have been any underscheduling penalty payments made or distributed. Forcing such payments at this late date will have no effect on past behavior, and the markets have now seemed to stabilize with the combined effects of the other features of our orders. Therefore, although accurate scheduling is still paramount, as both underscheduling and overscheduling can present severe problems in reliable operation of the ISO's system, the underscheduling penalty should be eliminated.

We will not hesitate to impose prospectively a similar penalty if chronic underscheduling again creates a reliability problem in California, although we believe this scenario is unlikely since overall supply and demand are now more in balance and the must-offer obligation will remain in place through September 30, 2002.

In light of this determination, we find the ISO's Tariff Amendment No. 38 filed in Docket Nos. ER01-1579-000 and -001 proposing to suspend the penalty to be moot, and we will terminate that docket. Similarly, we will dismiss the complaint in Docket No. EL01-34-000 as moot.

3. QF Issues

The December QF order waived certain regulations to allow QFs to sell their excess production to load located in California in order to alleviate the inadequate generation resources. The order also provided that additional power generated as a result of the waivers above historical output was to be sold through negotiated bilateral agreements. SoCal Edison filed a request for immediate modification of the order, claiming that permitting sales of excess production interfered with existing contractual relationships, created uncertainty between the parties, and was unworkable given the short time period for the waiver (less than a month). SoCal Edison requested that the Commission limit its order to waiving efficiency and fuel use standards, and allow the parties to determine how the waiver would impact their contractual rights and obligations, including whether to negotiate a contract amendment.

In the December 15 Order, the Commission extended the waiver of those regulations through April 30, 2001.[303] IEP states that it generally supports the Commission's actions in the December 15 Order. IEP states, however, that some statements in the Commission's December 15 Order could lead to unintended consequences, including QF power becoming unavailable to serve the California market as a result of the California Commission repricing existing long-term QF contracts. IEP asks the Commission to clarify that PURPA pricing provisions still apply to the sale of QF electric power following the December 15 Order.

CE Generation expresses similar concerns. CE Generation states that the California Commission has indicated that it intends to regulate QFs in ways inconsistent with PURPA, including requiring QFs to sell power at rates lower than those contained in existing long-term QF contracts. CE Generation asks the Commission to declare that the California Commission does not have jurisdiction to regulate the price of power sold at wholesale pursuant to long-term contracts that were entered into pursuant to PURPA and that the California Commission must allow California IOUs to recover the costs of their purchases made pursuant to such long-term contracts.

Commission Response

As we stated above in our discussion addressing the rehearings of the June 19 and July 25 Orders,[304] QFs are not being compelled to make sales inconsistent with the pricing provisions of PURPA. The QFs' primary sales remain sales pursuant to contracts either freely negotiated between parties and containing negotiated rates or pursuant to contracts imposed under PURPA and at avoided cost rates set by the State Commission.[305] Nothing in our December 15 Order interferes with existing long-term contractual arrangements between QFs and utilities. The pricing provisions contained in the long-term contracts remain in effect unless a state court or a bankruptcy court finds that the contracts have been breached and are no longer in effect. New contractual arrangements for the sale of "excess power" must be pursuant to bilateral contracts with negotiated rates. In sum, PURPA pricing provisions remain in place following the

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[303]The Commission later extended the waiver through April 30, 2002, and we extend it elsewhere in this order through December 31, 2002. See Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States, 94 FERC ¶ 61,272, order on reh'g, 95 FERC ¶ 61,225 at 61,767-68, order on further reh'g, 96 FERC ¶ 61,155, order on further reh'g, 97 FERC ¶ 61,024 (2001).

[304]See supra, section B.1.b.

[305]See 18 C.F.R. § 292.301- 292.304 (2001).

December 15 Order, as we foresee no sales resulting from our December 15 Order which would take place at rates inconsistent with our regulations implementing PURPA.

Regarding CE Generation's issues, we note that one of the principal benefits of QF status is that QFs are exempt from much state law and regulation, including rate regulation (other than regulation implementing our avoided cost regulations contained in 18 C.F.R. §§ 292.301 - 292.308 (2001)).[306] We also note, as CE Generation points out, that courts have addressed the relationship between state regulation and this Commission's authority with respect to PURPA on a number of occasions.[307] Our regulations also provide that, upon the request of any person, the Commission may determine whether a QF is exempt from a particular state law or regulation.[308] While we stress that our orders addressing the California energy crisis were not intended to require QF power sales at prices inconsistent with PURPA, we have not been presented in this rehearing with details of any specific state action inconsistent with PURPA. Nor have we before us a request that we determine whether a QF is exempt from a particular state law or regulation. Accordingly, we decline to make any declarations at this time about any proposed California Commission action. We will clarify that the Commission was not authorizing in its December 15 Order any state action inconsistent with PURPA.

4. Governance of the ISO

In the December 15 Order, the Commission required that the existing stakeholder ISO Governing Board be replaced with a non-stakeholder Governing Board whose members are "independent of market participants."[309] The order called for "further on-the-record procedures to discuss with California representatives the selection process for the new ISO Board."[310] Pending those discussions, the ISO Governing Board was to turn over decision-making power and operating control to the management of the ISO by January 29, 2001, and subsequently serve as a stakeholder advisory committee until the

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[306] See 18 C.F.R. 292.602(c) (2001).

[307] See, e.g., Independent Energy Producers Association v. California Commission, 36 F.3d 848 (9th Cir. 1994); Freehold Cogeneration Association v. Board of Regulatory Commissioners of the State of New Jersey, 44 F.3d 1178 (3rd Cir. 1995).

[308] See 18 C.F.R. § 292.301(c)(ii)(4) (2001).

[309] December 15 Order at 62,013.

[310] Id.

new ISO Governing Board was seated.[311] The ISO's bylaws were to become null and void as of January 29, 2001, to the extent they were inconsistent with this directive.[312] The Commission also stated that "if no consensus is reached regarding an acceptable means to select new ISO Board members [by April 29, 2001], then the procedures proposed in the November 1 Order will be carried out."[313]

The ISO, the Oversight Board, and the Western Power Trading Forum (WPTF) each filed a request for rehearing of the governance provisions of the December 15 Order. The ISO seeks rehearing and a stay of the requirement that the ISO Governing Board surrender authority to ISO management by January 29, 2001. The ISO argues that such a move could place a "cloud" over the ISO's corporate authority and, therefore, disrupt arrangements with lenders.

The Oversight Board argues that the December 15 Order should be revised to allow the State of California to restructure the ISO Governing Board subject to subsequent Commission review. The Oversight Board argues that because the ISO was expressly created by California law, California has the right to amend its restructuring law to change the governance structure of the ISO without prior Commission approval.

WPTF argues that it is inappropriate to allow California any significant role in the selection of a new ISO Governing Board. WPTF states that the ISO Governing Board must operate free from State influence in order to ensure that all market participants are treated fairly.

Commission Response

There are a number of pending proceedings that implicate the ISO's current governance structure and the extent of its independence. The context for approaching ISO governance has changed dramatically since issuance of the December 15 Order. The Commission finds it more appropriate to address governance issues in the context of these other, more recently filed proceedings. In addition, a Commission-initiated operational audit of the ISO is currently underway. Therefore, the arguments and concerns raised herein will be addressed in a future order.

5. Forward Contracting

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[311] Id. at 62,013-014.

[312] Id. at 62,014.

[313] Id.

A primary goal of the December 15 Order was to eliminate undue reliance on spot markets and thus the order took several measures to encourage longer-term contracting. Recognizing, inter alia, the expected shift of significant load from the spot to the forward market, the Commission adopted an advisory benchmark of $74/MWh for five-year contracts for supply around-the-clock and stated such contracts at or below that price "can be deemed prudent."[314] The Commission commented that this benchmark could be used as a reference point by buyers and sellers during negotiations, and that the Commission would consider that figure when addressing any complaints about prices in the long-term markets for contracts negotiated over the next year.[315] The order commented that the Commission was not establishing a new standard for market-based prices for long-term contracts and that buyers could reasonably elect to negotiate rates above that level for contracts containing terms and conditions which suited their particular needs.[316]

The order declined to mandate forward contracts at specified prices, however. Discussing a proposal by the California Commission to require medium-term forward contracts at regulated prices, modeled on "vesting contracts" used in New York, the order held that the idea would not be workable given the differences between the restructurings in New York and California.[317]

The California Commission and Reliant request rehearing of the determination that five-year contracts for supply around the clock at the benchmark can be deemed prudent. The California Commission argues that the decision is arbitrary and capricious, not based on substantial evidence, and not calculated properly, while Reliant asserts that the benchmark is unjust and unreasonable because it fails to take into account current market conditions and is not based on substantial evidence and objects that parties had no opportunity to comment on the idea.

The California Commission also requests rehearing on the basis that the Commission did not require that generators enter into medium-term forward contracts at regulated prices, alleging that the decision was arbitrary and capricious and not the product of reasoned decisionmaking. The California Commission asserts that such a

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[314] See 93 FERC at 61,994-95.

[315] Id. at 61,995 and 62,000.

[316] Id. at 61,995.

[317] Id. at 62,000.

requirement would not be unworkable and reiterates its argument that the Commission is required to impose cost-based rates when it finds that a market is dysfunctional.

Commission Response

The Commission presented the $74/MWh benchmark to assist buyers and sellers in their negotiations for longer-term contracts and has never relied on the figure in any proceeding. Since issuance of the December 15 Order, the Commission has never modified any rates or charges on the basis of the advisory benchmark. Further, no party has requested in a complaint that the Commission adjust a negotiated rate on the basis that it exceeds the benchmark. Thus, the California Commission and Reliant cannot allege that they were aggrieved by this aspect of the December 15 Order, and the Commission will dismiss these rehearing requests.[318] Should the issue be relevant in a future proceeding, the parties may raise their arguments concerning the development and level of the benchmark at that time.

As discussed elsewhere in this order, a return to cost-based rates in the California marketplace is not required by FPA section 206, and is not in the public interest. The California Commission's proposal to mandate forward contracts at regulated rates is not consistent with our approach throughout this proceeding and, in any event, is beyond the scope of this proceeding, which is limited to the spot markets. Accordingly, we will deny the rehearing request.

6. Issues of Procedure

On rehearing of the August 23 Order, PG&E and SoCal Edison request that the Commission clarify that refunds are appropriate where rates are found to be above just and reasonable levels. In addition, PG&E argues that the Commission should grant rehearing and immediately impose price caps pending the outcome of the investigation in the consolidated docket, and objects that the Commission did not address its request for interim, short-term mitigation measures. Finally, PG&E asserts that the Commission should begin hearing procedures immediately.

On rehearing of the November 1 Order, the California Commission argues that, until the Commission has the opportunity to review and respond to the comments filed

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[318] Section 313(a) of the Federal Power Act, 16 U.S.C. § 825l, permits only those persons that are aggrieved by a Commission order to request rehearing of that order. See, e.g., City of Summersville, 84 FERC ¶61,073 (1998) and Arizona Public Service Co., 26 FERC ¶61,357 (1984).

on November 22, 2000, the Commission is not able to determine whether disputes concerning material facts can be resolved without an evidentiary hearing. Specifically, the California Commission states that the Commission needs "further study of high-priced bidding by individual firms or periods when individual generators were not running."

The Cities of Santa Clara and Palo Alto, California (Cities) seek rehearing of the December 15 Order's directive that the ISO file revised congestion management procedures by January 31, 2001, arguing that the Commission in effect endorsed the proposed redesign under consideration as of December 15, 2000 because there would not be sufficient time to modify it before the January deadline.[319]

Commission Response

PG&E's and SoCal Edison's concerns have been addressed by subsequent orders. The Commission established paper hearing procedures in November 2000, and has applied the refund methodology to all transactions within the scope of the proceeding subsequent to the refund effective date. These measures protect the utilities' interests during the refund period. Accordingly, we will deny their rehearing requests.

We will reject the California Commission's argument. As the Commission explained in the November 1 Order,[320] we are not required to reach decisions on the basis of an oral, trial-type evidentiary hearing unless the material facts in dispute cannot be resolved on the basis of the written record.[321] The Commission's task in the November 1 and December 15 Orders was to fashion remedies to address dysfunctions in California's wholesale bulk power markets. While the Commission did require a factual understanding of the causes of the dysfunctions, this need was met by the parties' pleadings. Thus, a trial-type evidentiary hearing was unnecessary. The necessary determinations were made on the basis of a written record developed with paper hearing procedures.[322] Notably, the California Commission has not identified any specific factual dispute that the Commission could not resolve on the basis of the written record.

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[319] See December 15 Order at 62,017-18.

[320] November 1 Order at 61,373, n. 96.

[321] See, e.g., Duke Energy Moss Landing LLC and Duke Energy Oakland LLC, 86 FERC ¶ 61,187 at 61,657, n.7 (1999).

[322] Moreover, the July 25 Order set for hearing the remaining issues of fact required to be resolved so that the refund methodology could be implemented.

With respect to the Cities' argument, on January 30, 2001, the ISO filed a request for an extension of time to file its proposed congestion management redesign; as of this date, the ISO has not submitted a proposal and continues to allow further debate regarding redesigning its congestion management, thus satisfying Cities' concerns. We will, however, require the ISO to submit its proposal by May 1, 2002, in light of the necessity for adequate market structures to be in place when the price mitigation ends on September 30, 2002.

7. Other Related Dockets

a. ISO Amendment No. 33 (Docket Nos. ER01-607-000 and ER01-607-001)

The Commission accepted the ISO's Amendment No. 33 on December 8, 2000, the same day that the ISO filed its proposed tariff amendments.[323] Amendment No. 33 made three changes to the ISO Tariff. First, the existing $250/MWh purchase price cap on bids in the ISO's real-time Imbalance Energy Market was converted into a $250/MWh breakpoint. Second, generators that failed to comply with an ISO emergency dispatch order became subject to a penalty. Third, a Scheduling Coordinator with unscheduled demand or undelivered generation became liable for the cost the ISO incurred to obtain electricity through bids above the $250/MWh breakpoint or through out-of-market dispatches.

After issuance of the order, many entities filed motions to intervene (as listed in Appendix B) and requests for clarification, modification or rehearing objecting to the first two tariff revisions.

i. Due Process Issues

Interventions

Fourteen entities filed motions to intervene subsequent to the order's issuance and many of them sought rehearing. Several parties complain that the Commission violated due process by not affording the public any notice and opportunity to comment on Amendment No. 33.

Commission Response

[323] See supra, n.5.

The Commission generally denies late interventions filed for the purpose of seeking rehearing.[324] Here, however, the Commission did not provide any notice of the ISO's filing before acting on it and, in fact, acted on the day of the filing. Thus, there was no opportunity for interested persons to seek to intervene or protest before the Commission took action. Also, all of the motions to intervene and requests for rehearing were filed within the 30-day deadline for filing rehearing requests under section 313(a) of the Federal Power Act, 16 U.S.C. § 825l(a) (1994), and Rule 713(b) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.713(b) (2001). Therefore, under these extraordinary circumstances, we find good cause to deviate from our usual practice and grant all of the motions to intervene filed in Docket Nos. ER01-607-000 and -001.

Due Process

Dynegy, Northern California Public Entities[325] and the California Commission argue that the Commission failed to provide due process when it accepted ISO Tariff Amendment No. 33 on the day that it was filed.

Commission Response

When the ISO filed Amendment No. 33, Stage 3 emergencies[326] had begun. The ISO stated in its filing that expedited implementation of Amendment No. 33 was needed to address a "severe and persistent bid insufficiency" in its real-time market, as well as failure by Participating Generators to respond to its emergency dispatch orders.[327] The situation was so grave that four days after the Commission accepted Amendment No. 33,

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[324] See, e.g., Southern Company Services, Inc., 92 FERC ¶ 61,167 at 61,565 (2000) (allowing intervention after issuance of an order in order to challenge that order, would result in unjustified delay and disruption of proceeding and undue burden on other parties); ISO New England, Inc., 94 FERC ¶ 61,237 at 61,845 n. 2 (2001) (denying intervention after issuance of order "consistent with Commission precedent"); see also The Power Company of America, L.P. v. FERC, 245 F.3d 839, 843 (D.C. Cir. 2001) (upholding FERC's denial of late intervention for failure to establish good cause for delay).

[325] These include TANC, Modesto, M-S-R Public Power Agency, and the Cities of Santa Clara and Redding.

[326] In a Stage 3 emergency, the ISO is authorized to curtail firm customers.

[327] Transmittal Letter for Amendment No. 33 at 2.

the Secretary of the Department of Energy, using rarely invoked emergency powers under section 202(c) of the Federal Power Act,[328] issued the first of several orders directing certain suppliers to provide electricity to California utility companies when the ISO certified that there was inadequate electrical supply.[329]

These circumstances demanded that we act immediately. Also, although the Commission did not provide specific notice of the ISO's filing of Amendment No. 33, the Commission had already provided notice in the November 1 Order that it was actively considering remedies of the sort included in that Amendment. In fact, the $250/MWh breakpoint provision of Amendment No. 33 was superseded days later by the $150/MWh breakpoint in the December 15 Order. Finally, by granting all requests for intervention in Docket No. ER01-607-000 and -001 and then considering all arguments raised on rehearing by intervenors, we have given all interested persons an opportunity to comment on Amendment No. 33. Therefore, we conclude that we have provided the due process necessary in the emergency circumstances presented.

Commission Determination Not to Consolidate

The Northern California Public Entities, noting the overlap between the issues addressed in the November 1 Order and the Amendment No. 33 Order, argue that the Commission acted improperly by docketing Amendment No. 33 in Docket No. ER01-607-000 rather than Docket Nos. EL00-95-000, et al., and contend that the Commission should consolidate the dockets.

Commission Response

Tariff amendments are properly filed pursuant to FPA section 205 (rather than FPA section 206, which is the vehicle for complaints such as the SDG&E proceeding). We accepted Amendment No. 33 to provide some immediate relief from a sudden emergency. In light of the urgency of that situation, we find that our decision to act through a separate docket was justified. Moreover, the administrative docketing of a filing does not determine the applicable procedures or substantive outcome and instead serves as a convenience in tracking proceedings. Nevertheless, we agree that it is appropriate to address the requests for rehearing of the Amendment No. 33 Order and the December 15 Order in a single order, which is what we are doing in this order. As we

[328]16 U.S.C. § 824a(c) (1994).

[329]DOE Order Pursuant to Section 202(c) of the Federal Power Act (Dec. 14, 2000).

are not setting any of the matters for hearing, however, there is no need to consolidate the dockets.

ii. Replacing the $250/MWh Purchase Cap with a $250/MWh Breakpoint

Adequacy of Breakpoint

The California Commission, PG&E, and SDG&E state that the Commission should not have allowed the ISO to remove the purchase cap and implement the $250/MWh breakpoint. PG&E argues that the $250/MWh breakpoint was too high; Dynegy argues that it was too low. Several parties state that the $250/MWh breakpoint in the ISO market had unintended consequences in the PX markets.

Commission Response

The $250/MWh breakpoint has been superseded by the July 25 refund methodology and prices for sales when Amendment No. 33 was in effect will be mitigated in accordance with that refund methodology. Thus, arguments about the breakpoint are moot. As discussed above, we conclude that the July 25 refund methodology will yield a just and reasonable outcome, and is a preferable, more market-oriented approach than a purchase cap. More importantly, the purchase cap was, by the ISO’s unrefuted admission (confirmed by the Secretary’s orders issued pursuant to FPA section 202(c)), impairing the ISO's ability to secure adequate supplies to ensure the reliability of operations within its control area. Our approval of the ISO's proposed breakpoint was a reasonable measure in ensuring continued service for the ISO's customers.

Implementation Issues

Parties raise concerns about reporting requirements and refunds for transactions that occurred while the $250/MWh breakpoint was in place. The ISO and PG&E seek clarification that generators who bid above $250/MWh must file cost information with the Commission, the ISO and the Oversight Board justifying their bids and making such bids subject to refund, as had been anticipated in the November 1 Order. Dynegy objects to submitting cost information to the ISO and the Oversight Board, arguing that the Commission is the only entity with jurisdiction to monitor justifications for wholesale market-based rates. The Northern California Public Entities seek clarification that any rates modified by Amendment No. 33 are still subject to any final determination the Commission makes regarding refunds in Docket Nos. EL00-95-000, et al.

Commission Response

Refund potential was established in the August 23 Order for sales that occurred during the period that Amendment No. 33 was in effect; although the Commission has moved away from the breakpoint approach and did not impose reporting requirements in the Amendment No. 33 Order, those transactions remain subject to refund. We clarify that final determinations regarding the refund methodology were made in the July 25 Order, as modified herein. With respect to requiring generators to submit cost justifications to the ISO and the Oversight Board, we note that the April 26 Order requires that cost justifications for bids above the mitigated reserve deficiency MCP be submitted to the ISO. In addition, parties have had access to generators' costs for the period between October 2, 2000 through June 20, 2001 pursuant to the Protective Order approved by the presiding judge in the refund hearing. We will not require direct submission of cost data to the Oversight Board because it has no authority to evaluate wholesale rates. We have previously determined that the Oversight Board's role is limited to matters within state jurisdiction.[330] The ISO, on the other hand, has a legitimate market monitoring function.

Effect on PX Markets

Several parties argue that Amendment No. 33 had unintended consequences in the PX markets. PG&E and SoCal Edison note that prices in the PX markets were restrained by the purchase cap in the ISO's real-time market, because buyers and sellers knew that if sellers demanded prices above the cap in the forward markets, buyers would hold out and obtain power at the capped price in the real-time market. Therefore, they argue that elimination of the purchase cap in the ISO market without the imposition of a breakpoint on sales in the PX markets left buyers more vulnerable to high prices. The PX, WPTF, Reliant, and Dynegy argue that despite the ISO's and the Commission's intent to encourage scheduling in forward markets, Amendment No. 33 actually created a disincentive for generators to bid into the PX forward markets. These parties note that

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[330] See California Power Exchange Corporation, et al., 85 FERC ¶ 61,263 at 62,067-69 (1998), reh'g denied, 86 FERC ¶ 61,114 (1999); Oversight Board, 88 FERC ¶ 61,172, at 61,576 (1999), reh'g denied, 89 FERC ¶ 61,134 (1999), dismissed sub nom. Western Power Trading Forum and Coalition of New Market Participants v. FERC, No. 99-1532 (D.C. Cir. filed April 10, 2001). We note that the Commission is considering the role of State Commissions in market monitoring in the context of the development of RTOs. See Notice of Extension of Time and Opportunity to Submit Comments on Regional Transmission Organization Issues Discussed at Workshops, Docket No. RM01-12-000, issued October 30, 2001.

prior to Amendment No. 33, a $250/MWh purchase cap was in place for all bids in ISO markets, not only bids in the real-time market, but also Adjustment Bids for protection of schedules during periods of congestion. Yet Amendment No. 33 only removed the purchase cap on real-time bids. Generators had been required to submit Adjustment Bids when they bid into the PX markets. The PX, WPTF, Reliant, and Dynegy argue that after Amendment No. 33, generators knew that in congestion situations they would be unable to protect their schedules at prices above the $250/MWh cap and, therefore, had an incentive to hold their bids until the real-time market, in which Adjustment Bids did not apply.

Commission Response

These concerns are now moot for several reasons. First, the December 15 Order applied the breakpoint to the PX spot markets, thus eliminating any disparity between PX and ISO markets. Second, the July 25 Order applied the refund methodology, based on the marginal costs of the least efficient unit dispatched, to PX spot market transactions for the period October 2, 2000 through January 31, 2001, when the PX ceased operations. In addition, the mechanism adopted by the ISO and PX to accommodate PX Adjustment Bids described in the ISO's compliance filing submitted in Docket No. EL00-95-008, et al., on January 2, 2001, resolved the adjustment bid issue.[331]

iii. Imposing Penalties For Noncompliance With ISO Emergency Dispatch Orders

Dynegy and others argue that it is unfair to impose penalties on generators who fail to respond to ISO emergency dispatch orders, arguing in part that generators should not be held responsible for NOx emission penalties incurred when responding to such dispatch orders.[332] Dynegy argues that the ISO has failed to offer adequate justification for assessing costs for undelivered generation. With regard to the assessment of costs for unscheduled load and undelivered generation, PG&E claims that assessing costs for underscheduled demand will give sellers unfair leverage.

Commission Response

[331]The ISO's compliance filing is addressed in an order that is being issued concurrently with this order.

[332]Dynegy also raised this issue in its emergency motion for clarification on creditworthiness issues filed in Docket No. EL00-95-006.

The June 19 Order removed the penalty challenged by Dynegy for periods that price mitigation is in effect, as necessary in light of the must-offer requirement. The Commission agreed with generators that they should not be subjected to additional penalties for withholding generation for operational reasons. However, the Commission finds that the penalty was appropriately imposed prior to the imposition of the must-offer requirement and that it reasonably accepted the Tariff Amendment No. 33 in response to the immediate crisis facing California's markets in December 2000.

As an initial matter, we note that each Participating Generator entered into a Participating Generator Agreement through which it agreed to comply with the ISO's emergency dispatch orders, and each Scheduling Coordinator agreed to submit balanced schedules. Nevertheless, the ISO reported in its filing that "some Generators dispatched out-of-market [were] refusing to operate in response to the Dispatch instructions issued by the ISO, even during emergency conditions, unless special payment provisions [were] negotiated in real-time."[333] Compliance with emergency dispatch orders is critical to system reliability. The ISO's authority to issue such orders is limited to extreme situations involving imminent threats to reliability. When responding to such situations, the ISO should not be held hostage negotiating deals to entice Participating Generators into fulfilling their obligations. Imposition of a penalty for noncompliance with an emergency dispatch order was an appropriate mechanism for ensuring that the ISO would be able to deal effectively with threats to reliability.

We need not address Dynegy's argument that the rate the ISO Tariff sets for payment of power provided in response to such orders is confiscatory. We note that the issue of the rates paid for out-of-market calls will be addressed in Dynegy's complaint filed in Docket No. EL01-23-000, and we will not consider that issue here. We have addressed Dynegy's creditworthiness concerns in our March 6, 2001 order, in which we clarified that third-party suppliers are entitled to assurances of a creditworthy buyer for all energy delivered through the ISO, including energy supplied in response to an emergency dispatch order.[334]

We agree with Dynegy that a generator should not be held responsible for NOx emission penalties incurred as a result of complying with an ISO emergency dispatch order; prior orders have resolved this concern. The June 19 Order removed this penalty

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[333] ISO's Application in Docket No. ER01-607-000, at p. 2 .

[334] California Independent System Operator Corporation, et al., 95 FERC ¶ 61,024, reh'g denied, 95 FERC ¶ 61,391, further reh'g rejected, 96 FERC ¶ 61,267 (2001). See also California Independent System Operator Corporation, 97 FERC ¶ 61,151 (2001) (enforcing the earlier creditworthiness orders).

effective as of June 20, 2001, and pursuant to the July 25 Order, emissions costs will be offset against refund liability.

We disagree with Dynegy's argument that the penalty provision unfairly locked out of the market those generators who had intended to bid, but had not done so before the ISO issued the call. We conclude that the ISO needed the flexibility to issue dispatch orders before the deadline for regular submission of bids into the markets, so that the ISO could give Participating Generators as much advance notice as possible and have time to make adjustments for those Participating Generators who are unable to respond.

Finally, Dynegy argues that a penalty of twice the ISO's price of obtaining energy from an alternative source plus $1,000/MWh, if service is curtailed to consumers who are not covered by interruptible service policies, is disproportionate, citing our October 30, 1997 order conditionally approving operation of the ISO.[335] In that order, we noted that penalties charged by the ISO generally should be proportionate to the profits estimated to be earned by the abuse of market power. However, we also noted that "the penalty should also be greater than the estimated profits in order to serve as a deterrent to market power abuse."[336] Furthermore, in this case, the penalty was not in place simply to deter action that would result in unjust enrichment, but rather existed to protect the very reliability of the system. We conclude that the size of the penalty is appropriate for this purpose.

b. Docket Number EL00-97-001

On August 3, 2000, Reliant Energy Power Generation, Inc., Dynegy Power Marketing, Inc., and Southern Energy California, L.L.C. (Joint Complainants) jointly filed a complaint requesting that the Commission find that the ISO must compensate participating generators, Scheduling Coordinators, or other sellers (collectively, Market Participants) for their actual damages and lost opportunity costs in the event the ISO curtails energy exports scheduled by a Market Participant. In support of their complaint, Joint Complainants contended that the ISO Tariff does not specify how Market Participants are to be compensated if their energy exports are curtailed by the ISO in response to an ISO-declared system emergency. Joint Complainants stated that under standard arrangements for export transactions for firm delivery, Market Participants can be held liable to the would-be buyer for liquidated damages for failure to deliver. Joint Complainants also stated that in addition to liquidated damages, if export schedules are

[335] See Pacific Gas and Electric Company, et al., 81 FERC ¶ 61,122 at 61,554 (1997).

[336] Id.

curtailed, Market Participants will lose the opportunity to sell the exported energy at competitive market prices. Therefore, Joint Complainants contended, if the ISO terminates an export transaction, the ISO should be made to hold the generator harmless from any damages that result from the ISO's decision and to provide the generator full recovery of its opportunity costs on the canceled export sale.

The December 15 Order rejected the complaint. The order found that, contrary to Joint Complainants' contention, the ISO Tariff does in fact contain a compensation mechanism for curtailed exports, i.e., the OOM payment mechanism codified in section 11.2.4.2 of the ISO Tariff.[337] The December 15 Order noted that the Tariff's current mechanism had been accepted by the Commission as part of Docket No. ER00-555-000 (ISO Tariff Amendment No. 23)[338] and, to the extent the complaint challenged the relevant Commission-approved Tariff provisions, the complaint was a collateral attack on that order.[339] In addition, the December 15 Order found that Morgan Stanley Capitol Group Inc., 92 FERC ¶ 61,112 (2000), which limited the ISO's authority to require sellers to bid into its markets, was not relevant to curtailments for the maintenance of system reliability, and Commission commented that the new pricing methodology would mitigate the adverse impacts of the ISO's reduced purchase price cap, lessening sellers' incentive to pursue exports.

Dynegy and Reliant[340] each object to the December 15 Order's rejection of the complaint. On rehearing, Dynegy and Reliant argue that the Commission wrongly concluded that sellers no longer would have incentives to pursue exports, that the Morgan Stanley case was not relevant, and that existing ISO Tariff provisions for OOM

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[337]Under that mechanism, OOM payments are calculated by using either the hourly Ex Post Price or a price consisting of: (1) a capacity component based on certain market indices; (2) an energy component based on certain market indices; (3) verifiable start-up fuel costs; and (4) verifiable gas imbalances charges (if any).

[338]See California Independent System Operator Corp., 90 FERC ¶ 61,006 (2000), reh'g denied, 91 FERC ¶ 61,026 (2000), order on compliance filing, 90 FERC ¶ 61,165 (2000).

[339]December 15 Order, 93 FERC at 62,019-20.

[340]Enron also sought rehearing of the Commission's decision to reject the complaint in Docket No. EL00-97-000. We note, however, that Enron did not intervene in Docket No. EL00-97-000 and thus has no standing to seek rehearing of this aspect of the December 15 Order.

calls were adequate compensation for curtailed exports.[341] Dynegy explains that the complaint intended to request compensation along the lines of the "replacement price" adopted by NEPOOL and approved by the Commission.[342]

Commission Response

As an initial matter, the Commission did not mean to imply that, after removing the purchase price cap in the Amendment No. 33 and December 15 Orders, sellers would no longer have any incentives to pursue export transactions. Rather, the Commission was taking note that removal of the cap, the level of which triggered the Joint Complaint initially, resolved the adverse impacts complained about, both with respect to bidding incentives and the effect on the level of compensation.

With respect to the remaining matters raised on rehearing, we note that Joint Complainants offer no explanation why Morgan Stanley is relevant, and we have no reason to change our finding on that matter. Further, Joint Complainants have not demonstrated any changed circumstances that would warrant reconsideration of our December 15 Order. There, the Commission found that Joint Complainants were incorrect in asserting that the ISO Tariff provides no compensation for curtailed exports. On rehearing, Joint Complainants have failed to demonstrate that this was an incorrect conclusion. Rather, they continue to challenge the level of compensation that is available through the Tariff. The Commission explicitly rejected that argument in its December 15 Order, explaining that the argument was a collateral attack on a prior Commission order.[343] On rehearing, the only changed circumstances that Joint Complainants raise are events that could make curtailments more likely – they do not go to the level of compensation that may be appropriate.[344] Thus, we deny their request for rehearing.

In any event, the Commission understands that the ISO has never curtailed exports; thus, the alleged harm to Joint Complainants remains speculative.

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[341]See Requests for Rehearing of Dynegy at 12-18, and Reliant at 20-22.

[342]See Request for Rehearing of Dynegy at 17, citing New England Power Pool, 91 FERC ¶ 61,045 (2000) and New England Power Pool, 91 FERC ¶ 61,303 (2000).

[343]See December 15 Order, 93 FERC at 62,019-20.

[344]We note that the ISO's authority to require curtailment of imports is limited to reliability purposes, and it cannot be used to depress prices.

c. Complaints in Docket Nos. EL00-104-001, EL01-1-001, and EL01-2-001

Three additional complaints were filed with the Commission after SDG&E's complaint seeking relief related to the dysfunctional markets in California. First, the Oversight Board filed a complaint in Docket No. EL00-104-000 asking the Commission to find that the wholesale markets in California are not workably competitive and requesting that the Commission affirmatively direct the ISO to maintain bid caps at certain levels. Second, CMUA filed a complaint in Docket No. EL01-1-000 requesting that the Commission impose cost-based rates on public utility sellers into the ISO and PX markets. In support of its complaint, CMUA argued that California consumers were experiencing unprecedented high, sustained wholesale power prices. CMUA also argued that the California market was not workably competitive and that the framework to correct the problems was not in place. Third, CAlifornians for Renewable Energy, Inc. (CARE) petitioned the Commission to find that the wholesale markets in California are not workably competitive and make findings that the events and circumstances surrounding the June 14, 2000 rolling outage in the San Francisco Bay area warrant investigations by the United States Department of Justice of antitrust activities in restraint of trade and of alleged civil rights violations rendered by various entities.

The December 15 Order rejected the Oversight Board's and CMUA's complaints, noting that the modifications established in the order were intended to provide for uniform pricing and to remove incentives for load and resources to participate in one market over another, and that the relief sought would either disrupt that uniformity or introduce new incentives in the markets. CARE's complaint was denied on the basis that it had not provided adequate evidence in support of its allegation of an ISO/generator trust, nor did it document a single instance of restraint of trade or civil rights violations. The order also found that, in any event, the matter of whether the alleged violations warrant the initiation of an investigation by the Department of Justice was clearly not within the Commission's jurisdiction.

The California Commission and the Oversight Board argue on rehearing that the Commission erred in rejecting the latter's complaint on the grounds that no opportunity was given to conduct discovery, and reiterated the request for "hard" price caps. CMUA asserts that the Commission violated its statutory duty under the FPA by relying on the remedies in the December 15 Order, arguing that the Commission presented no empirical evidence for the proposition that those remedies are superior to the imposition of a cost-based rate. On rehearing, CARE largely reiterates its original allegations. CARE notes that it is a not-for-profit corporation relying on public funding and that it does not have the resources to obtain legal counsel to fully participate in the Commission's processes; thus, it requests assistance with its participation. In addition, CARE argues that it is the

Commission's responsibility to conduct a full and fair investigation of the matters in the proceeding and that its petition need not rise to the level of "substantial evidence." On March 23, 2001, CARE filed a request for Alternative Dispute Resolution services to resolve its complaint with the ISO, and specifying seven remedial actions not previously mentioned in its complaint. On August 30, 2001, CARE submitted a request for compensation for expenses associated with its participation in this proceeding. CARE invokes FPA section 319 (which authorizes certain assistance to the public),[345] contending that it does not have the resources to obtain legal counsel or other expert assistance.

Commission Response

As discussed elsewhere in this order, the remedies implemented in this proceeding have sufficiently mitigated the adverse market conditions in California. The Commission continues to believe that our market-oriented approach will enhance investment in new generation and promote greater efficiency. Moreover, the West-wide investigation and price mitigation measures instituted in Docket No. EL01-68-000 obviate the need to establish a regional cap in this proceeding.

Although we acknowledge CARE's concerns regarding lack of resources, we nonetheless will deny CARE's requests for rehearing and administrative aid. CARE's request for rehearing merely reiterates the allegations and evidence included in its initial complaint, and we reject it for the reasons stated in the December 15 Order. The discussion above relative to the Oversight Board and CMUA complaints also responds to CARE's request in its complaint and on rehearing that the Commission rectify the unjust and unreasonable prices stemming from the ISO and PX markets. CARE's rehearing does not address the fact that antitrust and civil rights violations are not within the Commission's jurisdiction or expertise. We will reject CARE's March 23 request for ADR procedures, because the motion, which outlines remedies not previously requested, constitutes a new complaint, and CARE has not followed the proper procedures for filing a new complaint.

Regarding CARE's request for administrative aid, on November 5, 2001, the Presiding Administrative Law Judge in Docket Nos. EL00-95-045 and EL00-98-042 issued a procedural order rejecting CARE's August 30, 2001 request for compensation. The Presiding Judge stressed that even if the pleading, which lacked the required certificate of service to other parties, had been properly filed, he would have denied the

[345] 16 U.S.C. § 825q-1 (1994).

request on the merits. Subsequently, on November 13, 2001, CARE refiled its request for compensation directly with the Commission and included a certificate of service.

We will deny CARE's request for the following reasons. Initially, FPA section 319 was enacted by Congress as part of the Public Utility Regulatory Policies Act of 1978 ("PURPA").[346] In section 212 of PURPA (later codified as FPA section 319), Congress created within the Commission an Office of Public Participation (OPP). Section 319 required the Director of the OPP to "coordinate assistance to the public with respect to authorities exercised by the Commission." As relevant here, Congress authorized funding for the OPP through fiscal year 1981. It did not authorize funding for OPP beyond that time and has not since appropriated any funds to the Commission to operate the OPP. Therefore, for lack of financial support, we deny CARE's request.

Further, even assuming that funding for the OPP still existed, because the nature of CARE's contribution to this proceeding, if any, cannot be determined at this time, the Commission denies CARE's request as premature.[347] Finally, even assuming the funds were available and CARE's request were not premature, the Commission denies the request on its merits because, as the Presiding Judge noted, "[t]he public interest [already] is represented by Commission Staff and state agencies and private interests are represented by interested parties who retain separate counsel." Granting CARE's request for administrative aid would be pointless, given the Commission's lack of jurisdiction over certain aspects of its complaint, and the abundant representation by other parties regarding the other matters raised by CARE.

d. Docket Nos. ER00-3461-001 and ER00-3673-001

In August 2000, the PX filed a tariff amendment proposing to impose maximum prices for bids in its Day-Ahead and Day-of markets of $350/MWh (Docket No. ER00-3461-000). Shortly thereafter, the ISO proposed to remove the existing November 15, 2000 termination date of its purchase price cap authority and to preserve its discretion to adjust the cap levels as appropriate (Docket No. ER00-3673-000). The November 1

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[346] Public Law No. 95-617 (1978).

[347] See Central Power and Light Company 8 FERC ¶ 61,065 at 61,220, order denying rehearing and modifying order, 9 FERC ¶ 61,011 (1979), reh'g denied, 10 FERC ¶ 61,131 (1980) (declining a similar request under Section 319 for attorney's fees, expert witness' fees, and other costs of intervening and participating before the Commission, explaining that "[u]nder the terms of that section, any such compensation must be made post-hearing and after a determination as to the nature of the intervenor's contribution to the proceeding."

Order rejected both of these proposals. With respect to the ISO's purchase price cap, the Commission found that the cap had served to mitigate price volatility in both the ISO and PX markets, but had also served to disrupt the market by encouraging sellers to wait for the ISO to make needed purchases on an out-of-market basis at the last minute.[348] Thus, the Commission decided not to allow either the ISO or the PX to implement changes that would disrupt the price mitigation measures proposed in that order. The Commission in the November 1 Order directed the ISO to retain its existing $250/MWh purchase price cap through the end of the year, until the proposed price mitigation measures would be implemented.

The California Commission and the Oversight Board sought rehearing, arguing that the Commission erred by removing such an important price control tool and that the Federal Power Act does not allow the Commission to "abandon customers to an unworkable marketplace."[349]

Commission Response

We will deny the rehearing requests of this aspect of the November 1 Order. The Commission has been and remains committed to establishing market-driven price mitigation measures, but the ISO and PX proposals would have disrupted efforts to move in that direction. Contrary to the assertions of the California Commission and the Oversight Board, customers were not left to the whim of "an unworkable marketplace." The November 1 Order made clear that refund potential was in place for the period October 2, 2000 forward, and transactions during the refund period were subject to the refund methodology adopted in the July 25 Order.

e. ISO Amendment No. 30 (Docket No. EL00-95-002)

On September 11, 2000, in response to a Commission directive given in the August 23 Order, the ISO filed Tariff Amendment No. 30. In that filing, the ISO proposed to amend section 2.5.3.1.5 of the ISO Tariff to clarify the ISO's authority to contract without first soliciting bids. The ISO indicated its belief that, while the current tariff provision did not specify that a competitive solicitation must be conducted for forward contracting, clarification of any ambiguity was appropriate. The ISO also proposed to amend one section of the ISO Tariff and to add another section for the purpose of allocating the costs of any forward contracts to those Scheduling Coordinators who are responsible for the incurrence of such costs (i.e., generation or

[348] November 1 Order at 61,371.

[349] California Commission at 22.

load that deviates, in real-time, from schedules) in proportion to their deviation. According to the ISO, fairness and providing appropriate economic incentives to Scheduling Coordinators to align their forward and real-time schedules, dictated the allocation. In addition, the ISO explained that to the extent that such allocation was not sufficient to make the ISO whole for the costs it incurs, any remaining balance would be incrementally flowed through the Tariff's neutrality clause (section 11.2.9) as charges incurred for the benefit of all market participants.

The December 15 Order accepted without modification the ISO's proposed Tariff Amendment. Regarding the intervenors' concerns that the ISO be limited in its use of forward contracting, the Commission stated that the remedies imposed therein, particularly those intended to significantly reduce underscheduling, would serve that purpose. Thus, the Commission found, to the extent that the ISO's need to procure energy for the real-time market would be significantly reduced, the ISO's need to procure energy through forward contracting would be lessened accordingly. In addition, with respect to the arguments opposing the ISO's proposed allocation methodology, the Commission found those arguments to be without merit, stating that the proposed methodology allocates costs in a manner consistent with other such methodologies the Commission has accepted in the past.

On rehearing, PPL contends that the Commission should have rejected ISO Tariff Amendment No. 30 for two reasons. First, PPL argues that the provisions allowing the ISO to charge any unrecovered balance to all Scheduling Coordinators is unjustified because it penalizes those entities who submitted accurate schedules. Second, PPL contends that under Tariff Amendment No. 30, the ISO became a market participant, thus jeopardizing its neutrality and independence contrary to the Commission's previous mandates (e.g., Order Nos. 888 and 2000).[350]

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[350] See Order No. 888, Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, FERC Statutes and Regulations, Regulation Preambles January 1991-June 1996 ¶ 31,036 at 31,731 (1996) (stating "[a]n ISO should have the primary responsibility in ensuring short-term reliability of grid operations"), order on reh'g, Order No. 888-A, FERC Statutes and Regulations ¶ 31,048 (1997), order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998), aff'd in relevant part sub nom., Transmission Access Policy Study Group, et al. v. FERC, 225 F.3d 667 (D.C. Cir. 2000).

In a similar vein, Modesto asserts that the Commission erred by failing to require the ISO to comply with the separation of function requirements of Order No. 889.[351] Modesto claims that the ISO is performing a wholesale merchant function and thus should conform with the Standards of Conduct rules in 18 C.F.R. § 37.4.

Commission Response

We will deny PPL's request for rehearing. In the context of the extraordinary circumstances before us in this proceeding, we believe that Tariff Amendment No. 30 constitutes a reasonably balanced effort to satisfy both the ISO's independence requirement under Order No. 888 as well as one of the Commission's primary goals in this proceeding of reducing the cost to Scheduling Coordinators of the ISO's real-time energy market. The ISO recognizes that it "should not be competing against Load-serving entities for the energy needed to satisfy Load that is reasonably predictable,"[352] and makes clear its intent to restrict its market activities to a minimum.

In addition, we find PPL's contention regarding Tariff Amendment No. 30's cost allocation methodology to be without merit. PPL's allegation merely reiterates arguments the Commission previously rejected in the December 15 Order, and we reject them now for the reasons stated therein.[353] As explained above, the allocation of costs to all Scheduling Coordinators applies only if the primary allocation methodology (i.e., to those Scheduling Coordinators who deviate, in real-time, from schedules, in proportion to their deviation) is not sufficient to make the ISO whole for the costs it incurs. In view of this fact, and in light of our precedent discussed above, PPL has not shown the allocation methodology to be an unreasonable means of ensuring that the ISO fully recovers its costs for maintaining system security.

Regarding Modesto's argument, the Commission agrees that the ISO must comply with the separation of function requirements described in 18 C.F.R. § 37.4. Given the ISO's limited usage of its forward contracting authority, however, we find no need at this

[351] Open Access Same-Time Information System (Formerly Real-Time Information Networks) and Standards of Conduct, Order No. 889, 61 Fed. Reg. 21,737 (May 10, 1996), FERC Stats. & Regs. ¶ 31,035 (1996), order on reh'g, Order No. 889-A, 62 Fed. Reg. 12,484 (March 14, 1997), FERC Stats. & Regs. ¶ 31,049 (1997), order on reh'g, Order No. 889-B, 81 FERC ¶ 61,253 (1997).

[352] Transmittal Letter for Amendment No. 30 at 2.

[353] December 15 Order at 62,020.

time for any additional measures requiring the ISO to prove that it is in compliance with the Standards of Conduct, as Modesto requests.

f. Compliance Filings in Docket Nos. EL00-95-007, et al.

The ISO, the PX, and the three IOUs submitted compliance filings in late December and early January. The Commission acted on the PX's compliance filing in an order issued January 29, 2001.[354] The ISO's compliance filing is addressed in an order being issued concurrently with this order. The remainder of the compliance filings will be addressed herein.

PG&E, SDG&E, and SoCal Edison describe how they implemented the directive not to sell or buy through the PX markets. These actions did not require the companies to filed revised tariff sheets. PG&E and SoCal Edison included requests for clarification of the December 15 Order with their compliance filings. SoCal Edison requests that the Commission clarify that it may continue to sell into the PX output from its retained fossil generating resources because it may be unable to obtain cost recovery under state law if it does not bid those resources into PX markets. SoCal Edison also seeks clarification that it may sell its surplus output to any customer, including the PX. It explains that this clarification is necessary because the PX's markets are the only approved markets for SoCal Edison's market-based rate sales.

PG&E sought five areas of clarification: (1) whether the Commission intended to preclude even optional use of the PX's markets; (2) whether the Commission intends to review bids above the breakpoint despite lack of implementation by the ISO and/or PX; (3) how Ancillary Services above the breakpoint could be justified, given that the costs of providing such services are sunk unless units are dispatched; (4) whether reporting requirements for transactions above the breakpoint include bilateral contracts entered into by sellers in ISO and PX markets; and (5) how customers are to be provided an opportunity to review costs and justifications for above-breakpoint transactions. With respect to this last issue, PG&E requests that the Commission provide data on such bids to customers, and an opportunity to request cost support, evaluate the data, and contest the cost justification. NCPA and PPL filed answers to PG&E's request for clarification, objecting to the scope of data disclosure PG&E seeks. In addition, PPL comments on the proper scope of the reporting requirements.

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[354] San Diego Gas & Electric Co., et al., 94 FERC ¶ 61,085, reh'g denied, 95 FERC ¶ 61,021 (2001).

Notices of the filings were published in the Federal Register, 66 Fed. Reg. 2897 and 4813 (2001), with motions to intervene and protests due on or before January 23, 2001, for SDG&E's and PG&E's filings, and on or before February 1, 2001 for SoCal Edison's. No comments or protests were filed with respect to the companies' compliance with the December 15 Order; NCPA's and PPL's responses relate solely to PG&E's request for clarification.

Commission Response

We will accept for filing PG&E's, SoCal Edison's, and SDG&E's compliance filings. We will also address those requests for clarification that are not moot as a result of the cessation of the PX markets or have not previously been answered.

We clarify for SoCal Edison that it may sell its surplus output to customers other than the PX, but we will require it to file an amended market-based rate tariff to reflect this change.[355] PG&E's concerns about the treatment of Ancillary Services are addressed elsewhere in this order. Regarding participants' opportunity to review cost data, we note that sufficient data will be available to parties that have executed a non-disclosure agreement in the refund hearing before Administrative Law Judge Birchman.

D. Rehearing of Remaining Issues from March 9 Order

Numerous parties sought rehearing of the Commission's March 9 Order. Many of the arguments raised in those rehearings are identical to arguments raised on rehearing of the orders that are being addressed in this order. Furthermore, a number of the rehearings raise issues that have since been rendered moot by subsequent orders issued by the Commission. We will address below the rehearing issues that remain open for resolution.

1. Treble Damages

The California Commission argues that this Commission should order refund amounts comparable to the treble damages awarded in an antitrust case.

Commission Response

The Commission recently dealt with this very same argument in AES Southland, Inc., Williams Energy Marketing & Trading Co., 95 FERC ¶ 61,167 (2001). In that

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[355] We note that, for most hours, SoCal Edison is in a net short position so that it has little generation, if any, to sell.

order, the Commission explained that while it can order equitable remedies, such as disgorgement of unjust enrichment,[356] the Commission does not have authority to order treble damages as under the antitrust laws.[357]

2. Hearings

The ISO argues that, given the "dysfunctional" state of the California wholesale electricity market, it was arbitrary and capricious for the Commission to not have held trial-type evidentiary hearings to determine just and reasonable rates. Specifically, the ISO cites Cajun Electric Power Cooperative, Inc. v. FERC[358] for the premise that "it is an abuse of discretion for the Commission to refuse to hold a hearing when the petitioner has proffered facts that raise serious doubts concerning the mitigation of the utility's market power."

Commission Response

We will reject the ISO's argument. In general, the Commission must hold an evidentiary hearing "only when a genuine issue of material fact exists, and even then, FERC need not conduct such a hearing if [the disputed issues] may be adequately resolved on the written record."[359] Contrary to the ISO's argument, this is not a case like Cajun, where the record revealed a substantial factual dispute as to whether a Commission-approved tariff truly mitigated a utility's monopoly power,[360] and where the Commission "ignored this important question" and "failed to adequately explain its approval."[361] In this case, the Commission carefully considered the potential for market power by generators through its review of these generators' weekly transaction reports, as well as monthly reports from the ISO and the PX, and the system conditions that occurred in the ISO and PX markets. Furthermore, the Commission thoroughly

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[356] See generally Transcontinental Gas Pipe Line Corp. v. FERC, 998 F.2d 1313 (5th Cir. 1993) (and cases cited therein).

[357] See, e.g., Sunflower Electric Cooperative v. Kansas Power & Light Co., 603 F.2d 791 (10th Cir. 1979).

[358] 28 F.3d 173 (D.C. Cir. 1994) (Cajun).

[359] Id. at 177 (internal quotations and citations omitted).

[360] See id. at 175.

[361] Id. at 180.

discussed in the March 9 Order its methodology and the logic used to support its findings. Accordingly, we find no merit to the ISO's contention that the Commission erred when it failed to hold a trial-type evidentiary hearing.

3. City of San Diego's Motion to Sequester Funds

On March 13, 2001, the City of San Diego filed a motion for an order requiring sellers of wholesale power in California to sequester funds to satisfy refund obligations. Specifically, the City of San Diego requests that the Commission order these sellers to sequester any amounts collected from sales that are in excess of costs and maintain these amounts, with accumulating interest, adequate enough to pay potential refund obligations. The County of San Diego filed an answer in support of the City of San Diego's motion in which it argued that the Commission must protect the beneficiaries of potential refunds.

The Pinnacle West Companies, Duke, Williams, PPL Energy Plus, LLC, PPL Montana, LLC, Enron Power Marketing, Inc., and Reliant filed answers in opposition to the City of San Diego's motion to sequester funds. All of these parties contend that the City of San Diego's motion is premature and speculative in that there has been no showing that the sellers will be unable to pay any refunds, if they even exist. Enron, the Pinnacle West Companies, Duke, also argue that the City of San Diego is attempting to circumvent the Commission's policies or orders, such as the December 15 and March 9 orders, through the imposition of cost-based regulation. PPL Energy Plus, LLC and PPL Montana, LLC submit that the harms of the motion greatly outweigh any benefits and that the Commission should only grant the motion if the movant makes the same showing necessary to obtain a preliminary injunction.

Commission Response

The Commission has found that requiring escrow payments pending resolution of a dispute is a form of equitable relief that temporarily protects a party's rights.[362] This form of equitable relief has been found appropriate when a preliminary assessment of the merits of the underlying dispute demonstrate the potential for irreparable harm or that it would be in the public interest.[363] However, in this case, we agree that the City of San Diego's concern that the wholesale electric energy sellers will not have money to pay

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[362]Public Service Company of New Hampshire v. New Hampshire Electric Cooperative, Inc., 55 FERC ¶ 61,028 at 61,079 (1991).

[363]Id.

potential refund amounts is speculative.[364] The City of San Diego simply has not shown that these sellers are unable to pay. Moreover, the City's request is particularly inappropriate in light of the large amounts that have not been paid to sellers for those sales; indeed, the ISO only recently invoiced purchasers for transactions in January 2001 and forward.[365] Accordingly, we deny the City of San Diego's motion requesting that sellers of wholesale power in California sequester funds to satisfy potential refund obligations.

4. Termination of ER Dockets

The Commission finds that the following dockets, which were created upon the filing of the rehearing requests of the March 9 Order, are moot because of the Commission's issuance of the July 25 Order: ER01-1444-001, ER01-1445-001, ER01-1446-001, ER01-1447-001, ER01-1448-002, ER01-1449-002, ER01-1450-001, ER01-1451-002, ER01-1452-001, ER01-1453-001, ER01-1454-002, ER01-1455-002, and ER01-1456-002. Accordingly, we will terminate these dockets herein.

E. Rehearing of Remaining Issues from June 19 Order

1. Outage Coordination

Dynegy argues that the Commission ceded overly expansive control of generation outage schedules to the ISO. Dynegy argues that the ISO's outage plans, as reflected in the proposed ISO Tariff language in its May 11 Compliance Filing, are flawed. Dynegy alleges that the plans are too complex and lengthy; fail to foster outage cooperation; exclude specific objective procedures to allocate scarce outage time; attempt to dictate market outcomes through outage coordination by including market prices as an element to consider in outage coordination when reliability should be the sole governing factor; and usurp the Commission's power to approve procedures for coordination and outage control by granting the ISO authority to amend its outage coordination mechanism by posting changes on its home page. Dynegy recommends instead the adoption of a PJM-like mechanism for outage coordination.

Commission Response

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[364] See Duke Energy Moss Landing LLC and Duke Energy Oakland LLC, 86 FERC ¶ 61,187 at 61,657 (1999).

[365] See California Independent System Operator Corp., 97 FERC ¶ 61,151 (2001).

To ensure the availability of sufficient energy resources while also providing for reliable plant operation, the April 26 Order emphasized the importance of cooperation between the ISO and generators in scheduling generating unit maintenance and outages. Accordingly, the Commission gave the ISO a broad directive to propose a mechanism for control and reporting of generating unit outages by the ISO, and found that the ISO must be provided with the authority to achieve greater systematic control over all generating units that the ISO must dispatch, i.e., those units that have signed Participating Generator Agreements.[366] As directed in the April 26 Order, the ISO submitted proposed tariff revisions related to outage coordination in its May 11 Compliance Filing.

In an order issued on October 23, 2001,[367] the Commission accepted and rejected in part the portion of the ISO's May 11 compliance filing related to its proposed outage coordination mechanism, and addressed a number of issues similar to those raised by Dynegy on rehearing of the June 19 Order. The Commission found, in pertinent part, that the ISO's proposed outage coordination provisions are sufficiently detailed and that the ISO's existing provisions contain adequate alternative outage procedures to resolve incompatible outage requests. The Commission rejected the ISO's use of market prices as a criterion for canceling scheduled generator maintenance outages without prejudice to the ISO refiling the proposal with further justification. Furthermore, Dynegy's contention that granting the ISO authority to amend its outage coordination mechanism by posting changes on its home page usurps the Commission's power to approve procedures for coordination and outage control disregards the fact that any change to the procedures for maintenance and outage control would require a filing by the ISO under section 205 of the FPA. Accordingly, we deny rehearing of the June 19 Order with respect to outage coordination.

2. Must-Offer Requirement

a. Available Generation

The April 26 Order required all utilities that own or control generation in California, as a condition of selling into the ISO markets which are subject to the Commission's exclusive jurisdiction, or of using the ISO-controlled interstate transmission facilities, to offer the ISO all of their capacity in real-time during all hours if

[366] April 26 Order at 61,355.

[367] San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Services, et al., 97 FERC ¶ 61,066 (2001).

it is available and not already scheduled to run through bilateral agreements.[368] The Commission specified that "the must offer obligation is designed to ensure that the ISO will be able to call upon available resources in the real-time market to the extent that energy is needed."[369] The June 19 Order applied this requirement to all generators in the WSCC.

On rehearing, generators dispute what constitutes "available" generation subject to the must-offer requirement. Reliant contends that the Commission should not apply the must-offer requirement to generating units with long start-up lead times or other operational limitations. Reliant requests that the Commission confirm that the must-offer obligation is not a bid obligation, but rather an obligation to offer all generation that is available for real-time delivery. Reliant also requests clarification that the must-offer obligation only apply to resources that are on-line or timely can be brought on-line such that they are available to meet real-time needs of the ISO or West-wide real-time needs. Williams urges the Commission to clarify the impact of the must-offer requirement on units that are available but offline for economic reasons. Williams also requests that the Commission require the ISO to modify its bidding process to allow, as an option, time for a unit to be brought online with payment for start-up costs and minimum load costs or, alternatively, that the ISO be required to pay generators' minimum load costs to keep units online.

Commission Response

The Commission grants rehearing that generators subject to the must-offer requirement can recover their actual costs for complying with the ISO's instructions to keep their units on-line at minimum load status to be available for dispatch instructions issued by the ISO. As the Commission explains more fully in the order addressing the ISO's compliance filings issued concurrently with this order, the ISO must compensate a generator 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 requirement but not dispatched by the ISO.

b. Extent of the Must-Offer Requirement/Exemptions

Numerous load serving entities (LSEs) contend that the Commission improperly applies the same standards to merchant generators as it applies to LSEs, which neglects the fundamental difference between generation primarily intended to meet retail load and

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[368] April 26 Order at 61,355-56.

[369] April 26 Order at 61,355.

"merchant" generation intended for market sales only.[370] LSEs also contend that the June 19 Order expropriates the resources of LSEs which have responsibly contracted in the forward markets and requires them to provide such resources without adequate compensation to other retail customers who have not contracted in the forward market.[371] To the extent that Southern Cities' resources are physically unable to respond to ISO scheduling protocols and operating procedures, they request clarification that the must-offer obligation does not apply in such circumstances.

A number of parties argue that the June 19 Order does not address how generating units outside of California are to deal with environmental limitations on their operations.[372] For example, Puget Sound argues that other states in the WSCC outside California have not waived environmental restrictions on power plant operations as has California. Certain LSEs and QFs contend that they should be allowed to reasonably conserve environmentally limited thermal resources to meet load-serving obligations.[373]

Duke argues on rehearing that the must-offer requirement inadequately reflects the myriad environmental restrictions imposed on generators, the opportunity costs associated with those restrictions, and the uncertainty as to the applicability of the exemption. Duke adds that environmental constraints are often imposed in the form of aggregate limits on production over a period of hours, days or even the entire year. Duke alleges that the June 19 Order fails to account for the reasonable prospect during a pertinent period that, if a unit is required to provide energy at full capacity during any requested hours, it will subsequently, within the pertinent period, violate a particular restriction. Duke states that if a must-offer requirement is retained at all for limited run units, it must be conditioned to allow all generators to determine available capacity taking into account the possible future applicability of a binding environmental restriction on output. Moreover, NCPA requests that the Commission clarify adequately what constitutes a violation of a certificate with respect to resources that are energy limited by reason of air emissions restrictions.

Tri-State requests clarification, assuming the Commission intends that environmentally-limited units must operate at full capacity notwithstanding commitments

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[370] See, e.g., Request for Rehearing of City of Redding, California.

[371] See, e.g., Request for Rehearing of City of Redding, California.

[372] See, e.g., Requests for Rehearing of Tri-State and Puget Sound.

[373] See, e.g., Requests for Rehearing of Avista Utilities, NCPA, Puget Sound, and Tri-State.

under bilateral contracts, whether it is the buyer or the seller that is obligated to make up for the generation deficiencies after the permitted hours of operation are exhausted. Tri-State also requests clarification that where the output of a unit is committed under a bilateral contract, and the buyer does not otherwise schedule deliveries in a particular hour, it is the buyer that is responsible for meeting the must-offer requirement so that the seller does not violate the contract with the buyer.

Commission Response

We reject arguments that the June 19 Order expropriates the resources of LSEs which have contracted in the forward markets. LSEs buy in forward markets to ensure a supply of power at a known price, avoiding the uncertainty of spot markets. If LSEs do not need this power in real-time to serve their load, LSEs must resell the power, thus offsetting the sunk costs of serving their load. We have established a reasonable pricing approach for such sales, while requiring LSEs to offer available power in real-time as part of our remedy for the problems in these markets. LSEs facing a revenue shortfall for all jurisdictional sales may seek to justify additional revenue recovery. Thus, we see no reason to exempt LSEs from the must-offer obligation. In response to Southern Cities' request for clarification, to the extent that their resources are physically unable to respond to ISO scheduling protocols or operating procedures, they may seek exemption from the ISO of the must-offer obligation.

We deny rehearing concerning the effect of environmental restrictions on the ability of thermal generators to comply with the must-offer obligation. The July 25 Clarification Order specifies two ways that a generator could be exempted from the must-offer requirement due to environmental restrictions if certain evidentiary standards were met. First, a generator must demonstrate that running its unit violates a permit, would result in a criminal or civil violation or penalties, or would result in that QF units violating their contracts or losing their QF status. Second, a generator may obtain a declaratory order from an appropriate court finding that the generator's compliance with the must-offer requirement will result in a violation of its permit.[374] We clarify that the mechanism set forth in the July 25 Clarification Order for waiver of the must-offer requirement applies to all generators in the WSCC.

We deny Duke's request for compensation of opportunity costs incurred in operating under environmental restrictions. Duke has not provided any method for determining how these opportunity costs would be recovered nor suggested adequate procedures for review of these costs by the ISO and the Commission.

[374] July 25 Clarification Order at 61,448.

We reject Tri-State's requests for clarification on the obligations of the buyer or the seller in meeting the must-offer requirement where the output of a unit is committed under a bilateral contract. As discussed in another section of this order, the must-offer and price mitigation requirements will no longer apply to governmental entities and RUS-financed cooperatives transacting solely in bilateral markets throughout the WSCC.

c. Other Must-Offer Issues

On rehearing, IEP argues that the June 19 Order fails to articulate why the ISO should have the authority to cut export schedules in light of uniform price restrictions. IEP asserts that the cutting of export schedules yields commercial uncertainty for existing bilateral arrangements of the type otherwise generally encouraged by the Commission.

Dynegy argues that generators should not be required to sell power to parties that cannot meet basic requirements of creditworthiness.

Dynegy argues that the must-offer requirement should be limited to emergency conditions or to peak months.

Avista Energy, Avista Utilities, Puget Sound, and NRECA argue that the Commission's must-offer requirement is inconsistent with the authority vested exclusively in the Secretary of the Department of Energy by section 202(c) of the Federal Power Act,[375] as amended by the Department of Energy Organization Act,[376] to declare emergencies and impose must-offer obligations.

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[375]FPA § 202(c), as amended, states that:

> During the continuance of any war in which the United States is engaged, or whenever the [Secretary of Energy] determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes, the [Secretary of Energy] shall have authority, either upon its own motion or upon complaint, with or without notice, hearing, or report, to require by order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest.

[376]42 U.S.C. §§ 7157, 7172; 10 C.F.R. ¶ 205.370.

Commission Response

IEP's argument that the June 19 Order did not address the ISO's curtailment authority disregards the fact that the June 19 Order did not change the existing provisions in the ISO's Tariff regarding curtailment of export schedules in the event of an emergency. Therefore, IEP's argument is not properly on rehearing before the Commission. In any event, unless a party can establish discernible harm, the Commission is not persuaded at this time to change the ISO's curtailment authority.[377]

As stated above, the Commission is considering in separate proceedings issues related to selling power to creditworthy parties. Dynegy's concerns regarding selling power to a non-creditworthy party will be addressed in conjunction with the Commission's determination in those proceedings. In an order issued on November 7, 2001, the Commission provided, in part, that the ISO must enforce the creditworthiness requirement of its Tariff and prior Commission orders regarding creditworthiness by requiring a creditworthy party to back transactions.[378] The Commission explained that "[t]he must-offer requirement assumes a matching must-pay requirement."[379]

The Commission denies Dynegy's rehearing request to limit the must-offer requirement to emergency conditions or to peak months. The Commission will continue to apply the must-offer requirement in all hours to ensure that all available energy is in the market and to prevent physical and economic withholding in order for the ISO to call upon available resources in the real-time market to the extent that energy is needed.

While section 202(c) of the FPA, as amended, grants authority to the Secretary of the Department of Energy to institute certain emergency measures, that provision does not conflict with the Commission's implementation of the must-offer requirement. The Commission instituted the must-offer requirement to prevent physical and economic withholding and thereby ensure that the ISO will be able to call upon available resources in the real-time market to the extent that energy is needed. In concert with the other components of the Commission's mitigation plan, we continue to believe that the must-

[377]See June 19 Order at 62,554.

[378]California Independent System Operator Corporation, 97 FERC ¶ 61,151 (2001).

[379]Id. at 61,659.

offer requirement is necessary to ensure just and reasonable rates in the WSCC as required under section 206 of the FPA.[380]

3. Demand Response

On rehearing, several generators contend that the Commission erred in failing to compel demand response measures to provide price responsiveness in the ISO and WSCC markets or to establish a timetable for implementing such measures.[381]

Commission Response

As the Commission has stated in prior orders, a demand response mechanism is a critical component in developing a robust market, which relevant state authorities should actively promote.[382] Due to technical impracticalities, the Commission did not address the demand response requirement in the June 19 Order, but indicated its intention to hold a staff technical conference.[383] The Commission remains committed to the creation of a healthy demand response mechanism in wholesale electricity markets, and has scheduled a conference on this topic, co-sponsored with the U.S. Department of Energy, on February 14, 2002. This conference should fulfill the purpose of the staff technical conference proposed in the June 19 Order.

The proliferation of demand response programs in California in 2001- from the utilities, the California Energy Commission, and the ISO- appears to have led to some degree of customer confusion and limited participation. Therefore, we encourage California to plan early and coordinate its demand response offerings for maximum customer participation and effectiveness. In addition, because of the interdependence of the Western electric market, we encourage California to work with other Western state regulators and utilities to develop a coordinated and complementary set of demand response programs to serve customers and moderate markets across the entire marketplace.

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[380] See also FPA § 309, 16 U.S.C. § 825h ("The Commission shall have power to perform any and all acts, and to prescribe, issue, make, amend, and rescind such orders, rules, and regulations as it may find necessary or appropriate to carry out the provisions of this Act.").

[381] See, e.g., Requests for Rehearing of Reliant, Dynegy, and Mirant.

[382] See December 15 Order at 61,982; June 19 Order at 62,555.

[383] June 19 Order at 62,555.

4. Continuation of Market-Based Rates and Limitation of Mitigation to Spot Market Transactions

Some parties argue that the Commission's investigation should encompass all public utility sales for resale pursuant to market-based rate authority and all transactions of less than one year, including California wholesale bilateral transactions.[384] APPA also recommends that the Commission impose price mitigation capping on all short term non-firm energy sales by public utilities at 85 percent of the mitigated reserve deficiency MCP for the applicable region. Similarly, several parties argue that the Commission should mitigate prices for forward contracts entered into before the Price Mitigation Orders became effective.[385] The Nevada Attorney General argues that not applying prospective price mitigation to forward contract sales unreasonably and arbitrarily penalizes forward contract customers, including Nevada customers. Nevada Commission contends that the mitigation plan rewards entities that rely on the spot market while working to the disadvantage of those who have minimized reliance on the spot market.

APX requests clarification that the price mitigation applies only to spot market transactions in the WSCC, i.e., transactions whose duration is no more than the 24-hour period immediately before delivery. Enron requests clarification that option agreements exercised for spot-market sales are not themselves spot sales, and Duke requests clarification of the term "spot market" or "24-hour sales" in the context of sales scheduled for delivery over or following a weekend. The ISO also requests clarification of the spot transactions subject to price mitigation.

Allegheny Energy argues that the mitigation plan eliminates the ability of private parties to freely sell under next-day bilateral contracts and that it fails to recognize the fundamental differences between the day-ahead and real-time markets by grouping them both as "spot markets" subject to the same pricing. Specifically, Allegheny Energy states that price caps in the day-ahead, same-day and real-time markets will not foster forward contracts because market participants enter into forward contracts to hedge the risk of price volatility. Allegheny Energy asserts that market mitigation eliminates this volatility and creates a disincentive to contract on a forward basis. Allegheny Energy seeks

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[384] See, e.g., Requests for Rehearing of APPA, Southern California Water Company.

[385] See, e.g., Requests for Rehearing of City of San Diego, City of Seattle, Sierra Pacific Power and Nevada Power, Southern California Water Company.

clarification that the functionally different day-ahead market is exempted from the market mitigation plan.

Puget Sound argues that the Commission should specify that price mitigation measures, and refunds from such measures, that are not applied to or followed by all sellers (including municipal utilities and Bonneville) are unjust and unreasonable.

Commission Response

The Commission denies clarification or rehearing regarding the limitation of mitigation measures solely to spot markets. Applying mitigation to spot market transactions results in mitigation of generation market power in forward markets by creating a kind of competitive "standard offer" service for customers. If sellers attempt to charge excessive, non-competitive prices in forward markets, customers can avoid them by waiting to purchase in the real-time market. This puts market pressure on sellers to offer competitive prices in the forward markets. In turn, when sellers offer competitive forward prices, many buyers will prefer to purchase in the forward markets in order to gain price certainty.[386]

Allegheny Energy's objection to mitigation of prices in the day-ahead is not timely. This Commission has treated day-ahead, day-of, and real-time energy sales similarly since the inception of this proceeding and has found that the market structure and market rules in California caused and continue to have the potential to cause unjust and unreasonable rates in all of these short-term markets.[387] Therefore, we reject this argument. We agree, however, with Allegheny Energy's point that the real-time and day-ahead markets are functionally different in some respects, and we believe that a well-functioning day-ahead energy market would relieve some of the current California scheduling problems. Accordingly, we will direct the ISO to propose a plan for the creation of a day-ahead energy market; this submission must be filed by May 1, 2002, and should be integrated with the revised congestion management plan that is also to be filed on that date, as discussed elsewhere in this order.

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[386] See AEP Power Marketing Inc., et al., 97 FERC ¶ 61,219 at 61,972 (2001).

[387] See, e.g., November 1 Order, 93 FERC at 61,349.

The Commission denies requests to extend price mitigation measures to forward contracts. The Commission instituted the price mitigation measures based on a finding that rates in spot markets are unjust and unreasonable.[388]

The Commission disagrees with Nevada Commission's contention that the mitigation plan works to the disadvantage of those who have minimized reliance on the spot market because the mitigation measures do not apply for sales over 24 hours, i.e., sales that help minimize reliance on the spot market.

The June 19 Order defined "spot markets" or "spot market sales" as sales that are 24 hours or less and that are entered into the day of or day prior to delivery.[389] We will continue to apply this definition for transactions within California and throughout the WSCC.

To the extent Duke is requesting that the Commission clarify that sales scheduled for delivery over or following a weekend constitute spot-market sales, we will deny the request. Only those transactions that are entered into the day of or the day prior to the sale are subject to mitigation. Similarly, with respect to Enron's request for clarification that option agreements exercised for spot-market sales are not themselves spot-market sales, we clarify that such sales are entered into for future periods and therefore are not subject to mitigation.

5. Price Mitigation in All Hours

Generators generally contend on rehearing that the Commission failed to provide a sufficient basis to extend price mitigation to all hours, in all spot markets, throughout the WSCC region. Mirant argues that this decision is inconsistent with the Commission's own findings and that the Commission's change in position is not supported by any new evidence, while Duke states that the reserve deficiency market mitigation is premised on dysfunctional market rules operating during periods of tightened reserves, and not on findings that any seller exercised market power. Generators also continue to oppose mitigation measures that cap prices below the true market price because they will

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[388]See id. (The Commission found that the electric market structure and market rules "in conjunction with an imbalance of supply and demand in California, have caused, and continue to have the potential to cause, unjust and unreasonable rates for short-term energy (Day-Ahead, Day-of, Ancillary Services and real-time energy sales) under certain conditions.").

[389]June 19 Order at 62,545 n.3; See also July 25 Order at 61,515.

discourage investment and delay development of competitive markets.[390] EPSA argues that: (1) the complex proxy price approach set out in the April 26 and June 19 Orders have created uncertainty and confusion; (2) price caps will lead to a sub-optimal mix of generating units, favoring base-load plants when peaking units may be needed; (3) below-market price caps will discourage demand-side management by dampening price signals and discouraging the development of much-needed risk management tools. Avista Utilities contends that the price mitigation scheme will discourage forward market transactions to cover load obligations.

A number of parties seek rehearing of the Commission's decision to base mitigation in non-reserve deficiency hours on 85 percent of the last Stage 1 price, contending that it establishes artificial limits and brings regulatory uncertainty and instability to the markets.[391] Generators argue that setting prices in non-reserve deficiency hours at 85 percent of the last mitigated reserve deficiency MCP subjects prices to manipulation by the ISO to reduce them to lower and lower levels;[392] that it violates section 206 of the FPA because the Commission never found rates during non-reserve deficiency periods to be unjust and unreasonable;[393] that the mechanism is unclear and inconsistent with the Commission's stated intent and its own findings and that it is unsupported by new evidence or evidence in the record;[394] and that such mitigation has skewed price signals when supplies are plentiful.[395]

Some parties argue that the mitigated non-reserve deficiency MCP leads to excessive rates that are unjustified, and contrary to the Commission's mandate to ensure just and reasonable rates.[396] Oversight Board recommends that the Commission implement a marginal cost proxy price methodology similar to that utilized in calculating the mitigated non-reserve deficiency MCP for non-reserve deficiency hours. PG&E

[390] See, e.g., Requests for Rehearing of EPSA, PPL, Nevada IEC/CC Washington and City of Vernon.

[391] See, e.g., Request for Rehearing of BP Energy.

[392] See, e.g., Request for Rehearing of Dynegy.

[393] See, e.g., Request for Rehearing of Enron.

[394] See, e.g., Requests for Rehearing of Duke, Enron, IEP and Mirant.

[395] See, e.g., Request for Rehearing of Allegheny.

[396] See, e.g., Request for Rehearing of City of San Diego and Southern California Water Co.

recommends that the Commission require the ISO to submit monthly reports of hourly market clearing prices to prevent excessive pricing in non-emergency hours. SMUD recommends that the Commission adjust the heat rate in the proxy price calculation for the mitigated non-reserve deficiency MCP to the equivalent of the last unit dispatched during the preceding reserve deficiency period, so that participants are aware before the fact of the mitigated non-reserve deficiency MCP.

Duke and Reliant request clarification that the mitigated non-reserve deficiency MCP should be 85 percent of the highest ten minute mitigated reserve deficiency MCP when a Stage 1, 2 or 3 emergency is in effect, not the hourly average of prices.

Commission Response

We continue to believe that it is appropriate to mitigate prices in all hours and will deny rehearing. In the November 1 and December 15 Orders, the Commission found that the California market structures and rules for wholesale sales of electric energy in California were seriously flawed, and that in conjunction with an imbalance of supply and demand in California, these rules and structures had caused and had the potential to continue to cause unjust and unreasonable rates for short term energy in certain conditions. Moreover, the Commission's dysfunctional market finding was not limited to reserve deficiency periods. In response to these findings, the Commission has sought to intervene in markets in as limited a manner as possible consistent with its responsibilities to ensure just and reasonable rates under the FPA, to rely on market principles whenever it can, and to balance carefully the need for price relief against the need for price signals to attract critical supply entry.[397]

Consistent with that approach, among other things, the December 15 Order eliminated the mandatory buy-sell requirement and the PX rate schedule to remove the California IOUs' over-reliance on spot markets and instituted a soft price breakpoint as an interim mitigation measure. In the March 9 and April 26 Orders the Commission implemented price mitigation for reserve deficiency hours.[398]

The ISO-declared emergency stages when extreme supply shortages led to reserve deficiencies that exceeded critical levels. However, even where reserves were above the

[397] June 19 Order at 62,545.

[398] In the March 9 Order, the Commission defined reserve deficiency hours requiring mitigation as when the ISO declared a Stage 3 emergency. In the April 26 Order, the Commission expanded its definition to include periods when the ISO declared a Stage 1 emergency.

threshold levels required to avoid an ISO-declared emergency, the ISO still required sufficient available supply to call upon to meet the real-time market requirements. To assure adequate supply when it is needed, the April 26 Order added to the Commission's arsenal the must-offer requirement during all hours if it was available and not already scheduled to run through bilateral agreements. At that point, the Commission believed that limiting price mitigation to emergency conditions would be sufficient because (1) during non-emergency conditions, a supplier has less of an incentive to bid a high price since it cannot be sure it will be dispatched when other suppliers might offer lower bids; and (2) suppliers have less incentive to withhold capacity in other than emergency conditions, since they would risk forcing an emergency condition in which price mitigation would apply.[399]

Despite the additional, incremental steps taken in the April 26 Order to ensure just and reasonable rates and adequate supply, the Commission became concerned that markets remained dysfunctional in all hours. For example, during March 2001, there were indications that prices in non-emergency periods did not reflect competitive markets.[400] As noted above, the Commission had previously believed that suppliers would have less incentive to bid high prices in non-emergency periods since they risked not being dispatched. However, during non-emergency periods where there were no excess supplies in the market and all suppliers would be dispatched, the incentive to bid high prices remained. Accordingly, in the June 19 Order, the Commission expanded the market monitoring and mitigation plan to produce spot market prices in all hours that are just and reasonable and emulate those that would be produced in a competitive market.[401] As the Commission explained, extending price mitigation to all hours would: (1) provide added protection to customers and the economies of the Western States, (2) permit all energies and attention to be focused on the tasks of adding new supply, upgrading energy infrastructure, transitioning California's markets to a balanced portfolio of short, medium and long-term supply arrangements, and (3) protect neighboring states from undue harm.[402]

Furthermore, the Commission exercised its discretion in setting the mitigated non-reserve deficiency MCP at 85 percent of the last Stage 1 price in order to ensure just and reasonable rates, i.e., rates that fall within a zone of reasonableness. Under competitive

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[399] April 26 Order at 61,361.

[400] See Request for Rehearing of the Oversight Board filed May 29, 2001.

[401] June 19 Order at 62,558.

[402] June 19 Order at 62,547.

conditions, the market is expected to clear at a lower price during non-reserve deficiency hours, as opposed to reserve deficiency hours, because there would be excess generation available to serve the load. Accordingly, the Commission set the mitigated non-reserve deficiency MCP to provide a structure that will minimize potential market power abuses, thereby lowering customer rates, while also encouraging adequate supply in the market for the immediate future.[403] Thus, the arrangement seeks to simulate the results of a competitive market, where prices will be lower when supply is higher relative to demand. Therefore, we deny requests for rehearing and clarification regarding the Commission's price mitigation mechanism in all hours.

We will deny requests by Duke and Reliant for clarification that the mitigated non-reserve deficiency MCP should be 85 percent of the highest ten minute mitigated reserve deficiency MCP because West-wide markets are hourly markets. Furthermore, Duke and Reliant do not provide a sufficient basis to switch from using an hourly average of prices.

6. Conditions on Market-Based Rate Authority

Dynegy and Reliant request rehearing or clarification of the provisions in the June 19 Order prohibiting anticompetitive bidding practices. Dynegy requests clarification of the types of bids generators can submit. Dynegy and Reliant claim that there are valid operational justifications for "hockey-stick" bids and bids reflecting scarcity, so they should not be prohibited. For example, Reliant states that "hockey-stick" bids reflect the potential replacement costs that would be incurred as a result of a unit outage where the seller bids the last available megawatts from a unit or portfolio and thereby exposes itself to a replacement cost risk. Reliant also claims on rehearing that the Commission erred in placing vague conditions on sellers' market-based rate authority in the absence of specific findings of market power abuse or unjust and unreasonable rates. In addition, Pinnacle West seeks reassurance that a filing to justify a bid in excess of the mitigated Market Clearing Prices will not be treated as inappropriate behavior that threatens an entity's market-based rate authority.

Commission Response

The Commission denies rehearing or clarification. To ensure that sellers do not engage in certain anticompetitive behavior, we will continue to condition sellers' market-based rates. As explained in the April 26 and June 19 Orders, behavior such as "hockey

[403] See June 19 Order at 62,559.

stick" bidding and related bidding is prohibited.[404] Sellers violating these conditions would have their rates subject to increased scrutiny by the Commission and potential refunds. We reject Reliant's argument regarding "hockey-stick" bids, since the June 19 Order directed the ISO to eliminate from its Tariff the replacement cost penalty which Reliant cites to justify such bids.[405] In addition, the Commission seeks to reassure Pinnacle West that filing to justify a bid in excess of the mitigated Market Clearing Prices will not be treated as inappropriate behavior.

7. Confidentiality of Data

The Oversight Board claims on rehearing that the June 19 Order's failure to require disclosure of data submitted by sellers to justify bids above the mitigated MCP to the Oversight Board and other public entities is contrary to law and violates due process. The Oversight Board asserts that reviewing and challenging the sufficiency of the attempted justifications is essential to any check on the authority and performance of the Commission.

Commission Response

We deny the Oversight Board's request to require disclosure of data by sellers that wish to justify bids above the mitigated MCP because the Oversight Board has no authority to evaluate wholesale rates. As discussed earlier in this order, we have previously determined that the Oversight Board's role is limited to matters within state jurisdiction.[406]

8. RTO Proposal and ISO Governance

A number of sellers contend that the Commission has afforded too much authority to the ISO in implementing the mitigation plan, given its lack of independent governance

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[404] See April 26 Order at 61,360; June 19 Order at 62,565.

[405] June 19 Order at 62,553.

[406] See California Power Exchange Corporation, et al., 85 FERC ¶ 61,263 at 62,067-69 (1998), reh'g denied, 86 FERC ¶ 61,114 (1999); California Electricity Oversight Board, 88 FERC ¶ 61,172, at 61,576 (1999), reh'g denied, 89 FERC ¶ 61,134 (1999), dismissed sub nom. Western Power Trading Forum and Coalition of New Market Participants v. FERC, No. 99-1532 (D.C. Cir. filed April 10, 2001).

and its position as a market participant.[407] Mirant recommends that the Commission establish a timetable for development of a regional RTO and that the ISO be required to reconstitute its governing Board. Pinnacle West urges the Commission to condition implementation of the mitigation plan on actual reform of the ISO Board and to scrutinize the ISO's declarations of Stage 1, 2, and 3 emergencies to ensure that they are in accordance with WSCC reserve deficiency triggers. PSColorado requests that the Commission adopt measures to correct problems arising from the ISO having control over setting the mitigated reserve deficiency MCP while lacking independence. Duke states that the ISO's July 10 Compliance Filing indicates that the ISO will use its discretion in calling system emergencies and requests clarification that the mitigated reserve deficiency MCP will only be recalculated when there is a reserve deficiency of less than 7 percent.

Commission Response

As noted earlier in this order, in light of more recently filed proceedings, the Commission will address issues related to the ISO's current governance structure and the extent of its independence in a future order. Sellers' arguments and concerns raised herein concerning the ISO's governance and independence will be addressed at that time.

We grant Duke's request for clarification that the recalculation of the mitigated reserve deficiency MCP will only be triggered when reserves in California fall below 7 percent. The April 26 and June 19 Orders specified that we will use a single market clearing price derived from must-offer and marginal cost bidding requirements for reserve deficiency hours, i.e., a recalculation of the mitigated prices would be triggered when reserves in California fall below 7 percent.[408] Prior to the April 26 Order, the Commission granted discretion to the ISO to declare system emergencies based on various factors; however, the declaration of a system emergency did not trigger new prices through the mitigation plan. For reasons identified in the compliance order issued concurrently with this order, this discretion is no longer warranted during the duration of the mitigation plan. Thus, in the order addressing the ISO's compliance filing issued concurrently with this order, we direct the ISO to modify its Tariff regarding the declaration of system emergencies to reflect a definition of a Stage 1 system emergency as when reserves fall below 7 percent, whereupon a new mitigated reserve deficiency MCP must be calculated. Therefore, we grant Duke's request for clarification that the

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[407] See, e.g., Requests for Rehearing of Allegheny Energy, Avista Energy, Avista Utilities, EPSA, IEP, Pinnacle West, and PSColorado.

[408] See April 26 Order at 61,361-62; June 19 Order at 62,555-56.

single market clearing price auction mitigation will be triggered when reserves in California fall below 7 percent.

9. West-Wide Implementation

Numerous sellers seek rehearing of the decision to extend mitigation to the remainder of the WSCC outside of California.[409] They argue that: the Commission exceeded its authority under section 206;[410] the Commission failed to provide notice of its intention to extend its price mitigation measures to the WSCC spot markets outside of California during hours of reserve sufficiency and to provide an adequate hearing with respect to the extension of price mitigation measures to the WSCC spot markets outside of California during both reserve contingencies and hours of reserve sufficiency;[411] the Commission has failed to provide a reasoned basis for extending price mitigation measure to the entire WSCC;[412] the Commission's decision to impose price mitigation for the entire WSCC is unsupported by evidence in the record that prices are unreasonable in that region;[413] California mitigation measures such as must offer are ill suited for the entire WSCC;[414] and the price mitigation methodology will discourage critically needed investment in infrastructure in the WSCC.[415]

Southern Cities argues that the assertion of jurisdiction over all transactions utilizing interstate transmission facilities in the WSCC goes beyond the targeted application of the Commission's conditioning authority in the Order No. 888 series and that it is legally deficient.

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[409]See, e.g., Requests for Rehearing of Avista Energy, Bonneville, Avista Utilities, Mirant, Pinnacle West, Mirant, Morgan-Stanley, Nevada IEC/CC Washington, PPL, PSColorado, Nevada Commission, and Reliant.

[410]See, e.g., Requests for Rehearing of Avista Energy and Avista Utilities.

[411]See, e.g., Requests for Rehearing of Avista Energy and Avista Utilities.

[412]See, e.g., Requests for Rehearing of Mirant and Morgan Stanley.

[413]See, e.g., Requests for Rehearing of Nevada IEC/CC Washington and Nevada Commission.

[414]See, e.g., Request for Rehearing of Nevada Commission.

[415]See, e.g., Request for Rehearing of Avista Energy.

The ISO contends on rehearing that the June 19 Order fails to provide for monitoring and enforcement of the West-wide mitigation requirements. The ISO recommends that the Commission monitor compliance with the must-offer requirement by requiring all non-hydroelectric generators in the West to file weekly reports with the Commission. In addition, the ISO suggests that to monitor compliance with spot price mitigation, the Commission should require all buyers and sellers of spot energy to submit weekly reports to the Commission. The ISO also requests that the Commission clarify the definition of spot markets in the WSCC.

On rehearing, Bonneville asserts that the Commission has no authority to apply the West-wide mitigation plan and the must-offer requirement to Bonneville because the Commission lacks jurisdiction over Bonneville. Bonneville states that sections 7(a)(2) and 7(k) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act)[416] give the Commission limited jurisdiction over review of Bonneville's power rates. Bonneville also states that the Commission's assertion of conditioning authority over Bonneville is not supported by statute and cannot override the limitation on its jurisdiction under the FPA and the Northwest Power Act.

APX seeks clarification that because the ISO will calculate the mitigated price after the hour in which it applies and this mitigated price will apply throughout the WSCC, the Commission should indicate that the ISO has an obligation to publish such prices immediately and in a way readily accessible to all market participants.

Commission Response

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[416]Sections 7(a)(2) and 7(k) of the Northwest Power Act, 16 U.S.C. § 839e(a)(2), provide that the Commission shall approve Bonneville's rates upon finding that such rates:

(A) are sufficient to assure repayment of the Federal investment in the Federal Columbia River Power System over a reasonable number of years after first meeting the Administrator's other costs,

(B) are based upon the Administrator's total system costs, and

(C) insofar as transmission rates are concerned, equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing such system.

The April 26 Order instituted an investigation under section 206 of the FPA into the reasonableness of the rates for wholesale sales in the spot markets in the Western Systems Coordinating Council (WSCC). In order to ensure that rates for sales for resale in spot markets in California and the rest of the WSCC continued to fall within a zone of reasonableness, the June 19 Order expanded price mitigation in California and throughout the remainder of the WSCC during all hours.[417]

The Commission has recognized in prior orders that the California market is integrated with those of other states in the WSCC and that regional solutions are a necessary part of any long-term restructuring of the western marketplace. Furthermore, a staff investigation report analyzing power markets in the Northwest in November and December 2000 found that the high prices and power crisis in California in the summer of 2000 reflected underlying problems in wider regional markets, and impacted the entire Northwest.[418] Based upon the continued need to ensure that rates throughout the Western region remain within a zone of reasonableness, the Commission will continue to apply its mitigation measures throughout the WSCC.

Although the Commission has not found that markets outside of California are dysfunctional, prices in California tend to draw supplies from, and increase prices in, other parts of the WSCC. Under the mitigation plan, spot market prices outside California can be lower than those in California markets, but they are essentially limited to no more than the mitigated Market Clearing Prices determined by the California spot market. This is appropriate because gas prices tend to be higher in California than in other parts of the West. Therefore, the Commission will deny rehearing on the implementation of the Commission mitigation plan throughout the WSCC.

With respect to the ISO's suggestion that the Commission should monitor compliance with the must-offer requirement and price mitigation by reviewing weekly reports submitted by generators in the West, the Commission is not persuaded that such reports are needed at this time. However, we will continue to require each marketer and independent power producing entity to post available capacity on a daily basis on its own web site and on the WSPP web site.[419] If a compliance problem arises, parties may file a complaint with the Commission.

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[417] June 19 Order at 62,546.

[418] See Staff Report to the Federal Energy Regulatory Commission on Northwest Power Markets in November and December 2000 at 11.

[419] See June 19 Order at 62,569.

We deny Bonnevilles request for rehearing regarding the limits imposed by the FPA and the Northwest Power Act over the Commission's jurisdiction over Bonneville's rates and exercise of conditioning authority. The FPA and the Northwest Power Act do not affect the Commission's ability to require governmental entities, including Bonneville, that make sales into the ISO's markets over which the Commission has exclusive jurisdiction to abide by the same conditions that are applicable to public utilities.[420]

We reject arguments that the Commission did not provide an adequate hearing with respect to extending price mitigation measures to the WSCC spot markets outside of California during reserve and non-reserve deficiency hours because the necessary determinations were made on the basis of a written record developed with paper hearing procedures. The necessary determinations were made on the basis of a written record developed with paper hearing procedures. Similarly, we reject arguments that the Commission failed to provide notice of its intention to expand its price mitigation measures to the WSCC spot markets during non-reserve deficiency hours. The June 19 Order explained the reasons for our decision to expand price mitigation measures. Parties have addressed those reasons in their rehearing requests and presented their countervailing arguments. Since those arguments have been fully considered and addressed in this order, no further procedure is necessary to addressthese issues.

a. Price Mitigation Outside of California

A number of sellers argue that the prices in California are inappropriate for the remainder of the WSCC.[421] They argue that: using California's market dynamics to establish maximum prices outside of California fails to recognize important regional demand variations;[422] seasonal differences and the existence of transmission constraints means that there will be periods when prices and reserve conditions in California have relatively little relationship to prices and reserve conditions in the Pacific Northwest;[423] there is no record support for the Commission's finding that the California market is an

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[420] April 26 Order at 61,356; June 19 Order at 62,551.

[421] See, e.g., Requests for Rehearing of Dynegy, IEP Nevada IEC/CC Washington, Portland General, PPL, PSColorado, Nevada Commission, Puget Sound, Sierra Pacific and Nevada Power.

[422] See, e.g., Request for Rehearing of IEP.

[423] See, e.g., Request for Rehearing of Avista Utilities.

appropriate proxy for the rest of the WSCC;[424] that there is no record support for the Commission's finding that 85 percent of the highest price in the California market during the last stage 1 emergency is an appropriate proxy price for non-emergency hours; that the Commission's remedy is based on an unreasonable assumption that prices will be lower throughout the WSCC when there is not a reserve deficiency in California;[425] that the Commission erred in precluding the recovery of legitimate opportunity costs and scarcity rents as well as credit premiums from buyers outside of California having insufficient credit;[426] that it creates harmful incentives against siting new generation or generation upgrades, against using forward contracts (where real-time prices are lower), and to prefer California markets due to the limitation of the creditworthiness adder to California markets;[427] and that it may adversely affect Nevada customers because Nevada utilities will have lower spot revenues to use to pay for their own fuel and purchased power costs, which they would have to recover through increased rates in Nevada.[428]

Bonneville claims on rehearing that the June 19 Order raises the potential for the price of power to be capped at an artificially high level, resulting in Bonneville customers paying unnecessarily high prices for power. Bonneville seeks clarification so that the June 19 Order takes into account the fact that California and Pacific Northwest experience their peak demands at different times of year.

PSColorado requests clarification that utilities in the WSCC outside of California may recover costs that California generators may recover, including start-up fuel and emissions costs, and other incurred costs such as purchased power and transmission costs.

Commission Response

In the November 1 Order, the Commission found that the "electric market structure and market rules for wholesale sales of electric energy in California are seriously flawed and that these structures and rules, in conjunction with an imbalance of

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[424] See, e.g., Request for Rehearing of Nevada IEC/CC Washington.

[425] See, e.g., Request for Rehearing of Nevada IEC/CC Washington.

[426] See, e.g., Request for Rehearing of PPL.

[427] See, e.g., Request for Rehearing of Nevada Commission.

[428] See, e.g., Request for Rehearing of Nevada Commission.

supply and demand in California, have caused, and continue to have the potential to cause, unjust and unreasonable rates for short-term energy . . . under certain conditions."[429] The Commission noted that, although the record did not support findings of specific exercises of market power, there was "clear evidence that the California market structure and rules provide the opportunity for sellers to exercise market power when supply is tight and can result in unjust and unreasonable rates under the FPA."[430]

The December 15 Order reiterated the earlier findings that the market structures and rules for wholesale sales of electric energy in California were seriously flawed and that these structures and rules, in conjunction with an imbalance of supply and demand in California, had caused, and continued to have the potential to cause, unjust and unreasonable rates for short-term energy under certain conditions. Accordingly, the Commission adopted a number of the proposed remedies presented in the November 1 Order.

The April 26 Order adopted a prospective monitoring and mitigation plan for wholesale sales through the organized real-time markets operated by the ISO. The April 26 Order also established an inquiry into whether a price mitigation plan similar to the one for the California ISO's organized spot markets should be implemented in the WSCC. Recognizing the "critical interdependence among the prices in the ISO's organized spot markets, the prices in the bilateral spot markets in California and the rest of the West, and the prices in forward markets,"[431] the June 19 Order expanded the price mitigation plan to include bilateral spot market sales throughout the WSCC. Based on the need for uniform pricing throughout the Western region, the June 19 Order proposed changes to the WSCC that would mirror the measures to be applied to California. Consistent with our earlier efforts to modify the existing market structure throughout the West to minimize the potential for market power abuse, thereby protecting against possible unjust and unreasonable rates, while also maximizing incentives for increased supply in the entire Western region, we believe that price mitigation is necessary outside of California. Therefore, we deny requests for rehearing of the application of price mitigation outside of California.

With regard to PSColorado's request for clarification that sellers in the WSCC outside of California may recover costs that California sellers may recover, including start-up fuel and emissions costs, and other incurred costs such as purchased power and

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[429]November 1 Order at 61,349.

[430]November 1 Order at 61,350.

[431]June 19 Order at 62,547.

transmission costs, PSColorado does not specify whether it is referring to transactions through the ISO or through bilateral contracts. We clarify that sellers in the WSCC outside of California that engage in transactions through the ISO will be treated like sellers in California. Accordingly, as with sellers in California, we will allow sellers outside of California transacting through the ISO to invoice the ISO for their start-up fuel and emissions costs. Sellers will receive these costs over and above the MCP. In addition, as with sellers in California, we will not allow sellers in the WSCC outside California transacting through the ISO to justify higher-than-mitigated prices based on purchased power and transmission costs. Furthermore, we will not allow sellers in the WSCC transacting outside of California through bilateral contracts to recover start-up fuel and emissions costs, or any other incurred costs. Such sellers can freely negotiate to recover these costs in their contracts.

10. Applicability to Governmental Entities and Cooperatives

Numerous parties seek rehearing of the application of the must-offer requirement and price mitigation plan to governmental entities.[432] They contend that the must-offer requirement and price mitigation plan cannot be applied to municipal utilities that have not signed Participating Generator Agreements (PGAs) with the ISO;[433] that it violates sections 201(f),[434] 205 and 206 of the FPA;[435] and that the Commission cannot indirectly impose requirements on governmental sellers by conditioning their use of the interstate grid that they cannot impose directly under the FPA.[436] Furthermore, LADWP contends that by reaching generation and transmission owned by LADWP, the Commission is taking the property of LADWP. PSColorado requests clarification that the must-offer requirement is limited to confirmed sales on an as-available basis and that it allows utilities to decide the amount of energy available to sell in the short-term wholesale markets. APPA suggests that the Commission should consider the establishment of a

[432] See, e.g., Requests for Rehearing of APPA, CMUA, Southern Cities, City of Burbank, California, Imperial Irrigation District, LADWP, PSColorado, Chelan County, WA PUD, Grant County, SMUD and Salt River.

[433] See, e.g., Requests for Rehearing of APPA and CMUA.

[434] See, e.g., Requests for Rehearing of APPA, Bonneville, City of Burbank, CMUA and Imperial Irrigation District.

[435] See, e.g., Requests for Rehearing of APPA, City of Burbank, NRECA and Salt River.

[436] See, e.g., Requests for Rehearing of CMUA and SMUD.

"safe harbor" framework for voluntary power sales by governmental entities similar to the safe harbor framework established by the Commission for the voluntary provision of open access transmission service in Order No. 888.

Cooperatives also seek rehearing of the applicability of the must-offer requirement to them.[437] NRECA argues that the Commission should recognize that there are differences between cooperatives and municipal utilities and that cooperatives face unique issues. NRECA requests clarification that cooperatives are released from the must-offer requirement if such sales would force the cooperatives to violate (1) the requirement to maintain their tax exempt status that 85 percent of their annual income must come from their members or (2) Rural Electrification Act (REA) requirements by forcing cooperatives to sell capacity that may be available into the market on a short-term basis making such capacity unavailable for their members at a time when their members desperately need the power (i.e., during a reserve deficiency period).

Commission Response

Parties have raised numerous issues regarding the applicability of the June 19 Order's must-offer and price mitigation requirements to governmental entities and cooperatives in the WSCC bilateral markets. Circumstances at that time appeared to indicate that we could not assure just and reasonable rates and reliable service in bilateral markets throughout the WSCC without those requirements. For example, the general consensus among experts in the Spring of 2001 predicted that California would suffer extensive rolling blackouts throughout the entire summer.[438] Those predictions in fact did not come true. In addition, since the June 19 Order, conditions affecting the electric energy markets in the WSCC began to improve (i.e., favorable temperatures, increased rainfall, and higher levels of gas storage).[439]

We find that, in light of these changes, our decision to apply the June 19 Order's must-offer and price mitigation requirements to governmental entities and RUS-financed

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[437] See, e.g., Requests for Rehearing of NRECA and AEPCO.

[438] See, e.g., North America Electric Reliability Council May 2001 Summer Special Report on Reliability of the Bulk Electric Supply in North America.

[439] See, e.g., United States Department of Energy's Energy Information Administration, U.S. Natural Gas Storage By State, available at http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/natural_gas_monthly/current/pdf/table_14.pdf.

cooperatives in order to assure just and reasonable rates and reliable service in bilateral markets throughout the WSCC proved to be unnecessary. Accordingly, we grant rehearing by vacating application of those June 19 Order requirements to governmental entities and RUS-financed cooperatives.[440]

F. Rehearing of Remaining Issues from July 25 Order

California Parties argue that the Commission should determine just and reasonable cost-based rates that should have been in effect throughout the refund effective period and should order refunds, with interest, of amounts in excess of cost-based rates. PG&E similarly argues that the July 25 Order's refund methodology should be replaced by a cost-of-service based refund methodology. City of San Diego also believes refunds should be based on sellers' cost of service. It contends that determining refunds is necessarily backward-looking and requires after-the-fact review and believes that use of proxy input prices to determine the marginal generator's actual running costs is unsupported and overstates actual costs. San Diego asserts that when actual cost data is readily available, there is no need to adopt a proxy methodology.

The ISO argues that the calculation methodology does not account for real-time congestion. Otherwise, generators in the lower priced zone would get the benefit of the mitigated Market Clearing Prices in the higher priced zone during times when there was real congestion, even though they actually would have received only the mitigated Market Clearing Prices of their own zone because there was insufficient transmission capability to allow prices in the zones to equalize.

Suppliers object to the procedures established leading up to the Chief Judge's recommendation and the Commission's use of the record developed in the settlement proceeding.[441] PSNM, Reliant and the Marketer Group contend that the Commission violated due process and its regulations by permitting the Chief Judge to act in an advisory capacity and by relying on his recommendations. Others allege that the Commission cannot rely on the Chief Judge's recommendation as support for the July 25 Order because it was based on an inadequate record and was procedurally

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[440] For the reasons previously discussed in this and other orders in these proceedings, however, it remains necessary to apply price mitigation and must-offer requirements to governmental entities and RUS-financed cooperatives to the extent that they participate in the ISO spot markets.

[441] See, e.g., Requests for Rehearing of Marketer Group, Nevada IEC/CC Washington, CAC.

impermissible.[442] Reliant argues that requiring refunds based on a methodology derived from confidential settlement proceedings and a perfunctory record violates sellers' rights to due process. Similarly, PG&E argues that the order's conclusions regarding the use of daily spot gas prices were based on oral testimony with no opportunity for discovery and urges the Commission to return to using monthly averages or to provide parties with additional process and data.

Duke argues that the Commission violated due process by constraining the period for the refund hearing and denying the opportunity for suppliers to present evidence of actual costs. Others point out that they had no opportunity to test purchasers' allegations or to present their own evidence, thus the procedures did not permit them to demonstrate that their rates were just and reasonable.[443] Burbank asserts that the 45-day limit on the refund hearing will not afford parties an adequate opportunity to present their cases and, thus, violates their due process rights.

With respect to the refund hearing, Dynegy argues that certain issues are properly raised in other forums. It states that there will be some disputes relating to the ISO settlement process that affect the refunds owed by suppliers which, under the ISO Tariff, must be resolved by arbitration if they are not settled. It also argues that the Commission lacks jurisdiction to adjudicate commercial disputes about amounts owed to suppliers, some of which are pending in the PG&E bankruptcy proceeding. Dynegy suggests that no purpose would be served by requiring resolution of those issues here and that it could take the parties and the Judge months or years to complete such an effort. Dynegy suggests that the better course is as follows. It would leave "baseline" data to be resolved in other proceedings where appropriate. The refund proceeding would resolve the issue of whether refunds are owed to suppliers, and if so, what amount. Then the parties should take at face value claims about amounts owed to suppliers or a range for each supplier, and those claims would be subject to adjustment in other proceedings and not finally decided at the Commission. If a supplier ends up owing net refunds, payments can be made at that time.

The Marketer Group and Mirant request clarification that, for purposes of the refund hearing, offsets to supplier refund liability include amounts owed to suppliers by the PX, as well as by the ISO.

Salt River requests clarification that the scope of the refund hearing includes: (1) the settlement statements recalculated by the PX and ISO; and (2) the offset of refund

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[442] See, e.g., Requests for Rehearing of Mirant, Duke.

[443] See, e.g., Requests for Rehearing of EPSA, PSColorado, PacifiCorp.

amounts owed by a supplier to the PX and ISO against refund amounts owed to the supplier by the PX and ISO.

Commission Response

Our prior orders have addressed at length the benefits of relying on market solutions and market mechanisms to mitigate prices. Parties have raised no new arguments on rehearing of the July 25 Order that convince us otherwise.

Constraining the period for the refund hearing was appropriate because of the limited scope of the hearing. No purpose would be served by allowing the presentation of actual costs in the hearing, because they would not be relevant to the determination of the mitigated price in each hour of the refund period pursuant to the refund methodology, nor to refunds owed or amounts past due. Nevertheless, we recognize that sellers have never had an opportunity to present evidence of their marginal costs, and also that the true impact of the refund formula on sellers' bottom lines will not be known until the conclusion of the refund hearing. Therefore, in order to assure adequate process, the Commission will provide an opportunity after the conclusion of the refund hearing for marketers and those reselling purchased power or selling hydroelectric power to submit evidence as to whether the refund methodology results in an overall revenue shortfall for their transactions in the ISO and PX spot markets during the refund period. For the Commission to consider any adjustments, a seller must demonstrate that the rates were inadequate based on consideration of all costs and revenues, not just certain transactions.

The Commission's use of the Chief Judge's recommendation was entirely appropriate. The Commission's regulations do not prohibit a settlement judge from issuing a recommendation to the Commission after conclusion of settlement talks, and this approach is a legitimate hybrid dispute resolution procedure. The Commission relied on the Chief Judge's recommendation in formulating a refund methodology because of his familiarity with the issues presented, yet made its own findings as to each aspect of the formula and modified the recommendation where needed. The one exception was the use of daily spot gas prices, where the Commission relied in part on record evidence gathered by the Chief Judge. This issue has been addressed earlier in this order, where the Commission determined that, even without the evidence relied upon in the July 25 Order, the determination was reasonable.[444]

We will reject the ISO's suggestion to take congestion into account in the refund formula. The ISO has presented no evidence that electricity customers would be better

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[444] See supra, section B.2.b.

off if separate mitigated Market Clearing Prices were calculated for each congestion zone. We take note that no other parties have requested rehearing on this issue, and we decline to impose an additional layer of calculations into an already complicated refund formula.

We do not believe that Dynegy's concerns require any action by the Commission. We agree that certain disputes about amounts owed to suppliers, such as those pending in PG&E's bankruptcy proceeding, are best resolved in other forums. Such circumstances will be addressed on a case-by-case basis as they arise in future proceedings.

We will clarify for the Marketer Group and Mirant that offsets to supplier refund liability should include amounts owed to suppliers by the PX as well as by the ISO. We recognize that the PX may not be able to pay amounts past due because of its pending bankruptcy. Nevertheless, we will expect suppliers to pay net refunds, or offset amounts that they owe to the PX from amounts the PX owes them. On another matter, we note that the November Creditworthiness Order requires the ISO to create a schedule for payment of amounts overdue by DWR so that amounts past due will be paid by February 2002. Thus, these amounts will not be offset against refunds owed by sellers.

We will grant Salt River's request and clarify that the settlement statements recalculated by the PX and ISO and the calculation of offsets are within the scope of the refund hearing.

G. Pacific Northwest Complaint (EL01-10-001)

On October 26, 2000, Puget Sound filed a complaint petitioning the Commission for an order capping the prices at which sellers subject to the Commission's jurisdiction, including sellers of energy and capacity under the Western Systems Power Pool Agreement, may sell energy or capacity in the Pacific Northwest's[445] wholesale power markets. Specifically, Puget Sound sought an order that prospectively capped the prices for wholesale sales of energy or capacity into the Pacific Northwest at a level equal to the lowest cap on prices established, ordered, permitted by the Commission for wholesale purchases in, or wholesale sales of energy or capacity to or through the markets operated by the ISO or the PX.

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[445] Puget Sound indicated that, as used in its complaint, the term "Pacific Northwest" has the meaning set forth in the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. § 839a(14) (1994).

The December 15 Order declined to implement a region-wide price cap because it found that such a pricing methodology was impracticable given the market structure in the Northwest and because the burden of proof had not been met to justify such an action.[446]

On rehearing, a number of parties contend that the Commission erred in rejecting Puget Sound's request for a price cap throughout the Northwest region. Puget Sound sought rehearing of the order urging the Commission to impose "a price cap for short-term (same day or day ahead) wholesale sales by jurisdictional sellers of power in the Western Interconnection that is equivalent to the 'soft cap' of $150 per MWh" for the ISO and PX spot markets.[447] In addition, other parties reiterate intervenors' comments that the Commission should expand such a cap throughout the entire WSCC. Several California parties (e.g., CMUA) argue that the December 15 Order's rejection of the regional price cap proposal was arbitrary and does not reflect the fact that the adverse market conditions discussed in the December 15 Order are not limited to California but are in fact regional in nature.[448] In addition, the Washington Utilities and Transportation Commission (Washington Commission) filed comments supporting Puget Sound's rehearing request and urging the Commission to consider how its actions to stabilize California's markets could be applied to stabilize conditions throughout the Western region.

On June 22, 2001, Puget Sound filed a motion to dismiss its complaint and a notice of withdrawal of its complaint and its subsequent rehearing request. Puget Sound explains that the June 19 Order satisfies its complaint because it implements price mitigation measures throughout WSCC. Several parties filed answers to the motion. Bonneville states that the Commission must fully resolve the issues raised in the complaint regardless of whether it grants Puget Sound's motion, arguing that the focus on spot markets in the June 19 Order is not appropriate outside of California, where utilities rely on forward contracts. The City of Tacoma and Port of Seattle jointly filed an answer opposing the motion on the basis that dismissal would unduly prejudice parties outside of California that relied on the existence of the complaint, and arguing that the issues raised in the complaint are an integral part of market issues that the Commission is addressing in the SDG&E proceeding.

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[446] December 15 Order, 93 FERC at 62,019.

[447] Request for Rehearing of Puget Sound filed January 12, 2001, at 10.

[448] See, e.g., Requests for Rehearing of California Commission, City of Seattle, CMUA, County of San Diego, Oversight Board, Puget Sound, and SMUD.

The City of Seattle (Seattle) and the Attorney General of Washington (Attorney General) filed motions to intervene out-of-time in Docket No. EL01-10-000 and motions opposing Puget Sound's notice. The City of Tacoma and the Port of Seattle filed a joint answer opposing the notice but without moving to intervene. Bonneville and the Washington Commission filed responses not explicitly opposing Puget Sound's pleading but urging the Commission to recognize that issues impacting the Pacific Northwest remain, regardless of the status of Puget Sound's complaint. Finally, Pinnacle West filed a response in support of Puget Sound's pleadings. On July 24, 2001, Puget Sound filed a motion to strike the motions of Seattle and Attorney General, and a motion in opposition to their requests to intervene.

As described above, the Commission established a preliminary evidentiary proceeding in the July 25 Order to facilitate development of a factual record on whether there may have been unjust and unreasonable charges for spot market bilateral sales in the Pacific Northwest. The proceeding was intended to help the Commission "determine the extent to which the dysfunctions in the California markets may have affected decisions in the Pacific Northwest."[449]

On rehearing, public utilities in the Northwest object to the Commission's establishment of a preliminary evidentiary proceeding, claiming that the docket was terminated as a matter of law by Puget sound's withdrawal[450] and that the Commission is without jurisdiction to consider sales in the Pacific Northwest.[451] Others contend that the earliest refund effective date that may be used is July 2, 2001, the refund effective date applicable to the West-wide proceeding in EL01-68-000,[452] or even 60 days after July 25, 2001.[453] A number of parties complain that the procedures for investigating the refund issues were unreasonable, violating the due process rights of the parties,[454] and Salt River warns that the proceeding is spiraling out of control and urges the Commission

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[449]July 25 Order at 61,520.

[450]See, e.g., Requests for Rehearing of Puget/Avista; BP, Pinnacle West.

[451]See, e.g., Request for Rehearing of PSColorado.

[452]See, e.g., Requests for Rehearing of BP, PSColorado, PSNM, Marketer Group, Nevada IEC/CC Washington, CAC.

[453]See, e.g., Request for Rehearing of Pinnacle West.

[454]See, e.g., Requests for Rehearing of PSColorado, Marketer Group, Nevada IEC/CC Washington, CAC.

to reverse its decision to hold such a proceeding or to narrowly limit its scope. PacifiCorp states that the Northwest parties had not asked for an opportunity to pursue claims against each other, but rather wanted to limit further harm to the Northwest by offsetting costs of purchased power contracts against any refund liability. Duke asks that the Commission clarify the scope and purpose of the hearing.

Governmental entities challenge the order to the extent it extends section 206 refund jurisdiction to their sales in the Pacific Northwest.[455] BP argues that the Commission erred in proposing to broaden the definition of a spot market sale. Pinnacle West and Puget/Avista contend the order is arbitrary and capricious because the Commission failed to define the transactions potentially subject to refund. Finally, Puget/Avista claim the Commission erred by granting late motions to intervene filed by Seattle and Washington Attorney General.

The Presiding Judge closed the record of the preliminary evidentiary proceeding on September 6, 2001 and issued recommendations and proposed findings of fact on September 24, 2001. Among the proposed findings of fact are that the preponderance of the evidence establishes the lack of exercise of market power by sellers in the Pacific Northwest, and that parties failed to show that market-based prices were unjust and unreasonable. Thus, the judge concludes "[t]he record demonstrates that the [Pacific Northwest] market for spot sales of electrical energy was at all times between December 25, 2000 to June 20, 2001 competitive and functional."[456] The judge also concludes that refunds would have a negative impact on markets in the Pacific Northwest. Regarding procedural issues, the Judge concludes that allowing intervenors to prosecute a refund claim beyond the scope of the initial complaint "and beyond the procedural path of that Complaint, including its withdrawal" would be improper.[457] In sum, the Judge recommends that the proceeding be terminated by affirming the December 15 Order's rejection of the complaint and allowing Puget Sound to withdraw its rehearing request.

The Commission issued a notice providing an opportunity for interested parties to comment on the Judge's recommendations and proposed findings of fact. The notice specified that motions to intervene and comments could be filed on or before October 31, 2001.

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[455]See, e.g., Requests for Rehearing of LADWP, Northwest PUDs, Chelan County.

[456]Recommendation, slip op. at 99.

[457]Id. at 189.

Commission Response

Parties have filed numerous comments about the Presiding Judge's recommendations and proposed findings of fact. Once the Commission has had an opportunity to consider the comments, we will issue an order on the merits of the issues pending in that proceeding. Thus, we will defer acting on the requests for rehearing of the December 15 Order and the July 25 Order related to Puget Sound's complaint, as well as Puget Sound's motion to dismiss and notice of withdrawal.

H. Hearing Procedures

On December 6, 2001, the Commission issued an order deferring the hearing procedures before Judge Birchman pending issuance of this order.[458] The requests for rehearing and clarification granted in this order modify the refund methodology and will require recalculation of the mitigated prices applicable to each hour of the refund period. However, the Commission does not anticipate that significant changes to the formula(e) previously used by the ISO to generate this data will be needed. We will direct Judge Birchman to resume the hearing schedule, modified as needed, to permit the Judge to certify findings of fact to the Commission, without an initial decision, as soon as practicable after the date the ISO provides the hourly mitigated prices.

On December 13, 2001, the ISO filed a motion requesting the Commission to clarify the refund hearing procedures in two respects. First, the ISO asks that, if the Commission maintains the requirement that a mitigated price be applied on an hourly or interval basis, the mitigated prices first be litigated to final Commission resolution (i.e., after the Commission addresses the Judge’s findings of fact and parties have an opportunity to seek rehearing) before the ISO (and PX) be required to recalculate settlement statements. The ISO explains that these settlement reruns are extremely resource intensive and, until the point that no subsequent modifications will occur, requiring such an effort is a waste of resources. Further, the ISO argues, the premature calculation of settlement statements will not inform the consideration of the mitigated prices. Second, the ISO asks that the Commission provide an opportunity to the parties to submit comments and reply comments on the report that will be submitted by Judge Birchman at the conclusion of the refund hearing.

On December 14, 2001, California Generators filed an answer opposing the ISO's motion, and California Parties filed in support thereof.

[458] San Diego Gas & Electric Company et al., 97 FERC ¶ 61,258 (2001).

Because all parties have not yet had a chance to comment on the ISO's motion, the Commission cannot determine the reasonableness of the change in sequencing of steps for this proceeding that the ISO seeks. Therefore, we will direct Judge Birchman to consider the request, along with any comments received thereon, and submit to the Commission a Report and Recommendation on the ISO's proposal by January 11, 2002.

We agree that parties should have an opportunity to comment on the Judge's findings of fact. Accordingly, we will permit any participant in the SDG&E proceeding to file comments on the findings of fact not later than 20 days after issuance thereof. Not later than 15 days after the comment date, any participant may file reply comments.

The Commission orders:

(A) The Commission hereby denies rehearing of the issues from the August 23 and November 1 Orders not previously acted upon.

(B) The Commission hereby denies rehearing of the Amendment No. 33 Order, as discussed in the body of this order.

(C) The Commission hereby grants rehearing of the December 15 Order with respect to the imposition of the underscheduling penalty and denies rehearing of that order in all other respects, as discussed in the body of this order.

(D) The Commission hereby dismisses as moot in part and denies in part requests for rehearing of the March 9 Order and terminates the following dockets: ER01-1444-001, ER01-1445-001, ER01-1446-001, ER01-1447-001, ER01-1448-002, ER01-1449-002, ER01-1450-001, ER01-1451-002, ER01-1452-001, ER01-1453-001, ER01-1454-002, ER01-1455-002, and ER01-1456-002.

(E) The Commission hereby grants rehearing in part and denies rehearing in part of the June 19 Order, as discussed in the body of this order.

(F) The Commission hereby grants rehearing in part and denies rehearing in part of the July 25 Order, as discussed in the body of this order.

(G) The Commission hereby rejects the ISO's Tariff Amendment No. 38 filed in Docket No. ER01-1579-000 as moot and dismisses the requests for rehearing in Docket No. ER01-1579-001.

(H) The Commission hereby dismisses the complaint in Docket No. EL01-34-000 and EL01-34-001 as moot.

(I) The Commission hereby directs SoCal Edison to amend its market-based tariff, as discussed in the body of this order.

(J) CARE's request for administrative aid under section 319 of the Federal Power Act is hereby denied, as discussed in the body of this order.

(K) The Commission hereby directs Judge Birchman to recommence the refund hearing schedule, as discussed in the body of this order.

(L) The Commission hereby directs Judge Birchman to submit a Report and Recommendation regarding the timing for the ISO recalculation of its settlement statements by January 11, 2002, as discussed in the body of this order.

(K) The ISO is hereby directed to file by May 1, 2002 its revised congestion management proposal and a plan for implementation of a day-ahead market.

By the Commission. Commissioner Massey dissented in part
with a separate statement attached.

(S E A L)

Linwood A. Watson, Jr.,
Acting Secretary.

Appendix A

Comprehensive List of Parties in Docket Nos. EL00-95-000, et al. and/or EL01-68-000

AES Alamitos, LLC *[intervention granted by Chief Judge Wagner]*
AES NewEnergy, Inc.
AES Pacific, Inc.
AES Southland, L.L.C. *[intervention granted by Chief Judge Wagner]*
Alcoa Inc., Columbia Falls Aluminum Company, and Kaiser Aluminum & Chemical Corporation (jointly)
Allegheny Energy Supply Company, LLC *[intervention granted by Chief Judge Wagner]*
American Association of Business Persons with Disabilities
American Forest & Paper Association (AF&PA)
American Public Power Association (APPA) *[intervention granted in 7/25 order]*
Arizona Districts
Arizona Electric Power Cooperative (AEPCO) *[intervention granted by Chief Judge Wagner]*
Arizona Public Service Company *[respondent from 3/9 order]*
Arizona Residential Utility Consumer Office, New Mexico Attorney General, and the Colorado Office of Consumer Counsel (jointly)
Atofina Chemicals, Inc., Goldendale Aluminum Company, and Northwest Aluminum Company (jointly)
Attorney General for the State of Nevada, through its Bureau of Consumer Protection (Nevada BCP) *[intervention granted by Chief Judge Wagner]*
Automated Power Exchange, Inc. (APX)
Avista Energy, Inc. *[party status clarified in 7/25 order; respondent from 3/9 order]*
Berry Petroleum Company *[intervention granted in 7/25 order]*
Bonneville Power Administration (Bonneville)
BP Energy Company (BP Energy)
Caithness Energy, L.L.C. *[intervention granted in 5/16 order]*
California Air Resources Board *[intervention granted in 6/19 order]*
California Cogeneration Council *[intervention granted by Chief Judge Wagner]*
California Department of Water Resources (DWR)
California Electricity Oversight Board (Oversight Board)
California Hydropower Reform Coalition and Environment Defense (jointly)
California Independent System Operator Corporation (ISO)
California Manufacturers and Technology Association
California Municipal Utilities Association (CMUA)
California Power Exchange Corporation (PX)

California Small Business Association and California Small Business Roundtable (jointly)
California State Assembly *[intervention granted in 6/19 order]*
CAlifornians for Renewable Energy, Inc. (CARE) *[intervention granted by order issued 8/13/01]*
Calpine Corporation (Calpine)
Carson Cogeneration Company, LP; Mojave Cogeneration Company, LP; O.L.S. Energy-Camarillo; O.L.S. Energy-Chino; and PE Berkeley, Inc. (collectively, QF Petitioners) *[intervention granted in 7/25 order]*
CE Generation LLC (CE Generation)
Cities of Anaheim, Azusa, Banning, Colton, and Riverside, California (jointly) (Southern Cities)
Cities of Redding, Santa Clara, and Palo Alto, California, and the M-S-R Public Power Agency (jointly) (Cities/M-S-R)
City and County of San Francisco, California (San Francisco)
City of Burbank *[intervention granted in 6/19 order]*
City of Dana Point, California
City of Escondido, California
City of Glendale, California *[intervention granted by Chief Judge Wagner]*
City of Oakland, California/Port of Oakland *[intervention granted by Judge Birchman]*
City of Pasadena, California *[intervention granted by Chief Judge Wagner]*
City of Poway, California
City of San Diego, California (City of San Diego)
City of Seattle, Washington (City of Seattle)
City of Tacoma, Washington *[intervention granted by Chief Judge Wagner]*
City of Vernon, California (Vernon)
City of Vista, California
County of Los Angeles, California *[intervention granted by Chief Judge Wagner]*
County of San Diego, California (County of San Diego)
Cogeneration Association of California and Energy Producers and Users Coalition (jointly) (CAC/EPUC)
Constellation Power Source, Inc.
Consumer Federation of America *[intervention granted in 6/19 order]*
Consumers First
Coral Power, L.L.C.
Duke Energy North America LLC, Duke Energy Trading and Marketing, LLC, and Duke Energy Merchants, LLC (jointly) (Duke)
Dynamis, Inc. *[intervention granted in 5/16 order]*
Dynegy Power Marketing, Inc., El Segundo Power, LLC, Long Beach Generation LLC, Cabrillo Power I LLC, and Cabrillo Power II LLC (jointly) (Dynegy)
EF Oxnard, Inc. *[intervention granted in 5/16 order]*

El Paso Merchant Energy, L.P. (El Paso)
Electricity Consumers Resource Council, American Iron and Steel Institute, and American Chemistry Council (jointly) (Elcon, et al.)
Electric Power Supply Association (EPSA)
Enron Power Marketing, Inc., and Enron Energy Services, Inc. (jointly) (Enron)
Exelon Corporation, on behalf of Exelon Generation Company, LLC, PECO Energy Company, and Commonwealth Edison Company (Exelon) *[intervention amended by Judge Birchman]*
FPL Energy, LLC
H.Q. Energy Services (U.S.), Inc.
IdaCorp Energy, LP *[intervention granted by Chief Judge Wagner]*
Idaho Power Company *[intervention granted by Chief Judge Wagner]*
Imperial Irrigation District *[intervention granted in 6/19 order]*
Independent Energy Producers Association (IEP)
Industrial Customers of Northwest Utilities
Internal Services Department of Los Angeles County
Los Angeles Dep't of Water and Power (LADWP) *[intervention granted in 6/19 order]*
Merced Irrigation District
Merrill Lynch Capital Services, Inc.
Metropolitan Water District of Southern California (Metropolitan)
MG Industries (MG)
Mirant California, L.L.C., Mirant Delta, L.L.C., and Mirant Potrero, L.L.C. (Mirant)
Mirant Americas Energy Marketing LP *[intervention granted in 5/16 order]*
Modesto Irrigation District (Modesto)
Morgan Stanley Capital Group Inc. (Morgan Stanley)
Mr. Mark B. Lively
Multiple Intervenors
National Rural Electric Cooperative Association (NRECA) *[intervention granted in 6/19 order]*
Nevada Power Company *[intervention granted by Chief Judge Wagner; also, respondent from 3/9 order]*
New Mexico Regulation Commission *[intervention granted in 7/25 order]*
New West Energy Corporation (New West)
New York Independent System Operator, Inc.
New York Mercantile Exchange (NYMEX)
North Star Steel Company
Northern California Power Agency (NCPA)
NRG Power Marketing, Inc.
Oregon Office of Energy *[intervention granted herein]*
Orion Power New York, Inc.
Pacific Gas and Electric Company (PG&E)

Pacific Gas and Electric National Energy Group *[intervention granted by Chief Judge Wagner]*
PacifiCorp
PacifiCorp Power Marketing *[intervention granted by Chief Judge Wagner]*
Peck Energy Company *[intervention granted by Judge Birchman]*
People of the State of California, ex rel. Bill Lockyer (Attorney General of California) *[intervention granted in 7/25 order]*
Pinnacle West Companies (Pinnacle West)
PJM Industrial Customer Coalition and Coalition of Midwest Transmission Customers (jointly)
Port of Seattle, Washington *[intervention granted by Chief Judge Wagner]*
Portland General Electric Company (Portland General)
PPL EnergyPlus, LLC and PPL Montana, LLC (jointly) (PPL)
Public Service Company of Colorado (PSColorado) *[intervention granted by Chief Judge Wagner; also, respondent from 3/9 order]*
Public Service Company of New Mexico (PSNM) *[intervention granted by Chief Judge Wagner]*
Public Service Electric and Gas Company, PSEG Energy Resources & Trade LLC, and PSEG Power LLC (jointly)
Public Utilities Commission of the State of California (California Commission)
Public Utilities Commission of Nevada (Nevada Commission) *[intervention granted in 7/25 order]*
Public Utility Commission of Oregon *[intervention granted herein]*
Public Utility District No. 1 of Chelan County, Washington (Chelan County) *[intervention granted by Judge Birchman]*
Public Utility District No. 2 of Grant County, Washington (Grant County) *[intervention granted by Judge Birchman]*[459]
Puget Sound Energy, Inc. (Puget Sound)
Reliant Energy Power Generation, Inc. and Reliant Energy Services, Inc. *[the latter, a respondent from 3/9 order]* (Reliant)
Ridgewood Power LLC (Ridgewood)
Sacramento Municipal Utility District (SMUD)
Salt River Project Agricultural Improvement and Power District (Salt River) *[intervention granted by Chief Judge Wagner]*

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[459] Grant County is joined by several other Public Utility Districts (PUDs) in its request for rehearing of the July 25 Order; collectively they are referred to as Northwest PUDs. The other PUDs have intervened only in Docket No. EL01-10-000. As only Grant County is a party in Docket No. EL00-95-000, et al, it alone has the legal status to challenge portions of the July 25 Order that relate to Docket No. EL00-95-000, et al.

San Diego Gas & Electric Company (SDG&E)
Secretary of the U.S. Department of Energy (Department of Energy)
Sempra Energy Trading Corporation *[intervention granted by Chief Judge Wagner; also, respondent from 3/9 order]*
Shell Energy Services Company, L.L.C.
Sierra Pacific Power Company *[intervention granted by Chief Judge Wagner]*
South Coast Air Quality Management District *[intervention granted in 6/19 order]*
Southern California Edison Company (SoCal Edison)
Southern California Water Company (SoCal Water) *[intervention granted in 7/25 order]*
Southern Energy California, L.L.C., Southern Energy Delta, L.L.C., and Southern Energy Potrero, L.L.C. (jointly) (Southern Energy) [became Mirant]
The Utility Reform Network (TURN)
Tractebel Power, Inc. *[intervention granted in 5/16 order]*
TransAlta Energy Marketing, Inc. (TransAlta) *[intervention granted by Judge Birchman]*
TransCanada Energy Ltd. *[intervention granted by Judge Birchman]*
Transmission Agency of Northern California (TANC)
Truckee Donner Public Utility District *[intervention granted herein]*
Turlock Irrigation District (Turlock) *[intervention granted in 6/19 order]*
Tucson Electric Power Company *[intervention granted by Chief Judge Wagner]*
Universal Studios *[intervention granted by Chief Judge Wagner]*
Unsecured Creditors Committee of Pacific Gas & Electric Company *[intervention granted by Chief Judge Wagner]*
Washington State Attorney General *[intervention granted by Chief Judge Wagner]*
Washington Utilities and Transportation Commission (Washington Commission) *[intervention granted in 7/25 order]*
Watson Cogeneration Company
Western Power Trading Forum (WPTF)
Williams Energy Marketing & Trading Company and Williams Energy Services Company *[the latter, a respondent from 3/9 order]* (Williams)

Appendix B

Parties in Docket No. ER01-607-000

California Department of Water Resources
California Electricity Oversight Board
California Power Exchange Corporation
City of Redding, California *
City of Santa Clara, California *
Dynegy Power Marketing, Inc.
M-S-R Public Power Agency *
Modesto Irrigation District *
Pacific Gas and Electric Company
Public Utilities Commission of the State of California
Reliant Energy Power Generation, Inc.
Southern California Edison Company
Transmission Agency of Northern California *
Western Power Trading Forum

* Entities that filed collectively as Northern California Public Entities

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company, Complainant v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange, Respondents	Docket Nos. EL00-95-001 EL00-95-004 EL00-95-005 EL00-95-006 EL00-95-007 EL00-95-010 EL00-95-011 EL00-95-019 EL00-95-039 EL00-95-046 EL00-95-047
Investigation of Practices of the California Independent System Operator and the California Power Exchange	Docket Nos. EL00-98-001 EL00-98-004 EL00-98-005 EL00-98-006 EL00-98-008 EL00-98-010 EL00-98-011 EL00-98-018 EL00-98-037 EL00-98-043 EL00-98-044
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., Complainants, v. California Independent System Operator Corporation, Respondent	Docket No. EL00-97-001

California Electricity Oversight Board,
Complainant,
v.
All Sellers of Energy and Ancillary Services Into the Energy and Ancillary Services Markets Operated by the California Independent System Operator and the California Power Exchange,
Respondents

Docket No. EL00-104-001

California Municipal Utilities Association,
Complainant,
v.
All Jurisdictional Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange,
Respondents

Docket No. EL01-1-001

Californians for Renewable Energy, Inc. (CARE),
Complainant,
v.
Independent Energy Producers, Inc., and All Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator 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,
Respondents

Docket No. EL01-2-001

Puget Sound Energy, Inc.,
Complainant,
v.
All Jurisdictional Sellers of Energy and/or Capacity at Wholesale Into Electric Energy and/or Capacity Markets in the Pacific Northwest, Including

Docket No. EL01-10-001

Parties to the Western Systems Power Pool Agreement,
Respondents

California Independent System Operator Corporation	Docket Nos. ER01-607-000 ER01-607-001
California Independent System Operator Corporation	Docket Nos. RT01-85-002 RT01-85-005
Investigation of Wholesale Rates of Public Utility Sellers of Energy and Ancillary Services in the Western Systems Coordinating Council	Docket Nos. EL01-68-002 EL01-68-008
California Power Exchange Corporation	Docket No.ER00-3461-001
California Independent System Operation Corporation	Docket No. ER00-3673-001
California Independent System Operator Corporation	Docket No. ER01-1579-001
Southern California Edison Company and Pacific Gas and Electric Company	Docket Nos. EL01-34-000 EL01-34-001
Arizona Public Service Company	Docket No. ER01-1444-001
Automated Power Exchange, Inc.	Docket No. ER01-1445-001
Avista Energy, Inc.	Docket No. ER01-1446-001
California Power Exchange Corporation	Docket No. ER01-1447-001
Duke Energy Trading and Marketing, LLC	Docket No. ER01-1448-002
Dynegy Power Marketing, Inc.	Docket No. ER01-1449-002
Nevada Power Company	Docket No. ER01-1450-001

Portland General Electric Company	Docket No. ER01-1451-001
Public Service Company of Colorado	Docket No. ER01-1452-001
Reliant Energy Services, Inc.	Docket No. ER01-1453-001
Sempra Energy Trading Corporation	Docket No. ER01-1454-002
Mirant California, LLC, Mirant Delta, LLC, and Mirant Potrero, LLC	Docket No. ER01-1455-002
Williams Energy Services Corporation	Docket No. ER01-1456-002

(Issued December 19, 2001)

MASSEY, Commissioner, dissenting in part:

This order essentially "stays the course" on our market mitigation program in the Western markets. The markets have behaved reasonably since our program was put in place, and I agree with staying the course. Today's order reaffirms many excellent aspects of our program, such as providing for refunds for some past sales, requiring most sellers in the WSCC to offer all available power in spot markets during all hours, conditioning market based rate authority to prevent anticompetitive behavior, and establishing price mitigation for all hours across the WSCC until September 2002. Thus there is a lot to like in this order.

Although I agree with the great bulk of the policy calls made in this order, there are some decisions regarding the refund program from which I dissented in our July 25 order.[1] Those decisions, reaffirmed here, are exercising jurisdiction over governmental entities to require refunds, refusing to deal with the generation withholding issue by basing refund calculations on the actual past dispatch instead of using some other means such as an "assumed economic dispatch," using spot gas prices in the refund calculation that are based on indices instead of on actual gas costs, and imposing a 10% creditworthiness adder in the refund calculations. I continue to disagree with these conclusions.

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[1] San Diego Gas & Electric Co., et al., 96 FERC ¶ 61,120 (2001) at 61,521-61,523.

For these reasons, I must respectfully dissent in part from an otherwise excellent, comprehensive and well-written order.

William L. Massey
Commissioner