SKADDEN, ARPS, SLATE, MEAGHER & FLOM LLP

1440 NEW YORK AVENUE, N.W.

WASHINGTON, D.C. 20005-2111

TEL: (202) 371-7000

FAX: (202) 393-5760

http://www.skadden.com

FIRM/AFFILIATE OFFICES

BOSTON
CHICAGO
HOUSTON
LOS ANGELES
NEWARK
NEW YORK
PALO ALTO
RESTON
SAN FRANCISCO
WILMINGTON

BEIJING
BRUSSELS
FRANKFURT
HONG KONG
LONDON
MOSCOW
PARIS
SINGAPORE
SYDNEY
TOKYO
TORONTO

May 22, 2002

FILED
OFFICE OF THE SECRETARY
02 MAY 22 PM 3:07
FEDERAL ENERGY
REGULATORY COMMISSION

Donald J. Gelinas
Associate Director of Office
of Markets, Tariffs & Rates
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices
FERC Docket No. PA02-2-000

Dear Mr. Gelinas:

Please accept for filing the response of Portland General Electric Company ("Portland General") to the May 8, 2002 Request for Admissions and Production of Documents issued by the Commission in Docket No. PA02-2-000 to Sellers of Wholesale Electricity and/or Ancillary Services to the California Independent System Operator and/or the California Power Exchange During the Years 2000-2001 (Listed on Attachment A). Although Portland General was not a seller listed on Attachment A, it has both bought power from and sold power to the Cal ISO and PX during the relevant period. Portland General is therefore voluntarily submitting the accompanying response in the belief that its activities fall within the intended scope of the Commission's investigation. In assembling this response, Portland General has not produced documents filed with the Commission, or documents that have been made public since release of the Enron memoranda, of which Portland General had no previous knowledge, *e.g.*, the Enron memoranda, website publications, news reports and similar material.

Respectfully submitted,

Cheryl Foley / ACL

Cheryl M. Foley
Counsel for
Portland General Electric Company

Enclosures

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

Fact-finding Investigation of Potential	)	
Manipulation of Electric	)	Docket No. PA02-2-000
and Natural Gas Prices	)	

RESPONSE OF PORTLAND GENERAL ELECTRIC COMPANY TO THE COMMISSION'S MAY 8, 2002 DATA REQUEST AND REQUEST FOR ADMISSIONS

Portland General Electric Company ("Portland General" or "Portland") submits this response pursuant to the Commission's May 8, 2002 order to sellers of wholesale electricity and/or ancillary services to the California Independent System Operator and/or the California Power Exchange (the "May 8th Order").

SUMMARY OF PORTLAND GENERAL'S INVESTIGATION PROCESS

Portland General became aware of the Commission's May 8th Order the day after it was issued. That Order directs each seller to conduct a thorough investigation into its trading activities and to respond, after conducting that investigation, to certain data requests and requests for admission by May 22, 2002.

Immediately upon learning of the Commission's Order, Portland's General Counsel began assembling a team of senior personnel to formulate and execute the most thorough investigation reasonably possible within the time frame dictated by the Order. While Portland General had no reason to believe that it engaged in any unlawful trading practices – and indeed stands firm in that belief today – given that the company is a subsidiary of Enron Corp, Portland General believed that it was *particularly* important to respond to the Commission's Order with the most thorough investigation possible.[1] Ultimately, Portland General's investigation – conducted with assistance of outside counsel – included the following significant components:[2]

- Creation of an "Investigative Team" (or "Team") – the lawyers on the Team and the staff members assisting them invested over 2,700 hours[3] conducting the inquiry called for by the Commission's Order;
- Circulation of memoranda from Portland General's CEO and from its General Counsel directing employees to fully cooperate with the investigation and specifically requiring that employees search their records and files for any potentially responsive documents;
- Conduct of 74 extensive interviews of individuals who have worked for Portland General, either currently or formerly;
- Execution of an extensive search of hundreds of thousands of electronically stored documents (including e-mails) using approximately 8,500 different computer aided searches for the specific terms used to describe the trading strategies discussed in the Commission's Order – and review of all documents appearing as "hits" for those terms; and
- Engagement in comprehensive follow-up on potentially responsive information – including subsequent interviews of various individuals, as well

---

1 As discussed in greater detail in another section of this submission, while Portland General is owned by Enron, it should be noted that Portland General's trading division at all times maintained *its own* policies and procedures, and that Portland General received legal advice *in its own right*, wholly separate and apart from Enron.

2 A more detailed description of the investigation is included as Addendum A to this submission.

3 This figure is a conservative estimate based on time records entered as of the time of this submission.

as review and transcription of voice recordings of particular trading days and transactions.

RESPONSE OF PORTLAND GENERAL

Preliminary Statement

Portland General is an integrated electric utility located in Portland, Oregon, serving approximately 736,000 customers at retail in the state of Oregon. As stated above, the Company is a wholly owned subsidiary of Enron Corp, but it is organizationally decentralized from the parent and managed through its Portland-based management team. Portland General engages in wholesale trading activities, the primary purpose of which is to manage risk, meet its load and reduce costs for its retail customers. Portland General has insufficient generating resources to meet its native load and must purchase significant amounts of power in the wholesale market each year. Consequently, Portland General's trading operations serve the critical function of acquiring resources for native load, balancing those resources with load requirements, and maximizing the value of owned generation and purchase contracts to the extent that available supply is excess to the needs of Portland's firm customers. This trading operation is completely separated from that of Enron Corp. It has at all times operated on a separate, secured trading floor, has its own policies and procedures, and is subject to the Commission's affiliate rules and Part 37 of the Commission's Rules & Regulations. These rules limit the communication that is permitted to take place between Portland General and other Enron companies, and set strict parameters for any inter-affiliate trading.

As part of its routine utility business and in order to take advantage of seasonal diversity between the Pacific Northwest and California, Portland General has both imported power to and exported power from California for over 30 years over the Pacific Northwest Intertie. In fact, this large capacity Intertie system was constructed to facilitate these seasonal exchanges between utilities and to create cost and resource efficiencies in the wholesale power markets of the Western region. The majority of Portland General's sales take place in Oregon, or at the Oregon border.

Portland General is a net buyer of power in these Western power markets, often purchasing in excess of 35% of its retail customers' requirements in the wholesale markets every year. As a net buyer, Portland General's interest and the interest of its customers is advanced when market prices and price volatility in the Pacific Northwest are low.

The Commission's May 8, 2002 order in this docket requests answers to specific Requests for Admissions and Production of Documents. Following are Portland General's responses:

I. Responses to Requests for Admissions

I. A. 1. Admit or Deny: The company engaged in activity referred to in the Enron memoranda as "**Export of California Power**" during the period 2000-2001, in which the company buys energy at the Cal PX to export outside of California in order to take advantage of the price spread between California markets (which were capped) and uncapped markets outside of California.

Portland General can neither admit nor deny this question without qualification. As noted above, Portland has purchased power from and exported power out of California for over 30 years to serve its retail load, and frequently resells any power excess to its needs in the wholesale market. This practice existed before the formation and start-up of the Cal PX and the Cal ISO and continues today.

Most of the power purchased by Portland General from the Cal PX during the period 2000-2001 was purchased to serve retail requirements, and, as market volatility increased and security of supply was threatened, to serve as an "insurance policy" that would protect this source of supply for its firm customers. Particularly during the peak demand months of late 2000 and early 2001, Portland General tried to secure additional length in the day-ahead market, rather than rely on the real-time market, because the real-time market was experiencing dramatic price spikes, and the availability of supply could not be guaranteed. These Cal PX purchases were made as part of standard winter buying practice and not as a specific strategy to deprive the state of California of needed power. Nor were they made as part of any specific strategy to circumvent price caps in the California market. As a retail service provider and as a net *purchaser* of power, increasing power costs and price volatility would not have been in the best interest of Portland General.

Further, when Portland General purchases power, it is then combined into a larger, blended portfolio of supply that is available for serving its retail load or for resale to numerous potential purchasers in the wholesale market. If ultimate prices were higher in the real-time market than the prices at which Portland had purchased in the day-ahead market (and assuming that it had excess to sell in any particular hour), then, obviously, resales from the portfolio would have been made at a profit. In that profit motivation did exist, resales most likely would have been made to the highest bidder, regardless of whether the bidder was located in the Pacific Northwest or California. Conversely, the company was at a risk of loss if real-time prices decreased below the price paid to Portland General's suppliers, including the Cal PX, in the day-ahead market or forward market. Portland General also was taking a risk of highly volatile real-time pricing if it had not purchased sufficient supply in the day-ahead market and had to purchase additional supply in real-time. Finally, it is important to note that tracing the resale of any particular megawatt in a blended portfolio of supply back to its source is theoretically impossible, notwithstanding bookout accounting practices or, for example, the periodic occurrence of "sleeve" transactions.

Given that it had neither the incentive nor the intent to participate in a strategy to deprive California of power or to increase prices in its own retail marketing area, Portland General does not believe that it has engaged in the strategy contemplated in the Enron memoranda or by the Commission's request for admission I.A.1. However, some transactions conducted by Portland General during 2000-2001 may have resulted in the company purchasing power from the Cal PX and reselling power from its portfolio of supplies at prices higher then those paid to the Cal PX.

I. A. 2. If you so admit, provide complete details as to all transactions your company engaged in as part of this activity, including the dates of all purchases and sales of energy and/or ancillary services, counter-parties to the transactions, prices and volumes, delivery points, and corresponding Cal ISO schedules. Also, provide all documents that refer or relate to the activity described immediately above.

Portland General submits that it is not possible to trace purchases into and sales out of a blended portfolio of supply, as seemingly contemplated by this question. However, for transaction data potentially relevant to this question, Portland General refers the Commission to information filed by Portland General in this Docket No. PA02-2-000 pursuant to a request from the Commission in an order dated March 5, 2002.

Also see Attachment I.A.2.

I. B. 1. Admit or Deny: The company engaged in activity described in the Enron memoranda as "**Non-Firm Export**" during the period 2000-2001, in which the company gets a counterflow (scheduling energy in the opposite direction of a constraint) congestion payment from the Cal ISO by scheduling non-firm energy from a point in California to a control area outside of California, and cutting the non-firm energy after it receives such payment.

Denied.

I. B. 2. If you so admit, provide complete details as to all transactions your company engaged in as part of this activity, including the dates of all transactions, congestion payments received, corresponding Cal ISO schedules, counter parties and delivery points. Also, provide all documents that refer or relate to the activity described immediately above.

Not applicable.

I. C. 1. Admit or Deny: The Company engaged in activity described in the Enron memoranda as "**Death Star**" during the period 2000-2001, in which the company schedules energy in the opposite direction of congestion (counterflow), but no energy is actually put onto the grid or taken off of the grid. This allows the company to receive congestion payments from the Cal ISO.

Denied. It is possible that, unknown to Portland General, it could have been used by a third party in partial execution of this strategy. See Responses to Questions I.K.1 and III.B.

I. C. 2. If you so admit, provide complete details as to all transactions that your company engaged in as part of this activity, including the dates of all transactions, all transmission and energy schedules, the counter parties, all congestion payments received. Also, provide all documents that refer or relate to the activity described immediately above.

Not applicable.

I. D. 1. Admit or Deny: the company engaged in activity described in the Enron memoranda as "**Load Shift**" during the period 2000-2001. This variant of "relieving congestion" involves submitting artificial schedules in order to receive inter-zonal congestion payments. The appearance of congestion is created by deliberately over-scheduling load in one zone (*e.g.*, NP-15), and under-scheduling load in another, connecting zone (*e.g.*, SP-15); and shifting load from a congested zone to the less congested zone, thereby earning congestion payments for reducing congestion.

Denied.

I. D. 2. If you so admit, provide complete details as to all transactions that your company engaged in as part of this activity, including the dates of all transactions, all schedules of load by zone, and all congestion payments received. Also, provide all documents that refer or relate to the activity described immediately above.

Not applicable.

I. E. 1. Admit or Deny: The Company engaged in activity described in the Enron memoranda as "**Get Shorty**" during the period 2000-2001, also known as "paper trading" of ancillary services in which it: (i) sells ancillary services in the Day-ahead market; and (ii) the next day, in the real-time market, the company "zeros out" the ancillary services by canceling the commitment to sell and buying ancillary services in the real-time market to cover its position. The phrase "paper trading" is used because the seller does not actually have the ancillary services to sell.

Denied.

I. E. 2. If you so admit, provide complete details as to all transactions that your company engaged in as part of this trading strategy, including the dates of all transactions; prices and volumes for sales of ancillary services in the Day-ahead market; the cancellation of such sales, prices and volumes for the purchase of ancillary services in the real-time market to cover the company's position; and corresponding schedules. Also, provide all documents that refer or relate to the activity described immediately above.

Not applicable.

I. F. 1. Admit or Deny: The Company engaged in activity described in the Enron memoranda as "**Wheel Out**" during the period 2000-2001. Knowing that an intertie is completely constrained (*i.e.*, its capacity is set at zero), or that a line is out of service, the company schedules a transmission flow over the facility. The company also knows that the schedule will be cut and it will receive a congestion payment without actually having to send energy over the facility.

Denied.

I. F. 2. If you so admit, provide complete details as to all transactions that your company engaged in as part of this activity, including the dates of all transactions, corresponding schedules; counter parties, and congestion payments received. Also, provide all documents that refer or relate to the activity described immediately above.

Not applicable.

I. G. 1. Admit or Deny: The company engaged in activity described in the Enron memoranda as "**Fat Boy**" during the period 2000-2001 in which the company artificially increases load on the schedule it submits to the Cal ISO with a corresponding amount of generation. The company then dispatches the generation it schedules, which is in excess of its actual load. This results in the Cal ISO paying the company for the excess generation. Scheduling coordinators that serve load in California may be able to use this activity to include the generation of other sellers.

Denied.

I. G. 2. If you so admit, provide complete details as to all transactions that your company engaged in as part of this activity, including the dates of all transactions, corresponding schedules, and payments from the Cal ISO for excess generation (including both price and volumes). Also, provide all documents that refer or relate to the activity described immediately above.

Not applicable.

I. H. 1. Admit or Deny: The company engaged in activity described in the Enron memoranda as "**Ricochet,**" also know as "megawatt laundering," during the period 2000-2001, in which the company: (i) buys energy from the Cal PX and exports to another entity, which charges a small fee; and (ii) the first company resells the energy back to the Cal ISO in the real-time market.

Denied. See, however, Response to Question I.K.1. Portland General may have been used as an intermediary by another party engaging in a similar activity.

I. H. 2. If you so admit, provide complete details as to all transactions that your company engaged in as part of this activity, including the dates for all transactions, names of counter parties and whether they were affiliates, the fees charged, prices and volumes for energy that was bought and then resold. Also, provide all documents that refer or relate to the activity described immediately above.

Not applicable.

I. I. 1. Admit or Deny: The company engaged in activity described in the Enron memoranda as "**Selling Non-firm Energy as Firm Energy**" during the period 2000-2001, in which the company sells or resells what is actually non-firm energy to the Cal PX, but claims that it is "firm" energy. This allows the company to receive payment from the Cal ISO for ancillary services that it claims to be providing, but does not in fact provide.

Denied.

I. I. 2. If you so admit, provide complete details as to all transactions that your company engaged in as part of this activity, including the dates for all transactions, prices and volumes, and corresponding schedules. Also, provide all documents that refer or relate to the activity described immediately above.

Not applicable.

I. J. 1. Admit or Deny: The company engaged in activity described in the Enron memoranda as "**Scheduling Energy to collect Congestion Charge II**" during the period 2000-2001, in which the company: (i) schedules a counterflow even though it does not have any available generation; (ii) in real time, the Cal ISO charges the company for each MW that it was short; and (iii) the company collects a congestion payment associated with the counterflow scheduled. This activity is profitable whenever the congestion payment is greater than the charge associated with the energy that was not delivered.

Denied.

I. J. 2. If you so admit, provide complete details as to all transactions that your company engaged in as part of this activity, including the dates for all transactions, corresponding schedules, prices and volumes, and congestion payments received. Also, provide all documents that refer or relate to the activity described immediately above.

Not applicable.

I. K. 1 Admit or Deny: The company engaged in any activity during the period 2000-2001 that is a variant of any of the above-described activities or that is a variant of, or uses the activities known as, **"inc-ing load"** or **"relieving congestion,"** as described above.

This request is so vague and far-reaching that it cannot be answered without Portland General speculating as to what it covers. Many trading products and services legitimately involve activities such as relieving congestion (*e.g.*, "circulation" transactions, requested of Portland General by the Cal ISO), providing control area services to marketers that they cannot provide themselves (*e.g.*, "parking and lending"), or bidding practices (*e.g.*, "incremental" and "decremental" bidding) that are necessitated by the California market design. However, if the intent of the Commission is to inquire into trading activities that involve knowingly submitting false load or delivery schedules, misrepresenting non-firm commitments as firm, causing artificial congestion, or receiving congestion payments without actually relieving congestion, then Portland General denies that it engaged in any such activity.

Although Portland General denies engaging in the strategies described in the Enron memoranda, or variants thereof, as a result of its investigation (and after reviewing and reaching what it believes is a basic understanding of the general nature of the strategies described in the memoranda), the company discovered that services it provided may have been used by third parties, such as an Enron Corp subsidiary ("Enron"), as a step toward execution of some of those strategies. For example, Portland General speculates that it *could* have been used by Enron to provide one of the steps leading into the I.C.1. strategy, although it had no knowledge of such possibility until the investigation. See Response to Question III.B. Further, after gaining an understanding of the strategies set forth in the memoranda, it is conceivable that other services provided by Portland General, such as its "Park and Lend" service, may have resulted in Portland General being used as an intermediary in partial execution of one or more of the strategies. Information describing "Park and Lend" is provided in Attachment I.K.1.

I. K. 2. If you so admit, provide a narrative description of each specific time in which the company engaged in such activity and provide complete details of those transactions, including the dates of the transactions, counter parties, prices and volumes bought or sold, corresponding schedules, and any congestion payments received. Also, provide all documents that refer to or relate to such activities.

Not applicable.

II. Requests for Production of Documents

A. Provide copies of all communications or correspondence, including e-mail messages, instant messages, or telephone logs, between your company and any other company (including your affiliates or subsidiaries) with respect to all of the trading strategies discussed in the Enron memoranda (both the ten "representative trading strategies" as well as "**inc-ing load**" and "**relieving congestion**"). This request encompasses all transactions conducted as part of such trading strategies engaged in by your company and the other company in the U.S. portion of the WSCC during the period 2000-2001.

Portland General Response:

To the best of Portland General's knowledge and belief after thorough investigation (see Addendum A), it is providing all material that it has identified as responsive to the request in Attachment II.A. Also see the material attached in response to Question III.B.

B. Provide copies of all material, including, but not limited to, opinion letters, memoranda, communications (including e-mails and telephone logs), or reports, that address or discuss your company's knowledge of, awareness of, understanding of, or employment or use of any of the trading strategies discussed in the Enron memoranda, or similar trading strategies, in the U.S. portion of the WSCC during the period 2000-2001. The scope of this request encompasses all material that address or discuss your company's knowledge or awareness of *other* companies' use of the trading strategies discussed in the Enron memoranda, or similar trading strategies, including, but not limited to: (i) offers by such other companies to join in transactions related to such trading strategies, regardless of whether such offers were declined or accepted; and (ii) possible responses by your companies to other companies' use of such trading strategies. To the extent that you wish to make a claim of privilege with respect to any responsive material, please provide an index of each of those materials, which includes the date of each individual document, its title, its recipient(s) and its sender(s), a summary of the contents of the document, and the basis of the claim of privilege.

Portland General Response:

To the best of Portland General's knowledge and belief after thorough investigation (see Addendum A), it is providing all material it has identified as responsive to the request in Attachment II.B. Also see the material attached in response to Question III.B.

Based on its investigation Portland General believes that various individuals in its organization had some level of awareness of certain of the trading strategies (or variants thereof) discussed in the Enron memoranda. The level of awareness is generic, possibly gained at an industry seminar or through a consultant's event report that may have been circulated on the internet or even through the ISO's public discussions of known interpretations or uses of its tariffs. In some instances (*e.g.*, "ricochet"), the term had general industry connotations. "Ricochet" has been used generically in the industry as a description for certain transmission paths and also in reference to the development of a potential NYMEX product. The generic knowledge of these terms by Portland General employees did not rise to the level of specificity that enabled them to define the strategies in detail or identify particular companies engaging in these strategies, other than as specifically reported herein. In its internal investigation, Portland General did not uncover instances or recollections where the company, itself, had engaged in or knowingly aided these strategies, except, again, as specifically reported herein.

III. Requests for Other Information

A. On page 2 of the December 8, 2000, Enron memoranda, the authors allege that traders have learned to build in under-scheduling of energy into their models and forecasts. State whether your company built under-scheduling into any of its models or forecasts during the period 2000-2001, and provide a narrative description of such activity. Provide copies of all such models or forecasts prepared by or relied on by your company during the period 2000-2001 that had under-scheduling built into them.

Portland General Response:

Portland General did not formally model what appears to have been a deliberate underscheduling of load by some or all of the California investor owned utilities. Expert traders did, however, take into consideration this well-known underscheduling in determining their daily bids.

B. Refer to the discussion of the trading strategy described as "**Ricochet**" in the Enron memoranda. State whether your company purchased energy from, or sold energy to, any Enron company, including Portland General Electric Company, as part of a "**Ricochet**" (or megawatt laundering) transaction during the period 2000-2001. Provide complete details as to such transactions, including the dates of the transactions; the names, titles and telephone numbers of the traders at your company who engaged in such transactions; the prices at which your company bought and sold such energy (on a per transaction basis); the volumes bought and sold (on a per transaction basis); delivery points; and all corresponding schedules.

Portland General Response:

Portland General has discovered 17 days during the April-June 2000 timeframe in which it was used as an intermediary in transactions that commenced with an Enron purchase from a California entity. Although these transactions do not fit the precise definition of a ricochet transaction, they appear similar. The exact counter party from which Enron took receipt in these transactions is unknown in most instances. The power was then sold by Enron to an independent third party, who resold the power to Portland General. Portland General then further resold the power to Enron. Enron took the energy south. Attachment III.B. provides a summary of the details of these transactions, prepared by Portland General on May 21, 2001. Attachment III.B. also includes the accounting logs for these transactions. Information discovered by Portland General since May 8, 2002, followed up with a review of trading floor telephone tapes for the transactions in question (see transcriptions of these conversations in Attachment III.B.), indicate that the service provided by Portland General during these days may have been used by Enron as one step of the strategy described in I.C.1.

ADDENDUM A

ADDENDUM A

GENERAL DESCRIPTION OF THE PORTLAND GENERAL INVESTIGATION

The Investigative Team

Portland General's Investigative Team, headed by its General Counsel, included nine in-house attorneys for the Company.[4] In addition, the Company's former Deputy General Counsel was appointed as Special Counsel to aid in formulating and executing the investigation. Furthermore, five outside counsel headed by a former FERC Commissioner oversaw the formulation and implementation of the investigation, and participated in its performance.

Identifying Individuals with Potentially Responsive Information or Materials

Within approximately one day of receiving notice of the Commission's May 8th Order, Portland General's Team determined that in order to ensure full compliance, it would be necessary to interview every employee considered potentially to possess responsive information, documents or records. To identify such individuals, the Team consulted with the Vice President of Power Supply/Power Operations and obtained a list of all employees who worked as part of the trading team (including managers), either currently or at any time during the period from 2000 through 2001. With the exception of fewer than a handful of current or former employees whom the Company believed to lack *any* knowledge or information regarding the issues in question, all of those individuals were included on the list for interview. Furthermore, throughout the course

[4] During the period from issuance of the Commission's May 8th Order through the date of this submission, Portland General has committed virtually 100% of the time of the majority of the Company's Legal Department to conducting the investigation.

of Portland General's investigation, the Team continued to add individuals to the list if it appeared they might possess responsive information or documents.

On May 13, 2002, two memoranda were circulated to all Portland General employees the Company intended to interview. The first memorandum, from Portland General's CEO, advised employees of the Commission's Order and requested full cooperation in preparation of a response. The second, from the Company's General Counsel, directed recipients to review their records and provide the Company with copies of any potentially responsive materials. (Copies of those memoranda are attached to this Addendum). Individuals added to the list received copies of the same memoranda as the other individuals to be interviewed.

The Interview Process

Teams of two lawyers (one in-house and one outside counsel) conducted individual interviews of those employees believed most likely to have responsive information.[5] Before the beginning of every interview, the lawyers stressed the seriousness with which the Company approached the task of complying with the Commission's Order, and further advised the interviewee of the importance of being honest and forthright in responding to the questions posed.

---

[5] Certain individuals considered highly *unlikely* to possess relevant information including, for instance, employees who joined Portland General after it had ceased any activity in the California ISO or PX markets, were interviewed by a single lawyer instead of a team of two lawyers.

Search For and Review of Potentially Responsive Documents

- *The May 13, 2002 Compliance Memo from Portland's General Counsel*

In his May 13, 2002 memorandum, Portland's General Counsel explained that each employee was "required to gather all correspondence, e-mails, other forms of communications, telephone logs, opinion letters, memorandum, reports, files at your desk (including materials you may have taken home) that may be relevant to each of the ten 'representative strategies' that employ 'inc-ing load' and 'relieving congestion' as described in Items I.A through I.K of FERC's May 8, 2002 order," a copy of which was attached to the memo (along with the Enron "trading strategy" memoranda posted by the Commission on its website).

The General Counsel's compliance memorandum was circulated to the same individuals identified for interviews, both by "red flag" (or priority) e-mail, and also by hand delivery.[6]

On May 14, 2002, Portland General's General Counsel sent a similar memorandum to certain former employees (by hand courier or overnight delivery), requesting that they search files or records they might have for any potentially responsive materials.[7]

To ensure that employees followed through on the directive of the General Counsel's memorandum, the lawyers who conducted the interview of a given individual were assigned responsibility of ensuring that all materials an interviewee indicated he or

---

6 To the extent that any intended recipient was not available to accept hand-delivery of the memorandum, actual receipt was confirmed by follow-up telephone calls.

7 Receipt of the memoranda by former employees was likewise confirmed by follow-up telephone calls.

she would provide had indeed been provided, and that any statement to the effect that an individual had searched his or her records but found no responsive materials was considered to be credible.

Every record or document supplied to the Company as a part of this aspect of the investigation was reviewed by at least one lawyer from the Investigative Team to determine whether it was responsive to the Commission's Order. Any materials considered to be responsive are being provided to the Commission as part of this submission.

- *Review of Computer and E-mail Databases*

In addition to directing current and former employees to search their own files and records for any materials potentially responsive to the Commission's May 8th Order, the Investigative Team consulted with management personnel in Portland General's Information Technology ("IT") Department regarding the viability of undertaking an extensive – but targeted – review of the Company's electronic document and email databases for the 2000 – 2001 time period. The IT Department reported that a review of the nature described by Investigative Team would be extremely time and labor-intensive, but that assuming appropriate parameters, such a review could be accomplished within the required time frame.

As the IT Department explained, Portland General's servers are "backed-up" on tape every week. The "back-up" tapes are stored at an outside facility. Before December 1, 2000, however, these back-up tapes were recycled on a rolling basis.

It was not possible (nor would it be reasonable) for Portland General to review all of the back-up tapes in its archive. Rather, the Investigative Team directed the IT

Department to search the back-up tapes for a number of dates during the period in question. Such a review, of course, would include vastly more documents and emails than just those created or edited on a particular date because every time a server is "backed-up," the tape captures *all* data on the server, except any data that was deleted. Thus, a back-up tape will include documents dating back as long as the server has been in use.

At the instruction of the Investigative Team, the IT Department searched the computer and email files of the approximately 27 current and former employees deemed most likely to include potentially responsive information. Within the individual Word, Excel and email files for such individuals – as well as in various "Group Directories" – the IT staff ran searches for the terms used by the Commission to describe the trading strategies in its Order: "inc-ing load," "congestion," "export of California power," "non-firm export," "death star," "load shift," "get shorty," "paper trading," "wheel out," "fat boy," "ricochet," "megawatt laundering," and "non-firm energy as firm energy."

The same searches were run on the Group Directory for Portland's Legal Department.

In all, the IT Department estimates that it executed over 8,500 individual searches of hundreds of thousands of electronically stored documents or emails. The IT Department estimates that including trouble shooting and re-running searches for quality control (a standardized component of the procedure followed in executing this project) the number of searches executed in all is far in excess in that number. This exhaustive undertaking was finally completed after approximately 1,200 hours of work by Portland's IT Department. While executing the project, the IT Department had teams of between eight and fourteen employees working in shifts "around-the-clock" to advance the project to completion and meet the Commission's May 22nd deadline.

Any document that indicated a "hit" for one or more search terms was "burned" onto a compact disk for review by one or more of the lawyers on the Team. Every disk has been reviewed and any document considered responsive to the Commission's Order is being produced as part of this submission.

Follow-up on Potentially Responsive Information

Throughout its investigation, Portland General's Investigative Team faithfully endeavored to engage in follow-up inquiries with respect to any information it believed might potentially lead to responsive information or documents. For instance, such follow-up inquiries and investigation included (but was not limited to):

- Subsequent interviews of certain employees;
- Review of specific email files based on information garnered during interviews;
- Review of voice recordings for certain specific trading days based on information garnered during interviews. The transcripts of those transactions Portland General believes are responsive to the Commission's Order are being provided as part of this submission.

PGE

MEMORANDUM

TO: All Employees Associated with Inquiry into California Trading

FROM: Peggy Y. Fowler *Peggy Y. Fowler*

SUBJECT: Interviews and Production of Documents Related to PGE Inquiry Related to Federal and State Investigations and Potential Litigation

DATE: May 12, 2002

I know you are all aware of the various investigations into wholesale electricity and gas trading involving California. You may also be aware of FERC's most recent order issued last Thursday requiring all sellers of wholesale electricity or ancillary services to the California ISO or PX to respond under oath by May 22 about their knowledge of the trading strategies contained in certain Enron memoranda released publicly early last week. I have asked PGE's General Counsel, Doug Nichols, to conduct the inquiry required by FERC and I know I can depend on you to cooperate fully.

PGE's continued credibility and the trust it enjoys with its customers and regulatory authorities depends on our continued cooperation in supplying truthful and timely information. Because of its importance and the short time frame we have to respond, I'm asking that you adjust your schedules as necessary to accommodate any interviews or data requests that may be asked of you.

I know many of us have been asked for a lot from FERC lately, and this is another demand that will require a real team effort. Keep that positive winning attitude and we'll get through this too!

PRIVILEGED AND CONFIDENTIAL

PGE

MEMORANDUM

TO:	**All Persons Associated with California Trading**
FROM:	**Doug Nichols, General Counsel**
SUBJECT:	**Interviews and Production of Documents Related to PGE Inquiry Related to Federal and State Investigations and Potential Litigation**
DATE:	**May 13, 2002**

As you know, various Federal and State investigations have been initiated relating to allegations of price manipulation for electricity and natural gas in the Western States, some of which could result in litigation involving PGE. In this connection, on May 8, 2002, FERC ordered sellers of wholesale electricity and/or ancillary services to the California ISO or PX during 2000 – 2001 to conduct a fact-finding investigation of certain trading practices. As a result of all of this, PGE is conducting its own fact-finding inquiry, and I know we can depend on you to give your full attention to cooperating with this effort.

Attached is a copy of a memorandum to each of us from Peggy Fowler emphasizing the need to give this priority so we can meet FERC's May 22 deadline.

In view of this, you are required to gather all correspondence, e-mails, other forms of communications, telephone logs, opinion letters, memoranda, reports, files at your desk (including any materials you may have taken home) that may be relevant to each of the ten **"representative trading strategies"** that employ **"inc-ing load"** and **"relieving congestion"** as described in Items I.A through I.K. of FERC's May 8, 2002 order, a copy of which is attached. If possible, provide copies (with a notation of where the original is kept) of all of these materials to Karen Lewis (at 1-WTC-17) by Wednesday, May 15. If that is not possible, provide what you have by that date and complete providing this material not later than noon Friday, May 17. Karen or other members of the document material team will be contacting you later this week about this. To aid you in defining the scope of this request, I am also attaching a copy of the Stoel Rives (December 8, 2000) and Brobeck (undated) memos referred to in the FERC order.

Please review the attached documents carefully. It is imperative that we have all materials requested by FERC.

Beginning today, Monday May 13, we will start conducting interviews of all recipients of this memorandum. Please bring the originals of these materials with you to the extent you can.

It should go without saying, but just for emphasis, there should be no disposal or destruction of any materials that could be remotely relevant to this inquiry.

If you have questions, please call me at 464-8402, Jay Dudley at 464-8860, or Karen Lewis at 464-8796.

Attachments

PGE

MEMORANDUM

TO:	**Former Employees Associated with California Trading On PGE's Behalf**
FROM:	**Doug Nichols, General Counsel**
SUBJECT:	**Interviews and Production of Documents Related to PGE Inquiry Related to Government Investigations**
DATE:	**May 14, 2002**

As you know, various Government investigations have been initiated relating to allegations of price manipulation for electricity and natural gas in the Western States. In this connection, on May 8, 2002, FERC ordered sellers of wholesale electricity and/or ancillary services to the California ISO or PX during 2000 – 2001 to conduct a fact-finding investigation of certain trading practices and respond to FERC by May 22, 2002. As a result of all of this, PGE is conducting its own fact-finding inquiry. We are soliciting your support and cooperation with this effort.

In view of this, we are asking that you gather any correspondence, e-mails, other forms of communications, memoranda, reports, or other files in your possession that may be relevant to each of the ten "**representative trading strategies**" that employ "**inc-ing load**" and "**relieving congestion**" as described in Items I.A through I.K. of FERC's May 8, 2002 order, a copy of which is attached. If possible, provide these materials to Karen Lewis (at 1-WTC-17) by Friday, May 17. If that is not possible, please provide what you have by Monday, May 20. Should you wish to refer to them, I am also attaching a copy of the Stoel Rives (December 8, 2000) and Brobeck (undated) memos referred to in the FERC order.

It is important that we have all materials requested by FERC. Of course, none of the materials that may be relevant to FERC's investigation should be destroyed or otherwise disposed of.

If you have any information about these trading strategies that you can share with us orally, or if you have any questions, please call me at 464-8402 or Karen Lewis at 464-8796.

Attachments

ADDENDUM B

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices	)))	Docket No. PA02-2-000

AFFIDAVIT OF DOUGLAS R. NICHOLS

I, Douglas R. Nichols, being duly sworn, depose and say:

1. I am General Counsel for Portland General Electric Company ("Portland General").

2. I have reviewed the Response of Portland General to the Commission's May 8, 2002 Data Request and Request for Admissions, and certify that the statements contained in the Response (including Addendum A) are true and correct to the best of my knowledge, information and belief.

3. I make this certification after having directly supervised and controlled a diligent and thorough investigation, as described in Addendum A of the Response, into the trading activities of the employees and agents of Portland General and its subsidiaries in the U.S. portion of the Western Systems Coordinating Council ("WSCC") during the years 2000 and 2001. Portland General's investigation did not include the trading activities of other Enron affiliates, including but not limited to, Enron Power Marketing, Inc. or Enron Corp.

4. I further certify that the documents produced in response to the Commission's Request are those documents identified through this investigation, that existed prior to the May 8, 2002 Order, and that I believe are responsive to the

Commission's Order. However, Portland General has not produced documents filed with the Commission or documents that have been made public since the release of the Enron Memoranda.

Executed this 21st day of May, 2002.

Douglas R. Nichols

STATE OF OREGON)
) ss.
County of Multnomah)

SUBSCRIBED AND SWORN to before me this 21st day of May, 2002.

Bari H. Gilbert
NOTARY PUBLIC in and for the State of Oregon
My Commission Expires: 12/28/2004

OFFICIAL SEAL
BARI H. GILBERT
NOTARY PUBLIC-OREGON
COMMISSION NO. 341511
MY COMMISSION EXPIRES DEC. 28, 2004

Fact-Finding Investigation of
Potential Manipulation of Electric
and Natural Gas Prices

FERC Docket No. PA02-2-000

**ATTACHMENT
I.A.2**

Portland General

Portland General Electric Co.

CALIFORNIA WINTER SUPPLY STRATEGIES

1. **Purchase Standard Energy Products at COB/NOB (S→N)**

   -Broker Market
   -Direct from California Publics
   -Daily/hourly Cal PX

   Pros: Meets base load energy requirements

   Cons: No Help for peak load hours/days
   Costs highly volatile based on market conditions.

2. **Power Purchases within California (NP-15, SP-15)**

   -Broker Market
   -In Area Generators (Williams, NorAm, Dynergy)
   -California Publics

   Pros: Meets base load energy requirements.
   PGE's ability to take "FLAT" product may benefit price negotiation!

   Cons: Limited flexibility for peak load hours/days by selling in-area with interruption rights.
   Subject to Congestion pricing and Export Fees.

3. **Purchase Power "OPTIONS"**

   -COB/NOB (S→N)
   -NP-15
   -California Publics

   Pros: Potential to meet peak load hours/days.
   Limits price risk to unforeseen events.

   Cons: Premium price can be expensive insurance.

4. **Negotiate Power Exchanges (Winter/Summer)**

   -California Publics
   -Other Scheduling Coordinators (SC)

   Pros: Provides some flexibility to meet peak loads depending on contract/scheduling terms.
   Historically, very useful from an operations perspective and economically efficient.

   Cons: May be difficult to establish value and negotiate terms in today's business environment.

5. **Import Power Products from Desert SW (APS, PNM, PV)**

   Pros: Winter prices can be favorable.
   Cons: Subject to transmission constraints and costs.

CALIFORNIA POWER EXCHANGE - OVERVIEW

AVAILABLE PRODUCTS AND PRODUCT SUMMARY

- **Day Ahead Sale to the California Power Exchange**
  This is an opportunity for PGE to participate in the regulated California market on a preschedule basis. As a consequence of California law mandating restructuring, opportunities to deal with regulated entities in California have been in many cases restricted to transactions arranged through a competitive bidding process. The disadvantage to this process is that proposed transactions are not firmed up until well after the normal hours of preschedule trading. Often the risk associated with participating in the California Power Exchange (CalPX) Day-Ahead market is justified by the relative difference in price between California and the Northwest. Unlike the normal preschedule transaction, which consists of on-peak or off-peak blocks, each hour is dealt with independently when structuring a bid to the CalPX. The ability to shape quantity and vary price hour-by-hour adds necessary flexibility in compiling the preschedule.

- **Day Ahead Sale of Replacement Reserves to the California Power Exchange**
  Not currently pursued.

- **Hour Ahead Sale to the California Power Exchange**
  The CalPX Hour-Ahead market, through a combination of energy and adjustment bids is an opportunity for real-time participation in (regulated) California. Although it is common for returns on sales to California to exceed that of the Northwest, the Hour-Ahead market provides the greatest advantage in timing. Bids are generally awarded before most northwest entities are willing to commit and a full hour in advance of the California ISO. This jump on the market allows time to arrange the purchase of energy and/or transmission to cover sales. Effective utilization of the CalPX Hour-Ahead market may provide our greatest opportunity to increase profits through arbitrage.

- **Hour Ahead Purchase from the California Power Exchange**
  Due to the service charges imposed on entities requesting to purchase energy from the (regulated) California market few purely north to south transactions occur. The reason is that California prices can't compete with Northwest pricing when the additional costs are considered. But services charges are only imposed on the net flowing out of the regulated California market. So if purchasing from the CalPX results in netting a preschedule (Day-Ahead) sale to a lessor amount, no additional costs are incurred. Again, bids are generally awarded before most northwest entities are willing to commit and a full hour in advance of the California ISO, providing necessary time to utilize the transaction.

- **Hour Ahead Sale of Replacement Reserves to the California Power Exchange**
  Not currently pursued.

- **Supplemental Energy Bid to Buy from the California ISO**
  PGE is billed per megawatt for each awarded transaction. This is in addition to any other fees or charges. So when selling to the California ISO it makes sense not to utilize the CalPX system, but when submitting a bid to buy from the ISO with a corresponding CalPX preschedule or Hour-Ahead sale to net out

AVAILABLE PATHS

PGEIML - Portland General Electric Import @ Malin **(sale to the CalPX)**

PGEINB - Portland General Electric Import @ NOB **(sale to the CalPX)**

ATTACHMENT
I.K.1

Parking and Lending

Typically when trades are entered into in either the Term (at least month ahead) or Cash (day ahead) they are scheduled from the generator to the load the day before it is delivered. Prescheduling is the task of taking all trades and lining up the paths that spell out who is generating, marketers involved, the transmission necessary to wheel the energy from the generator to the load, and the load. Prescheduling requires all participants in a transaction to be knowledgeable about the whole path. NERC tags are the means of communicating everything from generator to load. By mid-afternoon every business day at least the next day has been set up or scheduled showing trades from generator to load.

Since marketers generally don't have generation or load, their preschedules must be balanced (buys = sells). Therefore, marketers are typically unable to take a position into the next hour or real-time market like a control area or generator. Parking and Lending (P&L) allows the marketer to take an unbalanced position into the real time market. A marketer would be interested in doing this if they felt the prices in the real time market was going to vary from the preschedule market by an amount which exceeds the fee charged by the control area.

Parking & Lending

The product commonly referred to in industry standard practice as "Parking" is contractually referred to as "Short-term Storage". The product commonly referred to as "Lending" is contractually referred to as "Short Sales Transactions".

The product is commonly offered in the market as a day-ahead product, subject to mutual agreement at that time. This may be referred to as "pay as you go" parking and lending in the sense that neither party is obligated to enter into parking and lending transactions. Parties also offer a "reserved" parking and lending, allowing the buyer to pay a reservation fee up-front that obligates the seller of parking and lending to offer one or both products when the buyer of "reserved" parking requests it in pre-schedule.

Currently, there are the following regular market participants:

<u>Buying Parking and Lending</u>

- Aquila is a regular buyer of "pay as you go" parking and/or lending from "others around the country"
- El Paso is a buyer of "reserved" parking and lending at Mid-C
- Enron has historically purchased "pay as you go" parking and/or lending at Mid-C
- Williams has purchased "pay as you go" parking and/or lending from NRG and other counterparties
- Morgan Stanley bought pay as you go at Mid-C
- Duke
- TransCanada
- Illinova

<u>Selling Parking and Lending</u>

- PacifiCorp (at Mid-C)
- El Paso (at Palo Verde)
- Pinnacle West (in the Desert SW)
- PNM (in the Desert SW)
- Avista (at Mid-C)
- Chelan PUD (at Mid-C)

Parking

DAY 1

Customer

- Calls PGE to sell and Pre-schedule power for Delivery the next day.
- Provides the quantity, hours & price.
- Completes NERC Tag.

PGE

- Sets up pre-schedule for delivery on next day.

DAY 2

Customer

- Looks for a counterparty to sell power to in the real-time market.

Counterparty Found?

Yes

Customer

- No later than 1/2 hour prior to the delivery hour calls PGE with counterparty for the sink.
- Completes NERC Tag.
- Could be done each hour.

No
(Upon mutual agreement)

PGE

- Takes power into PGE system or finds a counterparty for the sale.
- Priced at index minus.

Example: (El Paso)

Day 1 (PreSchedule) Chain	Day2 (Real Time) Chain
PACW (Generator)	PGE (New Generator)
EPEM	EPEM
PGE (Sink)	PSE (New Sink)

I.K.1-004

LENDING

DAY 1

Customer

- Calls PGE to purchase and Pre-schedule power for Delivery the next day.
- Provides the quantity, hours & price.
- Completes NERC Tag.

PGE

- Sets up pre-schedule for delivery on next day.

DAY 2

Customer

- Looks for a counterparty to purchase power from in the real-time market.

Counterparty Found?

Yes

Customer

- No later than 1/2 hour prior to the delivery hour calls PGE with counterparty for the source.
- Completes NERC Tag.
- Could be done each hour.

No (Upon mutual agreement)

PGE

- PGE provides power from system or finds a counterparty for the source.
- Priced at index plus.

Example: (El Paso)

Day 1 (PreSchedule) Chain	Day2 (Real Time) Chain
PGE (Generator)	MAEM (New Generator)
EPEM	EPEM
AVST (Sink)	PGE (New Sink)

Fact-Finding Investigation of
Potential Manipulation of Electric
and Natural Gas Prices

FERC Docket No. PA02-2-000

ATTACHMENT
II.A.

Facsimile Cover Sheet

Company: Portland General Electric Company
To:
Phone:
Fax: 503-464-2200

From: Enron Power Marketing, Inc.

Date: 5/15/2002
Pages including this cover page: ~~12~~ 8 total
I miscounted

Comments:

Robert H. Walls, Jr.
Executive Vice President and General Counsel

Enron Corp.
*1400 Smith Street
Houston, TX 77002-7361
P.O. Box 1188
Houston, TX 77251-1188
713-646-6017
Fax 713-646-6227
rob.walls@enron.com*

VIA FACSIMILE
<u>VIA CERTIFIED MAIL</u>

May 15, 2002

Portland General Electric Company
121 SW Salmon Street
Portland, OR 97204
Attn: General Counsel
Fax: (503) 464-2200

Re: Disclosure

Gentlemen:

I am writing to you as a courtesy to inform you that Enron Power Marketing, Inc. ("EPMI") is producing certain documents that make reference to your organization in response to requests for production that Enron has received from the FERC, the CFTC, the California Attorney General and other governmental bodies.

More specifically, and as has been widely reported in the media, in response to the production by Enron last week of certain memoranda relating to energy trading in the California market, the FERC, the CFTC, and the California Attorney General have required that Enron immediately produce any additional documents that, among other things, relate to the trading strategies covered in the foregoing memoranda or the California ISO sanctions discussed therein. We are in the process of doing so, and are writing to inform you that some of these documents may contain information relating to your organization. Attached is a copy of the documents that reference your organization that we have been required to produce (to the extent that a document refers to other companies, redactions may have been made). EPMI has formally requested that the governmental recipients of the information being disclosed maintain the confidentiality of this information, but there is no assurance that such recipients will do so.

If you believe that the governmental agencies to whom these documents are being produced must maintain them as confidential, you should take whatever steps you believe are necessary and appropriate in that regard. In addition, we are also informing you that the documents are also likely to be the subject of inquiries from additional governmental agencies and Congressional committees. Finally, you should understand that in providing you with this notice Enron does not mean to suggest that you have any right to restrict the public disclosure of the information in question, and Enron does not waive any rights it may have under any applicable contract or otherwise.

Sincerely,

R. H. Walls

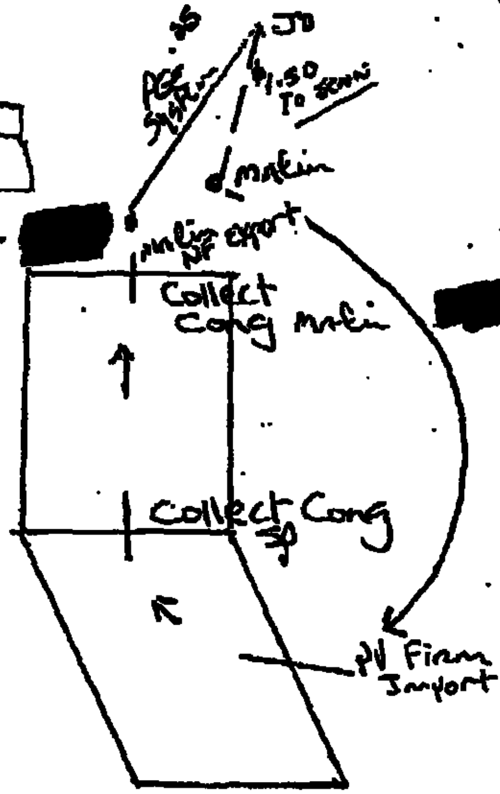
Robert H. Walls, Jr.

KBA/HBM

Attachment

FORNEY ~~Perpetual~~ Loop – J Forney 925-0415

[redacted] No MWs Flow, just call in schedules



[redacted] 87.33 + 33/mws = $

20 mw $150 13-22

LA(T) is firm malin > mead, t we can use malin > PV, not on n-f basis

1. Submit Firm Import & non firm export (adjust bids to pay, for example, $5 Dont touch load
2. Sell to [redacted] at Malin (Buy/Resale for $1)
3. [redacted] sells to PGE at Malin
4. PGE takes to their system
5. We use our Transm. to go JD/Malin
6. Hand to [redacted] Malin/PV (We have only 24mw due to (DI DERATION)
7. Import via [redacted] at PV

To do: 1 Call [redacted] every hour to advise of export
2 Call PGE MKT to advise of same
3 Call [redacted]
4. Call ISO. Intertie checkouts people at both PV and Malin.

ECI000227546

From: Michael M Driscoll 05/05/2000 03:48 PM

To: Portland Shift
cc:

Subject: The FINAL PROCEDURES FOR DEATH STAR, disregard the other 2 emails.

Project Deathstar has been successfully implemented to capture congestion relief across paths 26, 15 & COI.

We input the deals as follows:

1. EPMICAL POOL MEAD230 / MALIN
2. ONE DEAL TICKET, A BUY/RESALE WITH [redacted] SELLING AT MALIN, REPURCHASING AT PGE SYSTEM, (PAYING [redacted] $1 DIFFERENTIAL)
3. SELL INDEX FWD TO PGE AT PGE SYSTEM INPUT AT DOW JONES MID C INDEX .
4. BUY INDEX FWD FROM PGE AT JOHN DAY AT DOW JONES MID C INDEX PLUS .90
5. USE EXISTING PGE CONTRACT #146517 FOR TRANSMISSION FROM JD/MALIN
6. USE EXISTING [redacted] TRANSMISSION #292672 FROM MALIN>MEAD230

Everthing will link up, with the buy from PGE(JD) on top, all the trans and buy/resells in the middle, and the sell to PGE(system) at the end

7. CREATE ANNUITY TO REIMBURSE LT NW DESK FOR THE $1.50 VARIABLE COST OF THEIR PGE TRANS
8. CREATE ANNUITY TO REIMBURSE LT SW DESK FOR VARIABLE COSTS ASSOCIATED WITH THE [redacted] TRANSMISSION.
[redacted] TRANSMISSION COSTS .33/MW PLUS THE ONE TIME $87.33 SCHEDULING FEE. DIVIDE THE SCHEDULING FEE BY THE MW'S FLOWED THAT DAY TO GET AN AVG/MW PRICE. THEN ADD TO THE .33/MW TO GET TOTAL.

THANKS AND GOOD LUCK.

ECT000227548

[redacted] CONG CATCHER

PGE 1 +21
500

PGE2 -21
500 → [redacted]

GF TRANNY

N ↓

\$ PATH 15

PGE 4 +21
500

[redacted]

SCE 1 -21

500.01

<u>telling</u>

[redacted] in caps int-interchange

SELL 21 in NP-15
BUY 21 in ZP-26

21

21 PGE

$\frac{\Delta}{\%\ \text{cong}}$ $\frac{-}{-}$ Δ ZP & NP

21

Lester Rawson
12/24/99 04:41 PM

To: Donald Robinson/PDX/ECT@ECT, Smith L Day/HOU/ECT@ECT, Valarie Sabo/PDX/ECT@ECT, Lester Rawson/PDX/ECT@ECT, Scott McKinney/PDX/ECT@ECT, John M Forney/HOU/ECT@ECT, Carey Morris/PDX/ECT@ECT, Larry Daugherty/PDX/ECT@ECT

cc:

Subject: Annuity's and Big Foot

Shift Mates,

When inputting information into a annuity to transfer money from the Real Time book to the Northwest book for using their PGE transmission be aware that annuities liquidate every hour. This means that you need to have the strip in for the hour you want to capture before that hour begins. If you miss a hour just double up on the next one or pick a later block. As always there are exceptions in this case annuities don't liquidate on the weekend and holidays.

Also, the Big Foot deal (buy energy from [redacted] and schedule it in as supplementals) bookout price has been renegotiated down to $3.00 per Mw all other terms of the deal remain the same. If you buy from [redacted] and do real well on a supplemental you might consider giving them a few more dollars for there energy.

Questions please ask.

Have a great Holiday.

Regards,

Les Rawson

From: John M Forney 02/17/2000 10:41 AM

To: Portland Shift
cc: Stewart Rosman/HOU/ECT@ECT, Jeffrey Miller/HOU/ECT@ECT

Subject: REAL TIME OPPORTUNITIES

we have been getting fewer opportunities to do profit sharing transactions with certain members of their staff. We need to let Stewart and myself know when we call to get them involved and they have no interest. Their manager wants to do this every time we see fit. Everyone needs to know why they dont want to play.

wants to play again. They are willing to let us preschedule day ahead energy to them and profit share (fat boy) into the ISO.
Additionally, Steve at says that when we have the phones, we have the flexibility to sell into the expost if the bilat is trading much lower.
We will then profit share based on the bilat market as their basis. Do not watch sell during the day for $25 when the expost is $40
For example:

Expost is $100
Bilat trades at $50

gets $50 plus half the upside, $25 (less proportionate share of import expenses).
Enron gets $25/mw (less proportionate share of import expenses).

VALLEY ELECTRIC - We are now taking real time energy into the ISO. The preschedulers leave certain amounts for us to play with in a given day.
We have printed procedures for taking care of selling this into the ISO. We must call and as control area of Mead230. We have to do a real time tag for as they cannot function without something in writing.

owns transmission that is available on a RT basis. This will get us from Malin to Mead230.
This would be useful for using in conjunction with our PGE rights which get us from JD>Malin; we could conceivably buy cheap NW energy and transmit way down South to Mead.
Additionally, we could non-firm export from ISO at Malin, get paid for cong relief and transmit down South.
I will provide all info necessary for using this product that has RT capabilities.

We have been making our money in the ancillary services market the last two days. Both day ahead A/S profits and Hour Ahead profits are now split evenly between ST Call Desk and our ST Hrly Desk, so know that your work on A/S is really paying off for everyone.

Expost has been strong, but we've not been able to get players started, such as [redacted] Stewart and I will rectify that situation.

Thanks and lets get busy!!!!!

JMF

ECf000227571

II.A.-009

ATTACHMENT
II.B

KNOW THE ISO EVENT REPORT

ISO Filings at FERC Regarding the Final Order in Docket Nos. EL00-95-000, et al

January 18th, 2000

This report summarizes two ISO filings regarding the December 15th FERC order ("Order") on ISO/PX restructuring, in Docket Nos. EL00-95-00 et al. The filings, posted last night on the ISO Web site, were as follows:

- Request for rehearing and partial stay on governance issues, specifically the requirement that the ISO Board surrender its oversight authority to ISO Management on January 29th. *(http://www.caiso.com/docs/2001/01/18/200101181728197072.pdf, with accompanying Affidavit of William J. Regan, Jr. at http://www.caiso.com/docs/2001/01/18/200101181729147167.pdf)*

- Request for rehearing and motion for clarification of the following issues:
  - Application of the "soft cap" bid/payment structure to most Ancillary Services (A/S) capacity costs and negatively-priced Imbalance Energy (I/E) bids;
  - Application of under-scheduling penalties to load, but not to generation;
  - Potential elimination of the balanced schedule (loads and generation) requirement;
  - Application of the seller reporting requirements to Out-of-Market (OOM) transactions (including those with out-of-state entities), in addition to market bids; and
  - Scheduling of the FERC-ordered technical conference that will address longer-term issues.

  (http://www.caiso.com/docs/2001/01/18/200101181708014077.pdf)

The ISO position in each of these areas is summarized below.

Board relinquishment of oversight authority

Relevant provisions of the Order

- Directed selection of a new, independent, non-stakeholder ISO Board by April 27th, and specified qualifications for the new Board members and the manner in which they'd be chosen;
- Recognized that the Order conflicts with state requirements *(i.e., the new Board composition/selection procedures are inconsistent with those in California State legislation AB1890, which created the ISO)*, and expressed willingness to consult with state authorities to resolve any differences *(though the FERC procedures would take effect as scheduled if no agreement was reached)*; and
- Ordered the existing ISO Board transfer its decision-making power and operating control functions to ISO Management as of January 29th, 2001, and assume an advisory-only role until the sooner of seating of a new Board or April 27th.

ISO arguments

The ISO:

- "Has no quarrel" with changing the Board composition and member selection process; and
- Supports federal-state consultation, believing (with "a high degree of confidence") that agreement can be reached by April 27th.

However, the ISO states that a January 27th relinquishment of Board authority would create "severe problems," namely:

- ➢ It will violate state law; and
- ➢ The federal-state conflict will create uncertainty that would adversely affect ISO financial activities between January 27th and April 27th.

The argument about potential financial difficulties is based on the assumption that, during this interim period, lenders and other parties will be:

- ➢ Reluctant to provide capital for important ISO expenditures: These would include:
  - ■ "Numerous material transactions, including substantial capital expenditures" of up to $80 million; and
  - ■ Up to $110 million in new debt, of which:
    - $10 million would fund a new EMS system;
    - $20 million would fund initial Congestion Management reform phases;
    - $30 million would prefund FY2002 expenditures; and
    - $50 million would finance the proposed new ISO facility in Folsom.

➢ <u>Possibly willing to provide capital, but at a higher cost:</u> In view of the uncertainty, holders of the $300 million of current ISO debt might ask to be re-paid, as they are entitled to do, forcing the ISO to use more expensive bank back-up financing; and

➢ <u>Reluctant to enter into supply and service arrangements:</u> Without the certainty of Board approval, there may be difficulties in "consummating agreements" for the Summer 2001 Demand Relief Program, out-of-market or forward-purchased energy, Summer 2001 Peaking Generation, and routine consulting and other business arrangements.

<u>Relief requested:</u> Expedited rehearing on the authority transfer requirement, or a stay on the requirement until April 27th.

Application of "soft cap" bid/payment structure to most A/S capacity costs and negatively-priced Imbalance Energy bids

<u>Relevant provisions of the Order</u>

- The "single price auction" rule *(where all sellers are paid, and all buyers pay, the price of the last (most expensive) bid that clears the market)* will only apply up to a market-clearing price (MCP) of $150/MW;
- Bids accepted above that level will be paid the price bid, with the cost averaged with the uniform below-$150 MCP bids for purposes of charging loads.
- Reporting requirements are established for the ISO and the sellers for above-$150 bids, with the sellers required to provide cost justification for their pricing.

<u>ISO arguments</u>

Application of the "soft cap" bid/payment structure is not "appropriate" for the following services:

➢ ***Ancillary Services (A/S) capacity costs***, apart from the Regulation market (i.e., for Spinning Reserve, Non-Spinning Reserve, and Replacement Reserve); and

➢ ***Negatively-priced Imbalance Energy bids.***

(<u>Consultant note</u>: Negative Imbalance Energy prices can occur, for example, during conditions of over-generation, e.g., during heavy spring hydro conditions, when demand is low. Effectively, the ISO pays some generators to generate below their schedule to make up for others generating above their schedule.)

<u>Ancillary Services capacity costs (apart from Regulation)</u>

➢ <u>No bids above $150/MW can be justified based on cost:</u> If dispatched, the seller will receive its energy bid price, which under the soft cap structure the seller can set at a level that fully covers all reasonable costs. If not dispatched, the seller will still receive Market-Clearing Price (MCP) for the capacity. Basically, the ISO is arguing that, if the capacity is not dispatched, no (or few) costs are actually incurred, and therefore high-priced bids couldn't be justified.

(This rationale doesn't apply to Regulation service, because sellers only submit capacity bids. They receive the MCP for the energy, and that might not cover all their production costs, so they need the ability to recover their energy costs through their capacity bids, if necessary.)

➤ **This provision causes complications ("novel problems with interpretation and implementation") with other ISO market mechanisms:** The "Rational Buyer" protocol and the A/S "buyback" mechanism are specifically mentioned.

(Consultant notes:

- ***The Rational Buyer (RB) protocol is the ISO software that substitutes lower-priced A/S for higher-priced A/S, where reliability requirements allow it. For example, Spinning Reserve (10-minute availability, unit must be spinning) can substitute for Non-Spinning Reserve (10-minute availability, unit need not be spinning), and if Spinning Reserve capacity bids are priced lower, the RB protocol will buy more of that service and less Non-Spinning Reserve.***
- ***The A/S buyback mechanism refers to the situation where a seller's Day-Ahead A/S bid is accepted by the ISO, but the seller later withdraws the bid. The ISO then has to buy replacement capacity in the Hour Ahead (HA) market and charges the non-performing seller for the cost (previously, the HA Market Clearing Price).***
- ***In my own opinion, while these mechanisms would certainly be complicated by the soft cap, and some changes might need to be made, the ambiguities aren't insurmountable. However, it would be difficult without software modifications, and that would take time.)***

Negatively-priced Supplemental Energy bids

➤ **The requirements for justifying them are inadequate/unclear in the Order:** The ISO believes that the Order would require bids below -$150 to be cost-justified, as are prices above +$150. However, the Order contains no guidance on the appropriate justification for such prices or how/if FERC could review them.

(Consultant note: Since the Order literally required cost justification only for bids over +$150, I don't agree that justification is required for negatively-priced S/E bids. It shouldn't necessarily be assumed that the rationale for requiring justification of high positive bids really also applies to low negative bids. However, I also wouldn't assume that FERC specifically considered this situation, so clarification may be warranted.)

➢ <u>This provision causes Target Pricing mechanism difficulties:</u> Since the Target Price mechanism addresses overlaps between incremental and decremental S/E bids, the soft cap would cause "significant problems" if incremental bids are priced below -$150. *(Trust me, if you don't need to know about the Target Pricing mechanism, you're better off not worrying about it.)*

<u>Relief requested</u>

- ***<u>Ancillary Services capacity prices (except Regulation):</u>*** Allow the ISO to impose a "hard cap" (i.e., an absolute price limit for bids it will accept).
- ***<u>Negatively-priced Supplemental Energy bids:</u>*** Allow the ISO to impose a "hard cap" "tracking the level of the breakpoint on positive bids." ***(Consultant note: I assume that this means it would be the <u>same</u> as the breakpoint ($150 now).)***

Application of under-scheduling penalties to loads, but not to generation

<u>Relevant provisions of the Order</u>

- A penalty charge will apply to load (consumption) deviations from forward schedules above the greater of 5% of an entity's hourly requirements or 10 MW, with penalty revenues (above costs) dispersed to loads that scheduled accurately.
- The charge for deviations above that amount will be the lesser of twice the ISO's real-time Imbalance Energy cost or the imbalance cost plus $100/Mwh.
- The ISO is ordered to "consider other market design changes that would address under-scheduling" and "is free to propose a modification to [the] penalty procedures."

<u>ISO arguments</u>

➢ **<u>A loads-only penalty:</u>**

■ <u>Is an inadequate remedy:</u> Penalizing only loads addressed only part of the problem.

■ <u>Will bias load-generation negotiations:</u> Loads will have to take potential penalties into account if an agreement isn't reached and the load is unscheduled, while generators won't have to worry about the penalties if an agreement isn't reached and the generation is unscheduled (whether it's actually produced or not).

➢ **<u>The ISO should be able to consider all options to address under-scheduling problems:</u>** Despite FERC's choice not to impose a generation under-scheduling penalty in the Order, the ISO "is currently examining such options and hopes to develop a proposal in the near future."

Relief requested

- Clarify that the Order authorizes the ISO to submit a proposal for generation under-scheduling penalties; or, if it does not,
- Modify the Order to permit the ISO to develop and implement such a proposal.

Potential elimination of the balanced schedule requirement

Relevant provisions of the Order

"...Some of the under-scheduling problems may be a result of...many individual Scheduling Coordinators that are required to submit balanced schedules to the ISO. We therefore direct the ISO and PX to pursue establishing an integrated Day Ahead market in which all demand and supply bids are addressed in one venue."

ISO arguments

- ➤ Eliminating the balanced schedule requirement would require "sweeping changes" in ISO markets and operations.
- ➤ Nothing in either the November 1st draft order or the Order itself supports such a directive (i.e., there is no evidence or findings to form the basis for this change).

Relief requested

- Confirm that the Order does not mandate elimination of the balanced schedule requirement, only examination of the issues "related" to it; or, if the Order does so mandate,
- Grant rehearing on this issue.

Application of seller reporting requirements to OOM transactions, including those with out-of-state entities

Relevant provisions of the Order

Confidential weekly reports on ISO/PX "spot" market "transactions" are required for transactions with prices that exceed $150. (The Order includes a list of specific information to be included in the reports, geared to determine seller costs and other determinants of reasonableness.)

ISO arguments

- ➤ Imposition of reporting requirements on market bids, but not OOM transactions, would give sellers an incentive to withhold bids from the regular market and wait for ISO OOM calls.

- Imposition of reporting requirements on in-state sellers but not out-of-state sellers would give in-state sellers an incentive for in-state sellers to export the energy to other states and re-import it in a "ricochet" transaction.

Relief requested

Clarify that the reporting requirements apply to all transactions in the ISO's markets, including OOM transactions with entities both inside and outside California.

Scheduling of FERC-ordered technical conference to address longer-term issues

Relevant provisions of the Order

FERC staff is to convene a technical conference as a forum to resolve longer-term issues, including:

- Ensuring sufficient long-term supply and reserves;
- Alternative auction mechanisms, including use of simultaneous rather than sequential auctions;
- Balanced schedules (see above); and
- Demand-side response programs.

ISO arguments

- The ISO is busy preparing for:
  - The mandated January 31st Congestion Management reform filing; and
  - The January 23rd FERC conference on post-May 1st market monitoring and mitigation measures.
- The May 1st implementation of the new market monitoring/mitigation measures will require further effort and resources.
- Thus, for the next 1-2 months at lease, the ISO will be unable to devote sufficient resources "to properly develop our thoughts and positions on these weighty issues."

Relief requested

Postpone the technical conference on longer-term issues until at least May 1st (second quarter of this year).

KNOW THE ISO EVENT REPORT

ISO Department of Market Analysis

Draft Market Power Mitigation Plan

January 19th, 2000 (Updated January 22nd)

This report summarizes the ISO Department of Market Analysis ("DMA") proposal ("Proposal") for mitigation of generator market power. The proposal was prepared for discussion at the FERC staff technical conference on long-term market power monitoring/mitigation ordered in the December 15th FERC (Docket Nos. EL00-95-000, et al) ("Order"). That conference is scheduled for January 23rd.

Proposal elements

The proposal reflects many concepts and positions articulated previously by the ISO and DMA. The specific elements of the Proposal are as follows:

1. Mandatory long-term contracts (≥ 2 years) for both buyers and sellers;
2. Capacity reserve requirements for loads and availability standards for generators;
3. Local generator market power mitigation; and
4. Resource-specific mitigation and enforcement in markets not covered by long-term contracts.

Electronic document location: The Proposal is posted on the ISO Web site at this address: http://www.caiso.com/docs/2001/01/19/2001011917092328168.pdf.

Background: Summary of market power monitoring and mitigation measures ordered by FERC

Measures ordered

In the Order, FERC ordered three types of market power monitoring/mitigation measures:

- **Elimination of the Cal-PX buy-sell requirement**
  - Removed the obligation of the large California investor-owned utilities (IOUs) into the California Power Exchange (Cal-PX), and prohibited such sales; and
  - Urged the CPUC to remove the must-buy requirements from the IOUs.
- **Forward scheduling facilitation**
  - Imposed a penalty for under-scheduling loads by more than the smaller of 5% or 10 MW;

II.B.-009

- Removed some incentives for resources to favor the real-time market by providing that Replacement Reserve capacity be paid the capacity or energy price, but not both.

- **Establishment of "soft cap" price structure**
  - Only bids ≤ $150 can set the Market Clearing Price (MCP - the price paid for all power bid at prices lower than that);
  - Bids ≥ $150 are paid the price bid and are subject to reporting requirements.

Expiration date: These measures are to expire on May 1st, when a new monitoring/mitigation framework is to take effect. The January 23rd conference is to help develop this new framework, with a proposal to be filed by FERC staff by March 1st.

DMA comment on effectiveness of "soft cap" concept so far: The average December energy price of $295/Mwh was the highest since the April 1998 initiation of the restructured market, even with the $250 "soft cap" in effect most of the month. This suggests that further measures are needed. ***(Consultant note: The DMA report originally prepared for the January Board meetings shows a December price for energy plus Ancillary Services of $326.)***

Proposal element 1: Mandatory long-term (≥ 2 years) contracts

Purpose: Ensure sufficient supply to meet the majority of expected load at "just and reasonable" (J&R) rates, and give suppliers incentives to provide greater output.

Requirements for Load-Serving Entities (LSEs)

- ***Minimum threshold:*** Must forward-contract (≥ 2 years) for ≥ 85% of their forecasted requirements, adjusted for season and time of day, with LSE-owned generation counted toward satisfying those requirements.
- ***Regulatory reasonableness review:*** "Appropriate regulatory authorities" to review each contract for justness and reasonableness (J&R) of the prices. The CPUC and FERC should set up a coordinated review procedure.
- ***"Just and reasonable" price criterion:*** Maximum J&R prices should be forward-looking fixed and variable costs plus a "reasonable" rate of return. Prices could be lower than that.
- ***Ancillary Services requirements:*** No Ancillary Services (A/S) long-term contracting requirement, but LSEs "should be encouraged" to make such arrangements.

Requirements for generators

- ***In-state suppliers:*** Must offer ≥ 70% of their 1/1/01 capacity for the above long-term contracts. Capacity committed to transactions with parties other than California LSEs would not count toward satisfying these requirements.

- ***Out-of-state suppliers***: Must offer ≥ 70% of average monthly California sales in 2000 for the above long-term contracts.

- ***Exempt generation***
  - Renewables;
  - Suppliers with portfolios ≤ 50 MW; and
  - Incremental generation (additions to existing units, and new units).

- ***Compliance deadline:*** May 1st, 2001, with suppliers required to file with FERC by March 15th evidence that they will meet that deadline.

- ***Consequences of non-compliance:*** Non-complying suppliers will be:
  - ***Required to report all forward-market*** sales to FERC or "other designated regulatory agency" for 60-day review period, with those sales subject to refund for that period; and
  - ***Subject to stricter mitigation in the ISO real-time market*** than complying suppliers. *(See below.)*

Proposal element 2: Available capacity reserve (ACR) contract requirements for loads, and ACR availability standards for generators

Purpose: Ensure sufficient reserves, keep real-time transactions to a minimum, and prevent physical withholding of generation capacity.

Availability capacity reserve (ACR) standards for LSEs

- ***Minimum threshold:*** LSEs must contract for available resources equal to 115% of their "annual peak load" *(stated as about the same as current requirements for Regulation and Operating Reserve (Spinning and Non-Spinning Reserve))*.

- ***Penalties for non-compliance:*** $100-150/KW-year *(stated as a de-facto price cap on ACR service)*.

- ***Eligible ACR sources:*** The ACR can be purchased from any in-state generator and/or from identified out-of-state resources with demonstrated deliverability capability, and/or it can be self-provided using LSE-owned generation.

- ***Potential phase-in of requirements:*** Because of the short time before summer 2001, ACR requirements may be phased in, e.g.:
  - State or (as a last resort) ISO purchases of ACR, in lieu of LSEs, with the non-compliance penalty equal to the cost of the state/ISO purchase;
  - Implemented gradually from May to July 2001; and/or

> Implemented with a lower threshold than 115% if sufficient summer 2001 WSCC-area reserves aren't available.

ACR Availability standards for generators

- ***Service obligation:*** Must schedule, or bid into Regulation, Operating Reserve, or Supplemental Energy markets, the full ACR contract amounts.

- ***Unit substitution:*** Alternative generating units can provide the service in place of contracted units on forced outage, de-rate, or unauthorized maintenance outage, if done at no cost to the LSE or the ISO.

- ***Penalties for ACR non-delivery:*** Three options are discussed, in the context of non-delivery due to forced outage.

  - Replacement cost *(preferred option)*: Replacement cost of the energy at the real-time market price.

  - Outage allowance: Maximum allowed amount within a rolling time window ***[no mention of how the window would be determined or what the penalties would be for falling outside the window]***; and

  - Outage budget *(second-best option)*: Maximum dollar outage cost, e.g., outages in low-cost times wouldn't count against the "budget" as much as outages in high-cost times ***[again, no mention of how this budget would be established or what the penalties would be for accumulating a cost higher than this amount]***.

  Whatever the level of penalties, the document says that there should be separate penalties for failing to schedule/bid ACR capacity, and scheduling/bidding but failing to deliver.

- ***Curtailment of exports:*** If necessary during "emergency supply shortage conditions," in-state ACR suppliers must curtail exports, and those supplies will be purchased by the ISO at the real-time instructed energy price.

[Consultant comment: Most of this seems like just a complicated way to get loads to self-provide Ancillary Services.]

Proposal element 3: Local market power mitigation

Causes: The proposal states that local market power arises from two situations:

- ***The ISO Congestion Management (CM) protocols*** allow generators to submit infeasible schedules and force the ISO to take corrective actions in real time that benefit the party with the infeasible schedules; and

- ***Significant changes after the close of the forward market*** that create the need for real-time actions to maintain reliability.

Permanent solution *(to be addressed in the ISO's CM Reform proposal (to be filed on January 31st, and anticipated for implementation in 2002))* will:

- Include a comprehensive approach to local reliability and local market power.
- Cover both the forward and real-time markets.

Interim approach *(applicable when the resource has a bid in the market, otherwise the Out-of-Market (OOM) rules would apply)*

- **Rule for deciding when local market power is being exercised**
  - The resource is needed in real time at a specific location to ensure reliable service; and
  - The resource was not dispatched in normal merit (price) order.
- **Alternative (mitigated) price to use in place of the bid when local market power is exercised**

  (a) Preferred choice: Variable operating cost ("verifiable and on file with the ISO"), plus one-time costs actually incurred (e.g., start-up costs if the unit wasn't running).

  (b) If (a) can't be used because the necessary information is unavailable: Weighted average of all real-time prices or payments earned by the same resources over the past 30 days when it was dispatched in merit order, adjusted for "similar operating conditions (e.g., day of the week, operating hour, system load level)."

  (c) If (a) or (b) aren't possible: Variable operating cost of a unit of the same fuel type and similar size.
- **"Inconsistent" incentive:** The Proposal recognizes that the above recommendation might result in prices in congested areas that are lower than those in non-congested areas. It suggests that a possible approach might be to allow the resource with market power to receive the higher of their mitigated price or the real-time price in the zone where it is located.

Proposal element 4: Safety net

***[Note from your consultant:** In KTISO summaries, I try to translate what are sometimes complex or confusing proposals and concepts into language a normal, reasonably well-informed person would understand. For reasons that will probably be obvious once you start to read about the topics discussed below, it was difficult to determine in many areas just what was intended.*

Where the language wasn't decipherable for me, I simply show it to you as it was originally written, in quotes. So, where some of the language in quotes seems somewhat dense, don't feel bad.

Generally speaking, the market power mitigation measures discussed below seem to me <u>almost</u> the same as a return to cost-based regulation for all units, and it's very unclear how they would apply to imports, anything that doesn't run on natural gas, or power pools/exchanges.]

<u>Purpose:</u> Protect the real-time and A/S markets not under long-term contracts from exercise of market power through "economic withholding" (extracting a higher price than would be justified in a competitive market).

<u>Elements of the safety net</u>

- Measures to keep real-time transactions to 3-5% of total load;
- Price monitoring/mitigation in:
  - Real-time markets;
  - Ancillary Services markets; and
  - Other short-term contracts/markets;
- Bilateral contract monitoring; and
- Streamlining investigations, and increasing ISO authority to impose penalties and sanctions.

<u>Measures to minimize real-time transactions</u>
No additional information – just refers to the ISO January 16th request for rehearing, where the ISO requested that FERC impose under-scheduling penalties on generation as well as loads.

<u>Bid price monitoring/mitigation in real-time markets</u>

- ***<u>Bid "threshold" (maximum) prices</u>***
  - <u>Unit-specific threshold price for most units:</u> Variable cost, plus a fixed margin "that considers fixed-cost recovery and market conditions." ***["Market conditions" is not defined.]***
  - <u>Variable cost</u>
    - Based on "the average fuel prices of the previous week."
    - Only adjusted if average fuel prices move by the larger of 5% or $5 ***[per MMBtu? Doesn't say].***
    - If fuel prices change by more than 10% or $10 within a week, the price could be adjusted at that time.
  - <u>Variable cost for "energy-limited" resources (hydro mentioned):</u> In place of the variable cost, could use "some form of opportunity cost" which "may depend on water availability and checked with a forward price duration curve for the region." ***[OK, your guess is as good as mine.]***
  - <u>Treatment of emissions costs:</u> Would not be counted as a variable cost (i.e., for allowances) but would be an adder in the fixed margin "to allow for

investment in emission reduction equipment. ***[That is, they will pay you to clean up, not for continuing to run dirty.]***

- Fixed margin determination
  - The annual fixed margin would be based on annual fixed costs "including a healthy return to investment."
  - Fixed margin converted to per-MWh number based on the number of hours the threshold price is expected to be reached ***[sounds circular to me]***. Example given: If the annual fixed margin is $100,000 and the threshold price is expected to be reached in 500 hours, the hourly fixed margin would be $200/MWh ($100,000/500 hours).
  - The hourly fixed margins would be lowered by 50% if the ACR concept described above is adopted, because the ACR contracts would provide some of the fixed-cost recovery.
  - Hourly fixed margins would be lower for suppliers not complying with the above long-term contract requirements, e.g., it may not include any return on investment.
  - Other factors that might affect determination of the fixed margin:
    - ***Long-term contract rates:*** The higher those rates *(i.e., resources are recovering more of their costs through those contracts)*, the lower the real-time fixed margins should be.
    - ***Portion of load covered by long-term contract rates:*** The higher that fraction, the higher the real-time fixed margin should be.
    - ***ISO discretion:*** The ISO would have the ability to raise or lower the real-time fixed margin if "the overall market power impact is too high" or not very high, respectively.
  - In summary, assuming that ACR is implemented, and that long-term contract rates are "very close to the cost of production," the ISO proposes the following initial hourly fixed margins:

Portion of loads under long-term contracts	Fixed margin ($/MWh)
60%	$50
70%	$100
80%	$200
90%	$500

[Presumably, the numbers in this table refer to our example seller above with the $100,000 annual fixed margin, but this is not stated at all in the Proposal.]

- ***Payments to specific sellers for energy dispatched in real time***

- The ISO will adjust the prices in any bids that exceed the threshold, down to the threshold prices.
- Then, all generation dispatched in real time would receive the market-clearing price *(which could be higher than their particular threshold price)*.
- However, suppliers not compliant with long-term contract requirements would be paid no more than their threshold prices *(which would function as a payment cap)*.

Price monitoring/mitigation in Ancillary Services markets

- ***Alternative to bid caps (hard or soft):*** Possible resource-specific bid caps, based on "cost plus a sufficient margin." If this concept is preferred, the ISO recommends use of the same margin for a unit as determined under the "fixed margin" proposal described above.

- ***"Variable cost component of the bid price threshold"*** ***[maybe this is the energy bid that's submitted with the A/S capacity bid?]***: Maximum would be the average price bid by the unit over the preceding 90 days, looking only at hours when bids exceeded 120% of ISO A/S ***[capacity?]*** requirements and the resource was selected. If the resource had no accepted bids in the preceding 90 days, the average market-clearing price over that period when bids exceeded 120% of ISO requirements would be used.

  [Consultant note: A historical period as long as 90 days could be very problematic even with normal seasonal gas price fluctuations, e.g., fuel prices could be much higher/lower than three months earlier.]

Price monitoring/mitigation in other short-term markets/contracts

- ***Definition:*** Contracts between the (2+ year) long-term contracts and "short-term un-hedged load" ***[possibly the real time markets discussed above?]***

- ***Price mitigation:*** Would be based on "a general formula of variable cost plus a margin that allows fixed-cost recovery, including a reasonable return to investment."

  - Variable costs: Based on standardized formulas and fuel cost indices.

  - Fixed-cost margin: As calculated for the real-time market, with a "sliding scale" based on the length of the contract *(i.e., the longer the contract, the lower the margin)* and lower fixed margins for suppliers not complying with long-term contract requirements.

- ***Additional possible measures to discourage "ricochet" schedules*** *(energy exports imported back into California as imports)*:

  - Reporting requirements for bilateral contracts, and perhaps pre-approval *[by FERC?] requirements*, for any arrangements with:

- "Buy-back" or "supply-back" provisions ***[not defined]***; and/or
- Payments/contract terms linked to California market conditions.

> <u>Reporting requirements where sellers must show, for their "total" portfolios,</u> "the hourly gross and net flow of power from different supply sources and sales sinks," and showing "a reported cost of supply offered into the ISO's real time market as an import."

> <u>Refund and sanction provisions</u> if supply arrangements "are designed or have the effect of displacing thermal generation within the ISO or from a thermal generation source outside the control area as the source of energy bid into the ISO's market as an import from a different source." ***[Say what???]*** A potential penalty "might" be "an assumed cost" based on a relatively low heat rate (10,000 Btu), multiplied by a gas cost futures index (final Henry Hub given as an example).

- ***<u>A regional price cap</u>***, if "properly designed and coordinated with the rest of the market power mitigation components," might displace the need for this type of short-term mitigation.

<u>Bilateral contract monitoring</u>

- ***<u>Purpose:</u>*** Allow FERC to "assess key characteristics of the contract, including specific prices, quantities, and operational parameters of the transaction."
- ***<u>Proposed reporting requirements:</u>*** See <u>Appendix 2</u> for the list.

<u>Streamlining investigations and increasing ISO authority to assess penalties and sanctions</u>

- ***<u>Insufficient enforcement tools:</u>*** The ISO Market Monitoring and Information Protocols (MMIP) allow the ISO to identify questionable practices and market-power abuses, there are no explicit penalties/sanctions.
- ***<u>Information withholding:</u>*** The ISO has been denied site or records access to gather information it considers necessary to make the above determinations.
- ***<u>Recommend both code of conduct and streamlined investigative process</u>*** for potential violations and penalties/sanctions assessment.

  > <u>Code of conduct:</u> See the list of sanctionable behavior in <u>Appendix 2</u>.

  > <u>Streamlined investigative procedure:</u> Would contain opportunity to reply and appeals process.

- ***<u>Monetary sanctions</u>***
  > Based on the market impact of the infraction.

- CEO should have the power to triple the penalty if it relates to market power mitigation measures.
- Must be larger than incremental profit from sanctioned behavior.

- ***Other allowed enforcement actions should include:***
  - Mitigation of bid prices (e.g., adjustment to some "predetermined level");
  - Exclusion of bids from the market, and forced submission of bids "when participants have inappropriately withheld bids from the market;"
  - Publication of violations, market power abuse, gaming, and "other anomalous activities;" and
  - Reports to FERC and other regulatory agencies, with requests for additional sanctions.

ISO PROPOSED BILATERAL CONTRACT REPORTING REQUIREMENTS (verbatim)

1. General Contract Information Requirements

a. Contract Type – whether the transaction in an Internal Transaction (i.e., between the LSE and another division of the same parent company) or External Transaction

b. Contract Parties – named seller and buyer to the transaction and all affiliations

c. Market Products – energy and/or ancillary services

d. Contract Duration – the start date and time and end date and time for the transaction.

2. Contract Detail Information

a. Asset Contract Details – the name of a specific generator or load asset and the percentage of that asset that is being sold or purchased in the transaction

b. Contract Price and Quantity Information

- ***Price*** – the prices that are applicable to the relevant market product quantities submitted for the transaction
- ***Quantity*** – the MW amount or percentage entitlement representing the availability of the contract for the transaction

c. Must-take portion of the contract

d. Dispatch Information

3. **Schedule Information** – The schedule information consists of data related to the transmission reservations and operational tagging requirements associated with the transaction.

4. Non-Standard Contract Provisions

a. High Operating Limit
b. Low Operating Limit
c. Ramp Rate
d. Minimum Run Time
e. Start Time from Hot Conditions
f. Start Time from Cold Conditions
g. Minimum Down Time

5. **Any Pre-Determined Conditions** – conditions that determines the extent to which a contracted product is available to the buyer in any given period.

SANCTIONABLE BEHAVIOR UNDER ISO PROPOSED CODE OF CONDUCT (verbatim)

1) Failure to perform in markets, such as the failure to provide energy, services, or respond to dispatch instructions;

2) Failure by market participants to provide requested data and information, or refusal of ISO inspection at any participating generating facility;

3) Abuse of market power through physical withholding and economic withholding and abuse of locational market power beyond the limits set in the market power mitigation plan;

4) Activities of gaming the market rules, i.e., take advantage of market rules to engage in bidding, scheduling and operation activities that seek profit or other self-interest for the market participant but result in significant damage and cost to the overall market or other market participants; Due to the complexity of gaming and unpredictability, not all sanctionable gaming behavior can be all specified in advance. The Department of Market Analysis will conduct inquires and investigations, allow for response the market participant being investigated, issue warnings to market participants, and bring violations to the CEO and ISO Board who would have authority to levy penalize violation including publication of the violation.

5) Inaccurate Bid or Operating Information such as the understatement of a units high operating limit, misrepresentation regarding operating conditions, or the misrepresentation of resource availability; and

6) Failure to follow ISO instructions such as the failure to follow scheduling procedures, transmission instructions, or information.

KNOW THE ISO EVENT REPORT

FERC Technical Conference on California Market Power Monitoring and Mitigation

Proposals from Parties other than the ISO

January 23rd, 2000

This report summarizes the proposals from non-ISO parties for monitoring/mitigation of market power in California after expiration of the $150 "soft cap" structure on May 1st.

The proposals were prepared for discussion at the technical conference on this issue, ordered in the December 15th FERC decision (Docket Nos. EL00-95-000, et al) ("Order") and held on January 23rd. The purpose of the conference was to provide information to the FERC staff, which must file a proposal with FERC for revised rules by March 1st.

The complete proposals, along with the ISO's, are posted on the FERC Web site at http://www.ferc.fed.us/electric/bulkpower_comments.htm. Three parties besides the ISO submitted proposals:

- **Southern California Edison** ("SCE");
- **Reliant Energy** ("Reliant"); and
- **Electric Power Supply Association** ("EPSA"), a group of "competitive generators, power marketers and other suppliers."

The ISO's proposal, along with background information on the current structure, can be found in the ***January 19th/22nd DMA Market Power Mitigation Proposal Event Report.***

Overview

Not surprisingly, SCE's proposal was closer to the ISO's in content, while the two generator-issued proposals substantially agreed with each other. SCE believes that prices above variable cost are strong evidence of market-power, while the generator parties argued that factors such as opportunity cost and scarcity value should be considered.

Both SCE and EPSA agreed that the entity responsible for monitoring market power should be entirely separate from the ISO. They disagreed, though, on:

- What this entity should monitor; and
- Whether it should have mitigation/enforcement authority *(or whether all such action should be referred to FERC, or other appropriate authorities).*

SCE proposal

Primary position: Cost-based rates should be re-instituted for all generators, because supply/demand fundamentals will keep the market dysfunctional for several years.

- **Application:** Should apply to term contracts and spot-market sales.
- **Basis:** Cost of production, i.e., should guard against "daisy chains" and price justifications based on cost of last transaction.

Secondary position: Implement the changes described below, plus "other fundamental changes to market rules" necessary to yield just and reasonable rates.

Market monitoring entity: Overall characteristics should include:

- **Independence:** Should be completely separate from the ISO or Cal-PX.
- **Resources:** Should be adequate, including:
  - Full-time staff; and
  - Immediate access to all ISO/PX market information.
- **Scope of authority:** Should include, for ISO and Cal-PX markets:
  - Monitoring/investigating all operational and bid data;
  - Monitoring MW amounts controlled by parties through bilateral contracts;
  - Mitigating potential abuses prior to running markets, e.g., rejecting above-cost bids or preventing bids from certain units from setting market-clearing prices;
  - Mitigating possible abuses after markets are run, e.g., re-running markets and/or re-calculating prices after ex-post review;
  - Penalizing parties that have abused the market, including possible participant-specific market rules and/or trading restrictions; and
  - Changing market rules on an emergency basis, subject to later FERC review.

Penalties for market-power abuse: Should be high enough to:

- **Retract any profits** derived from the abuse;
- **Deter future abuses**; and
- **Compensate for harm to the market as a whole**, e.g., if the abuse raised the market-clearing price to loads, the penalty should cover at least the entire dollar amount of the increment, not just the share received by the abusing party.

Markets to be monitored

- **Electricity/electricity transportation** (transmission);
- **Gas/gas transportation** (as the variable cost for generation units at the margin);
- **Markets for other variable costs** (e.g., emissions); and
- **Ancillary Services.**

Electricity/electricity transportation market elements to be monitored

- **Unit bid prices relative to variable production costs** ***(not to include opportunity or fixed costs)***: Bids more than a "threshold" amount above variable cost should be mitigated or rejected.

- **Significant variations in bid prices from a single unit** "should be identified as an attempt to manipulate market prices," e.g., variations:

    - **In a single time period:** For example, bidding different portions of a unit's generation in the same hour bid at different prices;

    - **At different times, without corresponding changes in costs:** For example, bidding higher prices when a particular transmission line is de-rated;

    - **In the same time period in sequential markets** (i.e., day-ahead energy, transmission congestion relief, and real-time energy).

- **Lack of economic production:** Absence of bids, or reduction in capacity bid, when market prices exceed unit costs.

- **"Ricochet" sales:"** On a unit basis, electricity schedules as an out-of-state export and then sold back into the state in a later sequential auction.

- **Firm Transmission Rights (FTR) ownership**, on a path-by-path basis.

- **Systematic schedule changes:** "Should be investigated as a potential manipulation of energy and/or congestion markets;" for example, systematic:
    - Submittal of Day Ahead schedules that are withdrawn Hour Ahead; and/or
    - Submittal of schedules for transactions that are never delivered on.

- **Total electric capacity/energy controlled by a party through bilateral agreements**, e.g.:
    - With title to the electricity; or
    - Other control, such as scheduling, dispatch, or bidding.

Gas/gas transportation market elements to be monitored

- Ownership of gas transportation;
- Prices "at the source of production;"
- Difference between source price and delivered price to California (i.e., implied transportation price); and
- Participant-specific ownership and use of gas storage.

Other variable-cost markets to be monitored *(emissions were example given)*

- **Problems determining cost basis:** There is "no definitive method" to translate the cost of South Coast NOx emissions into costs of production because:

- **The market is illiquid** and relatively non-transparent; and
- **The program has complex rules,** including:
  - ***Annual emission credit allocation*** at "no added cost to the generator;" and
  - ***Provisions for borrowing credits*** against future allocations.

- **Enforcement actions can consists of a mix** of required actions and penalty prices.

- **Special rule where input prices can't be accurately assessed:** Might be desirable to prohibit bids from those units from setting the market-clearing price *(though they could still receive that price if they bid lower).*

- **Elements to be monitored**
  - Allocation of NOx and other emission credits;
  - Monthly consumption of emission credits;
  - Purchases and sales of emission credits, and transaction prices;
  - "Other unit-specific restrictions related to emissions;" and
  - "Other difficult-to-quantify costs" with a "significant" impact on unit production cost or availability.

Reliant proposal

Guiding principles

- **Standards to identify anti-competitive behavior**, by buyers or sellers, must be ***clearly identified*** and ***consistently applied.***

- **In assessing market power**, FERC should:
  - **Apply established antitrust standards, focusing on generation, load, and transmission market concentration levels.** Reliance on differences between price and hourly short-run marginal costs is inappropriate for determining market power because it doesn't account for:
    - Capacity value and scarcity rents;
    - Start-up and low-load costs ***[e.g., higher fuel use per kWh at lower load levels]***;
    - Opportunity costs; and
    - Risk premiums *(e.g., credit, liquidated damages, gas price volatility).*

  - **Explicitly identify, and propose specific remedies/milestones for, key factors adversely affecting market performance,** including:
    - Flaws in market structure and rules;
    - Barriers to entry; and

- Supply/demand imbalance conditions.

> **Analyze price levels combined with individual bidding behavior:** Focus on improving transparency and eliminating specific anti-competitive behavior, not on broad measures to mitigate "possible" market power that dampen/eliminate price signals to the market.

- **Oversight/enforcement of market rules should take place through a structure that ensures:**
  - Thorough, independent analysis of market performance and alleged misconduct;
  - Due process for market participants; and
  - Independent decision-making.

Implementation of these principles

- **Market monitoring unit (MMU) role:** Should be limited to:
  - Performing market analysis and reporting on the state of the markets;
  - Reviewing allegations of market misconduct; and
  - Making recommendations to the ISO/RTO Board ("Board") on:
    - *Improving market efficiency*, e.g., correcting market design flaws; and
    - *Addressing alleged misconduct* by individual market participants.

- **Proposed oversight/enforcement process**
  - **The MMU should make available, for review and critique, the aggregate data and analysis on which its studies and recommendations are based.** This requirement should also apply to any other entity proposing recommendations to the Board.
  - **The MMU should be required to "engage in discussions" with market participants** before submitting recommendations to the Board.
  - **Market participants should be allowed to present their own analyses and recommendations**, with equal standing before the Board.
  - **If the Board determines that misconduct has occurred, the matter should be referred to FERC** for determination of appropriate remedies.
  - **Market participants should have the right to appeal the Board's findings** to FERC.

EPSA proposal

Background

- **High prices aren't proof of anti-competitive behavior** but may reflect market fundamentals, such as:
  - ➢ **Supply scarcity**;
  - ➢ **High demand growth** over a short time period; or
  - ➢ **High variable costs.**

  If so, the price signals to the market are accurate and shouldn't be artificially adjusted.

- **Standards to identify/remedy anti-competitive behavior** in California should be:
  - ➢ ***Clearly stated*** and ***consistently applied***; and
  - ➢ Fundamentally the same as those applied elsewhere.

- **Propose 3 levels of market power assessment**
  - ➢ First-level assessment: **Identify "anomalous" market rules and recommend changes to improve market efficiency.**
    - ■ Apply traditional antitrust standards to generation and transmission market concentration levels and barriers to entry;
    - ■ Consider effects of specific market rules *(e.g., for loads, mandatory use of spot markets and prohibition against risk management, such as forward contracting)*; and
    - ■ Examine ability of end-users or their agents to respond quickly to commodity price signals.
  - ➢ Second-level assessment: **Review of market prices.**
    These can legitimately be above or below hourly marginal cost for a variety of legitimate reasons, e.g.:
    - ■ *Capacity/scarcity value*
      - Must be reflected in order to attract new investment and incent economic load curtailment; and
      - Varies as generation and load "get out of balance"
    - ■ *Opportunity cost*, i.e., opportunity to sell:
      - In another geographic market;
      - In the same geographic market but at another time with higher prices *(for units with limits on operating hours)*;
      - In another product market *(e.g., ancillary services vs. energy)*; and/or

- Another product *(e.g., sell gas or emission credits, rather than use them to generate).*

■ ***Risk management***, i.e., physical and financial commitments "made in the face of uncertainty."

➢ **Third-level assessment: Consideration of specific indicators that market-power abuse has occurred.**

■ ***Indicators:*** For example, those listed by FERC in the December 15th decision could be used:

- Outage rates of seller's resources;
- Failure to bid unsold MWs into the real-time market; and
- Variations in bidding patterns for the same or similar resources.

To support this monitoring/assessment, accurate unit outage reports should be required and should be subject to audit.

■ ***Legitimate occurrences:*** Sometimes these are legitimate behaviors, and standards should be defined differentiating those situations from real market-power abuse. For example, units might not bid in a particular hour because of:

- Limits on total operating hours;
- Limits on fuel or hydroelectric resources;
- Need to hedge against possible real-time outages of other units; and/or
- Maintenance requirements.

Market monitoring logistics

- **Independence of the monitoring entity:** Should be independent of the ISO.

- **Role of the monitoring entity:** Should have the authority to:

  ➢ **Investigate behavior and recommend remedies**, with enforcement left to FERC and the Department of Justice.

  ➢ **Identify and recommend rule changes** to improve market efficiency.

- **Process:** The entity's analyses should be transparent, and parties accused of abuse should have an opportunity to address the allegations.

- **Significance of market monitoring:** Should decline over time, as most buying/selling will likely occur through "voluntary, negotiated bilateral contracts."

KNOW THE ISO SPECIAL REPORT

Forward-Market Under-Scheduling (CMR)
ISO Board Conference Call
August 25th, 2000

At the request of ISO CEO Terry Winter, the ISO Board held a conference call meeting to consider an ISO Management request for approval of a tariff filing to address the increasing amounts of load/generation under-scheduling in the forward markets.

The ISO's definition of "under-scheduling" is simply final Hour-Ahead schedules that are significantly below Real-Time loads on the ISO system. (There's no judgment about bidding strategies and the like, just a focus on the end result.) Typically, the under-scheduling is worse in the Day Ahead market, then some more load and matching generation is scheduled in the Hour Ahead market.

A certain amount of under-scheduling, especially when the weather is hotter than normal, is due to normal forecast error. However, the ISO has seen increasing amounts and proportion of load moving into real time without a schedule, up to 15-16,000 MW. It's had to scramble, sometimes literally an hour before, to secure supplies through Out-of-Market (OOM) calls to neighboring Control Areas.

According to Terry, this situation has:

- **Jeopardized system reliability**, by forcing the ISO to divert Operating Reserves, causing WSCC violations and leaving the system more vulnerable to damage or collapse;

- **Placed an enormous amount of stress on ISO personnel**, and upon those in adjacent Control Areas (where limits on the number of Real Time transactions that can physically be processed are being reached); and

- **Forced the ISO to incur costs** that are then allocated to parties not responsible for this behavior.

Requested tariff amendment

Management asked the Board for approval of two tariff amendments:

1. **<u>Mandatory forward-market scheduling:</u>** Require Scheduling Coordinators (SCs) to schedule at least 90% of their actual loads in the Day Ahead market, and at least 95% in the Hour Ahead markets, for each zone and each settlement period. *(Settlement*

periods are 1 hour now and will be 10 minutes after the September 1st implementation of 10-Minute Settlements).

Terry Winter comment: I've heard some complaints that the generation just isn't bidding into the market, but if I can find it, you (load-serving SCs) can find it. Moreover, the implementation of 10-Minute Settlements should push more generation into the forward markets. *(10-Minute Settlements will set lower payments for uninstructed/unscheduled energy.)*

(Consultant note: **There were no penalties proposed for violations of this provision, but that was the implied next step if violations are widespread.)**

2. **Cost allocation to under-schedulers:** Allocate to SCs, in proportion to their deviations from scheduled loads, the costs that the ISO incurs for OOM supplies to serve the loads.

Terry Winter comment: The current allocation mechanism is totally unfair to the several SCs that do bid in all their loads and generation.

(Consultant note: **Currently, under-scheduled load is charged the Imbalance Energy price plus an allocation of a portion of Replacement Reserve. OOM costs (more correctly, the difference between OOM prices and Imbalance Energy prices) are allocated proportionally to all loads; this amendment would change that allocation to assign this cost directly to the under-schedulers.)**

Why this action is requested

Terry said it's necessary to sign longer-term agreements to obtain supplies, as utilities have traditionally done (and much of the western markets still do), in order to guarantee reliable supplies for California. ("I am at the end of the food chain, and trying to do 1-2 hour contracts with everyone else tied up in advance.")

He characterized much of the recent decline in imports, and the increase in energy exports (see below), as generators seeking price/revenue certainty. He said that those generators are willing to sign such contracts with California parties but find no takers for such arrangements. ("That 6-8,000 MW of power from outside California that we rely on isn't coming here because no one is tying it up in the long term.")

He stated that the choice was between forcing the entities responsible for load to procure the right amount of supplies for it in the forward markets (as utilities have traditionally done, and as the proposed tariff amendments would require), or have the ISO undertake such activity. He believes that having the ISO take a position like that in the markets would be contrary to the ISO's mission, and an activity it's not well-suited to perform (though FERC has given indications that it may be receptive).

In addition, though there aren't penalties proposed for the mandatory scheduling provision, Terry wants to send a message to the SCs and other entities responsible for load that summer 2001 will be worse than this summer, and they should start now to line up sufficient supplies to meet their needs.

In the end, the Board was not able to pass a motion granting Management's request, so no action was authorized.

Background information

Information provided to the Board

To set the stage for the conversation, Terry Winter sent out to the Board, and discussed briefly, several statistics illustrating the problem. Here's a summary of that information.

	YEAR		
MARKET PERFORMANCE MEASURE	**1998**	***1999***	**2000**
Percent of load unscheduled *(June 1st, August 15th (weekdays, peak hours, loads>38,000MW))*			
- Maximum Day Ahead %	19%	20%	30%
- Maximum Hour Ahead %	13%	11%	29%
WSCC operating reserve violations, June-Aug.	6	18	39
OOM calls, MWh for June-Aug.	N/A	3,200	160,000
IOU interruptible load program activation			
- Number of interruptions	2	1	12
- MWh curtailed	2,300	1,200	13,000
Emergencies declared			
- Stage 1	8	4	22
- Stage 2	4	1	14

The memo to the Board also included graphics showing that exports from California to other Control Areas, during peak load hours with loads above 40,000 MW, have increased greatly, and net energy imports are down significantly during those times.

Why it's rational for Investor-Owned Utility loads to refrain from scheduling forward

IOU loads are required to purchase generation to meet all their scheduled loads from the Power Exchange (PX). In the PX, demand bids from the utilities and others are matched with supply bids from generators and traders, and the price in each hour at which supply matches demand (Market-Clearing Price, or MCP) is paid by the loads and received by the generators.

A very large proportion of the generation that's bid into the PX comes in with a "zero" price – in other words, it's bid as a price-taker and willing to accept whatever the MCP turns out to be. This is typically because these generators are compensated outside the PX through other mechanisms and just need to make sure that they're scheduled to run.

(Some examples are nuclear, run-of-the-river hydro, QF units, and RMR units paid the contract price.)

Consequently, there's a relatively thin market in the PX for generation that's actually price-sensitive. This situation has been exacerbated by the divestiture of the utility generating units, which were previously required to sell all their generation through bids into the PX. The new owners may use a different SC than the PX *(e.g., arranging a bilateral transaction and scheduling themselves, since most of the large generators are certified as SCs).*

This supply-market thinness can result in a situation, especially when demand is high, when the price curve for supply above zero is relatively steep, i.e., a relatively small reduction in demand will lower the MCP dramatically.

The utilities study these price curves closely and know that scheduling less than their full forecasted load can reduce the MCP, the price applicable to the load that is scheduled (even now, the large majority of the load). Though they may be subjected to higher prices by the ISO for unscheduled load that must be served through Imbalance Energy in Real Time, the net savings can be dramatic.

Why it's rational for generators to behave this way

A certain portion of the generation market is generating without schedules because of their internal sales/operating practices. They may hold a portion of their generation out of the forward market as "backup units," to protect themselves against high Imbalance Energy charges they might incur if units they do schedule suffer forced outages or other operating problems.

These owners run the reserve units without a schedule in Real Time and receive the ISO Imbalance Energy price for doing so. As Terry mentioned, though, the implementation of 10-Minute Settlements will reduce the incentive for this behavior by reducing the price paid for such "Uninstructed Deviations."

Another aspect of the problem, from the utilities' perspective, is not that the units might operate without a schedule, but that the units simply aren't bid into the PX any more (and, therefore, the supply isn't accessible to the utilities), e.g., because they're scheduled:

- In-state, for a bilateral transaction through another SC; and/or
- For exports, to realize higher prices in another state or take advantage of a longer-term sales contract opportunity.

Public comment

SDG&E:

- Whatever you say, the ISO is still obligated to cover loads in Real Time. We don't see a reliability issue here - schedules are just "something on a piece of paper."

- This proposal would just paper over things and make this a forecasting game – what does "90% of load" mean, anyway?

- This would lock loads into higher-cost markets if the forward-market prices were less than the (real-time) Imbalance Energy prices.

  ISO response: Yes, but that wouldn't preclude you from forward contracting. *(SDG&E has been much criticized for not seeking the opportunities to forward-contract for supplies that PG&E and SCE have, and for not fully utilizing the authority it has, to mitigate the market volatility this summer.)*

Power Exchange (PX):

- We support efforts to get load into the DA market, but just a rules change without any economic incentives to comply won't do much.

- September may be warm, but summer 2000 is almost over, and it would be a shame for the Board to do something precipitous without determining if it will really fix the problem.

California Municipal Utilities Association (CMUA): Munis are very supportive of these scheduling and cost allocation proposals, but we're concerned about:

- The timing (especially with respect to FERC approvals);
- How the proposals mesh together; and
- Whether requiring 90-95% forward scheduling gives enough allowance for simple forecasting error, especially in hotter areas.

Sacramento Municipal Utilities District (SMUD): We agree that there needs to be some way to not punish the innocent, but we generally support these proposals.

Board discussion

All the Board members "attending" the meeting and commenting on the Management proposals expressed sympathy, empathy, understanding, admiration, etc. for the ISO Staff and its present situation. However, the Board was split between those who felt the proposals were:

- Unfair to loads;
- Maybe the right direction, but premature; and
- The right thing to do right now.

Here's a sample of the comments in each category.

The proposals are unfair to loads

Governor Hapner (PG&E):

- We think that this is a sledgehammer that you want to use, without having tried other tools.

- This would increase prices hugely, and we'd see them reach the $2,500/MW *[current PX]* cap – that's $85 million an hour – and the PX price cap won't be lowered to $350 *[per a recent PX Board vote and filing at FERC]* until FERC approves it.

- If this passes, PG&E would have no other option than to make an immediate filing to ask the CPUC and the legislature for permission to participate as an individual buyer/seller in the market, outside the PX. If you want to kill the PX, and I'm not sure that wouldn't be a good thing, this would be the way to do it.

- We could then schedule our own generation first for our own load - though that was not the intent in restructuring – to protect our customers.

- You're taking advantage of the one group - loads - that you can control. Maybe this would work with same rules on both generation and load, but this is half the solution.

- We do schedule our entire load, but the supply's just not there.

<u>Governor Fielder (SCE):</u>

- I agree with Dede (Hapner), this will not solve the problem - it'll just raise prices to $2,500, then keep them stuck at $350 after that's approved.

- If this passes, we'll just schedule our load and utility-owned generation through our utility-owned SC. *[SCE and PG&E have such entities to schedule for their muni/governmental transmission contracts that predate the ISO]*.

- We can't "find" the generation in the forward market if it won't bid into the PX, because right now we have to use the PX. We need an incentive for generation to show up in the PX market, or prices will be astronomical.

- The onus here shouldn't just be on the loads to fix the problem.

<u>Governor Florio (TURN – consumer advocacy organization):</u> This proposal would punish the victims of *[generator]* market power for being victims. I might support it if you change "loads" in the proposed resolution to "generation," i.e., require generation to schedule their energy in the forward markets.

<u>Governor Woychik (Strategy Integration, a consulting company that often represents TURN, along with UCAN (another consumer organization):</u> I don't think that this will work without mandatory bidding requirements for generation, like in PJM.

<u>These proposals are premature</u>

<u>Governor Kehrein (EMS Consulting, a company that often works for commercial/induatrial end-users):</u>

- We should try to get the market signals right before changing the rules without understanding the implications – there are always repercussions to that.

- I think it's premature – we need to consider fixing gaming that we can do something about, like "energy laundering." *[Known also as "ping-pong" schedules, this is the alleged practice of exporting generation outside California, then selling it back to the ISO through an OOM call when supplies are tight and the ISO is willing to pay high prices.]*

This is the right thing to do

Governor Barkovich (Barkovich and Yap, a consulting firm that often works for large industrial end-users):

- I have been recommending something like this for a couple of months now.

- It's appropriate to discipline the market, and I do see this as a reliability issue.

- A high degree of OOM activity also causes problems in developing real markets.

- Even if you could require all in-state generation to bid, you still wouldn't have enough when the demand is high, and I don't know how you could force out-of-state generators to bid.

- The utilities need to be honest – they may be "scheduling" their entire load, but they only offer to pay so much, and the load that doesn't clear at that price gets deferred to Real Time.

Governor Parquet (Enron):

- These proposals don't have a lot of teeth, but they have some teeth.

- Don't know that I agree with the "doom and glooms" - people can still under-schedule, but they will bear the consequences – I support this.

Governor Blue (Dynegy):

- We also support this – when we first started discussing price caps, I said that load under-scheduling is a major problem, and it still is.

- I understand that a big IOU problem with forward contracting is after-the-fact review by the PUC *[otherwise known as "Reasonableness Review, where the CPUC conducts an annual (but lagged) review of utility operations and purchase practices and may disallow certain expenditures as not "just and reasonable"].* Is there anything that the ISO can do to help them out?

  ISO Management response: ***We think that maybe the IOUs suggested that the ISO go out and contract for these supplies to exempt them from that CPUC review.***

The Board failed by a margin of one vote (12-6, with 13 votes needed to pass a motion) to adopt the Management proposal.

One last issue – Adjustment Bids on firm loads

There was one more issue in the ISO memo to the Board. However, since it wasn't a voting item, it doesn't really relate to the above activities and wasn't discussed after being mentioned by Terry Winter at the start of the meeting.

Explanation of Adjustment Bids

Adjustment bids are used by the ISO in the forward markets to resolve congestion across transmission paths. SCs can bid a price to the ISO to "increment" (increase) generation on the side of the congestion where there's not enough generation, and "decrement" (reduce) it on the side where there's too much generation, so balance is restored on both sides of the congested path.

The ISO calls on these bids in merit order, starting with the lowest-priced bids. The price of the last bid exercised (the market-clearing price for resolving the congestion) is charged to all transactions across the congested transmission path in the congested direction.

Loads can and do participate in the Adjustment Bids market. An SC can substitute a decrement to load for an increment to generation on the generation-short side of the congestion, and/or substitute an increment to load for a decrement to generation on the generation-surplus side.

The behavior bothering the ISO

Apparently, however, some large entities representing loads are submitting Adjustment Bids on firm loads, and at attractive (even negative) prices. They then are complaining that the ISO's congestion management software is taking their loads out of the forward market, and they have no choice but to serve it in Real Time with no forward schedule.

In this way, the entities responsible for serving the loads can legitimately claim that they are scheduling all their loads but still get the benefits of reducing demand (and prices) in the PX (which applies to the large portion of their load that is billed at those prices).

However, this causes a problem for the ISO when the congestion management software selects the Adjustment Bid with the firm load supposedly offering to decrement, thinking that the congestion across the transmission path the bid applies to is resolved. Of course, there was never any intent to curtail this load, and it shows up in full force in Real Time, forcing the ISO into real-time re-dispatch to adjust for it and exacerbating the above-described stresses on the system and the system operators.

Possible consequences?

Upon discovering this behavior, Terry Winter confronted the entities involved and asked how they could justify it, given the system problems. He said that they told him "we do it because we can" (in other words, because it's the economically rational thing to do).

Terry said that, through the upcoming Comprehensive Market Redesign (CMR) changes, "we will try to come up with some way to stop that behavior." It clearly colored Terry's view of the proper remedies to the under-scheduling problem, reducing any natural sympathy he might have had for the load-serving entities' arguments.

PHOENIX CONSULTING
A California Limited Liability Company
For subscription information, please call (916) 797-3106, or e-mail schneider@rsvi.net

KNOW THE ISO EVENT REPORT

September ISO Board Meeting
Part 1: Issues Voted on by the Board
September 7th, 2000

BOARD DECISIONS:

- *Election of new Municipal Utilities class ISO Governor:* Established election procedures to replace Governor Marcie Edwards, who resigned;
- ISO market price cap extension: Accepted Management recommendation to: (1) Request that FERC extend the ISO's current authority to impose caps; and (2) Extend the $250/MW price cap beyond the current October 15th expiration date;
- Neutrality Adjustment price cap: Approved increase from $0.095/Mwh to $0.35/Mwh, and directed staff to proceed with cost-allocation changes;
- Grid Management Charge unbundling: Approved tariff proposed by the staff to file previously-approved rate structure with FERC;
- 2001-3 LARS/RMR selections: Approved most of Management's proposed list of unit designations and generation/transmission/demand-side bids, including use of the Market Generation methodology in the Western LA Basin;
- RMR Pre-Dispatch Enhancement proposals: Accepted Management recommendation for changes coming out of the stakeholder process;
- ISO Articles of Incorporation amendments: Approved amendments to qualify for state property tax exemption, saving about $300K/year;
- Transmission Control Agreement (TCA) amendments: Approved clarifying amendments recommended by the Maintenance Coordination Committee (MCC);
- New ISO Maintenance Procedures: Approved addition of 3 new procedures recommended by the MCC; and
- *Scheduling Coordinator Annual Meter Data Self-Audit "Lessons Learned" Report:* Accepted staff report for April 1, 1998-June 30, 1999 period.

Overview of this month's ISO Board Event Report

The ISO Board and committees meet almost every month, over roughly a 2-day period. The monthly Board Event Report is usually distributed in 2 parts, but this month there are 3:

- ***Part 1A (this document),*** which covers ***all Board votes except those relating to Comprehensive Market Redesign (CMR)***;

- ***Part 1B,*** to be issued in a day or two, which (because of its importance) will cover separately the ***Board votes relating to CMR***; and

- ***Part 2,*** to be issued a day or two after Part 1B, which will cover ***Management status reports and other non-decision discussion items***.

The ISO presentations and reports are posted on the ISO Web site at www.caiso.com/pubinfo/BOG/documents (unless another location is specified).

The text of the Board motions can be found at: http://www1.caiso.com/pubinfo/BOG/documents/motions/index.cgi?b=20000907/Board.

Election of new Municipal Utilities class ISO governor

Governor Marcie Edwards of the Los Angeles Department of Water and Power (LADWP) submitted a letter of resignation, effective September 7th.

There were many expressions of regret about Governor Edwards' resignation, from ISO CEO Terry Winter and several other governors. She was widely viewed as one of the most knowledgeable and effective governors, in general and in her critical role as Chair of the Grid Operations/Reliability Committee of the Board.

Governor Dede Hapner (PG&E) was appointed Vice Chair of the Grid Ops committee and will chair the meetings for the time being.

The Board established October 9th as the "record date" by which entities wishing to vote in the Municipal Utilities class for a new governor must register with the ISO. LADWP served notice that it will nominate LADWP Executive Director David Freeman, as a candidate for the seat.

ISO market price cap extension

Background

There were two price-cap-related issues discussed at the Board meeting:

- **The ISO's current authority to set price caps:** The current authority expires on November 15th. Because of the 60-day period typically required for FERC review of any filing for extension, the filing must be made by September 15th.

- **The level of the price cap before November 15th:** The Board resolution in August lowering the ISO price cap to $250/MWh contained an expiration date of October 15th, so the level of the cap between October 15th and November 15th is unclear. ***(You can find that resolution in Appendix 1.)***

Management proposal
Though a number of different options have been considered over the last several months, Management simply proposed here to:

- Request extension of the current FERC authority to impose price caps by removing the November 15th, 2000 expiration date from the ISO tariff;

- Extend the current $250/MWh price cap level to November 15th, 2000, and to the beginning of summer 2001 if the requested authority is granted by FERC; and

- Require Management to report to the Board no later than March 31st, 2001 with the following:
    - Timetable for implementation of market reforms to reduce or eliminate the need for price caps; and
    - Recommendation regarding the need for/level of price caps for summer 2001.

Sources of background information
There have been four previous discussions on long-term price cap policy by the Board and the Market Surveillance Committee (MSC), documented in these ***KNOW THE ISO*** reports:
- ***August 9th Market Issues Forum (MIF) Event Report***, pp.5-7, and p. 12 on the FERC's decision on the Morgan Stanley complaint;
- ***July 24th MSC meeting Event Report***, pp.4-10;
- ***June Board meetings Event Report, Part 2***, pp.3-5; and
- ***June 30th MSC meeting Event Report***, pp.8-9.

Board discussion
Generally, with all the recent controversies around this issue, most of the Governors seemed weary of talking about it, and/or gun-shy. There were a few interesting remarks/exchanges during the discussion:

Governor Blue: Is there any thought as to an end date? Will we ask for indefinite authority?
Management response:* *It would be indefinite unless there's a subsequent Board motion.

Governor Blue: Didn't FERC require some kind report justifying an extension?
Management response:* *The filing will be based on previous FERC rulings, including the decision on the Morgan Stanley complaint. That decision characterized the ISO's price caps as simply a buyer's choice of how much it will pay, not a cap on the entire market (i.e., if sellers don't like it, they don't have to sell to the ISO). The ISO has the inherent right, like any other buyer, to decide what it's willing to pay.

We will also include reports by the DMA and the MSC justifying our request.

Governor Blue: I've heard forecasts that winter gas prices might reach $15-20/MMBtu at the California border. If we continue the $250 price cap, operating costs alone could exceed $250, wouldn't the CEO or the Board have to do something?

Governor Kirschner: Sure, we'll just pass a motion to lower gas prices! ***(much laughter)***

...

Governor Woychik: You've proposed a very suitable substitute for bid caps in the Comprehensive Market Redesign process (bid caps and possible unit availability requirements) - why were these not considered, instead of an extension of what you have already?

Management response: ***We haven't ruled that out, but we probably couldn't get that proposal developed and implemented by November 15th. It's still an option for the 3/31 report, though (i.e., summer 2001 implementation).***

Governor Roscoe: I agree, we should just leave things alone – we've done as much damage by discussing it as by changing it – let's get out of this subject.

Governor Cotton: I encourage you to do some work between now and March to come up with some more flexible price cap designs. All generation is not created equal, and we should think about a tiered system that recognizes differences between peaking, off-peak, and base-load generation.

Board vote

After an unsuccessful effort by Governor Woychik to lower the price cap to $100/MWh, the Board voted 21-1 to approve extending the current $250/MWh price cap to November 15th.

The Board approved a second motion (19-2, with 1 abstention) to request post-November 15th price cap authority from FERC, and to direct the report in the Management proposal.

Neutrality Adjustment price cap

Background

The ISO is a "revenue-neutral" entity, i.e., SC payments to the ISO must equal ISO payments to the SCs. The Neutrality Adjustment, allocated proportional to loads, was created to account for what were expected to be minor imbalances between payments and charges for market services, to allow the ISO to stay in balance overall.

The most common imbalances occur with the following ISO charge types:

- Ex-Post Ancillary Services Energy & Supplemental Energy charges;
- Generation Deviation charges;
- Load Deviation charges;
- Export Deviation charges;
- Import Deviation charge; and
- Unaccounted-for Energy (UFE).

More recently, other costs were added for recovery through the Neutrality Adjustment, including the following (with the first two constituting the largest components of the charge recently):

- ***Out-of-Market purchases by the ISO from other Control Areas*** (ISO costs in excess of the system Market Clearing Price (MCP) used to settle load/generation deviations);
- ***Real-time inter-zonal congestion costs*** (differences between the prices paid by loads, were the deviations can be on one side of an unexpectedly congested transmission path, and prices paid to generators, which may be on the other side of the congestion);

  ***(Consultant notes**: I think the second item is at least partly the result of one problem discussed in the August 25th ISO Board conference call (see the Event Report), where:*

  - *Some "large load-serving entities" are placing large decremental bids (offers to curtail loads on the generation-short side of a congested transmission interface) on firm loads, at attractive prices;*
  - *The bids are accepted by the ISO's congestion management software in the forward scheduling process, on the assumption that the load will be curtailed and the congestion will be relieved;*
  - *The load is not curtailed but shows up in Real Time, and the congestion "unexpectedly" is still there; and*
  - *The ISO then has to scramble to re-dispatch resources in Real Time to keep the system in balance, causing the zonal price differences (between both sides of the now-congested transmission path) which cause this cost item.)*

- ***Existing Contract charge exemptions*** (Existing Contracts are agreements in effect before creation, and the entities holding them are exempt from certain charges); and
- ***Participating Load summer demand program capacity payments.***

Beginning in May 2000, ISO tariff Amendment 27 placed a limit of \$0.095/Mwh on the Neutrality Adjustment. The tariff provides for Board review and revision of the charge for a "defined period," with 7 days notice to SCs required for any change.

Management stated that the intent of the tariff language was that this would be an annual limit, though this was not stated explicitly. However:

- The maximum level was exceeded for 5 of the first 6 months of 2000 (though the recent reduction of ISO price caps is expected to moderate the charge in the near future); and

- The lack of specificity for application of the threshold has caused some SCs to dispute charges that exceed that level, even on a ***daily*** basis.

Thus, Management recommended:

- Raising the limit to $0.35/Mwh, just above the January-June 2000 average, for the September 15, 2000 through January 15th, 2001 period;

- Giving SCs the required 7 day's notice for the change; and

- Continuing to explore methods to assure that future costs are allocated to the SCs which are responsible for them (e.g., allocating above-market OOM costs to SCs who deviate from their schedules, the reason why the OOM purchases are made).

(Consultant note: These changes wouldn't address the issue of whether the per-Mwh charge should apply on a daily, monthly, or (as the ISO stated) annual basis. The ISO mentioned that this would be fixed in an "October cleanup filing," possibly a reference to what was a ISO quarterly tariff filing that consolidated non-major tariff changes. However, no draft language or other information has been made available about such a filing.)

Public comment at the meeting

> City of Riverside (municipal utility)

- We realized with the June billings that the tariff level was being exceeded by a significant amount.

- We've been slightly overscheduled, but we're still getting allocated OOM costs in the Neutrality Adjustment that should be the responsibility of the SCs who are under-scheduling. It's been almost $1 million since ISO start-up.

- If you're going to increase the charge, you should act quickly to stop this cost-shifting, or provide for us to get our money back later.

> California Municipal Utilities Association (CMUA): This is not just an issue for Riverside, or for munis – we'd like some certainty on a timeline for fixing this problem, and a plan for what will happen if the timeline is lengthened later.

Board discussion

This issue was discussed in both the Finance and Market Issues/ADR Committees. Most of the Board members agreed that the cost allocation formula should be changed, and that there should be more definite language requiring those changes.

However, cost-allocation changes will require tariff changes, which require filings at FERC and FERC approval. The ISO tariff allows the cap-level increase without FERC approval, and it was clear that Management was in a rough spot with respect to settlements that probably couldn't wait for a FERC decision (minimum of 60 days after a filing is made) to be resolved.

Board vote

The Board granted Management's request for the increase, but it strengthened the language directing pursuit of cost-allocation changes to reduce the Neutrality Adjustment and assign the costs to the SCs responsible. Specifically, Management was instructed to "pursue the following actions and implement as appropriate:"

- Allocate above-market OOM costs to SCs proportional to "deviations from their schedules;"

  (<u>Consultant note</u>: I assume that this will apply to load that's greater than scheduled and generation that's less than scheduled, since these would be the actions that would leave the ISO short of supplies in Real Time and require OOM calls, and not just to <u>any</u> schedule deviations.)

- If feasible, allocate the costs incurred to resolve real-time inter-zonal congestion to "deviations, regardless of the zonal location of the deviations;" and

  (<u>Consultant note</u>: I assume that this is aimed primarily at the decremental load issue discussed above.)

- Report back to the board no later then the first quarter of 2001 on the progress made on the above items.

The motion passed on a 20-1 vote, with 1 abstention.

Grid Management Charge (GMC) unbundling tariff filing

<u>Background</u>

The Grid Management Charge is the fee, currently assessed proportionally to loads, that covers the cost to run the ISO. At the June Board meeting, the Board approved a proposal to unbundled the GMC into three components:

- <u>Control Area Services</u> *(45% of ISO costs)*, assessed proportionally to "gross" loads (i.e., including "behind the meter" loads of munis and retail loads with on-site generation) and exports in the ISO Control Area;

- <u>Congestion Management</u> *(7% of ISO costs)*, based on "net scheduled inter-zonal power flows" (excluding Existing Contract transactions, those which pre-date the creation of the ISO); and

- <u>Market Operations</u> *(48% of ISO costs)*, based on purchases and sales (both instructed and uninstructed) of Ancillary Services, Supplemental Energy, and Imbalance Energy.

At this meeting, the Board considered the actual tariff language proposed by Management to file at FERC in order to implement the June decision. The filing is planned for October 31st, for rates effective January 1st, 2001.

Sources of background information

- For a complete description of the new GMC rate design, and the Board discussion when it was adopted (including controversy over charging loads served by on-site generation), see the *June Board meeting Event Report, Part 1*, pp. 4-8; and
- For a further discussion of ISO policies with respect to loads served by on-site generation, see the *August 25th Distributed Generation Event Report.*

Public comment at the meeting

The Public Comment all centered on the requirement that the loads served by on-site generation be assessed the Control-Area Services portion of the GMC. A corollary issue was the analogy between these loads and municipal utility loads served "behind the interconnection meter" (i.e., with generation inside the muni service area) with respect to the assessment of this charge.

California Association of Cogenerators/Energy Producers and Users Coalition (CAC/EPUC)

Policy arguments

- The ISO staff policy to reach behind the meter and allocate ISO system costs is destructive to the ISO's goals to keep generating units on the system, and to bring more units on the system.
- ISO consideration of QF issues has been fragmented –you need to consider the collective impact of the ISO GMC, Transmission Access Charge (TAC), scheduling, metering, and Ancillary Services policies.
- Your policies will cause distributed generation to disconnect from the ISO Grid entirely. ***(Example cited: 20 MW generator, 2 MW of Auxilliary power use (e.g., lighting for generation facilities), 16MW serves on-site loads, and 2 MW of excess generation to sell into the grid. It would cost this generator an additional $625,000 annually to connect to the grid and sell that additional 2 MW. It would be much more economic for the generator to disconnect from the grid entirely and not sell the extra power. CAC/EPUC said that the numbers were "even more impressive" for larger generators.)***
- The proposed assessment assumes that the entire load will be scheduled on the ISO system even though it may never be, and pretends that the generation is scheduled on the system even though it's not.

Legal arguments

- QF loads are not like muni loads served through their own generation. QFs have a unique statutory framework and beneficial fuel-efficiency characteristics, and their systems behind the meter are typically radial systems, vs. muni network systems.

- The proposed assessment is unduly discriminatory, because it charges loads served by on-site generation to use the ISO Grid even when it's not, while loads not so served are only charged when they actually use the ISO grid.

- Reversing the assessment policy would conform the ISO position to the newly enacted state legislation disfavoring measures that discourage interconnection of cogeneration and self-generation with ISO Grid, and would recognize PURPA and state policy favoring fuel-efficiency and self-sufficiency (Section 218 of the PUC code).

Operational arguments

- This generation was built with the belief that the load served on-site was deemed not to be firm load on the system, and the WSCC has ratified that past practice as appropriate. The ISO doesn't need to buy reserves for it, and neither does anyone else.

- If the load has contracted for standby service with the local utility, it's already purchasing reserves *[yes, this seems to contradict the above point]* – the utility has the obligation to have wires and generation for that load when necessary, and they are doing it today by contracting with the ISO. There's less than a 4 percent likelihood that this generation will be out of service.

- The proposed assessment to behind-the-meter loads ignores integrated operation of on-site generation and load, as if they can be separated (which often they cannot).

California Municipal Utilities Association (CMUA)

- We're extremely supportive of the hard ISO staff work on this issue, and a lot of progress has been made.

- We don't necessarily disagree with CAC/EPUC about the benefits to the grid of behind-the-meter generation and the inequity of assessing loads served by it for ISO grid operations costs.

- Unlike the loads discussed by CAC/EPUC, some muni loads that would be assessed the Grid Operations Charge can't even be physically served using the ISO Grid.

- Many of the things the QFs point to, we can too, like the California constitution, federal law, and FERC rulings.

- However, we oppose cherry-picking the GMC consensus position, and this proposal to treat loads served by behind-the-meter generation (some of which are bigger than some munis) differently from muni loads that are similarly situated.

- Maybe as a potential compromise, you could lower the percentage of the GMC that's allocated to control-area services, and therefore billed on a "gross load" basis. That could be factually supported, and you could state that it's not precedental issue with respect to operating reserves and other issues that are bigger dollars.

Question from Governor Florio: Where would you re-allocate the costs?

CMUA response: To scheduling and other items related to congestion management – it's the smallest cost "bucket," and with the likely change to more zones through the Comprehensive Market Redesign effort, that might be appropriate.

ISO staff response to CAC/EPUC

- Our understanding about WSCC regulations regarding behind-the-meter generation/load isn't the same as CAC/EPUC's – we consider it to be firm load.
- The Board considered the CAC/EPUC issues in June, and those decisions shouldn't be changed.
- All loads benefit from ISO control-area services, no matter how they're served.
- The existing policy does treat all loads treated the same, and the change wouldn't – it would result in unfair cost-shifting.
- Unlike transmission charges, ISO/GMC costs are new costs not covered in standby rates, and the PTOs aren't providing control-area services any more.
- FERC has accepted gross load as a billing determinant for the TAC, and rejected the arguments about behind-the-meter loads.

Board discussion

Governor Barkovich *(who has closely followed the stakeholder process on this issue)*

- The vote today is on the GMC only, not the TAC and these other issues.
- The debate is around Control Area services only, not the whole GMC.
- Everyone benefits from the ISO and its provision of services.
- "Painstaking" doesn't begin to describe the technical work done in this area, and I'm surprised at the suggestion that it be undone at this late date given the amount of stakeholder input we've had.

Governor Roscoe

- This is the most troubling vote I've cast on the Board. I'm troubled by the ongoing philosophical shift with respect to load. We need to address the core issue, not just each piece, one at a time, in isolation.
- I have a paper plant that, under this scheme, would pay $1 million more a year (for the GMC and other cost items the ISO is trying to charge to "gross" load), so I haven't hooked up to the grid.
- This issue will cause guerilla warfare in the CPUC distributed generation proceeding.

Governor Kehrein

- Restructuring has changed the balance of benefits and burdens for many groups, but we hope that all in the long run will get some additional value.
- I agree with CMA and the ISO staff – we can't treat some loads different from others.

<u>Governor Ingwers</u> (new Governor, from SMUD): How will Management measure QF load behind the meter?

<u>Management response:</u> We're still working on that. We might use the same demand that the IOUs use for billing standby charges. The QFs have said they won't provide the information except to comply with a court order.

<u>Governor Florio:</u> How much money are we talking about on the GMC issue?

<u>Management response:</u> Control Area services are 45% of ISO costs, and QFs are about 2-4% of gross loads, so it's about 1-2% of ISO costs.

<u>Governor Florio:</u> What are the services that fall in this bucket?

<u>Management response:</u> They include operational studies, system security analyses, system planning, integration activities with other Control Areas, scheduling, and emergency planning.

<u>Governor Florio:</u> I'm prepared to vote for this, but we need to look at it in a broad context, not piecemeal. We already have a stakeholder process started *[presumably, a reference to the distributed generation meeting on August 25th]* – if we could have something resolved by November, I'd be more comfortable supporting this now. We also need to pursue the operating reserve issue with the WSCC.

<u>Management response:</u> We will probably be done with the stakeholder process by November.

<u>ISO Board Chair Smutny-Jones</u> *<u>(Executive Director of the Independent Energy Producers Association (IEP))</u>*<u>:</u> The QFs vs. munis issue reminds me of the similarity between cows and mice: they've both got 4 legs and that's it. Chevron [large cogenerator] doesn't have the right to sell retail service, and *[LADWP Executive Director]* Freeman isn't a QF. I've been very frustrated by this argument.

<u>Board vote:</u> The Board passed the Management proposal without amendment on a 15-1 vote, with 6 abstentions.

2001-3 LARS/RMR selections

<u>Background</u>

RMR units are those required by the ISO in a transmission-constrained local area (RMR Area) whose operation would be required to maintain reliable service to loads in the event of major facility (generation and/or transmission) outages. RMR units receive 12-month contracts from the ISO that cover a portion of their fixed costs, in return for making the unit available to the ISO whenever it's needed.

Originally, the ISO just designated units that were to receive RMR contracts. Now, the ISO looks at competitive alternatives before making an RMR award. That competitive process (termed the Local Areas Reliability Services, or LARS, process) provides for the selection of either existing RMR generation units, or proposed generation, transmission, or demand-side alternatives that can more competitively substitute for them.

The process is as follows:

1. The RMR Technical Study identifies the reliability needs in transmission-constrained local "RMR areas" (11 total);

2. The ISO screening process (shown in Appendix 2) removes ineligible units from the list;

3. The competitive solicitation invites bids from generation, transmission, and load management projects to replace RMR contracts; and, for the first time

4. The Market Generation analysis, applied this year on a pilot basis in the Western LA Basin, determines the local capacity that's competitive enough to be generating when local reliability needs are likely to be greatest, and subtracts that capacity from the area LARS/RMR contract need.

   The Western LA Basin analysis showed that one of the 5 units identified as needed for reliability reasons could be safely eliminated (for an annual savings of $3.4 million), with minimal risk of above-market cost incurrence if the unit has to be called out-of-market or out-of-sequence.

Here's a summary of the Management recommendation:

	# RMR units		# RMR MWs		Annual Fixed Payment ($MM)*	
PTO service area	2000	2001	2000	2001	2000	2001
PG&E	59	84	6,825	7,237	$239.8	$184.2
SCE	4	4	855	1,070	7.1	7.6
SDG&E	28	31	1,969	2,089	35.5	30.1
TOTAL	***91***	***119***	***9,649***	***10,486***	***$282.4***	***$231.9***
Change 2000-2001	***28 units***		***837 MW***		***-$50.5 million***	

**** Workpapers not provided; assumes some unspecified savings (about $80 million annually, offset partly by increased costs from adding units) due to application of a recent FERC decision regarding Southern Company.***

Sources of background information

ISO LARS/RMR information is in the following locations on the ISO Web site:

- ***RMR Technical Study*** (showing the capacity needs for each RMR area), and ***LARS/RMR meeting documents***:
  http://www.caiso.com/thegrid/planning/rmr/rmrstudy2001-3/;
- ***2001-2003 May 2nd LARS/RMR Request for Bids***:
  http://www.caiso.com/clientserv.lars.html;
- ***List of units selected***:
  http://www.caiso.com/docs/2000/08/17/2000081707274414038.pdf.
- ***Description of the bids received, and the LARS/RMR selections*** by geographic area:
  - **PG&E northern area:**
    http://www.caiso.com/docs/2000/08/17/2000081707242213527.pdf;
  - **PG&E Greater Bay Area, Stockton, and Fresno area:**
    http://www.caiso.com/docs/2000/08/17/2000081707252213954.pdf;
  - **SCE service area:**
    http://www.caiso.com/docs/2000/08/17/2000081707260413990.pdf; and
  - **SDG&E service area:**
    http://www.caiso.com/docs/2000/08/17/2000081707264614013.pdf.

The following *KNOW THE ISO* reports contain information about this process:

- ***August 21st LARS/RMR Event Report***: Summary of ISO staff recommendation by RMR area, and details of Market Generation application to the Western LA Basin area;
- ***May 3rd LARS/RMR Event Report***: Discussion of policy issues and preliminary results of the Market Generation methodology;
- ***April 11th LARS/RMR Event Report***: Specific steps for the Market Generation methodology, and stakeholder concerns about it;
- ***March Board Meetings Event Report, Part 1***, pp.6-7: ISO Board discussion when it adopted the RMR Technical Study;
- ***March 9th LARS/RMR Event Report***: Update of January 25th information and basics of the Market Generation methodology; and
- ***January 25th LARS/RMR Event Report***: History of the RMR process and description of RMR study methodology.

Public comment – written comments submitted before the meeting, and oral comments at the meeting

Southern California Edison (SCE)

- We support the ISO's recommendation for the Los Angeles Basin and approval of the transmission project for that area (re-conductoring 16 miles of 230kV lines and adding shunt capacitors, to be operational on January 1, 2002).
- The transmission project, and the Market Generation analysis, eliminate the need for LARS/RMR contracts in the basin beginning in 2002, and changes will be needed in the operating protocols for that area as a result.
- SCE questions some of the ISO's decisions to designate RMR units in small "load pockets." WSCC/NERC Reliability Criteria permit the controlled interruption of loads in local areas as long as it doesn't impact the overall security of the interconnected system. The costs to go beyond these criteria should be compared to the benefits before a decision is made.
- The ISO should be more open about its financial analysis methodology, e.g., how it decided that some transmission projects were preferred over some generation projects while others weren't.

Pacific Gas and Electric Company (PG&E)

- ***RMR Selection of West Point Powerhouse in the Mokelume Watershed:*** PG&E had submitted an RMR bid for the entire Mokelume Watershed. Normally, because of the interconnected operations of hydroelectric facilities in the same watershed, designation of one powerhouse in the watershed requires designation of all the others in the watershed. However, West Point uniquely can provide the reliability services without designation of the other units in the watershed, and PG&E agrees to this, provided that:
  - It doesn't set a precedent for other hydro facilities; and
  - The contract terms won't be restricted by the bid submitted, since the costs and operating factors may be different for the single unit than those included in the watershed bid. *(These parameters for the one unit alone aren't yet determined.)*
- ***RMR options for the Greater Bay Area (GBA):*** The selection of RMR units for the GBA was complicated by uncertainties regarding the on-line dates of several new generation and transmission resources. In particular, the operational date for the 540-MW Los Medanos Energy Center (LMEC) is a critical factor.

  PG&E is concerned about the scenario the ISO staff's recommended scenario, which assumes that LMEC is not operational by June 2001, requiring one Moss Landing unit to be under RMR contract in 2001. PG&E is concerned that this scenario will result in double payment for GBA RMR protection in 2001, since the longer-term RMR agreement between the ISO and LMEC requires the ISO to begin payments when it comes on line, even if another unit has already been designated to meet the local RMR need for that year.

  Since there will be no contracts in effect with Moss Landing at that point, there is no need to make a decision by October 1st (renewal date for effective RMR contracts). Therefore, the ISO should wait before designating a Moss Landing unit as RMR for

2001 until better information is available about on-line dates for LMEC and other transmission and generation projects in the area.

- ***Lodi Combustion Turbine:*** PG&E's proposed Lodi 60 kV Line Upgrade Project will eliminate the need for an RMR agreement with the City of Lodi's CT unit. At the 122-MW NCPA forecast for Lodi, the RMR agreement would not be needed.

(Consultant note: The ISO's analysis shows the opposite – that the Lodi CT RMR agreement would be needed with Lodi loads at 122 MW.)

- ***Inclusion of units with doubtful reliability provision capabilities:*** The ISO included, in its list of designated RMR units, several units that PG&E considers unable to provide the reliability services due to operational and other limitations, including:
  - **Humboldt area:** The ISO list shows three units not bid into the LARS/RMR process, with any two of the three required by the ISO; however, two of the units are currently not operating (Simpson Pulp and Blue Lake), and the other (LP Samoa) is used solely to meet on-site loads. None have Participating Generator Agreements with the ISO, and the ISO has no cost information.
  - **Cow Creek Watershed:** Four PG&E hydro units were designated as RMR units, even though their aggregate capacity doesn't meet the current 10 MW minimum RMR threshold and they're run-of-the-river plants, i.e., not dispatchable to meet area reliability needs.
  - **South Yuba Watershed:** Six PG&E hydro units were designated as RMR units, even though they're not hydrologically linked and don't individually meet the 10 MW minimum RMR threshold.

Northern California Power Agency (NCPA): We're concerned about the possibility that the RMR contract for the Lodi CT might not be renewed. We've been trying to get transmission upgrades to the City of Lodi for some time, and we're not sure they'll be in place for 2001. Even if they are, we're not sure that they'll even solve the entire problem.

SDG&E *(remarks targeted in particular at designation of 3 new San Diego-area 40-MW peaking plants as additional RMR units)*: The RMR contract decision for the new units should be deferred because:

- The ISO's summer 2001 RFB (for 3,000 MW statewide, with San Diego as one of the primary target areas) is still in progress and might reveal more economic alternatives than the new units. The RFB responses will only take another month.
- There's considerable uncertainty in San Diego peak loads due to price elasticity effects (from pass-through of market prices) "and the related slowdown in business expansion."

- Signing the recommended new RMR contracts would exacerbate the current difficult situation in San Diego by adding $5-15 million to costs.

Board discussion

Governor Barkovich: Is there any solid analysis behind the price elasticity argument for SDG&E?

SDG&E response: ***Looking at load growth, and the 40 MW of interruptible load we have, with the greater awareness of electricity prices we're expecting 200-300MW of load reduction next summer.***

Governor Hapner: We agree with ISO staff not to enter into multi-year contracts – there are a lot of changing assumptions beyond 2001.

There was a lengthy discussion regarding the Humboldt units, new CTs in various areas (e.g., Greater Bay Area, San Diego) and other units with uncertain on-line dates or other operating viability issues. The ISO staff asked that the Board designate these units as RMR candidates despite the uncertainty, but the staff intends to require that plants demonstrate that they are financially viable and can provide the necessary operating capability before signing a contract. *(The RMR agreements also have non-performance penalties.)*

Because these units aren't now under RMR contracts, the October 1st RMR contract renewal deadline isn't an issue, and more time can be taken to work out the details.

The ISO staff considered all options submitted in the LARS solicitation and chose the options that it felt would address the local reliability needs. Given that most of the questionable plants had no realistic local alternative, the ISO might simply be short of its needs in those areas if the plants aren't available or don't perform as required. However, in most cases, the local deficiencies wouldn't be much worse than in 2000.

Board vote

By a vote of 15-6, with 2 abstentions, the Board adopted the Management recommendation regarding transmission projects and RMR unit choices, but deferring the following decisions:

- Designation of two of the three questioned Humboldt units "until more information is forthcoming;"
- Designation of the Lodi CT "pending opinion of the ISO counsel after discussions with PG&E and NCPA (which must reach agreement under pre-ISO contract arrangements before the RMR agreement is extended);

  (Consultant note: Because the Lodi CT is currently under contract, the decision on the Lodi CT must be made by the October 1st RMR contract renewal deadline for the following year.)

- Designation of the three new RMR candidates in San Diego until the October 4th Board meeting (when the summer 2001 RFB decisions will also be made).

RMR Pre-Dispatch Enhancement proposals

Background

Reliability Must-Run (RMR) generation units are those deemed by the ISO to be critical to maintaining reliable service in local, transmission-constrained areas. These units receive a portion of their costs from the ISO in return for making their units available upon request.

Why pre-dispatch was implemented: Before pre-dispatch, the ISO would wait until it saw the final Day-Ahead market schedules to issue dispatch orders to RMR units not already scheduled in the market but needed to run the next day for reliability reasons. However, since Day-Ahead schedules contain balanced loads and resources, any subsequent dispatch of RMR generation could cause generation to exceed loads, so the ISO had to back down other generation units to "make room" for the additional RMR generation.

How pre-dispatch works now: Before the Day Ahead schedule submission deadline, the ISO determines which RMR units are needed to run for the next day, based on its load forecast and local conditions. The ISO issues the needed RMR units Day Ahead (DA) dispatch notices, with specified hourly dispatch levels for the next day. The RMR generators' Scheduling Coordinators (RMR SCs) are then responsible for submitting the required generation as part of their balanced schedules for the next day.

The ISO can also issue Supplemental Notices during the day changing dispatch instructions received the previous day. *(The revised dispatch level must be reflected through Hour Ahead (HA) schedule changes if the notice comes at least 2 hours before the change takes effect).*

Pricing options: After receiving dispatch notices, the RMR SCs can choose one of two pricing "paths:"

- *Contract Path:* The RMR SCs bid as a price-taker ($0 bid) into the PX DA market, and receive the payment specified in the RMR contract from the ISO, and refund the energy payment from the PX to the ISO;
- *Market Path:* The RMR SCs schedule in the DA market as they wish (market bid into the PX or APX, bilateral contract, etc) and keep the revenues from that market transaction instead of being paid the contract price by the ISO; if they are not successful in the DA market, they then must bid $0 or schedule a bilateral deal in their HA schedules.

Management recommended two changes to the current system:

- *Give RMR Owners increased pricing option election ability, by permitting:*
    - ***Different Market/Contract Path price elections*** for Pre-Dispatched RMR energy and energy later dispatched through a Supplemental Notice; and
    - ***Splitting of energy ordered by the ISO in a single dispatch instruction*** between Market and Contract Path options.

***Reason for recommendation:* Additional flexibility for the Owner to elect the Market Option would reduce the payments under the contract, and their increased participation in the market will increase competition (and, presumably, lower prices).**

- ***Penalize RMR Owners if unscheduled energy is not delivered***, by an amount equal to the net savings from not generating, i.e., the difference between: (a) the fuel cost savings from not generating; and (b) the loss of the Availability Payment (the non-performance penalty under the RMR contract).

  ***Reason for recommendation:* Remove perverse incentive, if the pre-dispatched generation is not scheduled for some reason and fuel costs are high, to not deliver the energy (and cause a local reliability problem).**

In addition, ISO Management stated that it plans to do the following (which don't require Board approval):

- Unilaterally restate the RMR contract contract capacity: If the capacity in the RMR contract is higher than the certified maximum for the unit, the ISO will issue a "notice to restate capacity." This would lower the RMR contract amounts to the unit certified values until the unit is retested or delivers energy at the higher level.

- Work with other parties to improve invoice template change procedures.

Sources of background information

ISO Documents related to RMR pre-dispatch can be found on the ISO Web page at the following locations:

- ***January 28th Amendment 26 (RMR Pre-Dispatch) filing:*** www.caiso.com/pubinfo/FERC/filings/;
- ***March 31st FERC order approving Amendment 26:*** www.caiso.com/pubinfo/FERC/rulings/;
- ***May 1st ISO compliance filing:*** www.caiso.com/pubinfo/FERC/filings/; and

The following ***KNOW THE ISO*** reports contain information on the pre-dispatch enhancement stakeholder process, and the invoice template change issues:

- ***August 14th RMR Pre-Dispatch Enhancement Event Report***;
- ***July 27th RMR Pre-Dispatch Enhancement Event Report***; and
- ***July 11th RMR Pre-Dispatch Enhancement Event Report***.

Public comment at the meeting

Southern California Edison (SCE): We urge you to reject the first two Management proposals, because:

- These issues were agreed upon in settlement at FERC, and to modify them apart from the rest of the settlement disrupts the balance of that settlement; and

- Generator concerns like this were addressed by FERC in its Amendment 26 (pre-dispatch ISO tariff language) decision last March.

Sempra *(SDG&E parent company)*

- The RMR Fixed Option Payment (FOP) was set higher to compensate owners for the risks of pre-dispatch, and the owners agreed not to seek additional compensation during the retail rate freeze period.
- This change would shift RMR unit owner risk to consumers without FOP reduction or other compensation.
- This change will cause significant settlements complications from the increased number of payment elections.
- FERC said that the Amendment 26 language is only temporary, pending CMR implementation, and CMR will reduce or eliminate RMR contracts.

Board discussion

Governor Woychik: I didn't see any consumer representation mentioned in the "stakeholder" meeting, or reflected in the memo.

***Management response:* That's right, but it was an open meeting and anyone could have attended.**

Governor Kehrein: I personally attended 2 of the 3 stakeholder meetings, and the CPUC *[Office of Ratepayer Advocates]* was very active and vocal on behalf of consumers - at times, I thought a fight might break out.

Governor Florio: I don't see why we should give the generators what they want.

***Management response:* It's good for us too – while we're sensitive to the arguments that settlement is a settlement, giving the RMR owners more opportunities to select the Market Path would lower RMR contract payments, increase market competition, and place the market risk on the owners.**

Governor Kehrein: A lot of these things are clean-up issues, and very reasonable. We would probably have said yes earlier if we'd been asked.

Governor Florio: As a matter of personal philosophy I agree, but I just hope that, if this passes, that some time in the future we get some reciprocity in another area.

Governor Cotton: We're dealing with FERC-jurisdictional contracts – why would the ISO even spend any ISO Management time on this? This isn't fine-tuning, it's changing the risk-cost relationship. If they want contract changes, their correct place of relief is FERC, not this Board.

Governor Woychik: I agree – it's inappropriate for ISO staff to intervene on an equity issue without a full statement of consumer impact.

Governor Kehrein: Some of this is coming from the anti-generator attitude that sometimes exists, and we have to separate ourselves from that.

Board vote: The Board approved the Management recommendation on a 16-1 vote, with 2 abstentions.

ISO Articles of Incorporation amendments

Background
The ISO applied earlier to the state Board of Equalization for an exemption from state property taxes. The application was rejected, but BOE staff advised the ISO that the exemption would be granted if certain changes were made to the ISO's Articles of Incorporation regarding the distribution of ISO assets upon any dissolution of the corporation.

Currently, the Articles provide for asset distribution (after payment of any obligations) to either:

- A state or local government for a public purpose; or
- "One or more exempt purposes" under Section 501(c)(3) of the Internal Revenue Code.

The required change would modify the second option to allow disbursement only to an organization or entity that has qualified for tax-free treatment under Section 501(c)(3).

The ISO estimates that the exempt status that this small change will save the ISO about $300,000 in taxes annually and possibly provide a retroactive refund of as much as $600,000 in "escrowed" funds.

Board discussion: None except a few "well, duh" type jokes.

Board vote: The Board approved the proposal, through the consent calendar.

Transmission Control Agreement (TCA) amendments (Appendix C)

Background
The MCC, with representation from the ISO, Participating Transmission Owners (PTOs), munis, labor interests, and others, is responsible for establishing, and monitoring and reporting PTO compliance with, transmission maintenance standards for ISO-Controlled Grid facilities.

The MCC has recommended (unanimously) several clarifying changes to the Transmission Control Agreement, the ISO-PTO contract governing the terms and conditions of the transfer of control to the ISO. The changes relate to Appendix C, which governs maintenance standards, and would:

- ***Provide for a separate high-voltage direct current (HVDC) class for maintenance and performance measurement purposes***, in addition to the current alternating current (AC) classes;

- ***Allow refinements in the statistical approach to measure availability of transmission line circuits***, to improve the consistency and accuracy of the transmission performance measurements; and

- ***Clarify in the ISO Maintenance Standards the respective ISO and PTO roles regarding safety***, including assigning responsibility for public and employee safety to the PTOs and providing that, in the event of a conflict between safety and reliability, that safety considerations shall take precedence.

After Board approval, Management would obtain official concurrence from the PTOs and make the necessary FERC filing.

Board discussion: None

Board vote: The Board approved the proposal, through the consent calendar.

ISO Maintenance Procedures amendments

Background
As with the proposed TCA amendments discussed above, the MCC unanimously recommended to the Board approval of 3 new ISO Maintenance procedures, to:

- ***Provide a detailed plan for implementing the transmission maintenance record-keeping and reporting provisions*** of the TCA;

- ***Define clearly which outages should be classified s as "forced," and provide guidelines for reporting*** such outages; and

- ***Establish performance criteria for PTO SCADA systems***, such as performance specifications for backup power sources.

The ISO would implement the changes by publishing them on the ISO Web site – no FERC filing is required.

Board discussion: none

Board vote: The Board approved the proposal, through the consent calendar.

Scheduling Coordinator Annual Meter Data Self-Audit "Lessons Learned" Report

Background
There are two sources of the generation and consumption meter data used in ISO settlements:

- *Meters read by the ISO directly*, mostly for large generators connected at transmission voltage that are active in the new energy/capacity markets; and

> ***Meter data reported to the ISO*** by Scheduling Coordinators (SCs).

Data submitted by SCs must be "Settlement Quality Meter Data" (SQMD), meeting certain procedural and accuracy standards. To ensure that the data are truly SQMD, the ISO tariff requires that SCs conduct an annual self-audit of their meter data processing systems.

This report covers the April 1, 1998-June 30, 1999 period. Twenty-two SCs participated (with others exempt because they don't report meter data to the ISO, e.g., because they only participate in the market through trades with other SCs).

Audit guidelines and a project timeline were developed through a cooperative stakeholder process. The auditing activities focused on identifying and correcting problems, so that, on a prospective basis, the data will meet SQMD standards.

The report found that fundamental controls exist for most SCs, and that the audit process itself helped the SCs focus their attention on their internal controls. The problems identified were corrected, and the information gained is being shared with SCs (to improve their future performance) and incorporated into training for new SCs.

The most common problems were related to data processing (as opposed to metering equipment or meter reading errors), such as:

- ***Lack of documentation*** for data processing procedures;
- ***Lack of knowledgeable back-up employees***; and
- ***Validation procedures not followed***, or validation tolerances set too high or too low.

The ISO Data Quality Group worked closely with the CPUC-sanctioned Data Quality and Integrity Working Group (DQIWG) in the audit effort and will do so in follow-up activities.

Board discussion (Audit Committee)

Governor Barkovich (Audit Committee Chair): I want to commend the ISO staff for the high degree of cooperation among audit participants. While this wasn't an easy issue, the quality of the data is paramount, and I'm pleased to see this level of attention to getting a system that really works.

Governor Kehrein: I agree – the ISO staff's helpful and positive attitude was the key to gaining the cooperation of SCs and retail Energy Service Providers (ESPs). It was also good to see the ISO working effectively with the CPUC staff.

Board vote: The Board accepted the staff report, through the consent calendar.

ADOPTED 8/1/00 ISO BOARD RESOLUTION ON ISO MARKET PRICE CAPS

Moved that: The Motion on Price Caps adopted June 28, 2000, shall be superseded by this resolution effective August 7, 2000. The ISO Board makes the following findings in support of the action set forth herein:

A. State officials and agencies have strongly urged that the ISO reduce the price cap applicable to the ISO markets to the lowest reasonable level in an effort to mitigate the effects of price spikes on ratepayers.

B. Absent the reforms described below, such reduction in the price cap will immediately increase the difficulty of ensuring electrical reliability in the state of California, will de-stabilize the markets for electrical power in California and may increase the occurrence of power interruptions throughout the state during periods of peak load, thereby harming ratepayers:

   1. Entities that schedule load should immediately apply for and use appropriate risk management tools, including use of medium and long term forward energy contracts as a means to mitigate price volatility on behalf of consumers.

   2. Generators should actively seek participation with loads in forward energy contracts as a means toward price stabilization for consumers. Furthermore, generators should bid all available capacity in existing markets, particularly during periods of high load.

   3. Regulatory agencies and/or the Legislature should:

      a. Remove constraints on hedging opportunities for UDCs.

      b. Remove constraints on participation by load in demand relief programs.

      c. Enable consumers to receive real time price information, through real time metering or other enabling technologies.

      d. Expedite, within a target period of one year, the approval of projects to build new generation and transmission facilities where needed within California.

C. The above reforms are viewed by the ISO to be essential to mitigate the near-term and long-term consequences of lowering the price cap as requested;

D. The ISO takes the action described below with the expectation that the identified risks to reliability will be mitigated through immediate implementation of the reforms described above.

Based on the foregoing findings, the ISO Board directs management as follows:

1. Temporarily to reduce caps in the ISO real-time, ancillary services, and congestion markets to $250, effective for the period August 7, 2000 to October 15, 2000, subject to the following:

    - Such reduced cap shall not apply to OOM calls placed by management to out-of-state generator resources.

    - Such reduced cap shall not apply to the energy payments in the Summer 2000 Demand Relief trial program currently in effect and shall not apply to any future demand relief programs which may be implemented.

2. Reduce its purchases of replacement reserves and cap capacity payments at $100.

3. Urge generators to bid and/or schedule in all of their capacity in periods of high demand.

4. Urge entities that schedule load to immediately apply for and use appropriate risk management tools, including use of medium and long term forward energy contracts as a means to mitigate price volatility on behalf of consumers.

5. Urge generators to actively seek participation with loads in forward energy contracts as a means toward price stabilization for consumers. Furthermore, generators should bid all available capacity in existing markets, particularly during periods of high load.

6. Explore alternative means for suppliers to recover their investments through some form of long-term payment.

7. To send a letter to the addressees identified below:

    Governor Gray Davis, State Senator Steve Peace, State Senator Debra Bowen, Assemblyman Roderick Wright, Michael Kahn, Chairman of the Electricity Oversight Board, and Loretta Lynch, President of the California Public Utilities Commission.

    Such letter shall advise them that action to reduce the price cap has been taken, shall further advise them of the findings set forth above and of the risks to reliability posed by the reduced price caps, and shall urge that they take immediate action on the reforms described above.

8. Develop and circulate to the Board and to the authorities identified above by August 11 a list of proposed "action items" that should be implemented as soon as possible in order to address the State's energy resource deficiencies; such list should include, among other items, the actions described above in paragraph 3, and: generation and transmission in constrained areas as well as other projects in front of the CEC that are non-controversial.

9. Deliver a report each month to the authorities identified above describing the progress of the responsible parties and/or agencies on each of the proposed action items.

LARS/RMR Unit Screening Process

All available generation units in a local area are not necessarily candidates to receive RMR contracts. The following types of units are excluded from RMR candidacy:

- **Qualifying Facilities (QFs), nuclear plants, and intermittent resources/run-of-the-river hydro generation** -- These "must-take" plants are excluded for the following reasons:
  - ***They operate under contracts with very strong economic incentives to be running at critical times*** (e.g., most) - no need to pay more when availability would likely be high already; or
  - ***They have no control over their output*** (e.g., run-of-the-river hydro plants and wind generators) - no need to pay more when additional financial incentives would not guarantee availability.
- **Municipal or governmental utility units covered by an Existing Contract,** many of which were already obligated to run under mutual-assistance agreements with Transmission Owners.
- **Units with capacity below 10MW,** which the ISO considers to be below the threshold for RMR administrative feasibility; however, these smaller units could become eligible for the 2001-2003 period if a bidder aggregates the units under a single contract.

PHOENIX CONSULTING
A California Limited Liability Company
For subscription information, please call (916) 797-3106, or e-mail schneider@rsvl.net

KNOW THE ISO SPECIAL REPORT

ISO Board Meeting

Part 2: Management Reports and Other Discussion Items

October 4, 2000

- *Summer 2001 Preparedness Update*
- Management Response to MSC June Price Spikes Opinion
- Comprehensive Market Redesign: Deferred Congestion Management Items
- Comprehensive Market Redesign: Global Issues
- RTO Update

Overview of this Special Report

This special meeting was originally added to the regular monthly Board schedule to address Comprehensive Market Redesign (CMR). Subsequent events caused this meeting to "morph" into a full-blown Board meeting.

The Board report for this meeting was divided into 3 parts:

- The lengthy discussion on price caps and generator market-power mitigation was covered in the ***KTISO Special Report*** earlier this week;
- The remaining voting items from the October 4th meeting were covered in Part 1 of the ***Event Report***, distributed Friday; and
- Management status reports and other discussion items are summarized in today's report.

Unless otherwise indicated, you can find complete copies of the ISO presentations and reports references here on the ISO Web site at www.caiso.com/pubinfo/BOG/documents.

Summer 2001 preparedness

Management will be reporting regularly to the Board on preparations for reliability-related activities in Summer 2001, reflecting widespread consensus that Summer 2000 activities might have gone smoother had they been planned further in advance.

Bill Wagner has been appointed ISO Project Manager for summer 2001 activities, and an internal team is already in place. They're working hard in several areas:

- ➢ <u>The California ISO Resource Action Plan</u>, submitted to the State Legislature on August 10th;
- ➢ <u>The August 24th Generation RFB</u>, to procure call rights on up to 3000 MW of generating capacity for summer 2001 and beyond; and
- ➢ <u>Cooperative activities with Air Quality Boards</u> and other governmental agencies regarding environmental and siting issues.

<u>California ISO Resource Action Plan</u>
This Plan is a compilation of ideas for transmission, generation, and demand-side resource enhancements that could potentially be on-line for summer 2001 and beyond, given the cooperation and leadership of California government and business leaders and government policy makers/agencies. It's posted on the ISO Web site at: <u>Http://www.caiso.com/docs/09003a6080/07/3f/09003a6080073f0f.pdf</u>.

Progress was reported in three areas:

- ➢ <u>Action Item #D-1 (State and Federal Facility Demand Curtailment):</u> This demand-side activity involves work with state and federal facilities for voluntary demand curtailment. One such effort in cooperation with the State Department of General Services resulted in a voluntary reduction of 180 MW on September 19th. *(The Action Plan states that "hundreds of MWs" of demand relief might ultimately be accessed through these kinds of programs.)*

- ➢ *<u>Action Item #D-6 (Expand ISO and Other Demand-Responsive Products):</u>* The ISO held the kick-off meeting for its summer 2001 demand response programs on September 20th. *(See the **September 20th Participating Loads Event Report** for more information.)* The planned schedule is as follows:

  - ***<u>Regional "design workshops:</u>"*** October 13th and 16th (SF and LA areas, respectively, with the same agenda for both – see your Phoenix Consulting ISO stakeholder meeting calendar);
  - ***<u>Discussion of "high level concepts:</u>"*** October 25th-26th Board meetings;
  - ***<u>Board decision on final Summer 2001 design:</u>*** November 29th-30th Board meetings (followed soon after issuance of a Request for Bids); and
  - ***<u>Board decisions on "procurement:</u>"*** In February.

- ➢ <u>Action Item #G-1 (Access Installed Capacity of QFs):</u> The ISO has begun discussions about securing QF capacity above contract limits for market participation. *(Many QFs were conservative about establishing contract capacity when they became operational and can produce at levels above that for various periods of time. The Action Plan estimates that up to 180 MW of generation might be available from those sources.)*

- **Action Item #G-13 (Otay Mesa Generation Project):** Received final determination of compliance from Air Quality Board.

- **Action Items #T-7 (SF Bay Area Import Projects) and T-8 (San Francisco and Northern SF Peninsula Transmission Projects):** Holding weekly discussions with PG&E about these transmission projects to ensure completion by June 2001.

Summer 2001 generation RFB

See update in *October 4th Board meetings Event Report, Part 1*, pp.2-6.

Cooperative action with Air Quality Boards and others

The ISO is working with the state Air Resource Board, local Boards, the CEC, the EPA, and others to coordinate environmental issues, such as expediting the approval/siting of new generating facilities and reducing operating constraints on the lowest-emission existing facilities.

Board Discussion

Concerning the ISO's Market Pilot demand response program

(program to allow aggregated and individual loads to participate in the ISO's Ancillary Services and Supplemental Energy programs with reduced technical requirements; a big reason for low participation was lack of CPUC approval of utility advice letters (about 3 months old) for IOU interruptible customers to participate)

- ***Chair Smutny-Jones:*** Where are we with the advice letters at the CPUC?

- ***Governor Barkovich:*** They're still not on the CPUC agenda – they're a little late for this summer.

- ***Jim Hendry, Advisor to CPUC President Loretta Lynch:*** We would like to get analytical support and results from the ISO. We're very unclear what part of this program was reliability and what part was price-responsiveness – it raised a lot more questions than it answered.

- ***Governor Barkovich:*** We were trying to do two things – through this bidding program (notoriously unsuccessful because the PUC refused to put it on the agenda), to expand the pool of bids and possibly lower prices. A second program (the Demand Responsiveness Program) was a straight reliability program.

  The existing IOU interruptible program will go away in only a year and a half, and there may be a lot of drop outs in November (when customers can decide whether they wish to continue for another year or not). We didn't learn much this summer from the bidding program because we couldn't get started without CPUC approval. I don't mean to sound rude, but a lot of bureaucratic wrangling at senior levels means that we won't have anything for next summer, either. We did get off to a late start this summer, and we can't afford to do that next year.

- ➢ ***Mr. Hendry:*** We're worried about overlap [between the IOU interruptible program and the ISO A/S and S/E program, i.e., paying twice for the same thing]. That's one reason why we're having an investigation into these programs. That rulemaking is the forum to coordinate this.

Concerning work with air quality authorities

- ➢ ***Governor Florio:*** I urge very strong coordination with the air quality authorities – everything I see makes me think that there's a very high probability of Stage 3 alerts *[<1.5% reserves, rolling blackouts]* next summer, and then backup generators will kick on all over the place, and lots of those things run on diesel. We need a program to use the cleaner ones, in least environmentally harmful way, to avoid Stage 3. This can help both reliability and air quality.

- ➢ ***Governor Nix:*** There's a lot of very legitimate concern about air quality. We're (CEC) trying to identify the cleanest of the backup generators and try to establish protocols to avoid Stage 3 in an orderly way.

- ➢ ***ISO CEO Terry Winter:*** That would be great. If at all humanly possible, I would not be involved with the Air Board *[laughter]*, but we really have to start thinking about what it costs to drop someone off vs. what it costs to provide this service. We may very well run out of power next summer, and even doing everything possible, there's still a very high likelihood that this will happen anyway.

ISO Response to MSC Report of September 7, 2000

Background

At the September 7th Board meeting, Market Surveillance Committee (MSC) Chair Frank Wolak presented the results of the MSC's analysis of the June 2000 price spikes in the California energy and Ancillary Services markets. (See ***September Board Event Report, Part 2***, pp. 8-9.)

A Management response, prepared at the request of Chair Smutny-Jones' request, was included in the Board meeting materials (though it wasn't discussed by the Board at this meeting due to lack of time). Here's a summary of the Management reply:

- **Under-scheduling of loads and generation: Increasing ISO Replacement Reserve purchases to cover in Real Time, and allocating the cost to under-scheduled load and over-scheduled generation**

  - ➢ MSC position - These actions have:
    - ■ Acted as an implicit tax on shifting loads out of the PX markets into Real Time, possibly increasing prices in both the PX and Real Time markets.

- Increased incentives for generation under-scheduling by making Real Time prices more attractive.

> **Management position:**
> - The cost allocation method was intended to incent loads back in to the PX markets by making under-scheduling more expensive; however, the incentive has been less effective in combination with ISO market price caps.
> - Management agrees with the MSC generation incentive conclusions.
> - In conclusion, Management agrees with the basic MSC conclusion that the Replacement Reserve activities may have had adverse impacts and is "evaluating possible alternatives, including the recent MSC recommendations."

- **Out-of-market (OOM) payment mechanism:** In January, the ISO implemented a new payment option for generators called Out of Market (OOM), i.e., when they have no bids in the market. Before that, those generators were paid the ISO Ex-Post price, basically the real-time market price. The new option provides for payment of verifiable start-up and gas imbalance costs, as well as a capacity and energy charge component.

  > **MSC position:** The MSC believes that the new payment mechanism has increased the incentive for generators to withhold their generation from the forward markets in hopes of getting a higher OOM payment when called in Real Time by the ISO.

  > **Management response:** The new mechanism was established because, in many cases, the reason that those generators weren't in the market was because prices were lower than their running cost *(especially in lower-demand times like the Spring, when units are sometimes called OOM because an RMR unit in their area is out of service getting geared up for the summer season)*. Management doesn't fell justified asking units to run with payments that are below cost, and it's seen no strong evidence that the new payment mechanism was problematic during summer 2000.
  >
  > However, Management will consult with the MSC further to see if the mechanism can be improved.

- **10-minute settlements**

  > **MSC position:** Different prices are paid for different types of energy produced within the same time period, creating an incentive for suppliers to behave so that their energy is classified as the one with the higher price, with possible detrimental impacts on system reliability and price volatility. Instead, the ISO should return to a one-price mechanism, but with a 5-minute settlement interval.

  > **Management response:** The mechanism is designed so that generators who follow ISO instructions always receive the highest prices for "instructed energy" (i.e., following the ISO's dispatch instructions) rather than "uninstructed energy" (deviating

from schedule without an ISO instruction to do so). However, Management will look into the MSC's 5-minute settlement interval idea further.

- **PG&E hydro divestiture**

  - **MSC position** – The ISO-PG&E market power mitigation agreement is inadequate, and the divestiture should de delayed so that the ISO can reconsider this agreement. Specifically, the agreement:
    - Places too much focus on enhancing system reliability and not enough on market power concerns; and
    - Fails to guarantee that wholesale prices won't be adversely impacted by the transfer from PG&E (who has an incentive to keep prices low) to its affiliate (which would have an incentive to keep prices high).

  - **Management response** – The ISO-PG&E agreement:
    - Would reduce the ability of the PG&E affiliate to exert market power while minimizing the need for regulatory intervention and any reduction in the value of the hydro portfolio; and
    - Allows the ISO to seek additional protections if circumstances change or the agreement is determined to be otherwise ineffective in addressing market power.

Comprehensive Market Redesign (CMR): Deferred Congestion Management items

Background

The ISO's Comprehensive Market Redesign (CMR) process began earlier this year with "Congestion Management (CM) reform," the ISO's re-design of its methodology to resolve transmission path congestion in the forward markets and in "Real Time." CM Reform was ordered by FERC in an order issued earlier this year.

After many stakeholder meetings and different proposals over many months, ISO Management produced a broad CM proposal for consideration by the Board at the September 7th meeting. The ISO Board decided most of the CM issues at that meeting. However, decisions could not be reached in the following four critical areas ("Deferred CM Issues"):

- Local Reliability Service (LRS) issues;
- LRS cost allocation;
- Activity rule on congestion iteration; and
- Resolution of real-time congestion.

At the September 26th-27th CMR stakeholder meeting, Management presented what were characterized as new recommendations for several of these items. *(All the details of the "old" and "new" positions are in the* ***September 26th-27th CMR Event Report, Part 1.****)*

However, in the materials prepared for this Board meeting, Management backed away a bit from those new recommendations. Instead, Management prepared discussion papers on these issues that characterized its old and new positions as "options" about which it intends to make "final" recommendations to the Board at the October 25th-26th Board meetings. *(That's when decisions on these issues, as well as the* ***Global Issues*** *that constitute the second major category of CMR (see below) are scheduled to be made by the Board.)*

There was only a very limited amount of new information provided in the Board materials, and time constraints eliminated the Board discussion opportunity on these issues. The new information was in the fourth topic area, Resolution of Real-Time Congestion, as described below.

Resolution of Real-Time Congestion

Original proposal

- **Modeling:** The original Management proposal for real-time dispatch would use an Optimal Power Flow (OPF) model, in conjunction with the proposed Commercial Network Model (CNM), to manage Inter-Zonal Congestion.

- **Real-Time Congestion Management:** The ISO system operator would resolve congestion problems within LPAs (zones) outside of the ISO optimization program, by departing from the optimal (merit order by price) Imbalance Energy dispatch and paying resources called Out of Sequence (OOS) at their capped bid prices, rather than at the Market-Clearing Price in the LPA.

- **Cost Allocation:** Re-dispatch costs would be allocated as they are today: To all loads within the area (here, the LPA).

Potential problems: The potential problems with this approach were restated to as four:

1. **Different inter-zonal and intra-zonal solutions.**

2. **Cost allocation for real-time re-dispatch costs**
   - ***Original proposal:*** All loads in the LPA, like today's cost allocation;
   - ***Workshop proposal:*** Those deviating from schedules, causing the congestion.

3. **Effectiveness-factor dispersion:** As discussed at the Workshop, two of the newly defined LPAs, NP15 *(current NP15 zone (most of northern California), less several transmission-constrained "Local Reliability Areas")* and SP15 *(current SP15 zone (most of southern California), less several other LRAs)*, may contain generating units that are not equally effective in resolving congestion throughout each LPA. This equivalent Effectiveness Factors assumption in an LPA is fundamental to the

accuracy of the Commercial Network model and the proposed price averaging within the LPA.

One possible solution would be the creation of new LPAs from the two large NP15 and SP15 LPAs, with more uniform Effectiveness Factors within the new smaller areas, and that possibility was put back on the table here. The framework mentioned at the Workshop would have split NP15 and SP15, so that there would be 14 zones total in the ISO's Control Area, up from 11 in the original proposal.

4. Operator discretion to deviate from the OPF.

Potential options: The options laid out (with no recommendation yet) included:

(a) Original proposal;

(b) Original proposal, with real-time re-dispatch cost allocation to schedule deviators;

(c) Original proposal, with 14 LPAs instead of 11;

(d) Dispatch using Full Network (3000-bus) Model (FNM), but with loads and generation still facing LPA-averaged prices, as in the original proposal; and

(e) Dispatch using FNM and loads facing LPA-averaged prices, but with generators receiving nodal prices (i.e., reflecting their individual Effectiveness Factors – more critical if only 11 LPAs are used).

Here's how the Board materials evaluated the five options against the four main problems:

	POTENTIAL OPTION ADDRESSES PROBLEM?			
PROBLEM AREA	(a)	(b) & (c)	(d)	(e)
1. Different intra/inter soln.	No	No	Yes	Yes
2. Cost alloc. = causation	No	Yes	Yes	Yes
3. Eff. Factor/price accuracy	No	(b) No; (c) Slight	Yes	Yes
4. Minimize need to depart from OPF model	Yes	Yes	Yes	Yes

Comprehensive Market Redesign (CMR): Introduction of Global Issues

It became obvious, once the CM reform process was initiated earlier this year, that changes in CM methodology would affect features throughout the ISO structure. The "**Global Issues**" were added to form the broader CMR process. The Global Issues, as revised in the latest Management proposal, are:

1. Expanding supply capacity in California *(including New Facility Connection Policy (NFCP)*;
2. Market stratification *("product differentiation," i.e., facilitating a separate generation market for peaking resources)*;
3. Increasing accuracy and completeness of Forward Schedules, and reducing the volume of the Real-Time Market;
4. Mitigating Market Power;
5. Expanding transmission (i.e., Long-Term Grid Planning (LTGP)); and
6. Increasing demand responsiveness to hourly prices.

We used the new materials prepared for this Board meeting in reporting Management's Global Issues proposals to you (*see the **September 26th-27th CMR workshop Event Report, Part 2***), and there were no changes in position between the issuance of those materials and the end of the meeting. However, FYI, we report below some excerpts from the Management presentation and Board discussion that you might find interesting.

Source of the market problems

The ISO staff listed 7 primary problems that the CMR effort needs to address:

1. Tight generation and supply in California and the West;
2. Insufficient transmission capacity;
3. Inadequate price-responsiveness of demand;
4. Lack of market differentiation (e.g., peaking and baseload generation in the same markets);
5. Insufficient forward contracting for supplies;
6. Under-scheduling in the forward markets; and
7. Exercise of market power, both on a system-wide basis (e.g., because of tight supply and demand) and locational (within transmission-constrained areas.

The ISO staff then ran into some trouble by repeating an assertion that's been a foundation of the CMR effort from the beginning but might have been stated a bit too simply here: that the "root" of the current problems was "independent of market design." They meant that the basic ISO congestion management system and other features could be preserved even if the incentives, market rules, and other features needed to be changed through the CMR process, and that action by entities besides the ISO would be required to address issues such as lack of adequate generation supply.

However, a couple of Board members took this statement to mean that Management thinks that the market overall is working just fine, despite the problems this summer, e.g.:

- Governor Woychik: How can you say that the root of the problems is not market design? We've had lots of discussions in meetings about market design problems.

You never had problems like strategic gaming before restructuring. This ignores the obvious sources of the problems – "it's the market structure, stupid."

- **Governor Florio:** I understand that some of the problems might be "independent" of market design, but ALL of them? I think that market design is one of the things that SHOULD be on the list, in a very fundamental sense. I want a comparison of our market design against others out there. I think that this decentralized market design is part of the problem, but if you don't want to talk about it here, OK, I will take that elsewhere.

- **Governor Hapner (response to the above):** Conversations like this really make me question whether we have the right governance structure for this Board. I totally respect that there's a diff of opinion, but we decided to move forward with what we have on Day 1. There are problems elsewhere with other structures, and if you open up things like ISO/PX separation, you open up every element. To totally zero-base the market structure without trying some incremental steps would be irresponsible. If we try and fail, then I'll be quite happy to dig deeper and deeper, but right now that's a distraction from our major tasks.

- **Governor Pope:** There's a lot of hard work in this package, but we have some suggestions:
  - ***Timeliness and completeness:*** The package emphasizes completeness more important than correctness. We're rushing through this faster than we should - we need to identify parts that need to be done now, vs. held over.
  - ***Complexity:*** The recommendations are becoming more and more complex. The solution is to move beyond principles and draft tariff language, so we can see details as we address the recommendations, not afterwards.
  - ***Start-up and ongoing cost:*** There's no cost estimate to customers – we need to see that before we make decisions.
  - ***Cost shift implications:*** There's been insufficient analysis of the economic impact on different groups – we need a cost-benefit analysis for public review, and more than 6 days before the meeting.
  - ***Incentives:*** If ISO itself is serving 25% of load in California (presumably, the up to 1/3 of the load that's not scheduling in advance, with ISO load as about 75% of California load), we need to see how this proposal will reduce that and incent the right behavior going forward.

Regarding transmission expansion ***(where Management is recommending a more active and assertive role for the ISO)***

- **Governor Pope:** I strongly believe that this focus on transmission is well-deserved. We need more generation and transmission, and we should give every incentive to PTOs or anyone else to build it. This is aggressive, but it needs to be even more aggressive. Anyone who builds a power plant anywhere should be able to get power to consumers.

- **Chair Smutny-Jones:** Path 15 will be a very expensive upgrade, but with $50 million in congestion costs in the past 12 months, it might be worth it. This may be a possible initial instance of how the ISO can be aggressive in pushing through an upgrade.

Regarding promotion of forward scheduling and contracts ***(multi-year, yearly, seasonal, monthly, i.e., more then Day Ahead)***

- **ISO VP of Operations Kellan Fluckiger:** Real forward scheduling used to be a lot forward – out a year, or 2, or 5 – and we're trying to create that same level of preparedness. Getting out schedules into Day Ahead will help operations, but it's that further step that will actually stabilize energy prices and calm the market in the way we want to see it.

- **Governor Blue:** I don't understand why you think that generators need incentives in the forward markets when they've been offering forward contracts all summer long.

- **Kellan Fluckiger:** We want to create a better market, with even stronger incentives.

- **Governor Woychik:** I'm concerned that this proposed Real-Time Charge *[for schedule deviations in Real Time]* is artificial, and a constraint on the market. You have no basis for quantifying it, you're just going to jack it up until you get a particular result. Where is there an example of such a charge in a market anywhere else?

  Management response:* *If Market Participants don't forward schedule, there's a real reliability and cost implication that's not captured in energy prices today. This is a way to try to capture that externality.

- **Governor Kirschner:** Have you given any thought to exempting intermittents [i.e., intermittent generation like wind and solar, which have trouble predicting their generation in advance]?

  Management response:* *Well, we did give a 10% tolerance Day Ahead and 5% Hour Ahead, and we're talking about a straight exemption for small facilities, e.g., "a minimum of 10% or 200 MW."

- **Governor Hapner:** I'm really pleased with this report - this is the kind of creativity I've wanted to see – but I want to see more fleshed out version ASAP. I'm especially happy to see a symmetrical version considered [i.e., incentives for both generation and load to forward-schedule].

  (Consultant note: The mandatory-scheduling requirement first requested by ISO Management, on the August 25th Board conference call (*see the August 25th Board Under-scheduling Special Report*) was applicable only to loads, with the idea that,

since schedules submitted to the ISO have to have loads and generation balanced, this would also bring generation into the forward markets.)

- Governor Florio: Is anyone actually contending that this should be put on loads only? The balanced approach seems perfectly logical to me. Maybe to accomplish something today, why don't we give guidance to the Staff to pursue that?
  Management response: ***The DMA [ISO Department of Market Analysis] and MSC [Market Surveillance Committee] highly prefer this approach. We were going to come in with a specific proposal later, but if you want us to pursue only that option, then great.***

- Governor Pope: I'm concerned about run-of-the-river hydro plants, which can't control their schedules *[same problem as intermittents]* – I hope you'll consider that.
  Management response: ***We will definitely look at that.***

At this point, the Board passed a motion (16-2, with 3 abstentions) approving an approach that gives incentives for forward schedules to both loads and generation. (My interpretation was that this was an approval for only the general approach, not for the specific detailed Management proposals – but the resolution language wasn't clear about that. We will see Management's interpretation later this month.)

Regarding schedule feasibility, specifically Adjustment Bids on firm loads (*See the August 25th Board Under-scheduling Special Report, pp.7-8, for a complete explanation of Adjustment Bids, how loads can participate in that market, and the problems that can occur if loads in Adjustment Bids don't really curtail.*): Management stated that there's not agreement within the ISO about what to do.

- **From an operational perspective**, it's clearly a problem for 3,000 MW to be cut in the forward markets when the Adjustment Bid is exercised by the CM software, so the congestion seems resolved, only to have it show up in Real Time and make the ISO operators scramble to adjust for it;

- **From an economic perspective**, however, some worry that if this option is removed, the entities responsible won't schedule that load anyway, and it will still show up in Real Time, so the problem won't be any better.

RTO Update

There was no formal presentation or Management documents. ISO CEO Terry Winter mentioned that the ISO was preparing to file as a California-only RTO but was trying to coordinate it s showing with others.

PHOENIX CONSULTING

A California Limited Liability Company

For subscription information, please call (916) 797-3106, or e-mail Schneider@rsvl.net

KNOW THE ISO Event Report

Market Surveillance Committee Meeting
December 1st, 2000

Important Topics Covered:

- Public comment from SCE on current market issues
- October and November 2000 market performance
- Comparison of OOM prices vs. Ex-Post market prices
- Impact of emissions costs on market prices
- Excess supply during ISO-declared Emergencies
- MSC response to draft FERC order on ISO/PX restructuring

The Market Surveillance Committee (MSC) advises the ISO on important policy matters and meets monthly to discuss them. The members are:

- Frank Wolak (chair), Professor of Business Strategy at UC Berkeley and a former Deputy Assistant Attorney General in the Antitrust Division of the Department of Justice;

- Bob Nordhaus, a partner at Van Ness Feldman law firm and former General Counsel for FERC and the Department of Energy; and

- Carl Shapiro, Professor of Economics at Stanford University and a former advisor on electricity pool reform in Britain.

This report summarizes the ISO Management presentations, and the subsequent discussion, at the December 1st MSC meeting. The presentations are on the ISO Web site at http://www.caiso.com/pubinfo/BOG/documents/market/msc/.

Except where otherwise noted, the ISO's Department of Market Analysis (DMA), not ISO Management, made the presentations. The DMA is "quasi-independent," so the opinions expressed at this meeting might not necessarily be the same as Management's recommendations to the ISO Board, though there are rarely serious disagreements.

Resignation of MSC member

Dr. Shapiro announced that he was resigning his position on the Committee, and that this would be his last meeting. This will reduce the Committee members to two.

(Management has not yet nominated the fourth MSC member authorized by the Board last February; that person was to be someone with actual market experience. See the February Board Event Report, Part 1, p.3.)

Public comment from SCE on current market issues

1. **November high prices/costs:** November total energy costs will be higher than either July or September. The Department of Market Analysis (DMA) has identified plant outages as a primary cause of high prices and supply shortages (e.g., emergencies during several days in November, an unprecedented event). This raises two issues:

   - Scheduled outages: What if 15,000 or 18,000 MW of generators decided to take their plants out at the same time? The ISO needs authority to prevent that, especially when there are so many forced outages.

   - Forced outages: We suspect that at least some are discretionary, meant to drive up prices. The ISO needs to verify that these outages are really legitimate, and punish those who are manipulating the market this way.

   A recent study by prominent economists Jaskow and Kahn *(commissioned by SCE and filed with its response to the draft FERC order on ISO/PX restructuring)* indicates, based on public information, that generators are not in the market even when their incremental revenue would exceed their incremental costs.

   That doesn't make sense unless you consider the situation on a portfolio basis, looking at all units owned/controlled by a company. The next step is to look at non-public data to determine why these generators are really staying out of the market.

2. **High gas prices:** The astronomical California border prices are more due to the transport cost to the, not the commodity cost. ***[Commodity prices are in the $6-6.50 range, with delivered California border prices around $15-18.]*** Someone should look at the entities that both hold significant interstate pipeline transportation capacity and own significant generating capacity in California to see if there's a connection. The best situation is to have market prices for your product rise due to high costs for everyone but you.

DMA presentation on October market performance and November trends

- **Continued high prices** despite seasonal drop in system loads, with significant south-to-north transmission congestion, characterized the market in October-November.

***October 2000 energy prices** ($/MWH)*

PRICE ELEMENT	NP15	SP15	ZP26	SYSTEM AVERAGE
ISO Real-Time Price				
Peak	$148	$83	$85	$115
Off-Peak	$134	$38	$40	$87
TOTAL	$144	$68	$70	$106
PX Constrained Price				
Peak	$109	$96	$96	$102
Off-Peak	$87	$65	$65	$76
TOTAL	$102	$86	$86	$94

November 1-27, 2000 energy prices *($/MWH)*

PRICE ELEMENT	NP15	SP15	ZP26	SYSTEM AVERAGE
ISO Real-Time Price				
Peak	$203	$140	$145	$172
Off-Peak	$181	$94	$101	$87
TOTAL	$196	$125	$130	$160
PX Constrained Price				
Peak	$174	$143	$143	$158
Off-Peak	$148	$89	$89	$118
TOTAL	$165	$125	$125	$145

- **Contributing factors** are:
  - High level of scheduled/forced generation outages;
  - Decrease in both gross and net imports;
  - Rising spot-market gas prices;
  - Increased reliance on thermal generation;
  - High NOx emissions costs; and
  - Continued exercise of generator market power (i.e., all the above don't fully explain the high prices in the market).

Generating capacity outages *(MW, estimated from bar chart)*

MONTH	SCHEDULED OUTAGES	FORCED OUTAGES	TOTAL
October 2000	4,500	3,400	7,900
October 1999	400	800	1,200
November 2000	5,900	5,100	11,000

November 1999	1,000	900
1,900		

- **Dr. Shapiro:** This is pretty striking compared to 1999. We need a study to look at which units are and aren't operating and whether that's reasonable. Do we see a pattern that's different for people who own other units? If they own only one unit, it's not market power if it's off. Is there a correlation between outages at different units that might be strategic?

  DMA: ***That would get us into engineering studies and really stretch our resources, but maybe we could commission it. In your mind, is having the unit off for maintenance (physical withholding) different from bidding it in at the price cap when that's above cost (economic withholding)?***

- **Mr. Nordhaus**: I would think that you'd be more concerned about physical unavailability, from a reliability perspective. Plus, if a unit's off-line, typically others would know and maybe take advantage of that through their bidding behavior, while if a unit's up and running, the owners aren't likely to share bidding strategies with their competitors.

- **Dr. Shapiro:** You can look at bids at the cap and determine whether it's market power, but if unit is not available, that's an infinite price and even more of a red flag unless there's a good reason. In the aggregate, it does appear that something strategic is going on.

  DMA: ***That's what we want to do through availability standards for a portfolio, based on experience. It's very difficult to verify each outage.***

  ISO Managing Director of Market Operations Ziad Alaywan: ***Plus, you have to look, not only at outages, but at other operating limitations on units, where they're running but at below capacity. We've had about 7-800 MW unavailable that way through things like lack of water for hydro, or lost feed water pumps.***

- **Dr. Shapiro:** Is there any way to coordinate the scheduled outages better?

  DMA: ***We do have a department of outage coordination, but running a unit is under the owners' discretion. We're thinking seriously about filing a tariff amendment giving the ISO more authority to coordinate outage scheduling. We also want to see more mandatory outage reporting, and get some availability standards with teeth.***

• **Decrease in gross and net imports:** Net imports are the total of imports into California, less exports to other states. Traditionally, California has been a net energy importer in most months.

Net imports have been decreasing for a while, driven mostly by growth in exports as generators have sought periodic higher prices elsewhere and (anecdotally) the long-term contracts that parties elsewhere seem willing to sign. ***(This export increase has sparked occasional calls to limit or prohibit generation exports when supplies are***

tight in California and, during the discussion here, SCE pointedly referred to this as another generator strategy to keep prices high in California.)

A worrisome new aspect of import-export activity in November was an actual decline in gross imports, from October and (especially) November 1999. DMA attributed this to load growth and colder weather in other states.

California Energy Imports and Exports *(MW, estimated from chart)*

MONTH	GROSS IMPORTS	GROSS EXPORTS	NET IMPORTS
October 2000	**6,900**	**2,200**	**4,700**
October 1999	7,300	1,700	5,600
November 2000	**6,700**	**2,900**	**4,800**
November 1999	9,400	1,600	7,500

- **Gas prices:** Have gone from a California border price of $6 to around $15 recently.
  - **Mr. Nordhaus:** Is that due to gas commodity or transportation to the border? ***DMA: We're not sure – we don't really track it that way.***
  - **Mr. Nordhaus:** I haven't seen San Juan Basin (in the southwest) gas above $5.50 – it's the middlemen picking up additional margin.
- **Increased reliance on thermal generation:** Must Take/Must-Run production down (hydro seasonal low production and nuclear plants out for refueling)

Average hourly energy production by source, 2000 vs. 1999
(nearest 100 MW)

ENERGY SOURCE	2000	1999	change
Net Imports	5,400	5,900	-500
Must-Take/Must-Run	9,700	9,900	-200
Other Hydro	3,400	3,600	-300*
Other Thermal	8,800	8,100	+800*

** Doesn't quite add up due to rounding error.*

Average November hourly energy production by source, 2000 vs. 1999
(nearest 100 MW)

ENERGY SOURCE	2000	1999	change
Net Imports	5,900	7,100	-1,200
Must-Take/Must-Run	9,400	10,600	-1,200
Other Hydro	3,400	3,100	-300

Other Thermal	8,300	5,500
+2,800		

- **Mr. Nordhaus:** What's the heat rate of the marginal unit? A lot of the high price effects looks like they can be explained by the gas prices. With a marginal heat rate of around 18,000 for a unit running at minimum load, wouldn't that explain these prices?
  ***DMA:* See our baseline price for November (below) – we partly capture the gas price effect and the incremental heat rate.**

Issues under investigation

1. Out-of-Market (OOM) purchase prices

When ISO market price caps were lowered, there were concerns that the ISO would have to pay higher prices anyway through increased OOM calls, and that generators would withhold capacity from the normal markets in hopes of being called OOM and getting the higher prices.

Above-market prices: While OOM calls have increased, DMA has found that prices have been around the same as the regular market prices. For the $108 million of OOM purchases this year, the ISO has paid about $8 million more than it would had the same amount of energy been bought at the ex-post (market) energy price.

OOM vs. market prices, May-October 2000 *($AVERAGE/MWH)*

MONTH	PRICE CAP	OOM PRICE	EX-POST PRICE
May	$750	$724	$521
June	$750	$680	$623
July 1 - Aug. 6	$500	$500	$463
August 7 - 31	$250	$252	$246
September	$250	$248	$248
October	$250	$193	$192
AVERAGE		$425	$394

Generator withholding to get OOM calls: The data indicate that this would not have been a profitable course of action, because by waiting for an OOM call, the generator:

- ***Wouldn't have received a greater energy payment*;**
- ***Would have given up a capacity payment*** (e.g., the $100/MW Replacement Reserve price cap payment); and

- ➢ ***Would have risked not receiving a call at all*** (and either getting no money, or running anyway and getting only the ex-post price (before the September 1st 10-minute settlements implementation) or the uninstructed energy price (after September 1st)).

2. Impact of emissions costs on market prices

Some have referred to the high recent cost of emissions offsets to explain high market prices in October and November. This has been a greater issue this year, with generating plants running many more hours than last year and exhausting their allowable operating hours without buying more offsets.

The current emissions market shortage and resulting high prices was created when actual emissions didn't decline as fast as "RECLAIM" allocations (the source of emissions credits under the tradeable program established in the mid-1990s). In the long run, the higher credits prices should incent investments to clean up emissions, so the price of emissions offsets should be limited by the cost of the emissions-reduction equipment.

The DMA sought to include this cost in its "Price-Cost Markup" model for examining market power. That model compares the estimated the variable cost of the theoretical "marginal" (price-setting) generating unit in the market with actual market prices to determine the "price-cost markup" (excess over that variable cost).

Emissions costs were estimated from historical data for the LA Basin, based on:

- Unit-specific NOx emissions rates (lbs/MW); and
- Market prices for credits, assuming a 1-month lag between trade execution and registration date (e.g., July trades registered in August) – these reached a high trade price of $37 in August.

The results were as follows:

- ➢ Because less-efficient and more-polluting units come on line only when loads are high, there's an increasing emissions cost effect with higher system loads and thermal generation levels. For example, with the $37 August emissions cost, here's the impact on the variable cost of the marginal unit in the market *(the highest-cost unit, if dispatch was in reverse order of variable cost)*:

Incremental variable cost ($/MWH) to marginal generation unit with NOx costs at $37/lb.

Total thermal generation	Variable cost increase
0-8,000 MW	
$0	
12,000 MW	$12-13
15,000 MW	~$35

- ***NOx costs could account for between $0 (in April) to $28 (in August) per MWH in additional generating costs at the margin***, not a huge amount compared to the lofty prices we have seen. The SCE-commissioned Jaskow-Kahn study referred to above came to very similar conclusions based on a different methodology.

Taking NOx costs into account, competitive prices *(based, in this methodology, on the variable cost of the marginal unit, assuming dispatch based on merit order)* should have been around $91/MWH in August and $110 in November, compared to weighted average market prices of $167 and $142. ***That makes the "Price-Cost Markups" in those months 46% and 23%, respectively, and still indicates a significant degree of market-power exercise.***

3. **Whether there was excess supply when the ISO called system-wide Emergencies?** *(DMA review of recent market studies by others)*

Joskow-Kahn Study: This SCE-commissioned study concluded that there was physical withholding of capacity in order to create market scarcity and high prices.

DMA concludes that the methodology is flawed in that the study looks at high-price hours, not the hours when DMA found that scarcity exists (which would cover only 16% of the hours in the study). Thus, DMA found that the study analysis does indicate market-power exercise but doesn't support the conclusion that scarcity was "created" by economic or physical withholding of capacity from the market.

The DMA notes that ISO operations staff try to consider all "available capacity from major thermal units before issuing stage 1 and Stage 2 alerts due to scarcity."

McCullough Study: This study by Professor McCullough from the Northwest (not further identified) that claimed that reserve margins in California were over 30% during ISO Stage 1 and Stage 2 Emergencies.

DMA concludes that the methodology is flawed in that it:

- Assumes availability of over 46,000 of generating capacity in the ISO Control area (vs. about 40,000 that's actually available);
- Looks at gross rather than net imports (i.e., doesn't take into account exports from California to other states); and
- Looks only at actual ISO loads, and doesn't take into account generation losses, Regulation Up requirements (capacity that must be left in reserve), or curtailed load.

DMA's recalculation of the study reserve margins during emergencies considering the above factors indicates that they were more like 5%, or 10% when out-of-state OOM purchases are considered).

MSC discussion

- **Dr. Shapiro:** There have been repeated accusations of supply withholding. There's so much money at stake that the ISO should sponsor an objective major study of this. If there's withholding, we should be able to prove it.
  ***DMA:* If you define not running when price is greater than a unit's marginal cost (or incremental operating cost), that happened this summer. This fall, we're seeing more physical outages, but looking into that requires more of an engineering perspective – which are you concerned about?**

- **Dr. Shapiro:** They're interrelated and can be integrated, and I'm not trying to limit it. The portfolio aspect is very important – we need to say here are the units and here are the owners, and here is their REAL marginal price, and they don't run because the marginal revenue is less than that real marginal price. It's fashionable to say that prices are unjust and unreasonable, but I'm trying to find actual data.
  ***Ziad Alaywan:* In the last few weeks, we called on units for OOM dispatch, and they weren't broke but weren't in the market – is that what you mean?**

- **Dr. Shapiro:** If they're not bidding in, and you have to go OOM to get them, that's a version of withholding – they're playing hard to get. However, the OOM price analysis (above) indicates that that strategy wouldn't make sense unless something else is going on.

- **Mr. Nordhaus:** I thought we were trying to get at physical scarcity – if there's scarcity, we would expect price to exceed marginal cost.

- **Dr. Shapiro:** I am very skeptical that we are on a completely vertical portion of the demand curve – that prices will go up until demand is finally choked off – and I don't think that's really right. There are a lot of ways to get incremental supply, maybe run the plants a little more, etc., and it's not my impression that this is what's going on. Maybe marginal costs are high, but are they really higher than the price cap?

- **Mr. Nordhaus:** That's the essential inquiry, isn't it?

- **Dr. Shapiro:** That's right. A lot of a lot of work has been done, great, but somehow we have never been able to nail this down. It's definitely worth some resources to figure out – it has to have credibility. Just subpoena the documents about how they're running the units and calculating the financial impact – how are you scheduling your maintenance, etc. Get the California Department of Justice or others to do it if the ISO doesn't have the authority. Even if you only look at it on a forward bases, if there's abuse, we need to look at it, and if you guys (the DMA and ISO) can't do it, get someone who can.

DMA: ***We've done studies suggesting that there are units in the state that are unused during emergencies. (Consultant note: Yes, this seems to contradict the DMA findings above.)***

- Dr. Shapiro: Can selling out of state be exercise of market power by creating shortage here, if they have a portfolio?

  DMA: ***Yes, especially long-term contracts with other entities.***

- Dr. Shapiro: Then add that to the study – that's not an absolute shortage. We want to know the strategy of those contracts, and also differences between owners of different facilities.

Analysis of FERC order and MSC recommendation

Committee prepared an analysis of the draft FERC order on ISO/PX restructuring, along with proposals of its own for what should be done. (The full MSC document is on the ISO Web site at http://www.caiso.com/docs/2000/12/01/2000120116120227219.pdf. See the ***November 1st KTISO FERC Order Summary*** for the major features of the proposed order.)

The MSC's analysis criticized the draft order, stating that it

- Will likely be ineffective to constrain generator market power;
- Could exacerbate California's supply shortfalls; and, thereby
- Could raise wholesale prices.

The MSC developed these conclusions on the following grounds:

- Sellers will evade the so-called "soft cap" of $150/MW applicable (only) to ISO and PX markets by diverting sales to other, uncapped markets, potentially crippling the PX.
- The cap would could be "rendered ineffective," even if it couldn't be avoided, by the proposed opportunity-cost and cost-based "rate exceptions" ***[i.e., justification to FERC about why a bid is above $150 is reasonable]***.
- Generators and markets will avoid the California market because of the uncertainty about whether and how the Commission might later order refunds, especially with the "tight supply margins in the WSCC market."
- Sellers will have perverse incentives to increase the price of their bids into the PX, knowing that buyers will face a penalty for not buying in advance of Real Time. "The result is likely to be higher PX prices without any necessary reduction in under-scheduling."

In place of FERC's proposals, the MSC suggests an "alternative mechanism which...will more effectively mitigate market power, curtail inder-scheduling, and ensure adequacy of supply to the California market." The MSC's proposal has the following features:

1. **PX buy-sell requirements:** Convert the current PX "must-buy" requirement for the IOUs into a "must-schedule" requirement. IOUs could buy their energy from any source but would be required to schedule it through the PX (which can schedule for bi-lateral deals in addition to the auction market).

   In the discussion, the Committee members said that keeping IOU loads in the PX would serve two purposes:

   - Keep the PX viable; and
   - Maintain price transparency in the market.

2. **Wider application of caps:** Apply any caps, soft or otherwise, not only to sales in ISO/PX markets but to any sales in the California market (stated in the meeting but not listed as a primary recommendation in the written filing);

3. **Forward contracting for energy sales:** To keep market-based rate authority, generators in the California market (those located here, plus importers) would have to offer a substantial portion of their California sales through 2-year contracts at "rates that approximate competitive prices" to Load Serving Entities (LSEs). ***(As an additional incentive to offer these contracts, the MSC also recommends that FERC consider relieving suppliers offering them of all refund obligations for sales prior to December 31st, 2000.)***

   Entities not offering these contracts would only be allowed to charge cost-based rates "for at least the two-year market-power mitigation period."

   Required forward-contract quantity: The required forward-market quantity for each supplier (with affiliated entities compromising a single "supplier") would equal:

   - ***The approximate share of the market for that supplier*** during a base period, proposed to be December 1st, 1999 to November 30th, 2000 *(i.e., the MSC's idea of the relative benefit they received from charging rates during this period that FERC found to be "unjust and unreasonable")*; times
   - ***The amount of residential and small commercial load*** in the market; shaped hourly to match:
   - ***The approximate load profile*** for those customer classes.

   Required price: Seems to be based on something similar to the "cost-price mark-up" competitive analysis, looking at the marginal unit, gas prices, and heat rates, with consideration of imports at the margin included.

(Consultant notes:

- ***(a) The proposed methodology for determining the quantities (especially) and prices is so structured/complex that I couldn't do it justice here - see the actual document for all the details. It would certainly require a large DMA staff increase to determine each supplier's allocation, ensure that the aggregation of each supplier's contracts with all LSEs meets the required terms and conditions, monitor hourly production/sales/prices for the suppliers' portfolios, etc.***
- ***(b) The other terms and conditions of the forward contracts (e.g., minimum take obligations of the buyers) are not addressed.***
- ***(c) While the MSC is concerned about how vague refund obligations might keep supplies out of the California market, highly structured hourly contract requirements at highly regulated prices might have the same result.***
- ***(d) It's not clear how resources that don't have discretion about when they produce and/or are not part of a large portfolio (e.g., intermittent generators (wind, solar), run-of-the-river or (to some degree) other hydro plants, or nuclear units) would fit into a structure requiring electricity production according to these highly structured allocations and profiles, much less how they could live up to contracts obligating them 2 years in advance to sell such specified hourly quantities.***
- ***(e) Since the forward-contract quantity requirement is based on a historical period, it's not clear whether new generation (inside California, or new importer) would be covered.***

4. **Forward contracting for Ancillary Services:** A similar process would be used to promote forward-market Ancillary Services contracts. Suppliers would have to offer these contracts *(with volumes by supplier based on historical volumes, for each Ancillary Service, for each hour, with some consideration of zonal procurement)* to LSEs in return for retaining market-based pricing for the remainder of the supplier's participation in those markets. ***(Presumably, these would also be 2-year contracts, though the MSC paper is not specific about either the term or the entity that would be purchasing through these contracts.)*** Prices would be based on the October 1st, 1998-September 30th, 1999 period, when the MSC calculations determine that prices were closest to theoretical competitive levels.

   (Again, I encourage you to look at this yourself for a full appreciation of the details.)

5. **Retail customer default rates:** The CPUC would be encouraged to set a default rate for IOU residential and small commercial customers base on the costs for these 2-year contracts. In conjunction with this, since small customers will be protected through these regulated contracts, the wholesale price cap for the rest of the market should be lifted (level unspecified) "as soon as possible" in order to

attract the necessary supplies from the rest of the WSCC during "tight system conditions."

6. **Real-Time Charge in place of load under-scheduling penalty:** The load under-scheduling penalty proposed by FERC should be "even-handed," i.e., also apply to generation under-scheduling. The MSC recommends a "Real-Time Charge," applicable to all real-time market activity, not only to load/generation under-scheduling, but to ***any*** schedule deviations, both uninstructed and instructed (e.g., dispatch of generation from Ancillary Services capacity).

PHOENIX CONSULTING
A California Limited Liability Company
For subscription information, please call (916) 797-3106, or e-mail Schneider@rsvl.net

KNOW THE ISO Special Report

ISO Emergency FERC Filing and FERC Orders Implementing "Soft" Price Cap and Deviation Penalties

December 8th, 2000

Important topics covered:

- Details of the filing;
- Questions/clarifications;
- FERC Order granting the ISO's request (and related order on QFs)

Phone number for additional information over the weekend: (916) 351-2140

On December 8th, the ISO filed emergency tariff modifications (Amendment 33) with FERC, to be implemented this evening (Hour Ending 1700 (5pm)). The terms and conditions in the amendment apply to all Supplemental Energy bids and Ancillary Service bids.

FERC, in two emergency orders:

- ***Accepted the ISO's proposed amendment*** on an emergency basis, waiving notice requirements; and
- ***Issued a temporary waiver (until January 1, 2001) of PURPA thermal operating and efficiency requirements applicable to QFs***, allowing production that might otherwise violate those standards if the power is sold through a negotiated bilateral agreement to serve California loads.

(Both orders are on the FERC Web site under Docket No. EL00-95-000.)

The ISO's proposal is intended to:

- Provide incentives for Market Participants to participate in the markets;
- Allow the ISO to continue using the existing real-time markets and Automated Dispatch System (ADS, the ISO's electronic dispatch system);
- Allow the ISO to better compete for regional energy; and
- Provides SCs compensation for verifiable costs in excess of the soft price cap.

The ISO said it was forced to implement these measures to maintain reliability on the system. There have been an unprecedented series of emergencies declared in November and December, and the ISO Control Area has been in Stage 2 Emergencies (reserves less than 5%) every day this week.

"Under-scheduling" (unscheduled load showing up in Real Time without provision for supply) has been large, and supplies in the ISO's markets have been sparse due to unit outages and exports to markets outside California when prices exceed the ISO's $250/MW price cap.

Moreover, the recent dramatic run-up in gas prices (I heard about $43/MMBtu prices at the border yesterday) has reportedly caused several smaller generators to either shut down their units (especially at night) or consider doing so, which would exacerbate the supply situation.

Reportedly, the filing was made at FERC without official ISO Board approval (no meeting was noticed, as far as I could tell), though the Board members were notified before notice was issued to the market at large.

Terms and conditions of Amendment 33

The filing contains three key elements:

1. Market payment mechanism

While Ancillary Services capacity bids will still be limited to the current "hard cap" of $250/MW ($100/MW for Replacement Reserve), the price structure for Imbalance Energy bids (Supplemental Energy, and energy dispatched out of Ancillary Services capacity) will be based on the "soft cap" concept proposed by FERC in its November 1, 2000 order.

Energy prices/payments

a. **Above-cap (AC) Energy bids:** These will no longer be rejected. Instead, they will be accepted and dispatched in merit order.

b. **Market-Clearing Price (MCP):** AC bids will not set the MCP for Imbalance Energy (price at which all generators are paid). That price will still be limited to the $250/MWh cap, and that's the most that generators submitting below-cap bids will be paid.

c. **AC bid payments:** SCs submitting AC bids would be paid "as-bid" (at the bid price), subject to refund (see below).

Reporting/Reasonableness

d. **Reporting requirement:** Scheduling Coordinators submitting AC bids must submit cost documentation to the FERC, ISO, and California Electric Oversight Board. This information must be submitted using a reporting template (not yet available).

e. <u>Reporting requirement for importers</u>: Out-of-state bidders are also subject to these requirements. ***(The ISO is afraid that doing otherwise would encourage so-called "ping-pong" scheduled, where energy is exported and then bid into the California market as imports, in this case to evade the reporting/reasonableness provisions.)***

f. <u>Reasonableness:</u> FERC will be the ultimate arbiter of the reasonableness of AC bids, and it's not clear exactly what the criteria might be. However, the draft FERC order in EL00-95-000 (ISO/PX restructuring) specifies the following content of information submittal (upon which the reasonableness determination would be made):

> ***"...legitimate, verifiable opportunity costs that are known (prior to the transaction) that the seller considered in developing its bid."***

g. <u>Confidentiality:</u> The ISO said that bidding information would be subject to the confidentiality agreements now in place with those entities related to the current California market investigations. ***(However, there seemed to be some uncertainty about that and I will refer you to your lawyers).***

2. Imbalance penalties for deviations from schedule

Effective December 12th, under-scheduled loads (loads not scheduled but consuming in Real Time) and over-scheduled generation (scheduled generation not produced in Real Time) will be subject to the following charges:

a. <u>Imbalance Energy costs:</u> Up to the $250/MWh cap;

b. <u>AC Energy costs:</u> Pro-rata allocation; and

c. <u>Out-of-Market (OOM) dispatch costs:</u> Pro-rata allocation of costs due to load under-scheduling/generation over-scheduling. ***(Costs related to local reliability issues, e.g., an RMR unit out of service in a particular area, will not be covered by this provision.)***

<u>Exemption for Regulation Down energy:</u> Technically, energy associated with Regulation service is classified as "uninstructed" and would be subject to the above charges for overscheduled generation (deliveries below schedule) if the upward and downward unit movements of the unit by the ISO don't net out to zero. However, the ISO will exempt providers of this service from the allocation of above-MCP costs.

3. Additional penalties for generators who fail to respond fully to ISO Dispatch instructions

The following penalties will apply, whether or not the generator has a bid in the ISO's markets, unless the ISO has not been notified of the unit's unavailability or de-rating (availability at less than full capacity):

a. **Penalty amount:** In any hour when an Alert, Warning or Emergency has been declared, the generator will be charged for the dispatched but undelivered energy at twice the highest price that the ISO paid for Energy for that hour.

> ***(Generators are required under their Participating Generator Agreements with the ISO to respond to ISO dispatch instructions to avoid or an "imminent System Emergency," or during such an emergency.)***

b. **Additional penalty if load is affected:** If the ISO had to curtail firm load during that hour to manage the System Emergency, the non-complying generator would pay an additional \$1000/MWh for dispatched energy not delivered.

c. **Exemptions:** Generators won't be penalized if:
   - The ISO is provided with advance notice of a de-rate or outage that would limit the unit's ability to respond;
   - Compliance with such Dispatch instruction would cause the Generating Unit to violate state or federal law; or
   - An outage or de-rate occurs in real-time and the SC provides the appropriate reason code with a decline or partial acceptance of an ADS instruction, subject to the following conditions:
     - ■ The ISO must be separately notified immediately (within the hour) of the details of the outage, including the time when the unit is expected to return to full capability; or
     - ■ The SC or Participating Generator must demonstrate later that:
       - The Generating Unit was physically unavailable; and
       - Notice of such unavailability could not have been reasonably provided in Real Time.

Penalties for failure to comply with a Dispatch instruction will be subject to the Dispute Resolution provisions of the ISO Tariff.

Details/clarifications

The ISO provided these additional details, in its e-mail notice or in response to Market Participant questions on a conference call late yesterday.

- ➢ All generating resources are supposed to use this mechanism to sell energy in the ISO's markets. ISO operators will no longer negotiate OOM prices for resources inside the ISO Control Area, and they will be "highly reluctant" to negotiate prices with resources out of the Control Area.

- Bilateral arrangements made with the ISO prior to this filing won't be altered by the changes.
- As of yesterday afternoon (the call went after 5pm), bids above $250 were already being received.
- The ISO is not changing its procedures on consideration of minimum unit run times.
- The expiration of this mechanism is the earlier of 90 days or by order of FERC.
- The ISO will post aggregated information on bids above $250. The exact form of the posting isn't yet clear, but aggregation by hour was mentioned. ***[So, generators who are subject to the non-compliance penalties of twice the highest price paid in the hour might not be able to easily verify what that is.]***

Future details/clarifications

On Monday, the ISO will:

- Issue a follow-up communication with the following information:
  - Software limitations on the maximum price level that can be bid; and
  - The exact form of the price information posting.
- Hold another informational conference call, with the time to be announced Monday morning.

From: FLOYD MULLETT
To: Joseph TAYLOR
Date: Mon, Jun 19, 2000 9:27 AM
Subject: Fwd: Transmission Accounting for Reserve Schedules to CAISO

dont know if you get these, but figured you would like to see a copy

Power OPS - REALTIME Routing Slip	Date 6/19	Initials
Mark Boesch	[illegible]	[illegible]
Fred Diaz		
Terry Findley	7/[illegible]	[illegible]
Chris Hartman	6-30-00	[illegible]
Chris Hawkins	7-17	CH
Mitch Hawks		
Judy Madsen		
Ken Purcell		
Steve Sundet	7-1	[illegible]
Randy Syverson	6/19/00	[illegible]
Joe Taylor		

From: MIKE RYAN
To: Control Area Operators
Date: Thu, Jun 15, 2000 4:41 PM
Subject: Transmission Accounting for Reserve Schedules to CAISO

There seems to be some confusion over how to account for transmission capacity needed to deliver reserves to the CAISO.

Until recently, the CAISO has only dealt with energy imports from the Northwest, and we have been subtracting a customer's net N-S AC Intertie (energy) schedule from his reservation in order to calculate his unused firm. And the sum of all the unused firm becomes the amount of non-firm we are allowed to resell.

Now the CAISO is also importing spinning/non-spinning reserves from the Northwest. Even though the energy being delivered will usually be zero, the CAISO is understandibly expecting that there is unloaded transmission capacity that can be used within the hour to deliver energy from the reserves if it becomes necessary to call on them. Unfortunately, our calculation of available non-firm based on just energy schedules incorrectly treats this unloaded capacity for reserves as unused capacity, which means that the amount of available non-firm is overestimated.

Everyone should review the attached e-mail from Matt Richard (originally sent out on 5/28/00) that describes the six special "Tran Cap" accounts (shown in "AC Transmission") that can be used to designate unloaded AC Intertie capacity for reserve deliveries. In essense, the used transmission capacity becomes the sum of the customer's "Trans Cap" account plus his net (energy) schedule. This change makes the calculation of available non-firm capacity come out right.

Here are a couple of points to keep in mind:

- You need to enter the sum of all reserve sales for each customer into his "Tran Cap" account. There may be pre-scheduled amounts in this account (as Matt says), reflecting pre-scheduled reserve sales; however, you also need to keep these accounts updated for same-day reserve sales and changes.

- Providing reserves is a legitimate use of transmission capacity. Even if the capacity is unloaded, we only get to resell unused capacity as non-firm.

- When a reserve import is actually called on to deliver energy, then you must reduce the "Tran Cap" account by the amount of energy being delivered, and of course enter the energy delivered in a normal scheduling account. These two changes offset each other in the calculations for used transmisson capacity.

- Customers should not ask to hold transmission capacity in "Tran Cap" for anything other than reserve imports that the CAISO either have or will pick up soon. We don't want this to become a means of unfairly restricting the availability of non-firm for upcoming hours. You don't need to press customers on this in real-time, but should flag any instances of apparant abuse for us to look into later.

You all know that our transmission customers are anxious to take advantage of the sky high prices for both energy and capacity in the California market. These relatively new reserve sales can be very lucritive. We need to do everything we can (with the restrictions of our tariff and our standards of conduct) to help our customers make sales.

THANKS!

Mike Ryan
Manager, Control Area Operations -- 3WTC0504
PGE; 121 SW Salmon St; Portland, OR 97204
(503) 464-8793 fax: (503) 464-8134
mike_ryan@pgn.com

From: Matthew Richard
To: Mike Ryan@HQ3.EM5
Date: Thu, Jun 15, 2000 3:57 PM
Subject: Transmission Capacity Transactions (Resend)

When I was interviewed for the scheduler job downtown, gad zeeks it's been six years now, I was asked what the difference was between energy and capacity. Well I was a nuke, this was simple stuff. Capacity was the amperage capability of a conductor and energy referred to the power component equivalent to current times voltage times the power factor times the square root of three (in a three phase circuit). Blew Damon away with that one I thought. Wrong!

In the business all of us now find ourselves in (the rest of the interview went pretty well, thank goodness), the difference between energy and capacity refers to transmission scheduling and the utilization of firm transmission reservations.. Up to now we have seen only energy schedules. Even our transmission schedules are energy schedules, they move MWh into our system and then out of it from a source to a sink. If a customer didn't use their reservation to move energy we would turn around and try to sell it or make it available for non firm energy transfers. On the other hand if a customer wanted to maintain a portion or all of their reservation intact to be able to move energy at a later time they would need some means to insure that they had that capability, in other words they would schedule capacity on their reservation for a specified amount over a specific period of time. Hence, the need for capacity schedules.

Recently SDGE has begun selling reserves to the CAISO on a preschedule basis. They have been submitting TAGS denoting values of capacity they desire to schedule for the next day. We had no means to schedule this capacity, i.e, no way to set their reservation aside so it wouldn't get sold as non firm. One of our transmission customers has also asked about the abilty to offer reserves to the CAISO, so it became apparent theat we needed to do something.

Enter capacity scheduling: When a customer submits a schedule for capacity N-S on the AC intertie we will now enter their values on a preschedule basis into customer specific capacity accounts. These accounts will offset the sum in the Non Firm ATC N-S calculation and their respective firm reservation (FMRV) Available calculations. The six new capacity transaction accounts are as follows:

AVA Tran Cap N-S (read: Avista Corp Transmission Capacity North to South)
AVST Tran Cap N-S
APC Tran Cap N-S
EPM Tran Cap N-S
PGM Tran Cap N-S
SDGE Tran Cap N-S

These six transactions are summed in the **AC TRAN CAP N-S** calculation to provide a total for all capacity schedules. This calculation is in the AC Trans Summary display group. The calc is then subtracted in the AC Non Firm ATC N-S calculation to offset unused transmission capability. The individual transactions are also members of their respective FMRV Availability calculations to show utilization of their firm reservation when scheduled. These are the only calculations that are affected. Interchange schedules and subsequent calculations including AGC, AC NET INTERTIE. Net Sched interchanges, etc, are not affected. Only energy schedules affect these accounts.

For now, capacity schedules will be entered on a prescheduled basis, being submitted to the preschedulers just as energy schedules are received with the same submittal requirements, in by 10:00 a.m., etc. Prescheduled capacity will have a corresponding TAG that will designate all data just as an energy TAG would, transaction path and capacity profile. On realtime the only actions that may be required would be if a customer transitioned their capacity schedule into an energy schedule if called upon to actually deliver energy. The Control Area Operator would remove the capacity values from the capacity account and enter them in the corresponding energy transmission accounts, both in and out. If the operator entered values in the energy accounts but failed to remove the capacity values the ATC and availability calculations would be inaccurate. There is only one capacity account for each transmission customer. If a customer submits more then one capacity schedule for any one day then those schedules would be entered in seperate details of the single account.

The PSAS schedule for May 28th has a SDGE capacity schedule entered into it. You may review this day to see how the various accounts are affected. As always, please bring up your concerns or questions.

From: Marlene Huntsinger
To: Mary Turina
Date: 5/9/02 1:00PM
Subject: Re: What do you think of the memos?

Hmm. Looks like the first set were done by someone that was familiar with the business and was providing some analysis. The second set was looking for good news about the activities, I think. I would say the second guy had a different goal set. I think both are accurate. We knew they were trying to push the envelope and make money from the mistakes the Cal ISO/PX created. We declined to help them in several instances. Looks like Puget helped. Im surprised Powerex did too. I know any marketer in business would have been pushing the envelope, too - the point is making money, right? If the Cal ISO/PX invented ways for that to happen, why wouldnt they use the holes?

I also dont think our parking/lending was directly related to their exploration of money-making with the Ca folks. I think it just used our control area capabilities that they as marketers did not have. That capability is what they have been complaining to FERC about in that they are left out of that market.

>>> Mary Turina 05/08/02 12:57PM >>>

From: Mary Turina
To: AW Turner; Cheryl Chevis
Date: 5/9/02 1:18PM
Subject: Fwd: Re: What do you think of the memos?

FYI, pls read the attached from Marlene. Since she was the GM of Trading during most of our CA trading, probably need to meet with her.

Answers To Path 26 Loading Conditions

(1) Have we determined the impact upon the market of a single bad ISO forecast?

(a) How much impact does this have upon market (energy) prices?

Any load forecast error and deviation of SC hourly schedules have a direct impact on the real time imbalance market. The ISO load forecast also has an impact on the amount of RMR procured in an area. The ISO hasn't quantified the specific impact on market prices.

(b) What have we done to minimize recurrence of this?

Deviation of an SC schedule is a market decision. Additional checks & balances have been initiated in ISO procedures to check DA forecasts & HA adjustment.

(2) What was the basis for using P15 CONG path to mitigate loading on P26?

(a) Explain rationale [Emergency action-which used a market tool to help solve a Real-time problem]

In order to keep the path flow within its rating the ISO took several actions including circulating power on the PDCI, raising generation south of Path 26 in exchange for lowering generation north of Path 26. Although overloads on Path 26 should be considered intrazonal congestion, there were insufficient adjustment bids available to manage the intrazonal congestion using only adjustment bids or incremental/decremental bids within the same zone (SP15). As a result the ISO resorted to the incremental and decremental bids from the imbalance energy market. Because there are a limited amount of resources in the zone (SP15) that are north of the constraint that could be reduced, the ISO was forced to resort to adjusting resources outside the congestion zone SP15 to control the path flows. As an emergency action, splitting the imbalance energy market in BEEP was an efficient and effective method to raise resources south of the constraint and reduce resources north of the constraint. Without splitting the system, BEEP would have continued to move resources on both sides of the constraint in the same direction and may have exacerbated the loading condition on Path 26. BEEP is only able to split the system along defined interzonal interfaces. The nearest interzonal interface is Path 15. Except for the resources in between P26 and P15, splitting the system provided market signals to increase generation south of Path 26.

(b) Under what tariff provision did you take this course of action?

Under ISO Tariff section 7.2.6.2 the ISO took advantage of the incremental and decremental bid from available sources of Imbalance Energy to help resolve an intrazonal problem (Step 3 of Section 7.2.6.2). In real time, there is no difference between intrazonal and interzonal congestion The ISO does not have the intrazonal software to resolve the intrazonal congestion in the DA or HA (i.e. Path 26). However, the ISO will use the following to resolve intrazonal congestion as specified in section 7.2.6.2 of the ISO Tariff. (As was done on 5/18)

Step 1 Use adjustment bids within the same zone.

Step 2 Use incremental or decremental bids within the same zone.

Step 3 In the event there are insufficient adjustment bids and incremental/decremental bids available, the ISO will exercise its authority to direct the redispatch of resources within the zone.

(c) How many other paths could potentially be used for intrazonal congestion which were not already defined?

Path 26 is the only Path that could benefit from splitting the system along Path 15 interzonal interface. Other internal paths such as South of Songs and North of Songs are already modeled and are monitored after the run of the markets. Path 26 will be added to the internal paths and we will continue monitoring it after market runs.

(3) How will the ISO pay for the HVDC losses incurred while circulating DC flow? (from BPA)

The tariff does not clearly define how to allocate the charges for this type of event. The ISO is evaluating alternatives and will issue a position early next week.

(4) Why did the ISO employ a DIFFERENT action today for a similar occurrence on P26?

(a) Why did SDGE see its units taken off AGC reg & ordered up per RMR today (5/19) when they had valid SE bids in today?

This was a judgement of the generation dispatcher to react quickly to a changing condition.

(b) Why wasn't BEEP used today to auto dispatch SE for units on AGC reg at SDGE?

The loading condition on Path 26 on 5/19 was managed without the need to split BEEP across Path 15.

The following is a clarification on the ISO load forecasting process.

The ISO is forecasting the ISO system load based on historical load and meteorological data provided to the ISO by PG&E, SCE and SDG&E. The load data provided incorporates municipal utility and agency load that was embedded in the former control area of the three IOUs. This would mean that SMUD, NCPA, Anaheim, WAPA, Vernon, Azusa, Colton, Banning, TID, MID, LMUD, MWD, Santa Clara,et. al. load is incorporated into the ISO load forecast. Also, load not included in the ISO load forecast is load associated with other control areas within California such as IID, LADWP and Pasadena.

The ISO actual load is calculated based on the sum of all generation including the municipal and agency generation in the ISO control area (listed below) minus pump load plus the net control area interchange.

ISO developed Day Ahead forecasts are compared to actual load on a Daily and Hourly basis to determine any future adjustments needed to the ISO lead forecast process. Other than the complications experienced this Monday, our hourly load forecast error ranges from 0-5%.

The total of all load schedules the ISO receives from Scheduling Coordinators is generally 1000-4000 MW less than the actual load during the partial-peak and peak hours. During off-peak hours the differences are generally smaller. The ISO attributes the difference between the SC load schedules and actual load during the partial-peak and peak hours to three areas. First, SMUD, MID, TID and WAPA load schedules the ISO receives are net load instead of gross load. This could account for roughly 1000-2000 MW of the differences. Second, system losses of 800-1000 MW are not being scheduled. Third, SC forecast error may account for some amount of the differences.

Monday's events were due in part to an error with the ISO forecasting. The ISO has taken steps to mitigate this particular problem in the future.

From: Tami Parr
To: TAYLOR, Joseph
Date: Thu, Dec 14, 2000 3:53 PM
Subject: CAISO

Hi Joe -

Thanks so much for the information, and also for your patience in running through this labyrinth with me. I have a couple of other questions, when you get a chance:

1. What is the relationship between inter-zonal congestion and a system emergency? Is congestion always an emergency, or only sometimes/never -- more like a general system management practice?

2. Is the current PGE situation (the circulating MW) pursuant to a specific emergency -- it sounded like it was from what you were saying? In other words, this does not happen all the time, as part of some general congestion management practice?

Thanks for your help.

Tami

PREFACE TO EMPLOYEE DISCUSSIONS

Drafted bullets to make sure we're ~~everyone~~ all on the same page. Will give to everyone I talk to from now on

- As Mary mentioned Monday, it important that you be honest and forthright in the information you give me. In fact, as I mentioned, that is a part of the requirements of our jobs.

- I am a PGE lawyer, and as such I am counsel to the Company, and that includes employees, but only on matters that are or were within the scope of their employment.

- The statements that you make to me are privileged and confidential, although I may need to share them with Company management. The privilege, however, is the Company's, not yours personally, and PGE may decide at some point to waive the confidentiality.

~~Scott~~
~~[illegible]~~

Kevin Nordt 3/1/02

late 1997 - after merger
~~[illegible]~~ living trading floor
transition

- Casey, Sean, others "last to leave" said unit of Enron (natural floor)
- Kevin charged w/ starting w/ Cal
- Kevin "leaned on" Enron to learn about Cal. market

- no talk of "why don't you do this or that?", but would ask Tim Belden & others about new "games" found in ISO
- bidding, ~~etc~~ potential change to tariff, & other subjects
- went on ~~[illegible]~~ until market started breaking down in 2000

- Tim, Sean ~~[illegible]~~ Crandall, Bob Badeer

many
Hour
ad given
OC training

- sharing of info was
- 5-10 conversations, generally at a time of tariff changes, e.g., changes in target price methodologies
- When ISO PX first started (spring '98?), BPA had swapped scheduling system
- BPA couldn't act control area don check-out
- Kevin worked 4:30 AM - midnight 7 days a week

II.B.-106

- everyone got mad, especially w/ PX
- "vented about "won't bid any more"
  - never followed - thru
  - [illegible] not recorded - cell phone or home phones

---

back to 1 -

- never agreement to work together

- talk to non-Enron traders at stakeholder meetings, e.g., ~~[illegible]~~ Idaho Power + [illegible]

---

games

- phantom congestion
  - applied to interties (AC line) at COB

- we could forecast Cal util's load

- ISO would ~~think~~ show TX was full, but Cal munis ~~[illegible]~~ part would be free

II.B.-107

- Kosin wrote [illegible] [illegible] [illegible]

- Random bubblizer
  - ISO used this to pick who among all lowest bidders over CDI would get picked
- Kevin built simulator to random bubblizer to see how it worked
- San Diego had part of Boardman, so they got hammered by neg bidding
- Seattle City bd disallowed neg bidding, so they were out of the market

3/4/02

Marlene

- Enron was going to schedule at a weak tie

Silver Tie ?
- Nevada deal that Fevoi told me about in which Enron got fined
- Marlene thinks Enron wanted us to help schedule

- ask Bill about Enron scheduling request

- parking & lending tariffs

- "stored" power 24 hrs in advance
- schedule imbalance at COB would be similar to Enron scheduling request

- maybe No 1 Enron Tx allocation because Enron took over ~~WAPA~~ WAPA's 3 ~~supplies~~
① power sale from PGE to WAPA
- Enron took that sale over
② supply for it was WAPA's contract, which was BPA product that could only be delivered to PGE

II.B.-109

- for both park & lend & Tx allocation, ... became more important

Talk w/ Casey
2/25
8:55 AM

- Enron wanted us to buy at COB from them
- they would cut, creating Tx situation – we refused (small)

- scheduling services for Enron (is this megawatt laundering?)
- we're taking title at both ends
- we'd do for anyone, but Enron locations often didn't make sense for anyone else

- trading in forward block would allow you to play PX against ISO
  - Avista stepped in on weekend when we couldn't post

1 time

- one time when Enron figured out an ISO tariff twist that they shared w/ us – Bill doesn't remember if we took advantage of it

- occasional scheduling times, we wound up supplying gen to Enron & discovered a month after the fact
  - went back & charged them index + \$3

From: Kevin Nordt
To: Joseph Taylor
Date: Thu, Apr 13, 2000 7:11 AM
Subject: Explanation of HA Cong vs realtime incs

Joe

I spoke with Ziad today about the phenomena we saw over the last few days. Basically, the ECRs: existing contract rights (the difference between physical limit - new firm use amount) is the culprit not extreme error in the power flow studies.

Currently, the ISO must assume that the existing contract rights are fully utilized in both the DA & HA markets. This has the potential to create psuedo-congestion (and at absolute best can only be neutral for the market but more likely to be negative) because these rights (~1500 MW) may be completely unscheduled and there may not even be the slighest expectation that this capacity will be scheduled on either but the ISO must reserve this ECR capacity until the scheduling rights associated with these rights expire (much closer to realtime). Therefore, in the HA market, if 1500 MW of ATC from JDA to COB exists, the ISO after reserving for existing contract rights could show an HA ETC of 0 MW. This would result in extreme congestion even though there is not even 1 MW of power scheduled on the 1500 ECRs reserved. Our HA energy bid would almost certainly get conged out. Then, as the ECRs expire at ~40 minutes prior to the dispatch hour, the ISO can pick up on this space. If inc bids for supp energy exist on the COI and the merit order of these bids is right, the ISO should and would pick up as much supp energy as it needs on the "newly" available 1500 MW of COI space.

This is just another manifestation of the mismatched pipe issue we have discussed before with respect to the day ahead market. I apologize that it did not dawn on me earlier to see that this was what must be happening (focussing on power flow study led me to not see the forest for the trees).

As we may soon find out in the NW if RTO picks up again, working for the best economic solution around a hodge podge of existing rights and non-juridictional parties can create some perverse results. The ISO recognizes the economic inefficiencies resulting from this but legally there is nothing that can be done. However, there is a proposal being put forward in the cong redesign process that would use "non-firm recallable" ATC to set the limits on ATC for HA market. This would have helped us over the last few days because HA capacity would have been higher and with no realtime ECR schedules, we would not have been bumped (non-firm bumping something we already live with elsewhere, so it is tolerable if not optimal). The big question is whether the munis et al will agree to it (they are small but powerful, can not be forced under ISOs thumb).

Hope this at least answers the questions you had even if you do not like the answer. We will track on cong redesign efforts and comment to the extent we can to at least get our 2 cents in the mix.

CC: Bill Casey

From: Joseph TAYLOR
To: "jniickel@caiso.com"@WIZ.IXGate
Date: Wed, Apr 12, 2000 6:13 PM
Subject: April 11th Hour Ahead Congestion

Attached is a spreadsheet containing most of the pertinent info. Bottom line is that congestion was managed by cutting not more than about 100 MW's of Hour Ahead Schedules and then the ISO picking up in some hours 700 MW's in the supplemental market on the supposedly congested line. We have the same situation again today. Is it the intent of the ISO to kill the CPX HA market and only utilize the supplemental market? I find it hard to believe ETC's to the tune of 700 MW's aren't released until they might only be used in the supplemental market. Do we have a case of market abuse/manipulation here? I look forward to your response.

PGEIML (our resource path to the CPX/ISO on the AC)

	1	2	3	4	5	6	7	8
Hour Ending	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**
DA Final	177	139	0	0	116.7	50	95	20
HA Resource	0					0	4.08	0
HA Total	177	139	0	0	116.7	50	99.08	20
@ HA MCP <OR>	20.9901	0	0	0	0	18.75	26.286	26.2882
@ DA Zonal	21.0157	14.0844	11.6	11.76	13.7504	21.0049	30.5013	31.1249
	3719.7789	1957.7316	0	0	504.67168	1050.245	04.87038	622.498
	18	16	14	13	13	15	17	19
	3186	2224	0	0	1517.1	750	1684.36	380
HA Final	177	139	0	0	116.7	50	99.08	20
@ HA Zonal	0	0	0	0	0	0	26.286	26.2882
@ DA Zonal	21.0157	14.0844	11.6	11.76	13.7504	21.0049	30.5013	31.1249
	3719.7789	1957.7316	0	0	504.67168	1050.245	04.87038	622.498
Change(cuts made due to HA Cong)	0	0	0	0	0	0	0	0
Supplemental bids awarded on >>>>								

	9	10	11	12	13	14	15	16
Hour Ending	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**
DA Final	120	120	120	120	120	120	120	120
HA Resource	2.32	22.98	81	75	75	100.01	99.23	96.01
HA Total	122.32	142.98	201	195	195	220.01	219.23	216.01
@ HA MCP <OR>	26.2898	28.8722	29.92	29.44	29.44	33.6015	33.4448	32.8012
@ DA Zonal	32.2499	32.1709	33.1888	33.65	33.97	33.56	33.56	32.33
	30.98034	23.99116	6406.176	6246	6284.4	87.68602	345.92750	28.84321
	20	24	24	26	26	26	26	26
	2446.4	3431.52	4824	5070	5070	5720.26	5699.98	5616.26
HA Final	122.32	142.98	201	157.49	120	120	120	133.04
@ HA Zonal	26.2898	28.8722	32.4	27.99	24.01	0	0	26.99
@ DA Zonal	32.2499	32.1709	33.1888	33.65	33.97	33.56	33.56	32.33
	30.98034	23.99116	6607.056	5087.3451	4076.4	4027.2	4027.2	4231.5496
Change(cuts made due to HA Cong)	0	0	0	-37.51	-75	-100.01	-99.23	-82.97
Supplemental bids awarded on >>>>				775	861	747	747	525

	17	18	19	20	21	22	23	24	
Hour Ending	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	
DA Final	120	120	120	120	120	120	0	0	
HA Resource	105.11	106.96	85.89	84.98	82	83.4	150.37	152.6	
HA Total	225.11	226.96	205.89	204.98	202	203.4	150.37	152.6	3684.64
@ HA MCP <OR>	34.6222	34.9916	32.6222	34.9937	33.9998	32.6239	27.5486	26.5865	
@ DA Zonal	31.6	31.6	31.9158	32.83	32.84	32.2497	31.2443	23.7579	
	431.13944	534.70154	531.81676	13.36463	5728.7836	590.79726	142.48298	4057.0999	111143.98589
	26	26	26	26	26	28	26	24	
	5852.86	5900.96	5353.14	5329.48	5252	5695.2	3909.62	3662.4	88575.54
								NW price	24.03913
								e per MW	30.16414
HA Final	225.11	226.96	205.89	204.98	120	92.45	42.33	152.6	2988.93
@ HA Zonal	27.02	34.9916	28.12	27.02	0	17.99	23.99	26.5865	
@ DA Zonal	31.6	31.6	31.9158	32.83	32.84	32.2497	31.2443	23.7579	
	5632.0722	534.70154	5245.1228	5235.7596	3940.8	3374.3395	1015.4967	4057.0999	87506.90999
									29.27700
Change(cuts made due to HA Cong)	0	0	0	0	-82	-110.95	-108.04	0	-695.71
Supplemental bids awarded on >>>>					116	637	250		4658

HA Congested Line

on line	**4,658.00**
IW's cut	**695.71**
per MW	**$1.94**
per MW	**$6.13**
pricing	**$0.89**
pricing	**$2,651.58**
d in NW	**$4,261.23**
stion"	**$6,912.81**

Greg Frisc
pa. 1: Kat
5-14-02

From: CHRIS HAWKINS
To: SCHEDULERS
Date: Thu, May 4, 2000 11:59 AM
Subject: REAL TIME SCHEDULING NOTES CPX

REAL TIME SCHEDULING NOTES
(05/04/200)

CPX PRICING

When the pre-schedulers enter the Day Ahead (D/A) schedule into the PPS400 the price entered is the D/A MCP (day ahead market clearing price) and the price is changed after the fact to the D/A Zonal price.

When Hour Ahead bids are finalized and all adjustments are made to the schedule either to buy or Sell , the final pricing for the H/A energy adjustments will be the H/A Zonal price.

When we are picked up on the Supplemental Energy Bid and the adjustments are made to the schedule, the pricing for the Supplemental Energy adjustment is based on the ISO 10 minute Beep average.

CPX SCHEDULE CHANGES

Day Ahead schedules are entered into the PPS 400 by the Pre-Schedulers usually by 5PM the prior day.
Adjustments to the D/A schedule are made via the H/A adjustments and Supplemental energy bids.
Notification of a change of the D/A schedule will come from the PX and show up on the PX computer approx. 1 1/2 hours prior to the scheduling hour (i.e. at 0730 for he 10) . You may or may not receive a call from the PX notifying you of the change, **it is up to you to check the computer hourly ! .**
The next and final chance to change the schedule is after you receive the H/A Final schedule
At this point **you** are to enter the H/A Supplemental Energy Bid to buy back the final schedule.
The Bid must be made prior to the top of the hour!
The only way you will be notified if your Supplemental Energy Bid has been excepted is by a phone call from the PX prior to the start of the scheduling hour (usually 30 min. prior to the start of that scheduling hour) Use the ISO 10 min. Beep average to price your supplemental energy .
Note: when trying to figure out at what price to enter to buy back on the H/A supplemental energy bid , keep in mind that you will be notified late in that scheduling hour of a change in your schedule, and you may have to back off a resource to accommodate the change.

An example of the above changes is HE 17 05/03/ 2000

Pre schedule was 55 mw To CPX Sale –AC (price was $64.72 MCP [Zonal price was also $64.72])
H/A adjustment bid to buy back (take the schedule from 55 to 0 or any portion there of) was
$ 44. 98
The D/A schedule of 55 mw was reduced to 39 mw (we bought back 16 mw @ $ 44.98) this is shown in
To CPX AC 55 to 39 ,
To CPX –AC Memo 16 mw @ $ 64.72
Fr CPX –AC -16 mw @ $ 44.98

We adjusted to D/A schedule to the H/A schedule , we then submitted a Supplemental Energy Bid to buy back the Final H/A schedule (39 mw) at $ 12
We were notified at 1530 by phone from the PX that our Supplemental Energy Bid to buy back the schedule had been excepted and the schedule was reduced from 39 mw to 4 mw , the price we were willing to pay for the energy was $ 12 , but due to extreme congestion the PX paid us $ 25/mwh to take the energy back.
This is shown in the PPS 400
To CPX –AC 39 to 4 mw
To CPX –AC Memo (detail 2) 35 mw @ $ 64.72
Fr CPX – AC Memo (detail 2)- 35 mw @ $-25

How much did we make $$$?

For the 4 mw we sent to them we were paid ***$928.73/MWH***

CC: Bill Casey

CA Term Trading Strategy

1. Focus primarily on directional bets and locational / near term time spreads, no long dated time spreads or options (maybe later). Get CPX block forwards going and include ancillary services activity to increase value over just energy positions (currently believe we are more knowledgeable in these markets).

2. Start with dailies and balance of month to pick up rhythm of market and ramp smoothly into prompt month position and eventually longer dated positions.

3. Use a time-weighted approach with heaviest emphasis (at least to start) on current and prompt month activity. Apply a monotonically decreasing weight on activity with an increasing time horizon.

4. Use a fundamentals informed trading strategy but maintain close connection to market to capitalize "market perceptions / shocks". Look for apparent mispricings based upon fundamentals, especially in those months where the CA market has been determined to be competitive. Spend effort to gain better than market knowledge of CA hydro to better anticipate its effect of prices. Currently our knowledge is ok but markets' is worse on average, belief is that better understanding ca hydro impacts will lead to incremental value for PGE.

5. Rely on creating value in term markets through daily markets. Rely on knowledge of ISO / PX rules to leverage additional value out of term positions. For example, potentially using portion of term position to take advantage of congestion revenues in ISO.

6. Consider activity at all points into CA and SW markets. Include potential activity at PV, NP, SP, Mead, 4 Corners, COB (in concert w/ PL & KM). When it makes sense, look to move SW power up to NW to aid in PGE position.

California ISO Bidding Policy

Numerous questions have been raised regarding how and when we should bid into the California ISO. This policy describes departmental expectations and sets guidelines for dealing with the California ISO.

Bidding Policy

1) On-shift personnel should continually monitor ISO activity:
   a) ISO Beep prices (updated @ 10 minute intervals).
   b) ISO Ex-Post Schedule/Price Info - Interchange (updated @ ~ 15 minutes after the hour).
   c) ISO Message System for notices of inter-zonal congestion and other events which may affect bidding decisions.
2) Energy bids to the ISO should be submitted each hour that flexibility exists to accommodate the award of a bid.
   a) Each scheduling hour the Generation Coordinator will convey, along with the amount of required energy transaction, the available PGE system flexibility.
   b) Each scheduling hour the Energy Scheduler will assess the energy market and the ability to buy and sell as may be necessary to accommodate various levels of bidding.
   c) Each scheduling hour the Energy Scheduler will identify transmission availability to accommodate both sales and purchases with the ISO.
   d) After reviewing the available information, the Real-Time Team shall be responsible for submitting bids to both buy and sell to the ISO each hour.
   e) If bids are not submitted, a reason shall be given each hour and logged in the Generation Coordinators Log.

Pricing Policy

1) Pricing of bids to sell to the ISO should be based on an evaluation pricing throughout the entire wholesale market.
   a) Each scheduling hour the Energy Scheduler will assess the energy market and determine based on the 10-Minute Beep, the profits associated with being awarded a bid.
   b) If the 10-Minute Beep prices are at or below market prices, the bid price should be at or above market prices.
   c) If the 10-Minute Beep prices are significantly above market prices, the real time team should evaluate the need to bid -$750. For example, when a market priced bid has been submitted but not accepted for several hours may warrant bidding -$750.

We believe it is highly unlikely that the ISO would be in a buy mode if the Market Clearing Price is negative. Since the ISO pays the higher of the Bid Price or the Market Clearing Price, if we are awarded a bid we believe the worst case pricing would be in the range of $0.00/MW. This being the case there appears to be little gained by submitting bids above -$750 when less than zero. One exception to this may be during periods of inter-zonal congestion when regardless of the MCP we will be billed our Bid price.

2) Pricing of bids to buy from the ISO should be based on an evaluation of pricing throughout the entire wholesale market and the dispatch cost of generating units which may be backed off to accommodate the purchase.
   a) Each scheduling hour the Generation Coordinator will assess the units available to displace and determine a price for each increment of displacement.
      i) Incremental dispatch costs for thermal plants are published daily and are located throughout the Scheduling Guidelines.
      ii) Incremental dispatch costs for hydro are based on the availability of shifting generation between differing price periods(on-peak to off-peak)
   b) Bid prices should be calculated for each increment of displaced energy.

$$\frac{(\text{Dispatch cost})-(\text{Margin})-(\text{Wheeling Access Charge})-(\text{Grid Management Charge})}{(1+\text{Operating Reserve Charge})}$$

<OR>

$$\frac{(\text{Dispatch cost})-(\text{Margin})-(\$3.93)-(\$0.7831)}{1.07}$$

Unscheduled Flow Mitigation Plan Reports for SCs

Originally, the ISO thought it could meet its reporting obligation for the WSCC Unscheduled Flow Mitigation Plan (USFMP) by requiring the SCs to individually complete their own report and send it to the ISO, in accordance to "Unscheduled Flow ISO Operating Procedure" S-301. The ISO would then prepare a cumulative report and forward it to WSCC. This procedure has not worked.

Most SCs simply are not sending the ISO the required information I a timely manner. The SC information that is received is not consistent with our records and is not in the form required by the USFMP for reporting. WSCC places the ultimate responsibility for reporting this information on the Control Area. The ISO has and will continue to prepare this report for the entire control area with one exception.

If an SC is a WSCC member or provides data on behalf of a WSCC member, which prefers to transmit their report directly to WSCC, the ISO and WSCC (in a letter sent out in April of this year) have asked all SCs route their reports through the ISO, to assure that the data is not double reported. Although WSCC requires all members to submit this information with the WSCC staff feel that it would be better that the member not send data at all, then to have it duplicated.

Since the ISO compiles USFMP data for the entire Control Area using our own database, it is no longer necessary for the SC to send USFMP information. Once the ISO has sent the Control Area report to WSCC, it will send to each SC its respective data. This change to Procedure S-301 will be reflected in a complete rewrite of the procedure shortly.

Some of the assumptions used by the ISO to complete the required WSCC USFMP Import report are highlighted below, in conjunction with some observations concerning the report's requirements.

1 The list of generating sources in the Import program does not match the list of Sending Areas in the WSCC USFMP matrix, nor do they match up on required information on NERC E-tags. It would be preferable if the E-tag indicated scheduled use of an USFMP qualified path. It is also difficult to determine if the generation was from specific generation plants.

2 There is a built in bias for being too specific when reporting source information. Example: Case 1 – The only schedules we have are a 100MWh import from FC4 and 100MWh export to APS, our net import is only the 100MWh from FC4. Case 2 – we choose to report schedules by only Control Area, CA, (or we do not know this is coming specifically from FC). Our net import is now zero.

A similarly effect happens when importing and exporting to CA in the same area. Example: If exporting 100MWh to the PSE CA and an USFMP event is declared on Path 31, we can import 100MWh from the PSE CA in real time (RT), because the net import before and after is still zero, but we cannot import from BPA in RT even though, for loads in N California, both are 3% contributors to Path 31.

3 Since the ISO does not yet have a way to freeze what the schedules are exactly when a USFMP event is declared, we are using the schedules as agreed to the previous day with all our adjacent CA as "pre-scheduled". Scheduling Coordinator can submit schedules into their workspace in the ISO scheduling system any time after the close of the Day-ahead, but they do not show in any of the ISO displays or programs until two hour before the hour starts. Example: Say an USFMP event was declared and contributing schedule cuts requested at 09:00 starting for HE11 and continues until HE18, for HE14 the ISO cannot tell if Hour-ahead schedules was submitted at 08:59 or 09:22 or any time except it had to be before 11:00. We are working on this and hope to have it fixed when our new Procedure S-301i takes effect.

4 These import reports include all net imports into the CA, ISO. This includes WSCC members inside the ISO. So far, no WSCC members inside the ISO who are sending import data directly into WSCC are also sending those reports to the ISO. In these cases information will be double reported. We do not believe the WSCC members, PG&E, SCE and SDGE are reporting and CDWR has agreed to stop reporting, so for these entities net imports will not be double reported.

5 As in 3 above, there is a built in bias for aggregating information for reporting on the load side. Example: If the only intertie schedules the CA – ISO had was an import from BPA to SMUD of 100MWh and an

export of 100MWh from MID to BPA, the net import for SMUD is 100MWh and zero for MID, but also zero for the CA – ISO.

6 The USFMP rules are also biased against the practice of RT changes. The whole plan was predicated by the concept of one to deal with pre-scheduled transactions. After the rules for pre-schedules was established it was decided RT changes are only allowed if the net effect of all RT changes does not add to the effected path. The ISO has experienced under scheduling of load by large amounts on a pre-scheduled basis that must be made up in RT and our Tariff has discourages us from arranging to meet this deficit for more than an hour at a time. The way the ISO reads the USFMP and its Administrative Practices, the intention to continue a specific schedule or the intention to continue the same level of imports, but from various providers does not count as pre-scheduled. It must be physically scheduled in the CA software at the time the event is declared. When the ISO is importing large amounts each hour of supplemental energy each hour from whom ever is the least cost (per our tariff), it is difficult to not continue when an USFMP event is declared.

I have re-written our USFMP procedure, S-301, to clarify how to select RT supplemental energy during an USFMP event as follows;

> After pre-schedules have been established no new schedules shall be allowed where the CAISO is the importing Control Area with the following exceptions;
>
> > i. unless, the net effect of all such imports helps unload the declared path or has no effect per the USFMP diagrams, Attachment D,
> >
> > ii. unless, not importing will force the ISO into a Stage 3 Emergency (the Security Coordinator will notify the effected USFMP path operator),
> >
> > iii. iii. unless, it is an energy conversion of a "pre-scheduled" A/S (the Security Coordinator will notify the effected USFMP path operator) or
> >
> > iv. unless, other actions are taken to unload the path, such as scheduling directly on the effected path in the counter direction of the actual flow or splitting BEEP (for Path 15). This must be well documented as actions taken for USF relief with specific amounts (or estimates) and for which path.

Administrative Practice 004 defines how to treat pre-schedules during Competing Requests for Qualified Path Relief, but not how to treat RT schedules. It also does not say how to treat a schedule on one qualified path and contributing to another qualified path. We have several schedules that was not curtailed as part of the accommodation on one path and was contributing to another path to the point that if the contributing part was analyzed by itself would have needed to be curtailed. In all of these cases we did not curtail the contributing schedules. Applying Practice 004 to schedules from BONZ and GAD means these schedules should not have curtailed (and we did not) – for BONZ, -41% and 26%, path 30 & 31 resp.; 26/540 < 2x41/509: and for GAD, -12% and 11%, path 30 & 31 resp.; 11/540 < 2x12/509.

7 Another predication of the plan is that all use of the transmission systems was represented by energy transactions. The ISO deals in another product using transmission. This product is Ancillary Services (A/S). The assumption we have made is, if the A/S is pre-scheduled by being in the ISO scheduling software at the time an event is declared, then the conversion to energy is allowed even during the event. The ISO is treating the pre-scheduled contributing A/S similar to a pre-scheduled contributing energy schedule in the sense we will reduce the amount of A/S according to the WSCC USFMP matrices. Example: An A/S schedule would need to be curtailed 10% pre-scheduled 20MW – we would curtail the A/S schedule to 18MW and allow up to 18MW of converted energy.

8 The ISO views dynamic generation/load similar to 8 above. Dynamics have a maximum rating. This is their capacity (contractual or physical). That capacity is deemed available through the pre-scheduled period. Even though they may have been estimated on a pre-scheduled basis to be a certain amount they may go up to the maximum in RT. To the extent they do this is only converting the pre-scheduled capacity to energy. The only difference we see is we have no way at this time to reduce the maximum amount that may be delivered.

9 For simplicity the designation of ISON and ISOS as the load was determine by what tie was used for the import. Imports at Cascade, COB and SPP's Summit were designated as sinking in ISON, all others ISOS.

10 To determine contributions for schedules on a DC line, we used the diagram for contributions before and after it got onto the DC.

11 Since RT changes do not currently require NERC tags the determination of the generating area for RT changes was from what little information available. If no determination could be made, the adjacent CA at that tie was used.

12 Data used has not been totally been checked (NERCed) out between the CAs.

13 The only individual schedules we can readily find using Path 15 are ones using Existing Transmission Contracts (ETC). These are so few that we have not included any on this report, i.e., no ISON to/from ISOS schedules.

14 As well as not counting wheeling schedules in our net imports, we have not included ricochet schedules, which are schedules going out to an intertie point then coming back into the ISO, so generation and load are both inside the ISO.

15 The new FERC order will help the ISO in some of the above problems by requiring 95% of the load to be met on a forward basics.

MEMORANDUM

To: Robin Tompkins

From: Tami Parr

Date: 12/14/00

Re: CAISO Netting

According to Joe Taylor, the circulating MW transaction has been negotiated between PGE and CAISO outside of the provisions of the Tariff, pursuant to CAISO's Emergency Powers. I looked at the Tariff to see if it gives any guidance for such transactions, particularly regarding settlements and/or netting. I did not find any guidance on this issue in the FERC order establishing the CAISO (81 FERC 61,122).

The CAISO Dispatch Protocol provides for 3 types of "emergencies" – a System Alert, a System Warning, and a System Emergency. (see Dispatch Protocol (DP) Section 10—I have this). The DP provides that, in a System Warning state, CAISO can "in accordance with Good Utility Practice, take such steps as it considers necessary to ensure compliance with Applicable Reliability Criteria, including the negotiation of Generation through processes other than competitive bids." (DP 10.1.2). Section 2.3 of the Tariff states that the ISO "shall take such action as it considers necessary" in the event of a System Emergency, acting in accordance with Good Utility Practice. During a System Emergency, CAISO can intervene in market operations pursuant to guidelines in DP 10.2.3. CAISO's Emergency Procedures (E-508) also provide that the ISO can, during a Stage 1 Emergency, attempt to acquire "by any means, including non-competitive bid, additional resources in an Amount sufficient to maintain minimum Operating Reserve" (E-508, Section 1.1.6). This establishes CAISO's authority, during specific situations, to negotiate outside the Tariff. Since November 13, the CAISO has been in either a System Warning state or a System Emergency state (with the exception of a few days (Dec. 1 and 2)).

I was not able to find any specific provisions in the Tariff containing guidelines for outside-the-Tariff negotiations. The DP does contain a price provision governing certain situations during a System Emergency, however. It provides, in 10.2.3(d), that during a System Emergency, the CAISO's Administrative Price for Congestion Management (which is one way to describe the circulating MW transaction with PGE) shall be set at the applicable market price during the immediately preceding Settlement Period. I did not find any provisions in the DP or the Tariff specifically governing settlements or netting arrangements pursuant to these prices, however. The only other constraining force on outside negotiations seems to be that the negotiations should be in accordance with "Good Utility Practice," defined in the Tariff (Appendix A) as:

> Any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods or acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been

expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be any one of a number of the optimum practices, methods or acts to the exclusion of all others, but rather to be acceptable practices, methods or acts generally accepted in the region.

The Tariff gives CAISO some leeway during a System Warning and System Emergency to operate outside of its constraints. Presumably the specifics (oral, written, etc.) of any particular transaction entered into during these heightened states would control that transaction. As such, parties could probably agree to settle out/net various exchanges if they chose to do so, as long as that is a common practice in the industry and/or it was expedient and reasonable, given the situation.

From: BILL CASEY
To: ROBIN TOMPKINS
Date: Wed, Dec 13, 2000 8:24 AM
Subject: CAISO Circulating MWs

Robin,

The practice is to help reduce congestion on their Path 15 which is located in about the middle of California and is electrically constrained. In this case they need relief from too much energy going south to north within California and we are purchasing power from them on the DC, which takes power out of Southern California, and we sell back to them on the AC which is putting it back into Northern California. We have an agreement with CAISO that they will manually adjust out by showing a payment to us for the export fees starting yesterday. We have also reduced our exposure to them on this transaction by setting the purchase price at $0 and the sell at $100. This will eliminate the amount shown we owe them. The only outstanding piece will be the losses and transmission costs, of which they should be minimal and are not with CAISO. I am waiting to hear from them on how far back they are willing to nullify the fees. If needed we can pursue reducing the purchase price on the circulating transactions to $0 historically which is about Sunday.

Any questions please let me know.

Thanks,
Bill

CC: Terri Peschka

From: BILL CASEY
To: Joseph TAYLOR
Date: Wed, Dec 13, 2000 8:26 AM
Subject: Fwd: CAISO Circulating MWs

Just wanted to verfiy I am not under or overstating our position.

From: Joseph TAYLOR
To: BILL CASEY
Date: Wed, Dec 13, 2000 8:40 AM
Subject: Re: CAISO Circulating MWs

Well put. Let me know if you want me to pursue corrections.

>>> BILL CASEY 12/13/00 08:24AM >>>
Robin,

The practice is to help reduce congestion on their Path 15 which is located in about the middle of California and is electrically constrained. In this case they need relief from too much energy going south to north within California and we are purchasing power from them on the DC, which takes power out of Southern California, and we sell back to them on the AC which is putting it back into Northern California. We have an agreement with CAISO that they will manually adjust out by showing a payment to us for the export fees starting yesterday. We have also reduced our exposure to them on this transaction by setting the purchase price at $0 and the sell at $100. This will eliminate the amount shown we owe them. The only outstanding piece will be the losses and transmission costs, of which they should be minimal and are not with CAISO. I am waiting to hear from them on how far back they are willing to nullify the fees. If needed we can pursue reducing the purchase price on the circulating transactions to $0 historically which is about Sunday.

Any questions please let me know.

Thanks,
Bill

AFFIDAVIT

State Of Oregon)
) ss:
County of Multnomah)

I, Aubrey Williams Turner, Jr., being duly sworn, depose and state:

I am an Assistant General Counsel with Portland General Electric Company (PGE). In July of 1999, I called John G. Klauberg with the New York office of LeBoeuf, Lamb, Greene and MacRae (LeBoeuf), seeking a legal opinion of a transaction Enron Power Marketing, Inc. (EPMI) was proposing to PGE. The transaction is roughly described in the attached 4 page document from John Maas, another LeBoeuf attorney. Some of LeBoeuf's documentation of communications with me, especially that written by Mr. Mass, indicate a willingness or desire on PGE's part to participate in the transaction EPMI was proposing. In fact, I told Mr. Klauberg in all of our communications that PGE had already rejected EPMI's request, and EPMI asked that PGE reconsider that decision. I therefore called Mr. Klauberg seeking a legal opinion that would support our decision to reject the request. I never indicated any support for EPMI's proposal.

Dated this 21st day of May, 2002

Aubrey Williams Turner, Jr.

Sworn to before me this 21st day of May, 2002.

Bari H. Gilbert

NOTARY PUBLIC, State of Oregon

My Commission Expires: 12/28/2004

OFFICIAL SEAL
BARI H. GILBERT
NOTARY PUBLIC-OREGON
COMMISSION NO. 341511
MY COMMISSION EXPIRES DEC. 28, 2004

LeBoeuf, Lamb, Greene & MacRae
L.L.P.
A LIMITED LIABILITY PARTNERSHIP INCLUDING PROFESSIONAL CORPORATIONS

633 Seventeenth Street
Suite 2000
Denver, CO 80202

August 2, 1999

TO: File

FROM: John Mass

RE: Power Transaction

FACTS

Note: Some of this requires further investigation and may be more or less incorrect.

The facts contemplate a potential power transaction between two companies: "EPMI," a large power marketing concern (which is not a utility and whose only business is trading power) and PGE ("Affiliate") an electric utility regulated by the Oregon Public Utility Commission. Affiliate and EPMI are wholly-owned subsidiaries of the same ultimate parent, Enron Corp.

The parties intend to enter into a contract (for an unspecified term) providing for Affiliate to serve as the "sink" for any large power transactions (say, 400MW) entered into between EPMI and any third parties (but not Affiliate) for delivery of such 400MW from anywhere in California or Nevada to one of several standard delivery points located at the California-Oregon border ("COB"). The "sink" is the jargon used to generically refer to the party into whose "control area" (a utility electrical system providing power to end users in a specified territory) the power transmitted in connection with a power transaction "leaves the transmission system," and does not necessarily mean the ultimate buyer of the power (i.e., the "sink" could be responsible to transmit the power further along to another party or could have agreed to receive the power on another party's behalf). The "source" is the point where the power in the transaction enters the transmission system for purposes of the power contract and could be the point of interconnection with a generating plant or simply a point at which the seller takes "delivery" of the power from its seller in turn. Power flowing north (and south) from California to the Pacific Northwest generally flows on a very large 500kV transmission system known as the Pacific Northwest Intertie ("Intertie"). The Intertie is a key resource to *flow power north to south from* the Pacific Northwest *into* California during periods of peak usage in California.

Under the contract, Affiliate will receive a fee for agreeing to be obligated to serve as the sink for all power which EPMI contracts to sell to third parties who can take delivery at COB or otherwise in the Pacific Northwest. However, EPMI has no real plans to enter into any such contracts and Affiliate knows that it is unlikely to ever be called to serve as such

DN 103473.1 61540 00308
8/2/99 10:06 AM

sink. Rather, the sole commercial purpose of the transaction is to afford EPMI the ability to "schedule" with the California Independent System Operator ("ISO") the 400MW of power for transmission from South (California) to North (COB) on the Intertie each day or whenever it wishes to do so, even though it does not, at the time of such scheduling, have either a contract to sell the power to a third party or, at the time of the scheduling, any present intention to enter into such a contract. EPMI cannot schedule the power without providing the identity of the source and sink. The scheduling would be done simply to reserve the necessary transmission capacity with the ISO, solely on a "non-firm" or interruptible basis (that is, if the ISO needs the transmission capacity for a more important or "firm" transaction, it can "bump" EPMI from the schedule at any time) in case EPMI were to find an opportunity to enter into a favorable transaction, although, as stated, it would have no actual intention of doing so at the time of the scheduling.

The ISO is an organization in California charged with scheduling all of the power flows across the transmission system for each hour of each day in California. The ISO has a tariff on file with the Federal Energy Regulatory Commission ("FERC") which provides for the prices and terms under which parties can acquire and reserve transmission on the system ("ISO Tariff") and FERC has exclusive jurisdiction over all "wholesale" power transactions in the United States. A wholesale transaction is between two parties neither of whom is the end user of the power. "Retail" transactions are where one of the parties actually consumes the power (i.e., to keep the lights on or run machinery) and are regulated exclusively by the state PUCs.

Early in the morning of each day, all of the certificated "scheduling coordinators" in California (including EPMI) must provide their schedules for power transactions and flows to the ISO for the next day so that the ISO can "balance" the transmission system. This is necessary because, due to the physical properties of electricity and power lines, if there is an imbalance between the amount of power put into the system by generating plants and the amount of power taken out of the system by end users, the system will "crash," much like our computers but with even more annoying results. The ISO's job is to make sure this doesn't happen while treating all users of the system fairly and equally with respect to priority of their transactions. The ISO must balance the system by obtaining other power or reductions in power input into the system (or in some cases, reductions in power taken out of the system) and this power is known as "ancillary services."

All power to be put into the system in California, is required to be "sold" through the California Power Exchange ("PX"), which basically acts as a market clearinghouse to set the prices and availability of power in California, except for certain ancillary services which the ISO can acquire directly from any party having them available for sale. Just like the ISO, early in the morning of each day, all parties who have power to sell into the system must "bid" the power into the PX, showing the amounts, hours and prices at which they are willing to sell. The ISO tells the PX how much power will be needed and for what hours, based upon the "day ahead" schedules filed by the scheduling coordinators, and the PX selects the parties to provide the power based upon their bids, going from lowest to highest (the price, I think, for everyone for a particular hour is the highest price that the PX reaches in order to satisfy the demand). (This is simplified to a considerable degree for our purposes.) With respect to ancillary services however, particularly for large, urgent transactions, the PX is not used and the ISO must pay whatever the market may be in order to preserve the balance of the system.

Power transactions, however, are constantly changing due to weather conditions and many other factors; therefore, it is necessary for the ISO to constantly adjust its schedules as each day and hour approach. The scheduling coordinators are required to update their schedules to reflect changes in their transactions and this often takes place in the "hour ahead" time frame, since the likely ultimate demand in a particular hour cannot finally be known until very close to the real time thereof. Thus, in our transaction, EPMI will file an "hour ahead" schedule releasing the non-firm transmission capacity it previously scheduled for its 400MW moving south to north over the Intertie when it files its schedule for the hour preceding the hour when that transaction otherwise would have begun.

Whenever this happens, there is created an imbalance in the system because the ISO was planning for this 400MW to be input into the system at the source (somewhere in California) and to be taken out of the system at COB by the sink, Affiliate and had arranged to balance the system accordingly. When a relatively small amount of power is involved, it is easy for the ISO to obtain the ancillary services necessary to manage this imbalance. However, if a very large amount is involved, such as our 400MW, it is more difficult for the ISO to obtain the ancillary services, especially at times of peak usage, because all of the generators are already committed and running full tilt and there is very little time in which to act. At such times, the laws of supply and demand operate to give a party that has power available a premium price. EPMI plans to have power available to take advantage of this opportunity which it will, in effect, to some degree have created. The result will be that the ultimate parties buying power in California to balance their systems and serve their end users (the utilities) will pay the ISO more for such power than they otherwise might have done had the 400MW not been scheduled and withdrawn.

EPMI and Affiliate believe this arrangement, while admittedly unusual, is lawful under the ISO Tariff because the ISO Tariff, apparently (I will be looking at this) does not require a transaction to have been already entered into as a prerequisite for having your scheduling coordinator schedule the amount of power for the transaction on a non-firm or interruptible basis, which is inexpensive because it can freely be bumped. This, EPMI believes it is acceptable under the ISO Tariff to schedule transmission for power that you know you are unlikely to need, or even that you know you will not need.

EPMI believes this represents a window of opportunity or "loophole" in the design of the new competitive marketplace in California which can be exploited to make a profit when the ISO has to "scramble" at the last minute to obtain ancillary services necessary to balance the system when the 400 MW non-firm schedule is withdrawn at the last minute. Because this market is new and developing, various parties have been able to exploit other such loopholes and make large profits as a result, but, insofar as we are aware, none of those transactions has involved a contract or agreement between two parties (or affiliates) but only a single party "gaming" the system by, say, the way in which it structures its bids for power to the PX. Many of these parties, particularly the utilities or very large generators, have information unavailable to the rest of the market that enable them, in EPMI's view, to manipulate the process to varying degrees that would not work if the market were fully informed.

The response so far of the entitiess charged with making this market work - the PX, the ISO and several market surveillance or compliance committees - has largely been to conduct investigations and make reports to the California regulatory authorities and FERC and then to file a revised ISO Tariff seeking to close the loopholes and make the market more efficient. EPMI feels that if this is likely to be the only response to the proposed transaction, then it would be foolish not to exploit the loophole to make a profit for its shareholders until the loophole is closed. However, if EPMI or Affiliate could be exposed to substantial damages or fines or other penalties, whether criminal or civil, then it will not enter into the proposed transaction. Affiliate has asked us to advise it on this question and whether it should agree to serve as the sink for the proposed transaction.

From: "John Klauberg" <jklauber@LLGM.COM>
To: <AW_Turner@pgn.com>
Date: 05/21/2002 1:02PM
Subject: Your Call Today

A.W.: I came over to our Denver office quickly to pick up your e-mail regarding the submission PGE will be making to FERC. My general recollection is that when you called us in July 1999 about the transaction in question you stated that EPMI had approached PGE about a possible energy transaction between EPMI and PGE involving the California ISO that PGE did not feel comfortable with. I also recall that after you briefly gave me an overview of the transaction, even though I was not familiar with the California ISO or its operating rules that may have been at issue, that I had the same initial reaction from a "gut" standpoint. My further recollection is that regardless of what the applicable ISO tariffs may have provided, our collective sense at the outset was that upon looking into the issues further there likely would be a number of legal theories (or potential causes of action) which would support the position that PGE should not participate in the transaction you posited. Please call me if you have any questions.
John

John Klauberg
LeBoeuf, Lamb, Greene & MacRae, L.L.P.
212 424-8125
john.klauberg@llgm.com

CC: <douglas_nichols@pgn.com>

Fact-Finding Investigation of
Potential Manipulation of Electric
and Natural Gas Prices

FERC Docket No. PA02-2-000

ATTACHMENT
III.B

SUMMARY OF TRANSACTIONS

OCCURING DURING 17 DAYS BETWEEN

APRIL 6 – JUNE 6, 2000

STUDY DATED MAY 21, 2002

Details of Transactions Described in Section III.B

	HE	Fr CISO WWPC Firm AC			To WWPC Sale MC Memo			Fr EPMI MC MEMO			To BPA PGE EPMI JD			To BPA EPMI (PGESYS)		
		MW		Price	MW		Price	MW		Price	MW		Price			
04/06/2000	10	-25	@	$28.25	25	@	$28.00	-25	@	$30.44	25	@	$31.44			
	11	-25	@	$28.25	25	@	$28.00	-25	@	$30.44	25	@	$31.44			
	12	-25	@	$28.25	25	@	$28.00	-25	@	$30.44	25	@	$31.44			
	16	-40	@	$26.25	40	@	$26.00	-40	@	$30.44	40	@	$31.44			
	17	-25	@	$26.25	25	@	$26.00	-25	@	$30.44	25	@	$31.44			
	19	-40	@	$26.25	40	@	$26.00	-40	@	$30.44	40	@	$31.44			
04/15/2000	12	-24	@	$17.00	24	@	Records Incomplete*	-24	@	$22.69	24	@	$23.59			
	13	-24	@	$17.00	24	@	Records Incomplete*	-24	@	$22.69	24	@	$23.59			
	14	-24	@	$17.00	24	@	Records Incomplete*	-24	@	$22.69	24	@	$23.59			
	15	-24	@	$17.00	24	@	Records Incomplete*	-24	@	$22.69	24	@	$23.59			
	16	-24	@	$17.00	24	@	Records Incomplete*	-24	@	$22.69	24	@	$23.59			
	17	-24	@	$17.00	24	@	Records Incomplete*	-24	@	$22.69	24	@	$23.59			
	18	-24	@	$17.00	24	@	Records Incomplete*	-24	@	$22.69	24	@	$23.59			
	19	-24	@	$17.00	24	@	Records Incomplete*	-24	@	$22.69	24	@	$23.59			
	20	-24	@	$17.00	24	@	Records Incomplete*	-24	@	$22.69	24	@	$23.59			
	21	-24	@	$17.00	24	@	Records Incomplete*	-24	@	$22.69	24	@	$23.59			
	22	-24	@	$17.00	24	@	Records Incomplete*	-24	@	$22.69	24	@	$23.59			
	23	-24	@	$17.00	24	@	Records Incomplete*	-24	@	$13.51	24	@	$14.41			
	24	-24	@	$17.00	24	@	Records Incomplete*	-24	@	$13.51	24	@	$14.41			
04/16/2000	3	-24	@	$17.00	24	@	Records Incomplete*	-24	@	$16.75	24	@	$17.65			
	13	-24	@	$15.00	24	@	Records Incomplete*	-24	@	$26.13	24	@	$27.03			
	14	-24	@	$15.00	24	@	Records Incomplete*	-24	@	$26.13	24	@	$27.03			
	15	-24	@	$15.00	24	@	Records Incomplete*	-24	@	$26.13	24	@	$27.03			
	16	-24	@	$15.00	24	@	Records Incomplete*	-24	@	$26.13	24	@	$27.03			
04/23/2000	3	-45	@	$3.00	45	@	$2.00	-45	@	$12.25	45	@	$13.15			
	4	-45	@	$3.00	45	@	$2.00	-45	@	$12.25	45	@	$13.15			

*Records Incomplete - Investigating Accounting Error

	HE	Fr CISO WWPC Firm AC			To WWPC Sale MC Memo			Fr EPMI MC MEMO			To BPA PGE EPMI JD			To BPA EPMI (PGESYS)		
		MW		Price	MW		Price	MW		Price	MW		Price			
04/26/2000	11	-29	@	$40.00	29	@	$39.00	-29	@	$28.44	29	@	$29.34			
	12	-29	@	$40.00	29	@	$39.00	-29	@	$28.44	29	@	$29.34			
	13	-29	@	$40.00	29	@	$39.00	-29	@	$28.44	29	@	$29.34			
	14	-29	@	$40.00	29	@	$39.00	-29	@	$28.44	29	@	$29.34			
	15	-29	@	$40.00	29	@	$39.00	-29	@	$28.44	29	@	$29.34			
	16	-29	@	$40.00	29	@	$39.00	-29	@	$28.44	29	@	$29.34			
	17	-29	@	$40.00	29	@	$39.00	-29	@	$28.44	29	@	$29.34			
	18	-29	@	$40.00	29	@	$39.00	-29	@	$28.44	29	@	$29.34			
	19	-29	@	$40.00	29	@	$39.00	-29	@	$28.44	29	@	$29.34			
	20	-29	@	$40.00	29	@	$39.00	-29	@	$28.44	29	@	$29.34			
	21	-29	@	$40.00	29	@	$39.00	-29	@	$28.44	29	@	$29.34			
	22	-29	@	$40.00	29	@	$39.00	-29	@	$28.44	29	@	$29.34			
05/01/2000	12	-25	@	$40.00	25	@	$40.00	-25	@	$34.46				25**	@	$35.36
	13	-25	@	$40.00	25	@	$40.00	-25	@	$34.46				25**	@	$35.36
	14	-25	@	$40.00	25	@	$40.00	-25	@	$34.46				25**	@	$35.36
	15	-25	@	$40.00	25	@	$40.00	-25	@	$34.46				25**	@	$35.36
	16	-25	@	$40.00	25	@	$40.00	-25	@	$34.46				25**	@	$35.36
	17	-25	@	$40.00	25	@	$40.00	-25	@	$34.46				25**	@	$35.36
	18	-25	@	$40.00	25	@	$40.00	-25	@	$34.46				25**	@	$35.36
	19	-25	@	$40.00	25	@	$40.00	-25	@	$34.46				25**	@	$35.36
	20	-25	@	$40.00	25	@	$40.00	-25	@	$34.46				25**	@	$35.36
	21	-25	@	$40.00	25	@	$40.00	-25	@	$34.46				25**	@	$35.36
	22	-25	@	$40.00	25	@	$40.00	-25	@	$34.46				25**	@	$35.36
05/02/2000	12	-15	@	$44.00	15	@	$44.00	-15	@	$49.77	15	@	$50.67			
	13	-15	@	$44.00	15	@	$44.00	-15	@	$49.77	15	@	$50.67			
	14	-15	@	$44.00	15	@	$44.00	-15	@	$49.77	15	@	$50.67			
	15	-15	@	$44.00	15	@	$44.00	-15	@	$49.77	15	@	$50.67			
	16	-15	@	$44.00	15	@	$44.00	-15	@	$49.77	15	@	$50.67			
	17	-15	@	$44.00	15	@	$44.00	-15	@	$49.77	15	@	$50.67			
	18	-15	@	$44.00	15	@	$44.00	-15	@	$49.77	15	@	$50.67			
	19	-15	@	$44.00	15	@	$44.00	-15	@	$49.77	15	@	$50.67			
	20	3	@	$44.00	3	@	$44.00	-3	@	$49.77	3	@	$50.67			
	21	-15	@	$44.00	15	@	$44.00	-15	@	$49.77	15	@	$50.67			
	22	-15	@	$44.00	15	@	$44.00	-15	@	$49.77	15	@	$50.67			

**** Transaction accounting is inconsistent with phone recordings that indicate delivery to John Day**

	HE	Fr CISO WWPC Firm AC			To WWPC Sale MC Memo			Fr EPMI MC MEMO			To BPA PGE EPMI JD			To BPA EPMI (PGESYS)		
		MW		Price	MW		Price	MW		Price	MW		Price			
05/03/2000	10	-13	@	$32.00	13	@	$32.00	-13	@	$63.76	13	@	$64.66			
	11	-13	@	$32.00	13	@	$32.00	-13	@	$63.76	13	@	$64.66			
	12	-20	@	$32.00	20	@	$32.00	-20	@	$63.76	20	@	$64.66			
	13	-20	@	$32.00	20	@	$32.00	-20	@	$63.76	20	@	$64.66			
	14	-20	@	$32.00	20	@	$32.00	-20	@	$63.76	20	@	$64.66			
	15	-20	@	$32.00	20	@	$32.00	-20	@	$63.76	20	@	$64.66			
05/04/2000	12	-10	@	$30.00	10	@	$30.00	-10	@	$37.51	10	@	$38.41			
	13	-4	@	$30.00	40	@	$30.00	-4	@	$37.51	4	@	$38.41			
	14	-10	@	$30.00	10	@	$30.00	-10	@	$37.51	10	@	$38.41			
	15	-10	@	$30.00	10	@	$30.00	-10	@	$37.51	10	@	$38.41			
	16	-10	@	$30.00	10	@	$30.00	-10	@	$37.51	10	@	$38.41			
	17	-10	@	$30.00	10	@	$30.00	-10	@	$37.51	10	@	$38.41			
	18	-10	@	$30.00	10	@	$30.00	-10	@	$37.51	10	@	$38.41			
	19	-10	@	$30.00	10	@	$30.00	-10	@	$37.51	10	@	$38.41			
	21	-10	@	$30.00	10	@	$30.00	-10	@	$37.51	10	@	$38.41			
	22	-10	@	$30.00	10	@	$30.00	-10	@	$37.51	10	@	$38.41			
05/05/2000	12	-45	@	$31.00	45	@	$30.00	-45	@	$30.97	45	@	$31.87			
	13	-45	@	$31.00	45	@	$30.00	-45	@	$30.97	45	@	$31.87			
	14	-45	@	$31.00	45	@	$30.00	-45	@	$30.97	45	@	$31.87			
	15	-45	@	$31.00	45	@	$30.00	-45	@	$30.97	45	@	$31.87			
	16	-45	@	$31.00	45	@	$30.00	-45	@	$30.97	45	@	$31.87			
	17	-45	@	$31.00	45	@	$30.00	-45	@	$30.97	45	@	$31.87			
05/09/2000	11	-15	@	$30.00	15	@	$30.00	-15	@	$39.51	15	@	$40.41			
	12	-15	@	$30.00	15	@	$30.00	-15	@	$39.51	15	@	$40.41			
	13	-15	@	$30.00	15	@	$30.00	-15	@	$39.51	15	@	$40.41			
	14	-15	@	$30.00	15	@	$30.00	-15	@	$39.51	15	@	$40.41			
	15	-15	@	$30.00	15	@	$30.00	-15	@	$39.51	15	@	$40.41			
	16	-15	@	$30.00	15	@	$30.00	-15	@	$39.51	15	@	$40.41			
	17	-15	@	$30.00	15	@	$30.00	-15	@	$39.51	15	@	$40.41			
	18	-15	@	$30.00	15	@	$30.00	-15	@	$39.51	15	@	$40.41			
	19	-15	@	$30.00	15	@	$30.00	-15	@	$39.51	15	@	$40.41			

	HE	Fr CISO WWPC Firm AC			To WWPC Sale MC Memo			Fr EPMI MC MEMO			To BPA PGE EPMI JD			To BPA EPMI (PGESYS)		
		MW		Price	MW		Price	MW		Price	MW		Price			
05/10/2000	13	-15	@	$30.00	15	@	$30.00	-15	@	$41.86	15	@	$42.76			
	14	-15	@	$30.00	15	@	$30.00	-15	@	$41.86	15	@	$42.76			
	15	-15	@	$30.00	15	@	$30.00	-15	@	$41.86	15	@	$42.76			
	16	-15	@	$30.00	15	@	$30.00	-15	@	$41.86	15	@	$42.76			
	17	-15	@	$30.00	15	@	$30.00	-15	@	$41.86	15	@	$42.76			
	18	-15	@	$30.00	15	@	$30.00	-15	@	$41.86	15	@	$42.76			
05/11/2000		-10	@	$30.00	10	@	$30.00	-10	@	$46.07	10	@	$46.97			
		-10	@	$30.00	10	@	$30.00	-10	@	$46.07	10	@	$46.97			
		-10	@	$30.00	10	@	$30.00	-10	@	$46.07	10	@	$46.97			
05/12/2000	12	-45	@	$30.00	45	@	$30.00	-45	@	$44.14	45	@	$45.04			
05/15/2000	15	-10	@	$30.00	10	@	$30.00	-10	@	$49.34	10	@	$50.24			
	16	-10	@	$30.00	10	@	$30.00	-10	@	$49.34	10	@	$50.24			
	17	-10	@	$30.00	10	@	$30.00	-10	@	$49.34	10	@	$50.24			
	18	-10	@	$30.00	10	@	$30.00	-10	@	$49.34	10	@	$50.24			
	19	-10	@	$30.00	10	@	$30.00	-10	@	$49.34	10	@	$50.24			
	20	-10	@	$30.00	10	@	$30.00	-10	@	$49.34	10	@	$50.24			
	21	-10	@	$30.00	10	@	$30.00	-10	@	$49.34	10	@	$50.24			
	22	-10	@	$30.00	10	@	$30.00	-10	@	$49.34	10	@	$50.24			
05/31/2000	23	-55	@	$65.00	55	@	$65.00	-55	@	$47.02	55	@	$47.92			
	24	-66	@	$65.00	66	@	$65.00	-66	@	$47.02	66	@	$47.92			
06/06/2000	14	-40	@	$87.00	40	@	$87.00	-40	@	$73.42	40	@	$74.32			
	15	-40	@	$87.00	40	@	$87.00	-40	@	$73.42	40	@	$74.32			

III.B-007

Summary of Transactions Described in Section III.B

	Originating Contol Area		Marketer		Marketer		Marketer		Sink/Source Contol Area		Marketer		Marketer		Marketer		Marketer		Sink * Contol Area
04/06/2000	CISO	>>>	ENE @ COB	>>>	WWP @ COB	>>>	PGE @ COB	>>>	PGE SYS	>>>	WWP @ SYS	>>>	ENE @ SYS	>>>	PGE @ SYS	>>>	ENE @ JD	>>>	CISO
04/15/2000	CISO	>>>	ENE @ COB	>>>	WWP @ COB	>>>	PGE @ COB	>>>	PGE SYS	>>>	WWP @ SYS	>>>	ENE @ SYS	>>>	PGE @ SYS	>>>	ENE @ JD	>>>	LDWP
04/16/2000	CISO	>>>	ENE @ COB	>>>	WWP @ COB	>>>	PGE @ COB	>>>	PGE SYS	>>>	WWP @ SYS	>>>	ENE @ SYS	>>>	PGE @ SYS	>>>	ENE @ JD	>>>	Can not verify
04/23/2000	CISO	>>>	ENE @ COB	>>>	WWP @ COB	>>>	PGE @ COB	>>>	PGE SYS	>>>	WWP @ SYS	>>>	ENE @ SYS	>>>	PGE @ SYS	>>>	ENE @ JD	>>>	LDWP
04/26/2000	CISO	>>>	ENE @ COB	>>>	WWP @ COB	>>>	PGE @ COB	>>>	PGE SYS	>>>	WWP @ SYS	>>>	ENE @ SYS	>>>	PGE @ SYS	>>>	ENE @ JD	>>>	Can not verify
05/01/2000	CISO	>>>	ENE @ COB	>>>	WWP @ COB	>>>	PGE @ COB	>>>	PGE SYS	>>>	WWP @ SYS	>>>	ENE @ SYS	>>>	PGE @ SYS	>>>	ENE @ JD	>>>	LDWP
05/02/2000	CISO	>>>	ENE @ COB	>>>	WWP @ COB	>>>	PGE @ COB	>>>	PGE SYS	>>>	WWP @ SYS	>>>	ENE @ SYS	>>>	PGE @ SYS	>>>	ENE @ JD	>>>	LDWP
05/03/2000	CISO	>>>	ENE @ COB	>>>	WWP @ COB	>>>	PGE @ COB	>>>	PGE SYS	>>>	WWP @ SYS	>>>	ENE @ SYS	>>>	PGE @ SYS	>>>	ENE @ JD	>>>	LDWP
05/04/2000	CISO	>>>	ENE @ COB	>>>	WWP @ COB	>>>	PGE @ COB	>>>	PGE SYS	>>>	WWP @ SYS	>>>	ENE @ SYS	>>>	PGE @ SYS	>>>	ENE @ JD	>>>	LDWP
05/06/2000	CISO	>>>	ENE @ COB	>>>	WWP @ COB	>>>	PGE @ COB	>>>	PGE SYS	>>>	WWP @ SYS	>>>	ENE @ SYS	>>>	PGE @ SYS	>>>	ENE @ JD	>>>	LDWP
05/09/2000	CISO	>>>	ENE @ COB	>>>	WWP @ COB	>>>	PGE @ COB	>>>	PGE SYS	>>>	WWP @ SYS	>>>	ENE @ SYS	>>>	PGE @ SYS	>>>	ENE @ JD	>>>	LDWP
05/10/2000	CISO	>>>	ENE @ COB	>>>	WWP @ COB	>>>	PGE @ COB	>>>	PGE SYS	>>>	WWP @ SYS	>>>	ENE @ SYS	>>>	PGE @ SYS	>>>	ENE @ JD	>>>	LDWP
05/11/2000	CISO	>>>	ENE @ COB	>>>	WWP @ COB	>>>	PGE @ COB	>>>	PGE SYS	>>>	WWP @ SYS	>>>	ENE @ SYS	>>>	PGE @ SYS	>>>	ENE @ JD	>>>	LDWP
05/12/2000	CISO	>>>	ENE @ COB	>>>	WWP @ COB	>>>	PGE @ COB	>>>	PGE SYS	>>>	WWP @ SYS	>>>	ENE @ SYS	>>>	PGE @ SYS	>>>	ENE @ JD	>>>	LDWP
05/15/2000	CISO	>>>	ENE @ COB	>>>	WWP @ COB	>>>	PGE @ COB	>>>	PGE SYS	>>>	WWP @ SYS	>>>	ENE @ SYS	>>>	PGE @ SYS	>>>	ENE @ JD	>>>	LDWP
05/31/2000	CISO	>>>	ENE @ COB	>>>	WWP @ COB	>>>	PGE @ COB	>>>	PGE SYS	>>>	WWP @ SYS	>>>	ENE @ SYS	>>>	PGE @ SYS	>>>	ENE @ JD	>>>	Can not verify
06/06/2000	CISO	>>>	ENE @ COB	>>>	WWP @ COB	>>>	PGE @ COB	>>>	PGE SYS	>>>	WWP @ SYS	>>>	ENE @ SYS	>>>	PGE @ SYS	>>>	ENE @ JD	>>>	LDWP

* **Derived through listening to taped phone conversations.** ***It was not required of Enron*** **to specify the Sink past delivery at John Day to PGE Marketing.**

	Fr CISO-WWPC Firm-AC				TRADER
	APRIL 6 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	0	0	0		
2	0	0	0		
3	0	0	0		
4	0	0	0		
5	0	0	0		
6	0	0	0		
7	0	0	0		
8	0	0	0		
9	0	0	0		
10	0	-25	25	PURCH (From: 0, To:-25 MWHs)	Terry F
11	0	-25	25	PURCH (From: 0, To:-25 MWHs)	Terry F
12	0	-25	25	PURCH (From: 0, To:-25 MWHs)	Terry F
13	0	0	0		
14	0	0	0		
15	0	0	0		
16	0	-40	40	wheel (From:-25, To: 40 MWHs)	Terry F
17	0	-25	25	wheel (From:-25, To: 0 MWHs)	Steve S
18	0	0	0		
19	0	-40	40	sale (Detail: 2, From: No Entry, To: 40)	Terry F
20	0	0	0		
21	0	0	0		
22	0	0	0		
23	0	0	0		
24	0	0	0		
	0		180		

	Fr CISO-WWPC Firm-AC				TRADER
	April 15 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	0	0	0		
2	0	0	0		
3	0	0	0		
4	0	0	0		
5	0	0	0		
6	0	0	0		
7	0	0	0		
8	0	0	0		
9	0	0	0		
10	0	0	0		
11	0	0	0		
12	0	-24	24	PURCH] (From: 0, To:-24 MWHs)	Judy M
13	0	-24	24	PURCH] (From: 0, To:-24 MWHs)	Judy M
14	0	-24	24	PURCH] (From: 0, To:-24 MWHs)	Judy M
15	0	-24	24	PURCH] (From: 0, To:-24 MWHs)	Judy M
16	0	-24	24	PURCH] (From: 0, To:-24 MWHs)	Judy M
17	0	-24	24	PURCH] (From: 0, To:-24 MWHs)	Judy M
18	0	-24	24	PURCH] (From: 0, To:-24 MWHs)	Judy M
19	0	-24	24	PURCH] (From: 0, To:-24 MWHs)	Judy M
20	0	-24	24	PURCH] (From: 0, To:-24 MWHs)	Judy M
21	0	-24	24	PURCH] (From: 0, To:-24 MWHs)	Terry F
22	0	-24	24	PURCH] (From: 0, To:-24 MWHs)	Terry F
23	0	-24	24	PURCH] (From: 0, To:-24 MWHs)	Terry F
24	0	-24	24	PURCH] (From: 0, To:-24 MWHs)	Terry F
	0	-312	312		

	Fr CISO-WWPC Firm-AC				TRADER
	April 16 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	0	0	0		
2	0	0	0		
3	0	-24	24	purch (From: 0, To:-24 MWHs)	Terry F
4	0	0	0		
5	0	0	0		
6	0	0	0		
7	0	0	0		
8	0	0	0		
9	0	0	0		
10	0	0	0		
11	0	0	0		
12	0	0	0		
13	0	-24	24	SALE FOR ENRON (From: 0, To:-24 MWH	Judy M
14	0	-24	24	SALE FOR ENRON (From: 0, To:-24 MWH	Judy M
15	0	-24	24	PURCH (From: 0, To:-24 MWHs)	Judy M
16	0	-24	24	SALE FOR ENRON (From: 0, To:-24 MWH	Judy M
17	0	0	0		
18	0	0	0		
19	0	0	0		
20	0	0	0		
21	0	0	0		
22	0	0	0		
23	0	0	0		
24	0	0	0		
	0	-120	120		

	Fr CISO-WWPC Firm-AC				TRADER
	April 23 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	0	0	0		
2	0	0	0		
3	0	-45	45	flip for epmi (From: No Entry, To:- 45)	Steve S
4	0	-45	45	flip for epmi (From: No Entry, To:- 45)	Steve S
5	0	0	0		
6	0	0	0		
7	0	0	0		
8	0	0	0		
9	0	0	0		
10	0	0	0		
11	0	0	0		
12	0	0	0		
13	0	0	0		
14	0	0	0		
15	0	0	0		
16	0	0	0		
17	0	0	0		
18	0	0	0		
19	0	0	0		
20	0	0	0		
21	0	0	0		
22	0	0	0		
23	0	0	0		
24	0	0	0		
	0	-90	90		

	Fr CISO-WWPC Firm-AC				TRADER
	April 26 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	0	0	0		
2	0	0	0		
3	0	0	0		
4	0	0	0		
5	0	0	0		
6	0	0	0		
7	0	0	0		
8	0	0	0		
9	0	0	0		
10	0	0	0		
11	0	-29	29	sale (From: 0, To:-29 MWHs) HE 11-18	Mark B
12	0	-29	29	sale (From: 0, To:-29 MWHs) HE 11-19	Mark B
13	0	-29	29	sale (From: 0, To:-29 MWHs) HE 11-20	Mark B
14	0	-29	29	sale (From: 0, To:-29 MWHs) HE 11-21	Mark B
15	0	-29	29	sale (From: 0, To:-29 MWHs) HE 11-22	Mark B
16	0	-29	29	sale (From: 0, To:-29 MWHs) HE 11-23	Mark B
17	0	-29	29	sale (From: 0, To:-29 MWHs) HE 11-24	Mark B
18	0	-29	29	sale (From: 0, To:-29 MWHs) HE 11-25	Mark B
19	0	-29	29	rt change late entry,	Mitch H
20	0	-29	29	enron error (From: 0, To:-29 MWHs)	Mitch H
21	0	-29	29	HE19-22	Mitch H
22	0	-29	29		Mitch H
23	0	0	0		
24	0	0	0		
	0	-348	348		

	Fr CISO-WWPC Firm-AC				TRADER
	May 1 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	0	0	0		
2	0	0	0		
3	0	0	0		
4	0	0	0		
5	0	0	0		
6	0	0	0		
7	0	0	0		
8	0	0	0		
9	0	0	0		
10	0	0	0		
11	0	0	0		
12	0	-25	25	wheel (From: 0, To:-25 MWHs)HE12-22	Steve S
13	0	-25	25		
14	0	-25	25		
15	0	-25	25		
16	0	-25	25		
17	0	-25	25		
18	0	-25	25		
19	0	-25	25		
20	0	-25	25		
21	0	-25	25		
22	0	-25	25		
23	0	0	0		
24	0	0	0		
	0	-275	275		

	Fr CISO-WWPC Firm-AC				TRADER
	May 2 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	0	0	0		
2	0	0	0		
3	0	0	0		
4	0	0	0		
5	0	0	0		
6	0	0	0		
7	0	0	0		
8	0	0	0		
9	0	0	0		
10	0	0	0		
11	0	0	0		
12	0	-15	15	purch (From: 0, To:-15 MWHs)	Steve S
13	0	-15	15	HE 12-22	
14	0	-15	15		
15	0	-15	15		
16	0	-15	15		
17	0	-15	15		
18	0	-15	15		
19	0	-15	15		
20	0	-3	3	epmi was cut (From:-15, To:-3 MWHs)	
21	0	-15	15		
22	0	-15	15		
23	0	0	0		
24	0	0	0		
	0	-153	153		

	Fr CISO-WWPC Firm-AC				TRADER
	May 3 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	0	0	0		
2	0	0	0		
3	0	0	0		
4	0	0	0		
5	0	0	0		
6	0	0	0		
7	0	0	0		
8	0	0	0		
9	0	0	0		
10	0	-13	13	FOR EPMI (From: 0, To:-13 MWHs)	Terry F
11	0	-13	13		
12	0	-20	20	CHANGE (From:-13, To:-20 MWHs)	Terry F
13	0	-20	20	he13-22	
14	0	-20	20		
15	0	-20	20		
16	0	-20	20		
17	0	-20	20		
18	0	0	0	LINE DERATES THIS DAY	
19	0	0	0		
20	0	0	0		
21	0	0	0		
22	0	0	0		
23	0	0	0		
24	0	0	0		
	0	-146	146		

	Fr CISO-WWPC Firm-AC				TRADER
	May 4 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	0	0	0		
2	0	0	0		
3	0	0	0		
4	0	0	0		
5	0	0	0		
6	0	0	0		
7	0	0	0		
8	0	0	0		
9	0	0	0		
10	0	0	0		
11	0	0	0		
12	0	-10	10	FOR ENRON (From: 0, To:-10 MWHs)	Terry F
13	0	-4	4	CUT (From:-10, To:-4 MWHs)	Terry F
14	0	-10	10	FOR ENRON (From: 0, To:-10 MWHs)	Terry F
15	0	-10	10	HE 14-22	Terry F
16	0	-10	10		Terry F
17	0	-10	10		Terry F
18	0	-10	10		Terry F
19	0	-10	10		Terry F
20	0	0	0	cut by epmi (From:-10, To: 0 MWHs)	Terry F
21	0	-10	10		
22	0	-10	10		
23	0	0	0		
24	0	0	0		
	0	-94	94		

	Fr CISO-WWPC Firm-AC				TRADER
	May 5 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	0	0	0		
2	0	0	0		
3	0	0	0		
4	0	0	0		
5	0	0	0		
6	0	0	0		
7	0	0	0		
8	0	0	0		
9	0	0	0		
10	0	0	0		
11	0	0	0		
12	0	-45	45	buy resell for enron with wwp (From: 0, To:-45 MWHs)	
13	0	-45	45	HE12-14	Mitch H
14	0	-45	45		
15	0	-45	45	rt wheel for enron with wwp (From: No Entry, To:-45)	
16	0	-45	45	HE15-16	Mitch H
17	0	-45	45	rt wheel for enron with wwp (From: No Entry, To:-45)	
18	0	0	0		
19	0	0	0		
20	0	0	0		
21	0	0	0		
22	0	0	0		
23	0	0	0		
24	0	0	0		
	0	-270	270		

	Fr CISO-WWPC Firm-AC				TRADER
	May 9 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	0	0	0		
2	0	0	0		
3	0	0	0		
4	0	0	0		
5	0	0	0		
6	0	0	0		
7	0	0	0		
8	0	0	0		
9	0	0	0		
10	0	0	0		
11	0	-15	15	PURCH FR ENRON (From: 0, To:-15 MWH	Judy M
12	0	-15	15	CUT BY CPX (From: 0, To:-15 MWHs	Judy M
13	0	-15	15	HE 12-14	Judy M
14	0	-15	15		Judy M
15	0	-15	15	PURCH FR WWPC (From: 0, To:-15 MWH	Judy M
16	0	-15	15	HE15-20	Judy M
17	0	-15	15		Judy M
18	0	-15	15		Judy M
19	0	-15	15		Judy M
20	0	0	0		
21	0	0	0		
22	0	0	0		
23	0	0	0		
24	0	0	0		
	0	-135	135		

	Fr CISO-WWPC Firm-AC				TRADER
	May 10 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	0	0	0		
2	0	0	0		
3	0	0	0		
4	0	0	0		
5	0	0	0		
6	0	0	0		
7	0	0	0		
8	0	0	0		
9	0	0	0		
10	0	0	0		
11	0	0	0		
12	0	0	0		
13	0	-15	15	epmi deal (From: 0, To:-15 MWHs)	Steve S
14	0	-15	15	epmi deal (From: 0, To:-15 MWHs)	Steve S
15	0	-15	15	epmi deal (From: 0, To:-15 MWHs)	Steve S
16	0	-15	15	epmi deal (From: 0, To:-15 MWHs)	Steve S
17	0	-15	15	epmi deal (From: 0, To:-15 MWHs)	Steve S
18	0	-15	15	epmi deal (From: 0, To:-15 MWHs)	Steve S
19	0	0	0		
20	0	0	0		
21	0	0	0		
22	0	0	0		
23	0	0	0		
24	0	0	0		
	0	-90	90		

	Fr CISO-WWPC Firm-AC				TRADER
	May 11 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	0	0	0		
2	0	0	0		
3	0	0	0		
4	0	0	0		
5	0	0	0		
6	0	0	0		
7	0	0	0		
8	0	0	0		
9	0	0	0		
10	0	0	0		
11	0	-10	10	epmi deal (From: 0, To:-10 MWHs)	Steve S
12	0	-10	10	HE11-22	
13	0	-10	10		
14	0	0	0	(Detail: 2, From: No Entry, To: 0)he14-22	Steve S
15	0	0	0		
16	0	0	0		
17	0	0	0		
18	0	0	0		
19	0	0	0		
20	0	0	0		
21	0	0	0		
22	0	0	0		
23	0	0	0		
24	0	0	0		
	0	-30	30		

	Fr CISO-WWPC Firm-AC				TRADER
	May 12 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	0	0	0		
2	0	0	0		
3	0	0	0		
4	0	0	0		
5	0	0	0		
6	0	0	0		
7	0	0	0		
8	0	0	0		
9	0	0	0		
10	0	0	0		
11	0	0	0		
12	0	-45	45	epmi purchase/resale (From: 0, To: 45 MW	Chris H
13	0	0	0		
14	0	0	0		
15	0	0	0		
16	0	0	0		
17	0	0	0		
18	0	0	0		
19	0	0	0		
20	0	0	0		
21	0	0	0		
22	0	0	0		
23	0	0	0		
24	0	0	0		
	0	-45	45		

	Fr CISO-WWPC Firm-AC				TRADER
	May 15 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	0	0	0		
2	0	0	0		
3	0	0	0		
4	0	0	0		
5	0	0	0		
6	0	0	0		
7	0	0	0		
8	0	0	0		
9	0	0	0		
10	0	0	0		
11	0	0	0		
12	0	0	0		
13	0	0	0		
14	0	0	0		
15	0	-10	10	purch (From: 0, To:-10 MWHs) wppc agree	Mark B
16	0	-10	10	HE15&16	
17	0	-10	10	purch (From: 0, To:-10 MWHs)	Mark B
18	0	-10	10	(Detail: 3, From: No Entry, To: 10)	Mark B
19	0	-10	10	(Detail: 3, From: No Entry, To: 10)	Mark B
20	0	-10	10	HE19-22	Mark B
21	0	-10	10	HE19-22	Mark B
22	0	-10	10	HE19-22	Mark B
23	0	0	0		
24	0	0	0		
	0	-80	80		

	Fr CISO-WWPC Firm-AC				TRADER
	May 31 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	0	0	0		
2	0	0	0		
3	0	0	0		
4	0	0	0		
5	0	0	0		
6	0	0	0		
7	0	0	0		
8	0	0	0		
9	0	0	0		
10	0	0	0		
11	0	0	0		
12	0	0	0		
13	0	0	0		
14	0	0	0		
15	0	0	0		
16	0	0	0		
17	0	0	0		
18	0	0	0		
19	0	0	0		
20	0	0	0		
21	0	0	0		
22	0	0	0		Judy M
23	0	-55	55	PICK UP FROM WWPC FOR ENRON (From: 0, To:-55 M	
24	0	-66	66	PICK UP FROM WWPC FOR ENRON (From: 0, To:-66 M	
	0	-121	121		

	Fr CISO-WWPC Firm-AC				TRADER
	June 6 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	0	0	0		
2	0	0	0		
3	0	0	0		
4	0	0	0		
5	0	0	0		
6	0	0	0		
7	0	0	0		
8	0	0	0		
9	0	0	0		
10	0	0	0		
11	0	0	0		
12	0	0	0		
13	0	0	0		Judy M
14	0	-40	40	PICK UP FOR ENRON (From: 0, To:-40 MWHs)	
15	0	-40	40	HE14&15	
16	0	0	0		
17	0	0	0		
18	0	0	0		
19	0	0	0		
20	0	0	0		
21	0	0	0		
22	0	0	0		
23	0	0	0		
24	0	0	0		
	0	-80	80		

	Fr CISO-WWPC Firm-AC				TRADER
	June 15 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	0	0	0		
2	0	0	0		
3	0	0	0		
4	0	0	0		
5	0	0	0		
6	0	0	0		
7	0	0	0		
8	0	0	0		
9	0	0	0		
10	0	0	0		
11	0	0	0		
12	0	0	0		
13	0	0	0		
14	0	0	0		
15	0	0	0		
16	0	0	0		
17	0	0	0		
18	0	0	0		
19	0	0	0		
20	0	0	0		
21	0	0	0		
22	0	0	0		
23	0	0	0		
24	0	0	0		
	0	0	0		

	To WWPC Sale MC Memo				TRADER
	APRIL 6 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	25	25	0		
2	25	25	0		
3	25	25	0		
4	25	25	0		
5	25	25	0		
6	25	25	0		
7	25	25	0		
8	25	25	0		
9	25	25	0		
10	25	50	-25	RT AT SYS (Detail: 2, From: No Entry, To: 25)	Bill C.
11	25	50	-25	RT AT SYS (Detail: 2, From: No Entry, To: 25)	Bill C.
12	25	50	-25	SALE (Detail: 2, From: No Entry, To: 25)	Bill C.
13	25	25	0		
14	25	25	0		
15	25	25	0		
16	25	65	-40	sale (Detail: 2, From: No Entry, To: 40)	Terry F
17	25	50	-25	(Detail: 2, From: No Entry, To: 25)	Terry F
18	25	25	0		
19	25	65	-40	sale (Detail: 2, From: No Entry, To: 40)	Terry F
20	25	25	0		
21	25	25	0		
22	25	25	0		
23	25	25	0		
24	25	25	0		
	600		-180		

	To WWPC Sale MC Memo				TRADER
	April 15 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	25	25	0		
2	25	25	0		
3	25	25	0		
4	25	25	0		
5	25	25	0		
6	25	25	0		
7	25	25	0		
8	25	25	0		
9	25	25	0		
10	25	25	0		
11	25	25	0		
12	25	49	-24	Entering "fake" memo to balance out sleeve w/WWP&EPMI for April (in July). WR (Detail:2, From: No Entry, To: 24)	
13	25	49	-24	Entering "fake" memo to balance out sleeve w/WWP&EPMI for April (in July). WR (Detail:2, From: No Entry, To: 24)	
14	25	49	-24	Entering "fake" memo to balance out sleeve w/WWP&EPMI for April (in July). WR (Detail:2, From: No Entry, To: 24)	
15	25	49	-24	Entering "fake" memo to balance out sleeve w/WWP&EPMI for April (in July). WR (Detail:2, From: No Entry, To: 24)	
16	25	49	-24	Entering "fake" memo to balance out sleeve w/WWP&EPMI for April (in July). WR (Detail:2, From: No Entry, To: 24)	
17	25	49	-24	Entering "fake" memo to balance out sleeve w/WWP&EPMI for April (in July). WR (Detail:2, From: No Entry, To: 24)	
18	25	49	-24	Entering "fake" memo to balance out sleeve w/WWP&EPMI for April (in July). WR (Detail:2, From: No Entry, To: 24)	

19	25	49	-24	Entering "fake" memo to balance out sleeve w/WWP&EPMI for April (in July). WR (Detail:2, From: No Entry, To: 24)	
20	25	49	-24	Entering "fake" memo to balance out sleeve w/WWP&EPMI for April (in July). WR (Detail:2, From: No Entry, To: 24)	
21	25	49	-24	Entering "fake" memo to balance out sleeve w/WWP&EPMI for April (in July). WR (Detail:2, From: No Entry, To: 24)	
22	25	49	-24	Entering "fake" memo to balance out sleeve w/WWP&EPMI for April (in July). WR (Detail:2, From: No Entry, To: 24)	
23	25	49	-24	Entering "fake" memo to balance out sleeve w/WWP&EPMI for April (in July). WR (Detail:2, From: No Entry, To: 24)	
24	25	49	-24	Entering "fake" memo to balance out sleeve w/WWP&EPMI for April (in July). WR (Detail:2, From: No Entry, To: 24)	
	600	637	-312		

	To WWPC Sale MC Memo				TRADER
	April 16 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	25	25	0		
2	25	25	0		
3	25	49	-24	Entering "fake" memo to balance out sleeve w/WWP&EPMI for April (in July). WR (Detail:2, From: No Entry, To: 24)	
4	25	25	0		
5	25	25	0		
6	25	25	0		
7	25	25	0		
8	25	25	0		
9	25	25	0		
10	25	25	0		
11	25	25	0		
12	25	25	0		
13	25	49	-24	Entering "fake" memo to balance out sleeve w/WWP&EPMI for April (in July). WR (Detail:2, From: No Entry, To: 24)	
14	25	49	-24	Entering "fake" memo to balance out sleeve w/WWP&EPMI for April (in July). WR (Detail:2, From: No Entry, To: 24)	
15	25	49	-24	Entering "fake" memo to balance out sleeve w/WWP&EPMI for April (in July). WR (Detail:2, From: No Entry, To: 24)	
16	25	49	-24	Entering "fake" memo to balance out sleeve w/WWP&EPMI for April (in July). WR (Detail:2, From: No Entry, To: 24)	
17	25	25	0		
18	25	25	0		
19	25	25	0		
20	25	25	0		
21	25	25	0		
22	25	25	0		
23	25	25	0		
24	25	25	0		
	600	720	-120		

	To WWPC Sale MC Memo				TRADER
	April 23 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	25	25	0		
2	25	25	0		
3	25	70	-45	Pricing sleeve (w/EPMI). WR (Detail:2, From: 45, To: 45)	
4	25	70	-45	Pricing sleeve (w/EPMI). WR (Detail:2, From: 45, To: 45)	
5	25	25	0		

6	25	25	0		
7	25	25	0		
8	25	25	0		
9	25	25	0		
10	25	25	0		
11	25	25	0		
12	25	25	0		
13	25	25	0		
14	25	25	0		
15	25	25	0		
16	25	25	0		
17	25	25	0		
18	25	25	0		
19	25	25	0		
20	25	25	0		
21	25	25	0		
22	25	25	0		
23	25	25	0		
24	25	25	0		
	600	690	-90		

	To WWPC Sale MC Memo				**TRADER**
	April 26 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	25	25	0		
2	25	25	0		
3	25	25	0		
4	25	25	0		
5	25	25	0		
6	25	25	0		
7	25	25	0		
8	25	25	0		
9	25	25	0		
10	25	25	0		
11	25	54	-29		
12	25	54	-29		
13	25	54	-29		
14	25	54	-29		
15	25	54	-29		
16	25	54	-29		
17	25	54	-29		
18	25	54	-29		
19	25	54	-29		
20	25	54	-29		
21	25	54	-29		
22	25	54	-29		
23	25	25	0		
24	25	25	0		
	600	948	-348		

	To WWPC Sale MC Memo				**TRADER**
	May 1 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	25	25	0		
2	25	25	0		
3	25	25	0		
4	25	25	0		

5	25	25	0		
6	25	25	0		
7	75	75	0		
8	75	75	0		
9	75	75	0		
10	75	75	0		
11	75	75	0		
12	75	100	-25	Fixing pricing. WR (Detail: 4, From: 25, To: 25)	
13	75	100	-25	Fixing pricing. WR (Detail: 4, From: 25, To: 25)	
14	75	100	-25	Fixing pricing. WR (Detail: 4, From: 25, To: 25)	
15	75	100	-25	Fixing pricing. WR (Detail: 4, From: 25, To: 25)	
16	75	100	-25	Fixing pricing. WR (Detail: 4, From: 25, To: 25)	
17	75	100	-25	Fixing pricing. WR (Detail: 4, From: 25, To: 25)	
18	75	100	-25	Fixing pricing. WR (Detail: 4, From: 25, To: 25)	
19	75	100	-25	Fixing pricing. WR (Detail: 4, From: 25, To: 25)	
20	75	100	-25	Fixing pricing. WR (Detail: 4, From: 25, To: 25)	
21	75	100	-25	Fixing pricing. WR (Detail: 4, From: 25, To: 25)	
22	75	100	-25	Fixing pricing. WR (Detail: 4, From: 25, To: 25)	
23	25	25	0		
24	25	25	0		
	1400	1675	-275		

	To WWPC Sale MC Memo				**TRADER**
	May 2 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	50	50	0		
2	50	50	0		
3	50	50	0		
4	50	50	0		
5	50	50	0		
6	50	50	0		
7	50	50	0		
8	50	50	0		
9	50	50	0		
10	50	50	0		
11	50	50	0		
12	50	65	-15	Fixing pricing. WR (Detail: 3, From: 15, To:15)	
13	50	65	-15	Fixing pricing. WR (Detail: 3, From: 15, To:15)	
14	50	65	-15	Fixing pricing. WR (Detail: 3, From: 15, To:15)	
15	50	65	-15	Fixing pricing. WR (Detail: 3, From: 15, To:15)	
16	50	65	-15	Fixing pricing. WR (Detail: 3, From: 15, To:15)	
17	50	65	-15	Fixing pricing. WR (Detail: 3, From: 15, To:15)	
18	50	65	-15	Fixing pricing. WR (Detail: 3, From: 15, To:15)	
19	50	65	-15	Fixing pricing. WR (Detail: 3, From: 15, To:15)	
20	50	53	-3	Fixing memos. WR (Detail: 3, From: 15, To:3)	
21	50	65	-15	Fixing pricing. WR (Detail: 3, From: 15, To:15)	
22	50	65	-15	Fixing pricing. WR (Detail: 3, From: 15, To:15)	
23	50	50	0		
24	50	50	0		
	1200	1353	-153		

	To WWPC Sale MC Memo				**TRADER**
	May 3 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	25	25	0		

III.B-020

2	25	25	0		
3	25	25	0		
4	25	25	0		
5	25	25	0		
6	25	25	0		
7	50	50	0		
8	50	50	0		
9	50	50	0		
10	50	63	-13	Fixing pricing. WR (Detail: 3, From: 13, To: 13)	
11	50	63	-13	Fixing pricing. WR (Detail: 3, From: 13, To: 13)	
12	50	70	-20	Fixing pricing. WR (Detail: 3, From: 20, To: 20)	
13	50	70	-20	Fixing pricing. WR (Detail: 3, From: 20, To: 20)	
14	50	70	-20	Fixing pricing. WR (Detail: 3, From: 20, To: 20)	
15	50	70	-20	Fixing pricing. WR (Detail: 3, From: 20, To: 20)	
16	50	50	0	Removing memo, due to us sinking energy. WR (Detail:3, From: 20, To:0)	
17	50	50	0	Removing memo, due to us sinking energy. WR (Detail:3, From: 20, To:0)	
18	50	50	0		
19	50	50	0		
20	50	50	0		
21	50	50	0		
22	50	50	0		
23	25	25	0		
24	25	25	0		
	1000	1106	-106		

	To WWPC Sale MC Memo				TRADER
	May 4 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	25	25	0		
2	25	25	0		
3	25	25	0		
4	25	25	0		
5	25	25	0		
6	25	25	0		
7	50	50	0		
8	50	50	0		
9	50	50	0		
10	50	50	0		
11	50	50	0		
12	50	60	-10	Fixing pricing. WR (Detail: 3, From: 10, To: 10)	
13	50	54	-4	Fixing pricing. WR (Detail: 3, From: 4, To: 4)	
14	50	60	-10	Fixing pricing. WR (Detail: 3, From: 10, To: 10)	
15	50	60	-10	Fixing pricing. WR (Detail: 3, From: 10, To: 10)	
16	50	60	-10	Fixing pricing. WR (Detail: 3, From: 10, To: 10)	
17	50	60	-10	Fixing pricing. WR (Detail: 3, From: 10, To: 10)	
18	50	60	-10	Fixing pricing. WR (Detail: 3, From: 10, To: 10)	
19	50	60	-10	Fixing pricing. WR (Detail: 3, From: 10, To: 10)	
20	50	50	0		
21	50	60	-10	Fixing pricing. WR (Detail: 3, From: 10, To: 10)	
22	50	60	-10	Fixing pricing. WR (Detail: 3, From: 10, To: 10)	
23	25	25	0		
24	25	25	0		
	1000	1094	-94		

	To WWPC Sale MC Memo				TRADER
	May 5 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	25	25	0		
2	25	25	0		
3	25	25	0		
4	25	25	0		
5	25	25	0		
6	25	25	0		
7	50	50	0		
8	50	50	0		
9	50	50	0		
10	50	50	0		
11	50	50	0		
12	50	95	-45	buy resell for enron with wwp (Detail: 3, From: No Entry, To: 45)	Mitch H.
13	50	95	-45	buy resell for enron with wwp (Detail: 3, From: No Entry, To: 45)	Mitch H.
14	50	95	-45	buy resell for enron with wwp (Detail: 3, From: No Entry, To: 45)	Mitch H.
15	50	95	-45	rt wheel for enron with wwp (Detail: 3, From: No Entry, To: 45)	Mitch H.
16	50	95	-45	rt wheel for enron with wwp (Detail: 3, From: No Entry, To: 45)	Mitch H.
17	50	95	-45	rt wheel for enron and wwp (Detail: 3, From: No Entry, To: 45)	Mitch H.
18	50	50	0		
19	50	50	0		
20	50	50	0		
21	50	50	0		
22	50	50	0		
23	25	25	0		
24	25	25	0		
	1000	1270	-270		

	To WWPC Sale MC Memo				TRADER
	May 9 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	25	25	0		
2	25	25	0		
3	25	25	0		
4	25	25	0		
5	25	25	0		
6	25	25	0		
7	75	75	0		
8	75	75	0		
9	75	75	0		
10	75	75	0		
11	75	90	-15	Adding missing sleeve (WWP/EPMI). WR (Detail:4, From: No Entry, To: 15)	
12	75	90	-15	Adding missing sleeve (WWP/EPMI). WR (Detail:4, From: No Entry, To: 15)	
13	75	90	-15	Adding missing sleeve (WWP/EPMI). WR (Detail:4, From: No Entry, To: 15)	
14	75	90	-15	Adding missing sleeve (WWP/EPMI). WR (Detail:4, From: No Entry, To: 15)	

15	75	90	-15	Adding missing sleeve (WWP/EPMI). WR (Detail:4, From: No Entry, To: 15)	
16	75	90	-15	Adding missing sleeve (WWP/EPMI). WR (Detail:4, From: No Entry, To: 15)	
17	75	90	-15	Adding missing sleeve (WWP/EPMI). WR (Detail:4, From: No Entry, To: 15)	
18	75	90	-15	Adding missing sleeve (WWP/EPMI). WR (Detail:4, From: No Entry, To: 15)	
19	75	90	-15	Adding missing sleeve (WWP/EPMI). WR (Detail:4, From: No Entry, To: 15)	
20	75	75	0		
21	75	75	0		
22	75	75	0		
23	25	25	0		
24	25	25	0		
	1400	1535	-135		

	To WWPC Sale MC Memo				TRADER
	May 10 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	25	25	0		
2	25	25	0		
3	25	25	0		
4	25	25	0		
5	25	25	0		
6	25	25	0		
7	50	50	0		
8	50	50	0		
9	50	50	0		
10	50	50	0		
11	50	50	0		
12	50	50	0		
13	50	65	-15	epmi deal (Detail: 3, From: No Entry, To: 15)	Steve S.
14	50	65	-15	epmi deal (Detail: 3, From: No Entry, To: 15)	Steve S.
15	50	65	-15	epmi deal (Detail: 3, From: No Entry, To: 15)	Steve S.
16	50	65	-15	epmi deal (Detail: 3, From: No Entry, To: 15)	Steve S.
17	50	65	-15	epmi deal (Detail: 3, From: No Entry, To: 15)	Steve S.
18	50	65	-15	epmi deal (Detail: 3, From: No Entry, To: 15)	Steve S.
19	50	50	0		
20	50	50	0		
21	50	50	0		
22	50	50	0		
23	25	25	0		
24	25	25	0		
	1000	1090	-90		

	To WWPC Sale MC Memo				TRADER
	May 11 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	25	25	0		
2	25	25	0		
3	25	25	0		
4	25	25	0		
5	25	25	0		
6	25	25	0		

7	50	50	0		
8	50	50	0		
9	50	50	0		
10	50	50	0		
11	50	60	-10	epmi deal (Detail: 3, From: No Entry, To: 10)	Steve S.
12	50	60	-10	epmi deal (Detail: 3, From: No Entry, To: 10)	Steve S.
13	50	60	-10	epmi deal (Detail: 3, From: No Entry, To: 10)	Steve S.
14	50	50	0		
15	50	50	0		
16	50	50	0		
17	50	50	0		
18	50	50	0		
19	50	50	0		
20	50	50	0		
21	50	50	0		
22	50	50	0		
23	25	25	0		
24	25	25	0		
	1000	1030	-30		

	To WWPC Sale MC Memo				**TRADER**
	May 12 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	25	25	0		
2	25	25	0		
3	25	25	0		
4	25	25	0		
5	25	25	0		
6	25	25	0		
7	50	50	0		
8	50	50	0		
9	50	50	0		
10	50	50	0		
11	50	50	0		
12	50	95	-45	(Detail: 3, From: No Entry, To: 45)	Chris H
13	50	50	0		
14	50	50	0		
15	50	50	0		
16	50	50	0		
17	50	50	0		
18	50	50	0		
19	50	50	0		
20	50	50	0		
21	50	50	0		
22	50	50	0		
23	25	25	0		
24	25	25	0		
	1000	1045	-45		

	To WWPC Sale MC Memo				**TRADER**
	May 15 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	25	25	0		
2	25	25	0		
3	25	25	0		
4	25	25	0		

5	25	25	0		
6	25	25	0		
7	50	50	0		
8	50	50	0		
9	50	50	0		
10	50	50	0		
11	50	50	0		
12	50	50	0		
13	50	50	0		
14	50	50	0		
15	50	60	-10	(Detail: 3, From: No Entry, To: 10)	Mark B
16	50	60	-10	(Detail: 3, From: No Entry, To: 10)	Mark B
17	50	60	-10	(Detail: 3, From: No Entry, To: 10)	Mark B
18	50	60	-10	(Detail: 3, From: No Entry, To: 10)	Mark B
19	50	60	-10	(Detail: 3, From: No Entry, To: 10)	Mark B
20	50	60	-10	(Detail: 3, From: No Entry, To: 10)	Mark B
21	50	60	-10	(Detail: 3, From: No Entry, To: 10)	Mark B
22	50	60	-10	(Detail: 3, From: No Entry, To: 10)	Mark B
23	25	25	0		
24	25	25	0		
	1000	1080	-80		

	To WWPC Sale MC Memo				**TRADER**
	May 31 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	25	25	0		
2	25	25	0		
3	25	25	0		
4	25	25	0		
5	25	25	0		
6	25	25	0		
7	50	50	0		
8	50	50	0		
9	50	50	0		
10	50	50	0		
11	50	50	0		
12	50	50	0		
13	50	50	0		
14	50	50	0		
15	50	50	0		
16	50	50	0		
17	50	50	0		
18	50	50	0		
19	50	50	0		
20	50	50	0		
21	50	50	0		
22	50	50	0		
23	25	80	-55	Fixing pricing. WR (Detail: 3, From: No Entry, To: 55)	
24	25	91	-66	Fixing pricing. WR (Detail: 3, From: No Entry, To: 66)	
	1000	1121	-121		

	To WWPC Sale MC Memo				**TRADER**
	June 6 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	25	25	0		
2	25	25	0		

3	25	25	0		
4	25	25	0		
5	25	25	0		
6	25	25	0		
7	25	25	0		
8	25	25	0		
9	25	25	0		
10	25	25	0		
11	25	25	0		
12	25	25	0		
13	25	25	0		
14	25	65	-40	Moving to "To WWP MC Memo" acct. WR (Detail: 2, From: No Entry, To: 40)	
15	25	65	-40	Moving to "To WWP MC Memo" acct. WR (Detail: 2, From: No Entry, To: 40)	
16	25	25	0		
17	25	25	0		
18	25	25	0		
19	25	25	0		
20	25	25	0		
21	25	25	0		
22	25	25	0		
23	25	25	0		
24	25	25	0		
	600	680	-80		

	To WWPC Sale MC Memo				**TRADER**
	June 15 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	25	25	0		
2	25	25	0		
3	25	25	0		
4	25	25	0		
5	25	25	0		
6	25	25	0		
7	50	50	0		
8	50	50	0		
9	50	50	0		
10	50	50	0		
11	50	50	0		
12	50	50	0		
13	50	50	0		
14	50	50	0		
15	50	50	0		
16	50	50	0		
17	50	50	0		
18	50	50	0		
19	50	50	0		
20	50	50	0		
21	50	50	0		
22	50	50	0		
23	25	25	0		
24	25	25	0		
	1000	1000	0		

	Fr EPMI MC Memo				TRADER
	APRIL 6 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	-5	-5	0		
2	-5	-5	0		
3	-5	-5	0		
4	-5	-5	0		
5	-5	-5	0		
6	-5	-5	0		
7	-2	-2	0		
8	-2	-2	0		
9	-2	-2	0		
10	-2	-27	25	RT AT SYS (Detail: 2, From: No Entry, To:-25)	Bill C
11	-2	-27	25	RT AT SYS (Detail: 2, From: No Entry, To:-25)	Bill C
12	-2	-27	25	RT AT SYS (Detail: 2, From: No Entry, To:-25)	Terry F
13	-2	-2	0		
14	-2	-2	0		
15	-2	-2	0		
16	-2	-42	40	PURCH (Detail: 2, From: No Entry, To:-40)	Terry F
17	-2	-27	25	PURCH (Detail: 2, From: No Entry, To:-25)	Terry F
18	-2	-2	0		
19	-2	-42	40	PURCH (Detail: 2, From: No Entry, To:-40)	Terry F
20	-2	-2	0		
21	-2	-2	0		
22	-3	-3	0		
23	-4	-4	0		
24	-4	-4	0		
	-71	-251	180		

	Fr EPMI MC Memo				TRADER
	April 15,2000				
HE	Presched	Realtime	Diff	Log Entry	
1	-5	-5	0		
2	-5	-5	0		
3	-5	-5	0		
4	-4	-4	0		
5	-4	-4	0		
6	-4	-4	0		
7	-4	-4	0		
8	-4	-4	0		
9	-4	-4	0		
10	-4	-4	0		
11	-3	-3	0		
12	-3	-27	24	Entering "fake" memo to balance out sleeve	
13	-3	-27	24	w/ WWP &EPMI in April (in July) WR	
14	-3	-27	24	Above entry in Historical Changes for HE12-24.	
15	-3	-27	24		
16	-3	-27	24		
17	-3	-27	24		
18	-3	-27	24		
19	-3	-27	24		
20	-3	-27	24		
21	-3	-27	24		
22	-3	-27	24		
23	-5	-29	24		
24	-5	-29	24		
	-89	-401	312		

	Fr EPMI MC Memo				TRADER
	April 16,2000				
HE	Presched	Realtime	Diff	Log Entry	
1	-5	-5	0		
2	-5	-5	0		
3	-5	-29	24	Entering "fake" memo to balance out sleeve	
4	-5	-5	0	w/ WWP &EPMI in April (in July) WR	
5	-5	-5	0	Above entry in Historical Changes for HE3,13-16	
6	-5	-5	0		
7	-5	-5	0		
8	-5	-5	0		
9	-5	-5	0		
10	-5	-5	0		
11	-5	-5	0		
12	-5	-5	0		
13	-5	-29	24		
14	-4	-28	24		
15	-4	-28	24		
16	-4	-28	24		
17	-4	-4	0		
18	-4	-4	0		
19	-4	-4	0		
20	-4	-4	0		
21	-4	-4	0		
22	-3	-3	0		
23	-5	-5	0		
24	-5	-5	0		
	-110	-230	120		

	Fr EPMI MC Memo				TRADER
	April 23,2000				
HE	Presched	Realtime	Diff	Log Entry	
1	-5	-5	0		
2	-5	-5	0		
3	-5	-50	45	(Detail: 2, From: No Entry, To:-45)	Steve S
4	-5	-50	45	(Detail: 2, From: No Entry, To:-45)	Steve S
5	-5	-5	0		
6	-5	-5	0		
7	-5	-5	0		
8	-5	-5	0		
9	-4	-4	0		
10	-4	-4	0		
11	-4	-4	0		
12	-4	-4	0		
13	-4	-4	0		
14	-4	-4	0		
15	-4	-4	0		
16	-4	-4	0		
17	-5	-5	0		
18	-5	-5	0		
19	-5	-5	0		
20	-5	-5	0		
21	-5	-5	0		
22	-5	-5	0		
23	-5	-5	0		
24	-5	-5	0		
	-112	-202	90		

	Fr EPMI MC Memo				TRADER
	April 26,2000				
HE	Presched	Realtime	Diff	Log Entry	
1	-5	-11	6	Adding deal that was just bookout-	
2	-5	-11	6	Helping EPMI WR (entered in July) LLH	
3	-5	-11	6		
4	-4	-10	6		
5	-4	-10	6		
6	-4	-10	6		
7	-4	-4	0		
8	-4	-4	0		
9	-4	-4	0		
10	-4	-4	0		
11	-4	-33	29	(Detail: 2, From: No Entry, To:-29) HE 11-18	Mark B
12	-4	-33	29	(Detail: 2, From: No Entry, To:-29) HE 11-19	Mark B
13	-4	-33	29	(Detail: 2, From: No Entry, To:-29) HE 11-20	Mark B
14	-4	-33	29	(Detail: 2, From: No Entry, To:-29) HE 11-21	Mark B
15	-4	-33	29	(Detail: 2, From: No Entry, To:-29) HE 11-22	Mark B
16	-4	-33	29	(Detail: 2, From: No Entry, To:-29) HE 11-23	Mark B
17	-4	-33	29	(Detail: 2, From: No Entry, To:-29) HE 11-24	Mark B
18	-3	-32	29	(Detail: 2, From: No Entry, To:-29) HE 11-25	Mark B
19	-3	-32	29	rt change late entry,	Mitch H
20	-3	-32	29	enron error (From: 0, To:-29 MWHs)	Mitch H
21	-4	-33	29	HE19-22	Mitch H
22	-4	-33	29		Mitch H
23	-4	-10	6		
24	-4	-10	6		
	-96	-492	396		

	Fr EPMI MC Memo				TRADER
	May 1 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	-5	-5	0		
2	-5	-5	0		
3	-5	-5	0		
4	-5	-5	0		
5	-5	-5	0		
6	-4	-4	0		
7	-3	-3	0		
8	-3	-3	0		
9	-3	-3	0		
10	-3	-3	0		
11	-3	-3	0		
12	-3	-28	25	wheel (Detail: 2, From: No Entry, To: 0)	Steve S
13	-3	-28	25	on 10-13-2000 ATF changed to -25 he12-22 per acct	
14	-3	-28	25	history page	
15	-3	-28	25		
16	-3	-28	25		
17	-3	-28	25		
18	-3	-28	25		
19	-3	-28	25		
20	-2	-27	25		
21	-2	-27	25		
22	-2	-27	25		
23	-5	-5	0		
24	-5	-5	0		
	-84	-359	275		

	Fr EPMI MC Memo				TRADER
	May 2 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	-5	-5	0		
2	-5	-5	0		
3	-5	-5	0		
4	-4	-4	0		
5	-4	-4	0		
6	-4	-4	0		
7	-3	-3	0		
8	-3	-3	0		
9	-3	-3	0		
10	-3	-3	0		
11	-3	-3	0		
12	-3	-18	15	for enron (Detail: 2, From: No Entry, To:-15)	Steve S
13	-3	-18	15	HE12-22	
14	-2	-17	15		
15	-2	-17	15		
16	-2	-17	15		
17	-3	-18	15		
18	-3	-18	15		
19	-3	-18	15		
20	-3	-6	3	fixing memo's WR	ATF
21	-3	-18	15		
22	-3	-18	15		
23	-5	-5	0		
24	-5	-5	0		
	-82	-235	153		

	Fr EPMI MC Memo				TRADER
	May 3 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	-5	-5	0		
2	-5	-5	0		
3	-5	-5	0		
4	-5	-5	0		
5	-5	-5	0		
6	-5	-5	0		
7	-4	-4	0		
8	-4	-4	0		
9	-4	-4	0		
10	-4	-17	13	(Detail: 2, From: No Entry, To:-15)	Terry F
11	-3	-16	13		
12	-3	-23	20		
13	-3	-23	20		
14	-3	-23	20		
15	-3	-23	20		
16	-3	-3	0	removing energy due to us sinking energy	WR atf
17	-3	-3	0	removing energy due to us sinking energy	WR atf
18	-3	-3	0		
19	-3	-3	0		
20	-3	-3	0		
21	-3	-3	0		
22	-3	-3	0		
23	-4	-4	0		
24	-4	-4	0		
	-90	-196	106		

	Fr EPMI MC Memo				TRADER
	May 4 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	-3	-3	0		
2	-3	-3	0		
3	-3	-3	0		
4	-3	-3	0		
5	-2	-2	0		
6	-2	-2	0		
7	-4	-4	0		
8	-4	-4	0		
9	-4	-4	0		
10	-3	-3	0		
11	-3	-3	0		
12	-3	-13	10	FOR ENRON (Detail: 2, From: No Entry, To:-10)	Terry F
13	-3	-7	4	(Detail: 2, From:-10, To:-4)	Terry F
14	-4	-14	10	(Detail: 2, From: No Entry, To:-10)	Terry F
15	-4	-14	10	HE 14-22	Terry F
16	-4	-14	10		Terry F
17	-4	-14	10		Terry F
18	-4	-14	10		Terry F
19	-4	-14	10		Terry F
20	-4	-4	0	cut by epmi (From:-10, To: 0 MWHs)	Terry F
21	-4	-14	10		
22	-4	-14	10		
23	-3	-3	0		
24	-3	-3	0		
	-82	-176	94		

	Fr EPMI MC Memo				TRADER
	May 5 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	-3	-3	0		
2	-3	-3	0		
3	-3	-3	0		
4	-3	-3	0		
5	-3	-3	0		
6	-2	-2	0		
7	-4	-4	0		
8	-4	-4	0		
9	-4	-4	0		
10	-3	-3	0		
11	-3	-3	0		
12	-3	-48	45	buy resell for enron with wwp (Detail: 2, From:-10, To:-45)	
13	-4	-49	45	HE12-14	Mitch H
14	-4	-49	45		
15	-4	-49	45	rt wheel for enron with wwp (Detail: 2, From: No Entry, To:-45)	
16	-4	-49	45	HE15-16	Mitch H
17	-4	-49	45	rt wheel for enron with wwp (Detail: 2, From: No Entry, To:-45)	
18	-4	-4	0		
19	-4	-4	0		
20	-4	-4	0		
21	-4	-4	0		
22	-4	-4	0		
23	-3	-3	0		
24	-3	-3	0		
	-84	-354	270		

	Fr EPMI MC Memo				TRADER
	May 9 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	-5	-5	0		
2	-5	-5	0		
3	-4	-4	0		
4	-4	-4	0		
5	-4	-4	0		
6	-4	-4	0		
7	-1	-1	0		
8	-1	-1	0		
9	-1	-1	0		
10	-1	-1	0		
11	-2	-17	15	Adding Missing sleeve (WWP/EPMI) 6/6/2000	WR atf
12	-2	-17	15	Adding Missing sleeve (WWP/EPMI) 6/6/2001	WR atf
13	-2	-17	15	Adding Missing sleeve (WWP/EPMI) 6/6/2002	WR atf
14	-2	-17	15	Adding Missing sleeve (WWP/EPMI) 6/6/2003	WR atf
15	-2	-17	15	Adding Missing sleeve (WWP/EPMI) 6/6/2004	WR atf
16	-2	-17	15	Adding Missing sleeve (WWP/EPMI) 6/6/2005	WR atf
17	-2	-17	15	Adding Missing sleeve (WWP/EPMI) 6/6/2006	WR atf
18	-2	-17	15	Adding Missing sleeve (WWP/EPMI) 6/6/2007	WR atf
19	-2	-17	15	Adding Missing sleeve (WWP/EPMI) 6/6/2008	WR atf
20	-2	-2	0		
21	-2	-2	0		
22	-2	-2	0		
23	-5	-5	0		
24	-5	-5	0		
	-64	-199	135		

	Fr EPMI MC Memo				TRADER
	May 10 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	-5	-5	0		
2	-5	-5	0		
3	-4	-4	0		
4	-4	-4	0		
5	-4	-4	0		
6	-4	-4	0		
7	-3	-3	0		
8	-3	-3	0		
9	-4	-4	0		
10	-3	-3	0		
11	-3	-3	0		
12	-3	-3	0		
13	-3	-18	15	(Detail: 2, From: No Entry, To:-15) HE13-18	Steve S
14	-3	-18	15	(Detail: 2, From: No Entry, To:-15) HE13-19	Steve S
15	-4	-19	15	(Detail: 2, From: No Entry, To:-15) HE13-20	Steve S
16	-4	-19	15	(Detail: 2, From: No Entry, To:-15) HE13-21	Steve S
17	-4	-19	15	(Detail: 2, From: No Entry, To:-15) HE13-22	Steve S
18	-4	-19	15	(Detail: 2, From: No Entry, To:-15) HE13-23	Steve S
19	-4	-4	0		
20	-4	-4	0		
21	-4	-4	0		
22	-4	-4	0		
23	-5	-5	0		
24	-5	-5	0		
	-93	-183	90		

	Fr EPMI MC Memo				TRADER
	May 11 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	-5	-5	0		
2	-5	-5	0		
3	-4	-4	0		
4	-4	-4	0		
5	-4	-4	0		
6	-4	-4	0		
7	-1	-1	0		
8	-2	-2	0		
9	-2	-2	0		
10	-2	-2	0		
11	-2	-12	10	epmi deal (Detail: 2 From: 0, To:-10 MWHs)	Steve S
12	-2	-12	10	HE11-22	
13	-2	-12	10		
14	-2	-2	0	enron cut (From:-10, To: 0 MWHs) HE14-22	Steve S
15	-2	-2	0		
16	-2	-2	0		
17	-2	-2	0		
18	-2	-2	0		
19	-2	-2	0		
20	-2	-2	0		
21	-2	-2	0		
22	-2	-2	0		
23	-5	-5	0		
24	-5	-5	0		
	-67	-97	30		

	Fr EPMI MC Memo				TRADER
	May 12 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	-5	-5	0		
2	-5	-5	0		
3	-5	-5	0		
4	-5	-5	0		
5	-4	-4	0		
6	-4	-4	0		
7	-4	-4	0		
8	-4	-4	0		
9	-3	-3	0		
10	-3	-3	0		
11	-3	-3	0		
12	-3	-48	45	(Detail: 2, From: No Entry, To:-45)	Chris H
13	-3	-3	0		
14	-3	-3	0		
15	-3	-3	0		
16	-3	-3	0		
17	-3	-3	0		
18	-3	-3	0		
19	-3	-3	0		
20	-3	-3	0		
21	-3	-3	0		
22	-3	-3	0		
23	-5	-5	0		
24	-5	-5	0		
	-88	-133	45		

	Fr EPMI MC Memo				TRADER
	May 15 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	-4	-4	0		
2	-4	-4	0		
3	-4	-4	0		
4	-4	-4	0		
5	-5	-5	0		
6	-5	-5	0		
7	-5	-5	0		
8	-5	-5	0		
9	-5	-5	0		
10	-5	-5	0		
11	-5	-5	0		
12	-5	-5	0		
13	-5	-5	0		
14	-5	-5	0		
15	-5	-15	10	(Detail: 2, From: No Entry, To:-10)	Mark B
16	-5	-15	10	HE15&16	
17	-5	-15	10	(Detail: 2, From: No Entry, To:-10)	Mark B
18	-5	-15	10	(Detail: 2, From: No Entry, To:-10)	Mark B
19	-5	-15	10	(Detail: 2, From: No Entry, To:-10)	Mark B
20	-5	-15	10	HE19-22	Mark B
21	-5	-15	10	HE19-22	Mark B
22	-5	-15	10	HE19-22	Mark B
23	-5	-5	0		
24	-5	-5	0		
	-116	-196	80		

	Fr EPMI MC Memo				TRADER
	May 31 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	-4	-4	0		
2	-4	-4	0		
3	-4	-4	0		
4	-4	-4	0		
5	-4	-4	0		
6	-4	-4	0		
7	-4	-4	0		
8	-4	-4	0		
9	-3	-3	0		
10	-3	-3	0		
11	-3	-3	0		
12	-3	-3	0		
13	-3	-3	0		
14	-3	-3	0		
15	-3	-3	0		
16	-3	-3	0		
17	-3	-3	0		
18	-3	-3	0		
19	-3	-3	0		
20	-3	-3	0		
21	-3	-3	0		
22	-3	-3	0		
23	-3	-58	55	Fixing Price WR (Detail:2 From No Entry to: -55)	Judy M
24	-4	-70	66	Fixing Price WR (Detail:2 From No Entry to: -66)	Judy M
	-81	-202	121		

	Fr EPMI MC Memo				TRADER
	June 6 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	-5	-5	0		
2	-5	-5	0		
3	-5	-5	0		
4	-4	-4	0		
5	-4	-4	0		
6	-4	-4	0		
7	-4	-4	0		
8	-4	-4	0		
9	-3	-3	0		
10	-3	-3	0		
11	-3	-3	0		
12	-3	-3	0		
13	-3	-3	0	Historical Change	
14	-3	-43	40	"Fr EPMI MC Memo" acct WR (Detail:2, From No Entry, To -40)	
15	-3	-43	40	"Fr EPMI MC Memo" acct WR (Detail:2, From No Entry, To -40)	
16	-3	-3	0		
17	-3	-3	0		
18	-3	-3	0		
19	-3	-3	0		
20	-3	-3	0		
21	-3	-3	0		
22	-3	-3	0		
23	-4	-4	0		
24	-4	-4	0		
	-85	-165	80		

	Fr EPMI MC Memo				TRADER
	June 15 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	-4	-4	0		
2	-4	-4	0		
3	-4	-4	0		
4	-4	-4	0		
5	-4	-4	0		
6	-3	-3	0		
7	-30	-30	0		
8	-30	-30	0		
9	-30	-30	0		
10	-30	-30	0		
11	-30	-30	0		
12	-30	-30	0		
13	-30	-30	0		
14	-30	-30	0		
15	-30	-30	0		
16	-30	-30	0		
17	-30	-30	0		
18	-29	-29	0		
19	-29	-29	0		
20	-29	-29	0		
21	-29	-29	0		
22	-29	-29	0		
23	-4	-4	0		
24	-4	-4	0		
	-506	-506	0		

NO ACTIVITY JUNE 15,2000

	To BPA-PGE EPMI JD				TRADER
	APRIL 6 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	5	5	0		
2	5	5	0		
3	5	5	0		
4	5	5	0		
5	5	5	0		
6	5	5	0		
7	68	68	0		
8	68	68	0		
9	68	68	0		
10	68	93	-25	SALE (Detail: 3, From: 25, To: 25)	Terry F
11	68	93	-25	(Detail: 3, From: 0, To: 25)	Terry F
12	68	93	-25	SALE (Detail: 3, From: 0, To: 25)	Terry F
13	68	68	0		
14	68	68	0		
15	68	68	0		
16	68	108	-40	SALE (Detail: 3, From: 0, To: 40)	Terry F
17	68	93	-25	SALE (Detail: 3, From: 0, To: 25)	Terry F
18	68	68	0		
19	68	108	-40	(Detail: 3, From: 0, To: 40)	Terry F
20	68	68	0		
21	68	68	0		
22	69	69	0		
23	4	4	0		
24	4	4	0		
	1127	1307	-180		

	To BPA-PGE EPMI JD				TRADER
	April 15,2000				
HE	Presched	Realtime	Diff	Log Entry	
1	8	8	0		
2	8	8	0		
3	8	8	0		
4	7	7	0		
5	7	7	0		
6	7	7	0		
7	83	83	0		
8	83	83	0		
9	83	83	0		
10	83	83	0		
11	82	82	0		
12	82	106	-24		
13	82	106	-24	(Detail: 3, From: 0, To: 24)	Judy M.
14	82	106	-24	(Detail: 3, From: 0, To: 24)	Judy M.
15	82	106	-24		
16	82	106	-24	(Detail: 3, From: 0, To: 24)	Judy M.
17	82	106	-24	(Detail: 3, From: 0, To: 24)	Judy M.
18	82	106	-24	(Detail: 3, From: 0, To: 24)	Judy M.
19	82	106	-24	(Detail: 3, From: 0, To: 24)	Judy M.
20	82	106	-24	(Detail: 3, From: 0, To: 24)	Judy M.
21	82	106	-24	(Detail: 3, From: 0, To: 24)	Terry F.
22	82	106	-24	sale (Detail: 3, From: 0, To: 24)	Terry F.
23	8	32	-24	(Detail: 3, From: 0, To: 24)	Terry F.
24	8	32	-24	(Detail: 3, From: 0, To: 24)	Terry F.
	1377	1689	-312		

:	To BPA-PGE EPMI JD				TRADER
	April 16,2000				
HE	Presched	Realtime	Diff	Log Entry	
1	8	8	0		
2	8	8	0		
3	8	32	-24	(Detail: 3, From: 0, To: 24)	Terry F.
4	8	8	0		
5	8	8	0		
6	8	8	0		
7	8	8	0		
8	8	8	0		
9	8	8	0		
10	8	8	0		
11	8	8	0		
12	8	8	0		
13	8	32	-24	(Detail: 3, From: 0, To: 24)	Judy M.
14	7	31	-24	(Detail: 3, From: 0, To: 24)	Judy M.
15	7	31	-24	(Detail: 3, From: 0, To: 24)	Judy M.
16	7	31	-24	(Detail: 3, From: 0, To: 24)	Judy M.
17	7	7	0		
18	7	7	0		
19	7	7	0		
20	7	7	0		
21	7	7	0		
22	6	6	0		
23	8	8	0		
24	8	8	0		
	182	302	-120		

	To BPA-PGE EPMI JD				TRADER
	April 23,2000				
HE	Presched	Realtime	Diff	Log Entry	
1	7	7	0		
2	7	7	0		
3	7	52	-45	(Detail: 3, From: 0, To: 45)	Steve S.
4	7	52	-45	(Detail: 3, From: 0, To: 45)	Steve S.
5	7	7	0		
6	7	7	0		
7	7	7	0		
8	7	7	0		
9	6	6	0		
10	6	6	0		
11	6	6	0		
12	6	6	0		
13	6	6	0		
14	6	6	0		
15	6	6	0		
16	6	6	0		
17	7	7	0		
18	7	7	0		
19	7	7	0		
20	7	7	0		
21	7	7	0		
22	7	7	0		
23	7	7	0		
24	7	7	0		

	160	250	-90		

	To BPA-PGE EPMI JD				TRADER
	April 26,2000				
HE	Presched	Realtime	Diff	Log Entry	
1	-5	-11	6	Adding deal that was just bookout-	
2	-5	-11	6	Helping EPMI WR (entered in July) LLH	
3	-5	-11	6		
4	-4	-10	6		
5	-4	-10	6		
6	-4	-10	6		
7	-4	-4	0		
8	-4	-4	0		
9	-4	-4	0		
10	-4	-4	0		
11	-4	-33	29	(Detail: 3, From: 0, To: 29)	Mark B.
12	-4	-33	29	(Detail: 3, From: 29, To: 29)	Mark B.
13	-4	-33	29		
14	-4	-33	29		
15	-4	-33	29		
16	-4	-33	29		
17	-4	-33	29		
18	-3	-32	29		
19	-3	-32	29		
20	-3	-32	29		
21	-4	-33	29	(Detail: 3, From: 0, To: 29)	Mitch H.
22	-4	-33	29		
23	-4	-10	6		
24	-4	-10	6		
	-96	-492	396		

	To BPA-EPMI(PGE SYS)				TRADER
	May 1 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	0	0	0		
2	0	0	0		
3	0	0	0		
4	0	0	0		
5	0	0	0		
6	0	0	0		
7	0	0	0		
8	0	0	0		
9	0	0	0		
10	0	0	0		
11	0	0	0		
12	0	25	-25	wheel (From: 0, To: 25 MWHs)	Steve S
13	0	25	-25	wheel (From: 0, To: 25 MWHs)	Steve S
14	0	25	-25	wheel (From: 0, To: 25 MWHs)	Steve S
15	0	25	-25	wheel (From: 0, To: 25 MWHs)	Steve S
16	0	122	-122	wheel (From: 0, To: 25 MWHs)	Steve S
17	0	122	-122	wheel (From: 0, To: 25 MWHs)	Steve S
18	0	122	-122	wheel (From: 0, To: 25 MWHs)	Steve S
19	0	122	-122	wheel (From: 0, To: 25 MWHs)	Steve S
20	0	122	-122	wheel (From: 0, To: 25 MWHs)	Steve S
21	0	122	-122	wheel (From: 0, To: 25 MWHs)	Steve S
22	0	122	-122	wheel (From: 0, To: 25 MWHs)	Steve S
23	0	97	-97		

24	0	97	-97		
	0	1148	-1148		

	To BPA-PGE EPMI JD				TRADER
	May 2 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	23	23	0		
2	23	23	0		
3	23	23	0		
4	22	22	0		
5	22	22	0		
6	22	22	0		
7	97	97	0		
8	97	97	0		
9	97	97	0		
10	97	97	0		
11	97	97	0		
12	97	112	-15	for enron (Detail: 3, From: 0, To: 15)	Steve S.
13	97	112	-15	for enron (Detail: 3, From: 0, To: 15)	Steve S.
14	96	111	-15	for enron (Detail: 3, From: 0, To: 15)	Steve S.
15	96	111	-15	for enron (Detail: 3, From: 0, To: 15)	Steve S.
16	96	111	-15	for enron (Detail: 3, From: 0, To: 15)	Steve S.
17	97	112	-15	for enron (Detail: 3, From: 0, To: 15)	Steve S.
18	97	112	-15	for enron (Detail: 3, From: 0, To: 15)	Steve S.
19	97	112	-15	for enron (Detail: 3, From: 0, To: 15)	Steve S.
20	97	112	-15	for enron (Detail: 3, From: 0, To: 15)	Steve S.
21	97	112	-15	for enron (Detail: 3, From: 0, To: 15)	Steve S.
22	97	112	-15	for enron (Detail: 3, From: 0, To: 15)	Steve S.
23	23	23	0		
24	23	23	0		
	1730	1895	-165		

	To BPA-PGE EPMI JD				TRADER
	May 3 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	23	23	0		
2	23	23	0		
3	23	23	0		
4	23	23	0		
5	23	23	0		
6	23	23	0		
7	23	23	0		
8	23	23	0		
9	23	23	0		
10	23	36	-13	(Detail: 3, From: 0, To: 15)	
11	22	35	-13	(Detail: 3, From: 0, To: 15)	
12	22	42	-20	CHANGE (Detail: 3, From: 15, To: 20)	
13	22	42	-20	CHANGE (Detail: 3, From: 15, To: 20)	
14	22	42	-20	CHANGE (Detail: 3, From: 15, To: 20)	
15	22	22	0	(Detail: 3, From: 0, To: 20)	
16	22	10	12	(Detail: 3, From: 20, To: 0)	
17	22	10	12	CUT (Detail: 3, From: 20, To: 0)	
18	22	10	12	CUT (Detail: 3, From: 20, To: 0)	
19	22	10	12	CUT (Detail: 3, From: 20, To: 0)	
20	22	9	13	CUT (Detail: 3, From: 20, To: 0)	

21	22	10	12	CUT (Detail: 3, From: 20, To: 0)	
22	22	10	12	CUT (Detail: 3, From: 20, To: 0)	
23	22	22	0		
24	22	22	0		
	538	539	-1		

	To BPA-PGE EPMI JD				TRADER
	May 4 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	22	22	0		
2	22	22	0		
3	22	22	0		
4	22	22	0		
5	21	21	0		
6	21	21	0		
7	99	99	0		
8	99	99	0		
9	99	99	0		
10	98	98	0		
11	98	98	0		
12	98	108	-10	(Detail: 3, From: 0, To: 10)	Terry F.
13	98	102	-4	CUT (Detail: 3, From: 10, To: 4)	Terry F.
14	99	109	-10	FOR ENRON (Detail: 3, From: 0, To: 10)	Terry F.
15	99	109	-10	(Detail: 3, From: 0, To: 10)	Terry F.
16	99	109	-10	(Detail: 3, From: 0, To: 10)	Terry F.
17	99	109	-10	(Detail: 3, From: 0, To: 10)	
18	99	109	-10	(Detail: 3, From: 0, To: 10)	
19	99	109	-10	(Detail: 3, From: 0, To: 10)	
20	99	99	0	(Detail: 3, From: 10, To: 0)	
21	99	109	-10	(Detail: 3, From: 0, To: 10)	
22	99	109	-10	(Detail: 3, From: 0, To: 10)	
23	22	22	0		Judy M.
24	22	22	0		
	1754	1848	-94		

	To BPA-PGE EPMI JD				TRADER
	May 5 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	21	21	0		
2	21	21	0		
3	21	21	0		
4	21	21	0		
5	21	21	0		
6	20	20	0		
7	23	23	0		
8	23	23	0		
9	23	23	0		
10	22	22	0		
11	22	22	0		
12	22	67	-45	buy resell for enron with wwp (Detail: 3, From: 0, To: 45)	Mitch H.
13	23	68	-45	buy resell for enron with wwp (Detail: 3, From: 0, To: 45)	Mitch H.
14	23	68	-45	buy resell for enron with wwp (Detail: 3, From: 0, To: 45)	Mitch H.
15	23	68	-45	rt wheel for enron with wwp (Detail: 3, From: 0, To: 45)	Mitch H.
16	23	68	-45	rt wheel for enron with wwp (Detail: 3, From: 0, To: 45)	Mitch H.
17	23	68	-45	rt wheel for enron and wwp (Detail: 3, From: 0, To: 45)	Mitch H.

III.B-040

18	23	23	0		
19	23	23	0		
20	23	23	0		
21	23	23	0		
22	23	23	0		
23	21	21	0		
24	21	21	0		
	532	802	-270		

	To BPA-PGE EPMI JD				TRADER
	May 9 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	21	21	0		
2	21	21	0		
3	20	20	0		
4	20	20	0		
5	20	20	0		
6	20	20	0		
7	68	68	0		
8	68	68	0		
9	68	68	0		
10	68	68	0		
11	69	84	-15	BUY FROM WWP AT COB FOR RE-SALE TO EPMI AT	Judy M.
12	69	84	-15	BUY FROM WWP AT COB FOR RE-SALE TO EPMI AT	Judy M.
13	69	84	-15	BUY FROM WWP AT COB FOR RE-SALE TO EPMI AT	Judy M.
14	69	84	-15	BUY FROM WWP AT COB FOR RE-SALE TO EPMI AT	Judy M.
15	69	84	-15	(Detail: 3, From: 0, To: 15)	Judy M.
16	69	84	-15	(Detail: 3, From: 0, To: 15)	Judy M.
17	69	84	-15	(Detail: 3, From: 0, To: 15)	Judy M.
18	69	84	-15	(Detail: 3, From: 0, To: 15)	Judy M.
19	69	84	-15	(Detail: 3, From: 0, To: 15)	Judy M.
20	69	69	0		
21	69	69	0		
22	69	69	0		
23	21	21	0		
24	21	21	0		
	1264	-199	1463		

	To BPA-PGE EPMI JD				TRADER
	May 10 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	21	21	0		
2	21	21	0		
3	20	20	0		
4	20	20	0		
5	20	20	0		
6	20	20	0		
7	20	20	0		
8	20	20	0		
9	21	21	0		
10	20	20	0		
11	20	20	0		
12	20	20	0		
13	20	35	-15	(Detail: 3, From: 0, To: 15)	Steve S.
14	20	35	-15	(Detail: 3, From: 0, To: 15)	Steve S.

III.B-041

15	21	36	-15	(Detail: 3, From: 0, To: 15)	Steve S.
16	21	36	-15	(Detail: 3, From: 0, To: 15)	Steve S.
17	21	36	-15	(Detail: 3, From: 0, To: 15)	Steve S.
18	21	36	-15	(Detail: 3, From: 0, To: 15)	Steve S.
19	21	21	0		
20	21	21	0		
21	21	21	0		
22	21	21	0		
23	21	21	0		
24	21	21	0		
	493	583	-90		

	To BPA-PGE EPMI JD				TRADER
	May 11 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	51	51	0		
2	51	51	0		
3	50	50	0		
4	50	50	0		
5	50	50	0		
6	50	50	0		
7	23	23	0		
8	24	24	0		
9	24	24	0		
10	24	24	0		
11	24	34	-10	epmi deal (Detail: 3, From: 0, To: 10)	Steve S.
12	24	34	-10	epmi deal (Detail: 3, From: 0, To: 10)	Steve S.
13	24	34	-10	epmi deal (Detail: 3, From: 0, To: 10)	Steve S.
14	24	24	0		
15	24	24	0		
16	24	24	0		
17	24	24	0		
18	24	24	0		
19	24	24	0		
20	24	24	0		
21	24	24	0		
22	24	24	0		
23	51	51	0		
24	51	51	0		
	787	817	-30		

	To BPA-PGE EPMI JD				TRADER
	May 12 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	3	3	0		
2	3	3	0		
3	3	3	0		
4	3	3	0		
5	2	2	0		
6	2	2	0		
7	25	25	0		
8	25	25	0		
9	24	24	0		
10	24	24	0		
11	24	24	0		
12	24	69	-45	(Detail: 3, From: 0, To: 45)	Chris H.

13	24	24	0		
14	24	24	0		
15	24	24	0		
16	24	24	0		
17	24	24	0		
18	24	24	0		
19	24	24	0		
20	24	24	0		
21	24	24	0		
22	24	24	0		
23	3	3	0		
24	3	3	0		
	408	453	-45		

	To BPA-PGE EPMI JD				**TRADER**
	May 15 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	7	7	0		
2	7	7	0		
3	7	7	0		
4	7	7	0		
5	8	8	0		
6	8	8	0		
7	30	30	0		
8	30	30	0		
9	30	30	0		
10	30	30	0		
11	30	30	0		
12	30	30	0		
13	30	30	0		
14	30	30	0		
15	30	40	-10	(Detail: 3, From: 0, To: 10) epmi said buy/resale price w	Mark B
16	30	40	-10	(Detail: 3, From: 0, To: 10) epmi said buy/resale price w	Mark B
17	30	40	-10	(Detail: 3, From: 0, To: 10)	Mark B
18	30	40	-10	(Detail: 3, From: 0, To: 10)	Mark B
19	30	40	-10	(Detail: 3, From: 0, To: 10)	Mark B
20	30	40	-10	(Detail: 3, From: 0, To: 10)	Mark B
21	30	40	-10	(Detail: 3, From: 0, To: 10)	Mark B
22	30	40	-10	(sale, From: 0, To: 10)	Mark B
23	8	8	0		
24	8	8	0		
	540	620	-80		

	To BPA-PGE EPMI JD				**TRADER**
	May 31 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	25	25	0		
2	25	25	0		
3	25	25	0		
4	25	25	0		
5	25	25	0		
6	25	25	0		
7	25	25	0		
8	25	25	0		
9	24	24	0		
10	24	24	0		

11	24	24	0		
12	24	24	0		
13	24	24	0		
14	24	24	0		
15	24	24	0		
16	24	24	0		
17	24	24	0		
18	24	24	0		
19	24	24	0		
20	24	24	0		
21	24	24	0		
22	24	24	0		
23	24	79	-55	SELL TO ENRON AT JOHN DAY (Detail: 3, From: 0, To:	Judy M
24	25	91	-66	SELL TO ENRON AT JOHN DAY (Detail: 3, From: 0, To:	Judy M
	585	706	-121		

	To BPA-PGE EPMI JD				TRADER
	June 6 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	59	59	0		
2	59	59	0		
3	59	59	0		
4	58	58	0		
5	58	58	0		
6	58	58	0		
7	28	28	0		
8	28	28	0		
9	27	27	0		
10	27	27	0		
11	27	27	0		
12	27	27	0		
13	27	27	0		
14	27	67	-40	(Detail: 3, From: 0, To: 40)	Judy M.
15	27	67	-40	(Detail: 3, From: 0, To: 40)	Judy M.
16	27	27	0		
17	27	27	0		
18	27	27	0		
19	27	27	0		
20	27	27	0		
21	27	27	0		
22	27	27	0		
23	58	58	0		
24	58	58	0		
	901	981	-80		

	To BPA-PGE EPMI JD				TRADER
	June 15 2000				
HE	Presched	Realtime	Diff	Log Entry	
1	101	101	0		
2	101	124	-23	SALE COST = DJ-MC +1 (Detail: 3, From: 0, To: 23) USED THIS ACCOUNT, ENERGY GOING TO SCL @ JD. (PER ENE)	Terry F.
3	101	101	0		
4	101	101	0		
5	101	101	0		
6	100	100	0		
7	26	26	0		

8	26	26	0		
9	26	26	0		
10	26	26	0		
11	26	26	0		
12	26	26	0		
13	26	26	0		
14	26	26	0		
15	26	26	0		
16	26	26	0		
17	26	26	0		
18	25	25	0		
19	25	25	0		
20	25	25	0		
21	25	25	0		
22	25	25	0		
23	78	78	0		
24	78	78	0		
	1172	1195	-23		

NO ACTIVITY JUNE 15,2000