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FEDERAL ENERGY
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January 16, 2004

The Honorable Linda Mitry
Acting Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: Enron Power Marketing, Inc., et al.
Docket No. EL03-180-000, et al.

Dear Secretary Salas:

Enclosed are an original and fourteen copies of the California Independent System Operator Corporation's ("ISO's") Prepared Direct Testimony and supporting exhibits in the above-captioned proceeding. This filing includes:

- Summary of the Prepared Direct Testimony of Dr. Eric Hildebrandt
- Exhibits:

Ex. No. ISO-1	Prepared Direct Testimony of Dr. Eric Hildebrandt
Ex. No. ISO-2	ISO document entitled "Analysis of Trading and Scheduling Strategies Described in Enron Memo," dated October 4, 2002
Ex. No. ISO-3	ISO document entitled "Addendum to October 4, 2002 Report on Analysis of Trading and Scheduling Strategies Described in Enron Memos," dated January 17, 2003

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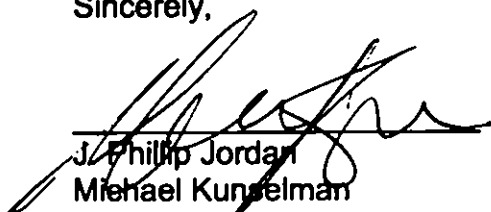
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|---------------|---|
| Ex. No. ISO-4 | ISO document entitled "Supplemental Analysis of Trading and Scheduling Strategies Described in Enron Memos," dated June 2003 |
| Ex. No. ISO-5 | CD-ROM (Disk #1 of 2) bearing the legend "Exhibit No. ISO-5, Filed on January 16, 2004 in Docket Nos. EL03-180, et al." (Filed under seal). |
| Ex. No. ISO-6 | CD-ROM (Disk #2 of 2) bearing the legend "Exhibit No. ISO-6, Filed on January 16, 2004 in Docket Nos. EL03-180, et al." (Filed under seal). |
| Ex. No. ISO-7 | Technical Supplement to Source Data |

Please note that this testimony is being filed under seal pursuant to the Protective Order adopted by the Presiding Judge in this proceeding. Specifically, Exhibit Nos. ISO-5 and ISO-6 contain "Protected Materials, Not Available to Competitive Duty Personnel." Therefore, these Exhibits have been redacted in the public copies included with this filing. Additionally, these Exhibits will be provided to parties on the official service list compiled in this proceeding who have not already received these Exhibits in the context of the Gaming Show Cause proceeding (Docket Nos. EL03-137, et al.). Any party receiving these Exhibits who have not signed the relevant Non-Disclosure Certificate should immediately discard these Exhibits.

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Also enclosed are two extra copies of the filing to be time/date stamped and returned to us by the messenger. Two courtesy copies of this filing are being provided to Presiding Judge Isaac D. Benkin. Please contact the undersigned if you have any questions regarding this filing. Thank you for your assistance.

Sincerely,



J. Phillip Jordan
Michael Kungelman
(202) 424-7500

Counsel for the California
Independent System Operator
Corporation

Enclosures

cc: The Honorable Isaac D. Benkin
Service List

Enron Power Marketing, Inc. et al.
Docket No. EL03-180-000, et al.

Exhibit No. ISO-1
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THE UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Enron Power Marketing, Inc.)	Docket No. EL03-180-000
and Enron Energy Services, Inc)	
City of Glendale, California)	Docket No. EL03-182-000
Colorado River Commission of Nevada)	Docket No. EL03-184-000
Modesto Irrigation District)	Docket No. EL03-193-000
Northern California Power Agency)	Docket No. EL03-196-000
Public Service Company of New Mexico)	Docket No. EL03-200-000

(Consolidated)

PREPARED DIRECT TESTIMONY OF
DR. ERIC HILDEBRANDT ON BEHALF OF
THE CALIFORNIA INDEPENDENT SYSTEM
OPERATOR CORPORATION

1 **Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS**

2 **A. My name is Dr. Eric Hildebrandt and I am the Manager of Market**
3 **Investigations for the California Independent System Operator Corporation**
4 **("ISO"). My business address is 151 Blue Ravine Road, Folsom, CA**
5 **95630.**

6 **Q. IN WHAT CAPACITY ARE YOU EMPLOYED?**

7 **A. I am the Manager of Market Investigations, within the Department of**
8 **Market Analysis.**

9

Enron Power Marketing, Inc., et al.
Docket No. EL03-180-000, et al.

Exhibit No. ISO-1
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1

2 **Q. WHAT ARE YOUR RESPONSIBILITIES AND ACTIVITIES IN THAT**
3 **POSITION?**

4 A. Among other activities, I have worked extensively on analyses of the
5 overall performance and competitiveness of California's Energy¹ and
6 Ancillary Services markets, analyses of and proposals to mitigate local
7 market power, and development and analysis of system market power
8 mitigation options. During the 2000-2001 period covered in this
9 proceeding, I played a lead role in analyzing and reporting to the
10 Commission on market conditions and outcomes in California's wholesale
11 energy markets. Since that period, I have testified before the Commission
12 in proceedings stemming from market conditions and activities of Market
13 Participants during that period, and have performed and supervised others
14 in the performance of various analyses of the types of scheduling and
15 trading practices that may constitute gaming or anomalous market
16 behavior.

17 **Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL**
18 **QUALIFICATIONS.**

19 A. I hold a B.S. degree in Political Economy from Colorado College, and an
20 M.S. and a Ph.D. in Energy Management and Policy from the University of

¹ Capitalized terms otherwise not defined in my testimony are defined in the ISO Tariff, Appendix A – Master Definitions Supplement.

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Docket No. EL03-180-000, et al.

Exhibit No. ISO-1
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1 Pennsylvania. I have specialized in economic analysis and research
2 relating to energy issues for over fifteen years, with an emphasis on
3 performing economic analysis, market research, and planning and
4 evaluation studies for the electric utility industry. I began my career in
5 energy research at the Center for Energy and Environment at the
6 University of Pennsylvania, and then worked for over six years as an
7 economic consultant to the electric utility industry with the firms of Xenergy
8 Inc. and Hagler Bailly Consulting in Philadelphia, Pennsylvania. Prior to
9 joining the ISO in 1998, I worked for over three years at the Sacramento
10 Municipal Utility District as Supervisor of Monitoring and Evaluation.

11 **Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE COMMISSION?**

12 **A. Yes. I have provided written and oral testimony on behalf of the ISO in the**
13 proceeding concerning refunds for transactions in the California wholesale
14 electricity markets (Docket Nos. EL00-95-000, *et al.*). I have also provided
15 written testimony on behalf of the ISO in the so-called "100 Days
16 Evidence" proceeding (Docket Nos. EL00-95-069 and EL00-98-042). In
17 addition, I have provided written and oral testimony in proceedings related
18 to Reliability Must-Run Contracts in California (Docket Nos. ER98-496-
19 000, ER98-1614-000, ER98-2145-000 and ER99-3603).

20

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Exhibit No. ISO-1
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1 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

2 A. I will describe briefly, and submit for the record of this proceeding, a report
3 and supporting data that the ISO's Department of Market Analysis ("DMA")
4 has produced concerning possible gaming and market manipulation in the
5 California wholesale electricity markets.

6 **Q. WHAT IS THE REPORT TO WHICH YOU REFER?**

7 A. I am referring to a report that consists of three ISO documents dated
8 October 4, 2002, January 17, 2003, and June 2003. I will refer to these
9 documents collectively as the "ISO Report." The ISO Report is provided
10 as Exhibit No. ISO-2 to my testimony.

11 **Q. WILL YOU BE SUMMARIZING THE FINDINGS IN THE ISO REPORT?**

12 A. No. The ISO Report speaks for itself, and therefore I believe there is no
13 need for me to summarize it.

14 **Q. WHY ARE YOU SUBMITTING THE ISO REPORT IN THIS**
15 **PROCEEDING?**

16 A. This proceeding was established by the Commission in the "Order to
17 Show Cause Concerning Gaming and/or Anomalous Market Behavior
18 Through the Use of Partnerships, Alliances, or Other Arrangements and
19 Directing Submission of Information," issued in the captioned dockets on
20 June 25, 2003 ("Partnership Order"). In that Order, the Commission noted

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Exhibit No. ISO-1
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1 that the Commission Staff cited the ISO Report in the Staff's Final Report
2 in the investigation in Docket No. PA02-2-000, which the Commission
3 relied upon, in part, in issuing the Order. Moreover, in the "Order to Show
4 Cause Concerning Gaming and/or Anomalous Market Behavior" ("Gaming
5 Order"), which was issued concurrently with the Partnership Order, the
6 Commission noted that it had reviewed the ISO Report, and that it was
7 issuing the Gaming Order based on the ISO Report as well as the Final
8 Staff Report and other materials (*i.e.*, the submissions in the 100 Days
9 Evidence proceedings). The Gaming Practices identified by the
10 Commission in the Gaming Order are the same practices at issue in the
11 present proceeding.

12 **Q. WHAT DOES THE SUPPORTING DATA YOU REFERRED TO EARLIER**
13 **CONSIST OF?**

14 **A. The data consist of the specific transaction data for each of the practices**
15 discussed in the ISO Report, along with a description of the "screens"
16 DMA had used to compile the ISO Report. The data and the description
17 are being provided on two CD-ROMs and in a paper copy of the ISO's
18 "Technical Supplement to Source Data" as Exhibit No. ISO-3. The CD-
19 ROMs provided in Exhibit No. ISO-3 are designated by the ISO as
20 "Protected Materials" pursuant to the Protective Order adopted by the
21 Presiding Administrative Law Judge in this proceeding. Therefore, the
22 version of Exhibit No. ISO-3 that is being made available for viewing by

Enron Power Marketing, Inc., et al.
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Exhibit No. ISO-1
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1 the public excludes the CD-ROMs, and contains only the Technical
2 Supplement to Source Data.

3 **Q. WERE THESE DATA AND EXPLANATIONS PREPARED BY YOU OR**
4 **UNDER YOUR DIRECTION?**

5 **A. Yes.**

6 **Q. HAS THE ISO PROVIDED THESE REPORTS AND UNDERLYING**
7 **DATA IN ANY OTHER PROCEEDINGS?**

8 **A. Yes.** In the Gaming Order, the Commission directed the ISO to provide
9 the transaction data underlying the ISO Report, along with the description
10 of the "screens," within 21 days after that Order, to all parties required to
11 show cause by the Gaming Order (the "Identified Entities"), The ISO
12 provided this data and explanation of the "screens" to the Identified
13 Entities, and the Commission. Subsequently, on November 3, 2003, I filed
14 Prepared Direct Testimony in the Gaming Order proceeding (Docket Nos.
15 EL03-137, *et al.*) which included the ISO Report, along with the supporting
16 data and explanations.

17 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

18 **A. Yes.**

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

City of Folsom
County of Sacramento

AFFIDAVIT OF WITNESS

I, Eric Hildebrandt, being duly sworn, depose and say that the statements contained in my Prepared Direct Testimony on behalf of the California Independent System Operator Corporation in this proceeding are true and correct to the best of my knowledge, information, and belief.

Executed on this 16 day of January, 2004.


Eric Hildebrandt

Subscribed and sworn to before me this 16 day of January, 2004.


Notary Public
State of California

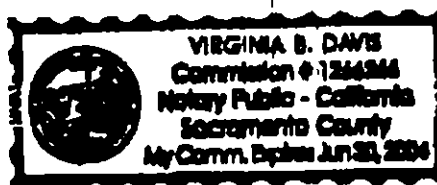


EXHIBIT NO. ISO-2

Enron Power Marketing, Inc., et al.
Docket No. EL03-180-000, *et al*

Exhibit No. ISO-2, Page 1 of 34

**Analysis of Trading and Scheduling Strategies
Described in Enron Memos**

Report

Department of Market Analysis

October 4, 2002

Introduction

This report summarizes additional analysis that has been done by the ISO on the various trading and scheduling practices outlined in the Enron memos. This document supplements analysis already provided as part of testimony submitted at recent Senate hearings, and follows the same numbering as that previous document.¹ The report is being submitted to Commission staff for use in its investigation of Western Markets. The ISO stands ready to provide Commission staff with additional documentation and analysis of these trading practices and to assist staff with any aspect of its investigation.

1. "Inc'ing Load" (a.k.a "Fat Boy")

This is a form of uninstructed deviation, also referred to as *overscheduling of load* through which suppliers can receive real time market price (as price takers) for power provided without ISO dispatch instruction. This can be done by in-state generators without overscheduling of load simply by overgenerating in real time. Since imports must be scheduled over inter-ties and cannot simply overgenerate, importers can schedule imported generation against "fictitious load", which creates a positive uninstructed deviation in real time for which they receive the real time market clearing (MCP).²

During 2000, Enron routinely overscheduled load by 500 to 1,000 MW (in excess of actual load of ~500 to ~1000 MW). Enron may have preferred this strategy rather than bidding energy in real time market since it "guaranteed" a sale and allowed them to schedule transmission in advance. Since the ISO rarely needed to decrement resources during this period due to chronic undersheduling by other market participants, Enron also faced minimal risk of receiving a price of zero for uninstructed energy price due to the target price mechanism that was implemented in spring 2000 and caused the price paid for positive uninstructed deviations to be zero for most hours when the ISO was decrementing resources or incrementing very small amounts of energy in real time.³

¹ See Exhibit 2 submitted with Testimony of Terry Winter before the U.S. House of Representatives, Subcommittee on Energy Policy, Natural Resources, and Regulatory Affairs, July 22, 2002. (<http://www.caiso.com/docs/09003a6080/18/93/09003a6080189353.pdf>)

² After implementation of 10-minute settlement on September 1, 2000, positive uninstructed deviations received the decremental energy price, based on the lowest decremental bid dispatched (if any) during any interval. If no decremental energy is dispatched in real time, the decremental price is equal to the incremental price, or the highest incremental bid dispatched. Prior to this time, deviations were paid a charges a single hourly ex post MCP based on a weighted average of inc and dec prices and volumes each 10-minute interval within the hour.

³ Also, until 10-minute settlements started in September 1, 2000, there was no difference in the price paid for uninstructed vs. instructed energy.

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Overscheduling by Enron dropped dramatically in late November and early December 2000, but resumed in August 2001 through November 2001.

FIGURE 1. OVERSCHEDULING BY ENRON (PEAK HOURS)

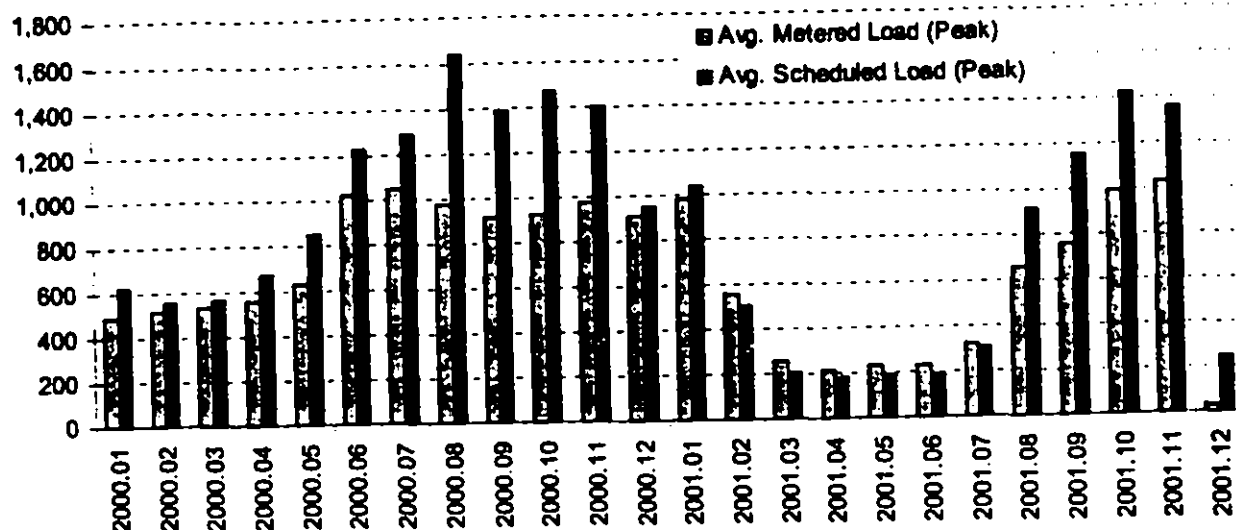
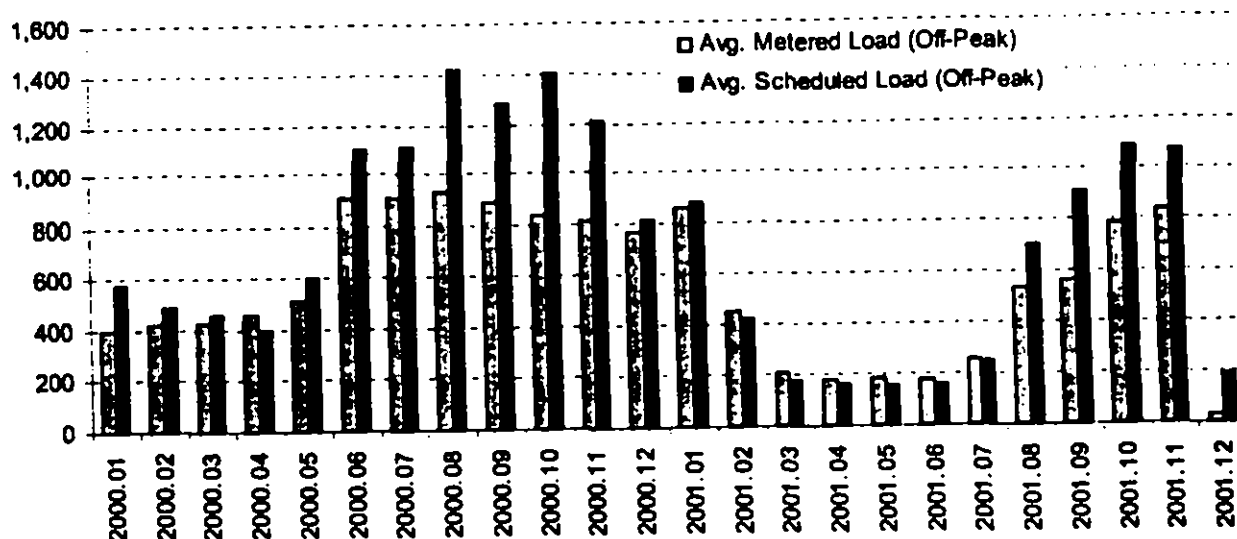


FIGURE 2. OVERSCHEDULING BY ENRON (OFF- HOURS)



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However, the incentive for overscheduling of load is greatly reduced as load forward schedules. If most loads have been forward scheduled, then such practice will depress real time prices to the disadvantage of the party who over-scheduled. The ISO's current market design (which includes 10-minute settlements and significant forward scheduling by CERS) discourages uninstructed deviations. However, as noted above, Enron continued to overschedule during the summer of 2001, despite a relatively low level of underscheduling by other market participants.

Future proposed market design (MD02) would further decrease the incentive to over/under schedule load in several ways, including the establishment of (1) available capacity obligations on load and generation, and (3) a more consistent system of locational marginal pricing (LMP) in the forward markets (Day ahead and Hour Ahead) and the real time market. Both of these market design modifications are expected to reduce price differences and the incentive to arbitrage between the Day Ahead/Hour Ahead and real time markets. In addition, another concept under discussion is to allow participants to submit "virtual demand bids" in the Day Ahead/Hour Ahead markets, so that participants could schedule generation against "virtual load", while allowing the ISO's ability to differentiate between "actual" load and virtual load" for purposes of making efficient Day Ahead unit commitment and real time dispatch decisions.

It should be noted that overscheduling of load is not a strategy that could be employed to "hide" generation from the ISO and cause the ISO to declare a system emergency or curtail load, as has been alleged by Mr. Robert McCullough before a California State Senate Committee.⁴ The ISO manages real time energy needs and declares system emergencies based on its actual loads and generation observed in real time (and short term projections for the next operating hour), not by Day Ahead or Hour Ahead schedules submitted by participants. Thus, any overscheduling of loads by participants does not "inflate" ISO's projection of loads for each operating hour. At the same time, any generation that is scheduled against "fictitious load" under this strategy is actually delivered, and is therefore fully visible to ISO operators. As a result, during periods of chronic underscheduling of load by the state's major IOUs, the net effect of overscheduling of load by other participants is to reduce the overall difference between observed loads and generation that the ISO must meet through its formal real time market (or through out-of-market purchases).⁵

The ability to overschedule load in selected congestion zones could be used in as part of a strategy of increasing congestion revenues earned by FTR holders by increasing congestion. However, as discussed in a later section of this report, analysis indicates that overscheduling of load in the ISO's southern zone (SP15) does not appear to have

⁴ See memo entitled "Three Crisis Days at the California ISO," submitted as testimony by Robert McCullough to the California Select Committee to Investigate Price Manipulation of the Wholesale Energy Market, September 16, 2002.

⁵ During periods of excess generation, overscheduling of load can negatively impact reliability by creating overgeneration. However, the system emergencies and outages discussed by McCullough could in no way be have been created or exacerbated by overscheduling of load, as McCullough contends.

been employed by Enron (or, in any event, was not successfully employed) as part of a strategy to increase Enron's FTR revenues on Path 26.

2. Export of California Power

During some periods when prices hit the ISO price caps, Enron and other SCs could presumably buy power from CA and sell to outside markets at higher prices.⁶

The ISO does not have access to information on the price at which power exported from the ISO system may have been sold. However, the ISO does routinely monitor price indices reported for the major trading hubs in neighboring control areas (Palo Verde and the California Oregon Border), and compare these to prices paid by the ISO for real time energy. Results of this analysis over the period of time in 2000 when different levels of "hard caps" were in effect suggest that the high prices observed in California's wholesale market tended to drive high prices in nearby regional markets, rather than being driven by prices in these other regional markets. Evidence of this is shown in Figure 3, which show that prices in the nearby trading hubs tracked prices in the ISO real time market very closely, and that prices in these hubs rarely exceeded prices in the ISO's real time market. More importantly, prices in these other markets dropped when the hard price cap in effect in the ISO's real time market were lowered from \$750 to \$500 and then again to \$250. This suggests that prices in neighboring trading hubs were typically being driven by prices in the ISO's real time market.

The export of power from one control area is always a concern when spot market supply is relatively tight and price caps in that area are lower than the surrounding areas. Resolution of this problem over the short to medium term requires continuation of regional market power mitigation, not a California only solution. Over the longer-term, problems associated with export of power may be addressed by imposing available capacity requirement on LSE's within the ISO. Establishing capacity requirement on a regional level would also address the potential problems associated with export of power by avoiding regional shortages and reducing reliance on spot markets. This conclusion is also supported by the fact that imports purchased out-of-market (OOM) by the ISO while hard caps were in place also tracked prices in the ISO's real time market closely, but rarely exceeded these hard caps or real time prices in the ISO's real time imbalance market, as shown in Figure 4. It should be noted, however, that as reported spot market gas prices began to soar above \$20/MBtu in late November 2000, the ISO did need to begin paying prices in excess of the \$250 hard cap in order to procure a sufficient quantity of imports out-of-market to meet system loads.

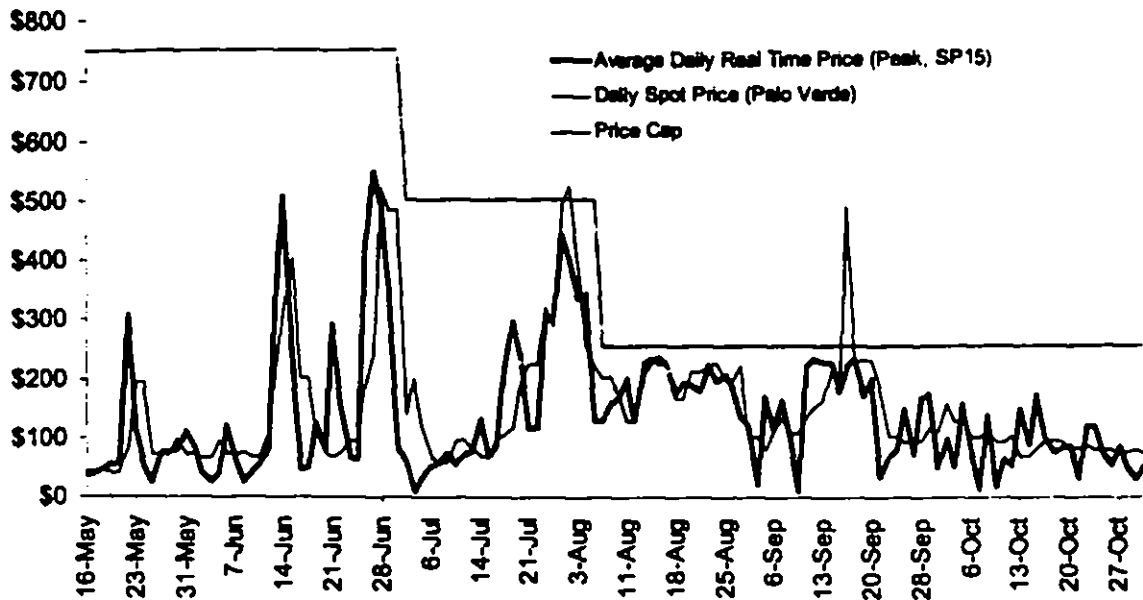
⁶ While export of power from California could be part of a strategy for exercising and benefiting from market power and circumventing price caps in effect within the ISO system, the Enron memos describe this trading practice as being limited to taking advantage of an arbitrage opportunity by buying power at capped prices from the PX market and exporting it for sale at a higher price.

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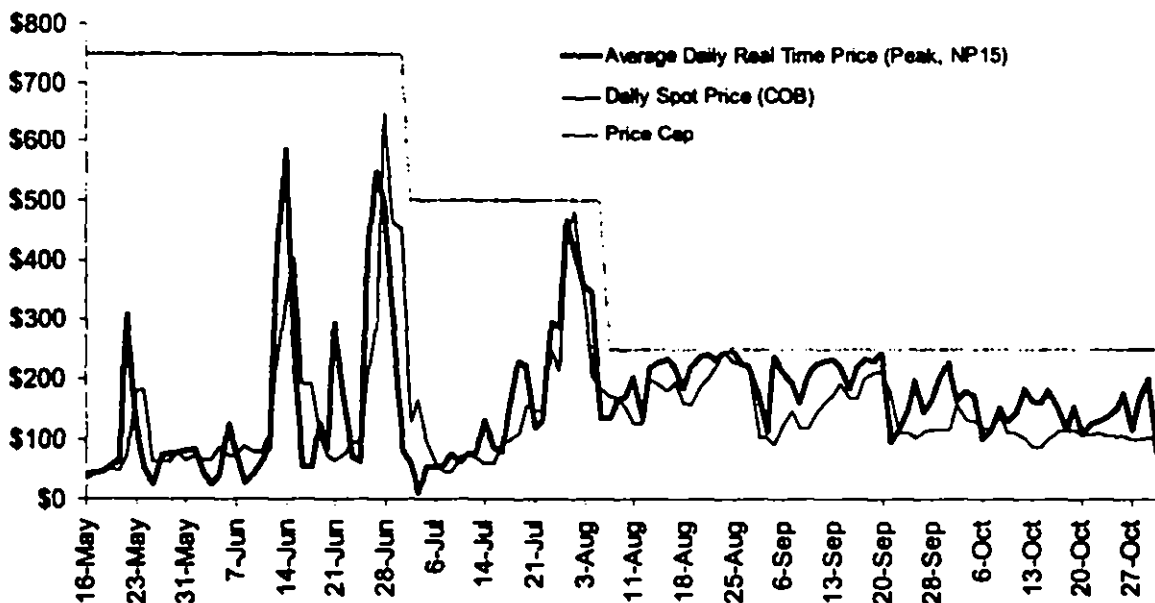
Docket No. EL03-180-000, et al

**Figure 3. Comparison of ISO Real-time Prices
With Daily Spot Prices in Neighboring Trading Hubs**

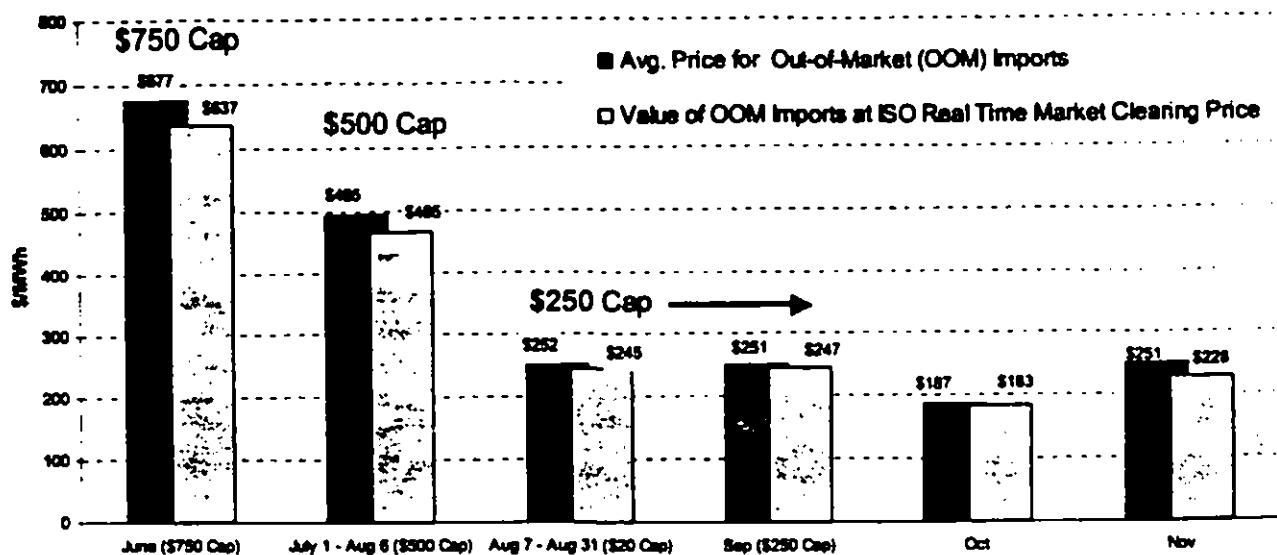
Palo Verde (Arizona) and SP15 (Southern California)



COB (California-Oregon Border) and NP15 (Northern California)



**Figure 4. Comparison of ISO Real-time Prices
Purchase Price Compared with Ex Post Price**



3. Non-firm Export

This strategy involves scheduling of "non-firm export" that supplier does not intend to deliver or cannot deliver. If importing inter-tie is congested, the supplier receives the congestion revenue, and then cancels the export after the close of the Hour-Ahead market, so no delivery takes place. This practice provides false relief of congestion prior to real time, and does not actually relieve congestion in real time since export does not occur.

Enron successfully used this strategy to earn a total of \$54,000 in congestion payments on three separate days between June 14 and July 20, 2000. The next day, on July 21, 2000, this practice was proscribed by the ISO under a Market notice issued under the MMIP, and this practice has not occurred since a market notice was issued. No other SCs appear to have successfully used this strategy prior to the incidents with Enron in June-July 2000 with the possible exception of Duke, which earned \$33,500 during 2 hours on May 27, 2000 for non-firm schedules that were cut in real time. Additional research would be needed to determine if this was intentional gaming, or simply schedules that were cut by the ISO.

The ISO is currently considering modifying its tariff to allow for payments of congestion revenues to be rescinded if final loads/generations actually provided in real time deviate from levels upon which congestion revenues were awarded in DA or HA market.

4. Death Star

The Death Star scenario described in the Enron memos is an example of what the ISO now refers to as "circular schedules", which may be defined as series of two or more export and import schedules that begin and end in the same control area.

The issue of circular schedules has undergone substantial discussion at the ISO, both before and after the Enron memos were released. First, it is important to note that although the type of circular schedule described as the Death Star strategy does not result in a physical flow of energy as portrayed in the schedule, such schedules may have the effect of reducing congestion charges in the Day Ahead and Hour Ahead market by, in effect, allowing the ISO's congestion management model to "divert" energy scheduled by other SCs over the congested path over the transmission lines outside the ISO system over which the circular schedule is made. However, ISO Grid Operations staff have expressed two concerns about such circular schedules.

First, concerns have been raised that circular schedules do not actually relieve congestion due to the fact that the ISO's scheduling and congestion management system is based on a simplified model in which energy flows are represented by the scheduled or "contract path" flows used throughout the WSCC, rather than based on actual electrical system conditions. Because of this discrepancy between how power flows are modeled in the ISO's congestion model and power flows under a full network model, power may not (and often does not) actually flow as scheduled.

A second concern expressed by Grid Operations staff is that because of the circular nature of the source and sink of a circular schedule, such schedules may make it more difficult for Operators to manage actual power flows by adjusting import/export schedules in real time. For example, the import portion of a circular schedule could not be curtailed due to a contingency on one branch group without cutting the source of an export schedule that is providing a counterflow on another branch group. Enron's practice does pose a risk to system reliability since the simultaneity of flows could not be verified by the operators and therefore was not appropriate.

The potential frequency and financial gains from circular schedules were analyzed by identifying import/export schedules (of equal quantities) by the same SC that generated congestion revenues from counterflows on interties and/or internal paths within the ISO. It should be noted that this approach may underestimate circular schedules since the analysis only includes import/export schedules that can be matched because they are of (approximately) equal quantities by the same SC.⁷ At the same time, since such matching would include wheeling schedules (or other combinations of export/import schedules) which may have a distinct physical source and sink outside the ISO control area, in addition to schedules that may be "re-circulated" outside the control area.

⁷ For instance, the strategy could also be employed by a single SC using more than two schedules (e.g. two 50 MW import schedules on two different ties, paired with a 100 MW export schedule on a third tie). In addition, it could be employed by two or more SC's (e.g. a 50 MW import schedule by one SC, coupled with an inter-SC trade to another SC, who then exported all or part of the amount transferred from the other SC).

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As shown in Table 1, this analysis identified about \$2.7 million congestion payments earned by Enron in 1998-2001 that may be attributable to circular scheduling, with about \$484,000 of this from counterflows created the import/export paths described as "Death Star" in the Enron memos (i.e. creating flows through the ISO system by importing from the AC lines in the Northwest and exporting to the Southwest, or vice versa). Another \$452,000 of counterflow revenues involved flows over the DC intertie (NOB). The largest portion of counterflows identified in this analysis (\$1.8 million) involve schedules flowing into and out of the ISO system over branch group in the Southwest.

DMA has reviewed a number of NERC tags of a sample of these schedules to see if it can be determined whether these schedules represent actual physical sources and sinks, or are the type of "circular" schedule with no physical source and sink, such as the Death Star scheme described in the Enron memos. However, a review of a sample of NERC tags indicates that in many if not most cases, there is not sufficient information for the ISO to make this determination due to the fact that no NERC tagging information was submitted or NERC tagging information is insufficient to make this determination.

In addition to the \$2.7 million in counter flow revenues earned by Enron from potential circular schedules, this analysis identified a total of about \$11.7 million in counter flow revenues earned by other SCs from potential circular schedules, representing a total of \$14.4. million over the 1998-2001 period (see Table 2). As shown in Table 3, about \$2.8 million of these revenues involved flows on the NOB DC line.

**Table 1. Total Congestion Revenues Earned by Enron from Counterflows
Created by Import/Export Schedules
(Matched by MW Amount) 1998-2001**

Import/Export Pattern	Import (Tie Point)	Export (Tie Point)	Counterflow Revenues
Death Star	MALIN_5_RNDMTN	FCORNR_5_PSUEDO	\$254,905
Death Star	PVERDE_5_DEVERS	MALIN_5_RNDMTN	\$94,859
Death Star	MEAD_2_WALC	MALIN_5_RNDMTN	\$5,128
Death Star	FCORNR_5_PSUEDO	MALIN_5_RNDMTN	\$118,718
Death Star	MALIN_5_RNDMTN	MEAD_2_WALC	\$8,309
Death Star	MALIN_5_RNDMTN	PVERDE_5_DEVERS	\$2,376
Sub-total (Death Star)			\$484,295
Southwest Loop	PVERDE_5_DEVERS	FCORNR_5_PSUEDO	\$486,326
Southwest Loop	MEAD_2_WALC	FCORNR_5_PSUEDO	\$73,651
Southwest Loop	PVERDE_5_DEVERS	MEAD_2_WALC	\$37,637
Southwest Loop	FCORNR_5_PSUEDO	MEAD_2_WALC	\$19,250
Southwest Loop	MEAD_2_WALC	PVERDE_5_DEVERS	\$54,019
Southwest Loop	FCORNR_5_PSUEDO	PVERDE_5_DEVERS	\$1,186,305
Sub-total (Southwest Loop)			\$1,857,188
DC Tie	SYLMAR_2_NOB	FCORNR_5_PSUEDO	\$133,277
DC Tie	SYLMAR_2_NOB	MEAD_2_WALC	\$99,444
DC Tie	SYLMAR_2_NOB	PVERDE_5_DEVERS	\$552
DC Tie	PVERDE_5_DEVERS	SYLMAR_2_NOB	\$68,367
DC Tie	MEAD_2_WALC	SYLMAR_2_NOB	\$84,908
DC Tie	FCORNR_5_PSUEDO	SYLMAR_2_NOB	\$69,518
Sub-total (DC Tie)			\$456,066
Total			\$2,797,548

**Table 2. Total Congestion Revenues from Counterflows
Created by Import/Export Schedules (Matched by MW Amount) by SC**

SC_ID Name	1998	1999	2000	2001	2002	Total
CRLP Coral Power, LLC			\$1,366,933	\$1,279,190	\$1,229,360	\$3,875,484
EPMI ENRON Power Marketing Inc		\$84,148	\$1,039,960	\$1,673,440		\$2,797,548
SETC Semptra Energy Trading		\$87,746	\$1,190,556	\$237,161	\$133,960	\$1,649,422
PWRX British Columbia Power Exchange			\$44,779	\$329,732	\$710,162	\$1,084,673
WESC Williams Energy Services		\$856,597	\$43,907	\$15,047	\$50,731	\$966,283
CAL1 Cargill Alliant, LLC			\$1,025	\$14,289	\$877,964	\$893,278
APX1 Automated Power Exchange, Inc				\$679,500	\$2,662	\$682,162
IPC1 Idaho Power Company			\$617,116	\$51,949		\$669,065
PAC1 PacificCorp	\$413,325	\$20,558		\$65,228	\$25,757	\$524,869
SCEM Mirant			\$54,436	\$146,243	\$295,658	\$496,337
DETM Duke Energy Trading	\$64,018	\$8,294	\$95,340	\$26,465	\$21,535	\$215,651
ANHM City of Anaheim			\$136,725	\$13,832		\$150,557
CALP Calpine Energy Services				\$4,376	\$127,984	\$132,360
APS1 Arizona Public Service Company		\$90,895	\$36,101			\$126,996
MID1 Modesto Irrigation District		\$34,398	\$24,358	\$20,847	\$326	\$79,929
MSCG Morgan Stanley Capital Group				\$36,614		\$36,614
AEPS American Electric Power Service					\$19,481	\$19,481
APX4 Automated Power Exchange				\$6,675	\$12,052	\$18,727
AQPC Aquila Power Corporation			\$6,288			\$6,288
PSE1 Puget Sound Energy			\$1,815			\$1,815
RVSD City of Riverside		\$1,501	\$0			\$1,501
Grand Total	\$477,343	\$1,184,151	\$4,659,341	\$4,600,587	\$3,507,633	\$14,429,055

Note: Includes all import/export combinations by the same SC (matched by MW amount) that earned net congestion revenues from counterflows on interties and internal ISO paths. The ISO does not have sufficient information to determine if these schedules represent actual physical sources and sinks that mitigated congestion, or are the type of "circular" schedule with not physical source and sink, such as the Death Star scheme described in the Enron memos.

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**Table 3. Total Congestion Revenues from Counterflows
 Created by Import/Export Schedules (Matched by MW Amount)
 by Import/Export Combination**

Export line point	Import line point	1998	1999	2000	2001	2002	Total
PVERDE_5_NG-PLV	NGILA_5_NG4				\$2,800		\$2,800
PVERDE_5_DEVERS	CAPJAK_5_OLINDA					\$326	\$326
PVERDE_5_DEVERS	CASCAD_1_CRAGVW					\$0	\$0
PVERDE_5_DEVERS	FCORN_5_PSUEDO		\$1,502	\$581,193	\$1,885,080	\$1,238,825	\$3,686,600
PVERDE_5_DEVERS	MALIN_5_RNDMTN			\$36,986	\$185,100	\$384,417	\$568,512
PVERDE_5_DEVERS	MEAD_2_WALC		\$812,022	\$150,288	\$216,472	\$849,028	\$1,827,791
PVERDE_5_DEVERS	MOENKO_5_PSUEDO		\$804	\$11,132	\$133,406		\$145,441
PVERDE_5_DEVERS	SUMITM_1_SPP					\$2	\$2
MOENKO_5_PSUEDO	MALIN_5_RNDMTN			\$3,050			\$3,050
MOENKO_5_PSUEDO	MEAD_2_WALC		\$5,955	\$5,899			\$11,854
MOENKO_5_PSUEDO	PVERDE_5_DEVERS		\$11,143	\$12,612			\$23,754
MEAD_2_WALC	CASCAD_1_CRAGVW				\$749		\$749
MEAD_2_WALC	ELDORD_5_PSUEDO			\$800			\$800
MEAD_2_WALC	FCORN_5_PSUEDO		\$80,895	\$922,831	\$39,768	\$4,818	\$1,058,112
MEAD_2_WALC	MALIN_5_RNDMTN			\$8,139	\$9,639	\$5,675	\$23,453
MEAD_2_WALC	PVERDE_5_DEVERS			\$233,641	\$85,490	\$10,564	\$329,695
MEAD_2_WALC	SUMITM_1_SPP				\$0		\$0
MALIN_5_RNDMTN	CASCAD_1_CRAGVW	\$398,020		\$539		\$4,637	\$401,196
MALIN_5_RNDMTN	FCORN_5_PSUEDO	\$17,308	\$28,532	\$82,795	\$145,690	\$41,801	\$314,124
MALIN_5_RNDMTN	MEAD_2_WALC		\$50,584	\$34,980	\$2,785	\$4,548	\$82,897
MALIN_5_RNDMTN	PVERDE_5_DEVERS	\$57,788	\$82,413	\$117,705	\$157,222	\$116,045	\$531,152
MALIN_5_RNDMTN	SUMITM_1_SPP		\$14		\$3,652	\$12	\$3,678
FCORN_5_PSUEDO	CASCAD_1_CRAGVW				\$11,323		\$11,323
FCORN_5_PSUEDO	MALIN_5_RNDMTN		\$1,829	\$213,999	\$761,953	\$36,059	\$1,013,839
FCORN_5_PSUEDO	MEAD_2_WALC		\$187,826	\$197,003	\$21,547	\$40,033	\$446,409
FCORN_5_PSUEDO	PVERDE_5_DEVERS		\$6,501	\$754,961	\$243,091	\$199,109	\$1,203,662
FCORN_5_PSUEDO	SUMITM_1_SPP				\$32,269		\$32,269
ELDORD_5_PSUEDO	MALIN_5_RNDMTN		\$5,062	\$22,338			\$27,400
ELDORD_5_PSUEDO	MEAD_2_WALC		\$2,887	\$30,848			\$33,735
ELDORD_5_PSUEDO	PVERDE_5_DEVERS		\$4,376				\$4,376
CAPJAK_5_OLINDA Total			\$21,131	\$814			\$21,745
CAPJAK_5_OLINDA	MOENKO_5_PSUEDO			\$614			\$614
CAPJAK_5_OLINDA	PVERDE_5_DEVERS		\$21,131				\$21,131
BLYTHE_1_WALC	MALIN_5_RNDMTN			\$899			\$899
BLYTHE_1_WALC	PVERDE_5_DEVERS			\$1,721			\$1,721
	Subtotal	\$471,093	\$1,132,704	\$3,407,378	\$3,898,035	\$2,715,700	\$11,624,909
FCORN_5_PSUEDO	SYLMAR_2_NOB			\$211,126	\$180,587	\$78,820	\$468,533
MEAD_2_WALC	SYLMAR_2_NOB			\$117,402	\$128,239	\$20,825	\$266,265
MOENKO_5_PSUEDO	SYLMAR_2_NOB			\$1,993			\$1,993
PVERDE_5_DEVERS	SYLMAR_2_NOB			\$447,362	\$313,949	\$470,680	\$1,231,991
SYLMAR_2_NOB	FCORN_5_PSUEDO		\$2,398	\$155,137		\$102,567	\$260,102
SYLMAR_2_NOB	MEAD_2_WALC		\$58,286	\$80,630	\$75,888	\$66,344	\$280,148
SYLMAR_2_NOB	PVERDE_5_DEVERS	\$8,250	\$11,893	\$258,927	\$3,891	\$55,888	\$338,849
	NOB Subtotal	\$8,250	\$72,578	\$1,252,577	\$702,552	\$791,834	\$2,825,890
Grand Total		\$477,343	\$1,184,151	\$4,659,341	\$4,600,587	\$3,507,533	\$14,429,056

5. Gaming of FTR Market by Shifting Load (Load Shift)

The strategy requires that Enron have FTRs connecting ISO zones (e.g. Path 26). First, the FTR owner creates congestion by false scheduling of load in different zones. The FTR owner may then get paid to relieve the congestion, and collects additional congestion revenues for FTRs it does not use to schedule its own load/generation.

During 2000, Enron owned 1,000 MW of FTRs in a north-to-south direction on Path 26, or 62% of all FTRs on this path. Since this initial FTR auction cycle, Enron has not owned any FTRs on Path 26 in later years.

The specific scenario outlined in the Enron memo was examined as follows:

- 1) The total north-to-south flow on Path 26 (the direction FTRs owned by Enron on this path) created by Enron's Day Ahead schedules during hours of congestion on Path 26 was calculated.⁸
- 2) Hours when Enron could have been "pivotal" in creating congestion in the north-to-south direction on Path 26 were identified by comparing the total north-to-south flow created by Enron's initial schedules in the Day Ahead and Hour Ahead markets to the total initial flow on Path 26.⁹
- 3) Hours when Enron could have been "pivotal" in creating congestion in the north-to-south direction on Path 26 and were paid to mitigate congestion by adjustment bids on its load schedules were identified.
- 4) Total congestion revenues earned by Enron through its ownership of FTRs was categorized by the 3 types of hour specified above.

As summarized in Table 4, results of this analysis show that only about 2% of the \$34 million in congestion revenues earned by Enron for the FTRs it purchased on Path 26 were earned during hours when Enron could have been pivotal in creating congestion, and only one-half of 1% of congestion revenues were earned when Enron was pivotal and utilized demand adjustment bids to alleviate congestion, as described in the Enron memos.

⁸ Calculations based on the degree to which Enron's initial schedules in the Day Ahead and Hour Ahead markets for zones north of Path 26 (NP15 and ZP26) exceeded its initial schedule in the zone south of Path 26 (SP15), including internal generation/loads, imports/exports and inter-SC trades.

⁹ Enron is "pivotal" in creating congestion if the north-to-south flows created by Enron's initial schedules equaled or exceeded the total amount by which total initial scheduled flows on Path 26 exceeded the available capacity, thereby triggering congestion management.

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**Table 4. Analysis of Enron's Net FTR Revenues on Path 26
 for the Period February 1, 2000 through March 31, 2001**

	Hours*	Net FTR Revenues
Could Not Have Caused Congestion (even a zero schedule, there would have been congestion)	879	\$33,912,567 97.9%
Potential for Causing Congestion (if congestion goes away without their schedule)	98	\$533,679 1.5%
Could have Caused Congestion and Used Load Shift Strategy as Described in Memo	21	\$181,227 0.5%
	998	\$34,627,473

* Only includes hours of congestion on Path 26.

Impact on Congestion Price

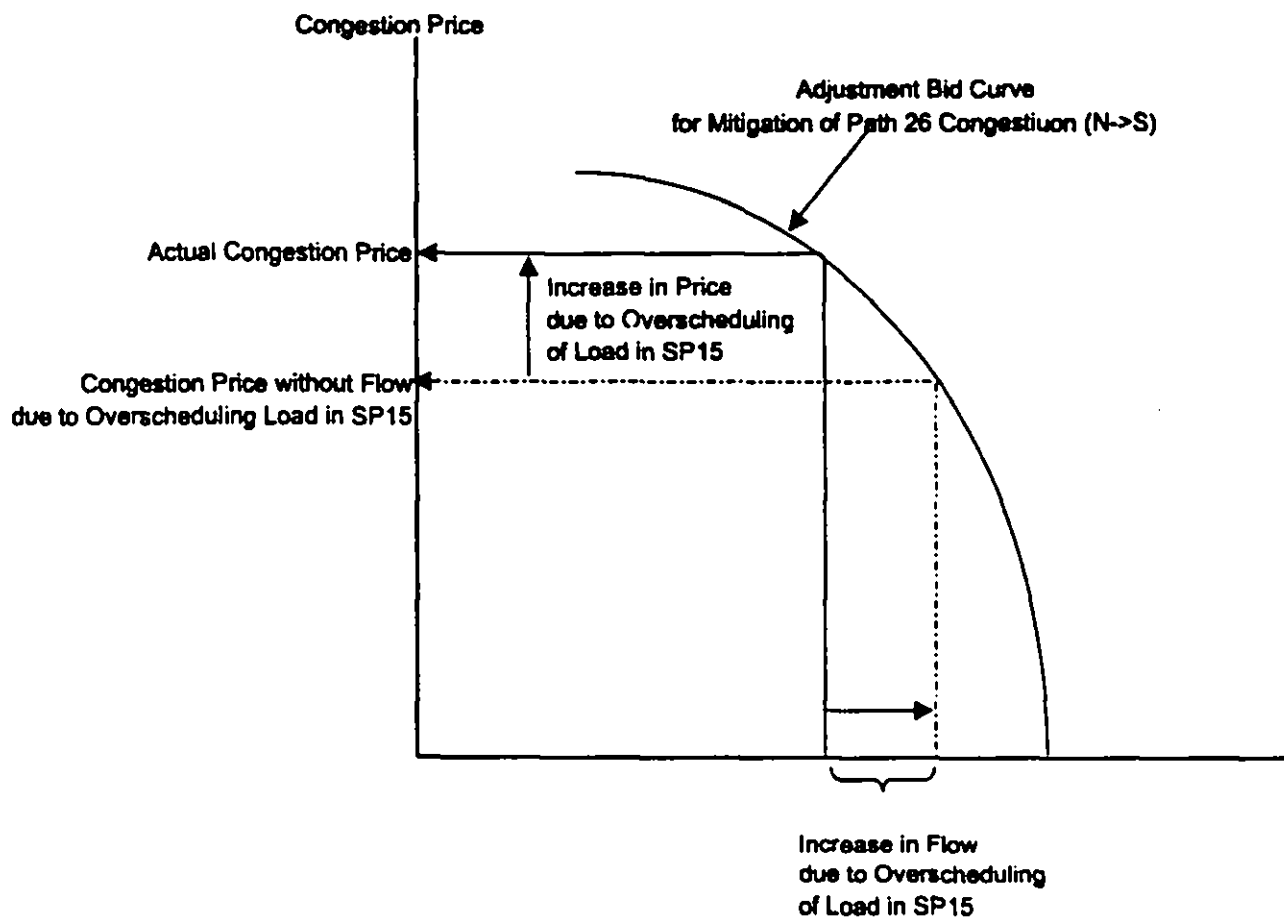
During hours when Enron was not pivotal in causing congestion, Enron could nonetheless affect the price of congestion by increasing the scheduled flow on Path 26, and, in effect, "shifting" the remaining supply of transmission on Path 26 downward, thereby raising the final congestion price. For example, Enron could have sought to increase congestion on Path 26 by oversheduling demand in SP15. Although this strategy as not discussed in the Enron memos, such a strategy would, in effect, represent a combination of two of the strategies outlined in the memos: (1) "inc'ing load" (a.k.a "Fat boy"), and (1) "Load Shift", or gaming of the FTR market to increase congestion revenues.

Methodology

Figure 5 illustrates how the impact of such a shift on the congestion price may be calculated based on the demand for transmission, as reflected in the Adjustment Bid Curve used in congestion management to curtail initial schedules and determine the congestion price paid by SC's for final scheduled flows. As showing in Figure 5, key data needed for this analysis includes (a) the net change in scheduled flows on Path 26 due to oversheduling of load in SP15 by Enron, and (b) the sensitivity (or elasticity) of congestion prices given such a change in scheduled flows.

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Figure 5. Impact of Change in Scheduled Flows on Congestion Price



Since every SC is required to submit schedules with a balanced amount of supply and demand within the total ISO system, the scheduled flow on Path 26 Flow in the Day Ahead market during hours when congestion occurred in the North to South direction on Path 26 can be calculated based on final schedules submitted by each SC within the southern zone (SP15), as summarized below:

$$\begin{aligned} \text{Net Scheduled Flow}_{N \rightarrow S} = & \text{Scheduled Generation}_{SP15} + \text{Scheduled Import}_{SP15} \\ & + \text{Inter SC Trade (Load)}_{SP15} - \text{Scheduled Load}_{SP15} \\ & - \text{Scheduled Export}_{SP15} - \text{Inter SC Trade (Generation)}_{SP15} \end{aligned}$$

The amount of this scheduled flow that may have been attributable to overscheduling of demand (i.e. scheduling of generation to meet "fictitious load") requires a *counterfactual scenario* to be developed representing the *change* in scheduled flow that may have occurred on Path 26 if Enron had not overscheduled demand. Since actual supply and demand of each SC are not balanced in real time (e.g. due to scheduling of actual generation against load that does not exist in an SC's portfolio), this counterfactual scenario cannot be developed by simply recalculating actual flows on Path 26 based on actual generation and demand of each SC in real time. For this analysis, a counterfactual flow representing the minimum flow that would have been needed to meet Enron's actual demand in SP15 was calculated by taking Enron's actual metered demand and actual delivered supply in SP15, and calculating the portion of actual demand in SP15 (if any) that would have had to have been met by generation north of Path 26 (NP15 and ZP26).

The first step in constructing this counterfactual scenario or flow on Path 26 is to calculate Enron's the total actual supply in SP15:

$$\begin{aligned} \text{Actual Supply}_{SP15} = & \text{Metered Generation}_{SP15} + \text{Scheduled Import}_{SP15} \\ & + \text{Inter SC Trade (Load)}_{SP15} \\ & - \text{Scheduled Export}_{SP15} - \text{Inter SC Trade (Generation)}_{SP15} \end{aligned}$$

The minimum north-to-south flow on Path 26 needed to meet Enron's actual demand in SP15 can then be calculated based on the difference (if any) between Enron's actual supply and actual load in SP15:

$$\text{Minimum Needed Flow}_{N \rightarrow S} = \text{Maximum} (0, \text{Metered Demand}_{SP15} - \text{Actual Supply}_{SP15})$$

The upper limit of the net impact on the final scheduled flow on Path 26 can then be calculated based on the difference Enron's final scheduled flow and the minimum actual flow needed to meet Enron's actual demand in SP15:

$$\begin{aligned} \text{Upper Potential Impact on Scheduled Flow}_{N \rightarrow S} = \\ \text{Net Scheduled Flow}_{N \rightarrow S} - \text{Minimum Needed Flow}_{N \rightarrow S} \end{aligned}$$

The impact of this net change in scheduled flows on Path 26 due to overscheduling of load in SP15 by Enron can then be calculated based on the sensitivity (or elasticity) of the congestion price given such a change in scheduled flows by Enron (or, equivalently, transmission capacity available for other Schedule co-ordinators):

$$\text{Net Impact on Congestion Price}_{N \rightarrow S} = \text{Upper Potential Impact on Scheduled Flow}_{N \rightarrow S} \times \Delta \text{ Congestion Price} / \Delta \text{ Transmission Capacity}$$

In practice, Adjustment Bid Curves, showing the change in congestion price that would occur with changes in available transmission capacity such as that depicted in Figure 5, are not stored by the ISO's congestion management software (CONG) and are therefore not available for such analysis. However, as part of the FTR monitoring system, the Department of Market Analysis calculates a Simulated Congestion Price Curve based on a variety of different hypothetical flows on each path, representing different points on the Adjustment Bid curve. Results of these runs can be used to estimate the sensitivity (or elasticity) of congestion prices associated with different levels of available transmission capacity (or changes in the amount of demand scheduled without adjustment bids). Two measures of the sensitivity or elasticity of congestion prices to changes in available transmission capacity calculated for some hours as part of FTR monitoring are the following:

- (1) Price Sensitivity #1 represents the slope of a linear regression line fit based on points on the Simulated Congestion Price Curve between (a) the minimum transmission level above which there is manageable transmission capacity (i.e. defined as schedules with Economic Adjustment Bids in both the INC and DEC directions to the point corresponding to the Initial Schedule, and (b) the total (aggregate) amount of capacity initially scheduled (prior to any curtailment due to congestion). This measure represents the overall slope of the Congestion Simulated Congestion Price Curve including schedules that were not curtailed but for which adjustment bids were submitted.
- (2) Price Sensitivity #2 represents the slope of the line formed by a point above and below the Final Scheduled Flow on the Simulated Congestion Price Curve. This measure represents the slope of the Congestion Simulated Congestion Price Curve at the point at which the congestion market "cleared".

In addition, a third price sensitivity measure (Usage Charge Per MWh Curtailed) can be calculated for each hour by dividing a) the final congestion price by (b) the total amount of initial flow curtailed at part of congestion management (e.g. curtailed MW = initial schedule flow – final flow). The resulting number (\$/MW) represents the overall slope of the adjustment bid curve over the range actually used in congestion management.

Finally, a fourth measure, designed to select the price sensitivity measure that is most accurately reflects the quantity (or change in transmission capacity or flows) for

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which the price impact is being assessed, was calculated by combining the second measure described above (Price Sensitivity #2) with the third measure (Usage Charge Per MWh Curtailed). With this approach, the second measure described above (Price Sensitivity #2) was used whenever the quantity (or change in transmission capacity or flows) being assessed was within the range actually used to calculate this price sensitivity. However, if the quantity (or change in transmission capacity or flows) being assessed was greater than the range actually used to calculate this price sensitivity, the third measure described above (Usage Charge Per MWh Curtailed) was used, on the basis that this measure may be more reflected of the actual price sensitivity.

Results

Results of this analysis indicate that:

- Overscheduling of load in excess of Enron's actual load in SP15 is estimated to have increased north to south congestion on Path 26 during about 57% of the hours in which congestion occurred on Path 26 in the north to south direction (about 571 out of about 998 hours) (426 hours).
- During the other 43% of hours of congestion on Path 26, the analysis indicates that the impact of Enron's overscheduling of load in SP15 was offset by the fact that Enron scheduled an equal or greater amount of generation in SP15 to meet this load.
- The net impact of overscheduling of load on Enron's Path 26 congestion revenues is estimated at to be a net increase of as much as \$1.4 to \$3.2 million (out of about \$34 million).

While these results continue to suggest that Enron's scheduling practices did not have a major impact on Path 26 congestion, the following caveats should be noted:

- Estimates do not include increased congestion charges paid by other SCs, or impacts on different market participants (losses and gains) due to increased differentials in the zonal prices in the PX Day Ahead markets that were based on congestion charges on Path 26. We have not calculated these since evidence seems inconclusive that Enron's scheduling practices did have a major impact on Path 26 congestion prices.
- Overscheduling of load in SP15 may have also increased congestion on the interties into SP15 from other control areas. Enron owned FTRs on several of these paths as well. More complex analysis would be required to assess the potential simultaneous impact of overscheduling of load in SP15 on all interties.

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**Table 5. Potential Impact of Overscheduling of Load in SP15
By Enron on FTR Revenues***

Method of Estimating Elasticity Of Congestion Price	Increase in FTR Revenues due to Overscheduling (571 hours)	Decrease in FTR Revenues due to Underscheduling (428 hours)	Net Increase in FTR Revenues
1. Linear Fit of Entire Congestion Curve	\$4,502,594	-\$2,387,804	\$2,114,990
2. Elasticity of Congestion Curve at Final Quantity (Flow after Curtailment)	\$6,049,962	-\$2,863,096	\$3,186,866
3. Congestion Price / Curtailed MW	\$3,313,958	-\$1,968,121	\$1,345,836
4. Method #2 if scheduled flow by Enron \leq quantity used to calculate price elasticity in Method #2; else Method #3	\$3,396,626	-\$1,980,867	\$1,415,759

Notes:

Estimates include portion of Enron's FTR revenues (~\$34 million) during 2000-2001 FTR cycle that may be attributable to overscheduling of load in SP15.

Estimates likely to represent upper range of impacts, since net impact on scheduled flows is based on difference between actual scheduled flow and minimum flow needed to meet actual demand in SP15.

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6. Ancillary Services Sellback ("Get Shorty")

Past Impacts

The Enron memo describes two distinct gaming "strategies" in the Ancillary Service (A/S) markets:

1. Taking advantage of systematic differences in the Day Ahead and Hour Ahead market prices for A/S by selling A/S in the Day Ahead market and buying them back at a lower price in the Hour Ahead market when there is A/S
2. Selling A/S in the Day Ahead market from imports for which resources are not actually available (with the intent to "buy back" these A/S in the Hour ahead Market at a lower price).

Total gains by each SC from selling back Ancillary Services in the Hour Ahead market were calculated based on the difference in Day Ahead Hour prices for each MW sold back by each SC in the Hour Ahead market. Any losses from the sellback of Ancillary Service capacity at prices that were higher than Day Ahead prices were included in the analysis to reflect the fact that the "sellback" strategy was not always successful. However, this analysis shows that gains from sellback of A/S far outweigh any losses, suggesting that SCs employing this trading strategy were highly successful at anticipating when the Hour Ahead prices would be lower than the Day Ahead prices. In addition, analysis shows that while gains from sellback of A/S were significant during 2000-2001, this strategy has been employed on a very limited scale so far in 2002. The tables below summarize these results.

In order to assess potential sales of Ancillary Services by Enron when no resources were actually available, data on compliance with instructions from the ISO to deliver energy from Ancillary Services capacity was collected from the ISO's Compliance Unit. These results are shown in the final table included in this section. However, it should be noted that these data would not provide an indication of the extent to which Enron may have sold Ancillary Services in the Day Ahead market when it did not have resources to back these Ancillary Services, but sold this capacity back in the Hour Ahead market. There is no way for the ISO to assess the potential extent of this practice except to quantify the total amount of A/S sold back to the ISO by Enron in the Hour Ahead market.

The ISO is currently taking steps to implement a tariff modification that will require that any A/S bought back in the HA market be bought back at either the DA price and/or the higher of the DA/HA price.

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**Table 6. Gains and Losses from Sellback of Ancillary Services by SC
 (through May 2002)**

SC_ID	Name	Gains	Losses	Net
CRLP	Coral Power, LLC	\$18,140,839	-\$1,026,754	\$17,114,085
SETC	Sempra Energy Trading Corporation	\$13,436,678	-\$376,652	\$13,060,026
AEI1	Avista Energy Inc	\$11,977,712	-\$149,293	\$11,828,418
MID1	Modesto Irrigation District	\$10,583,973	-\$266,593	\$10,317,380
EPMI	ENRON Power Marketing Inc	\$5,311,040	-\$256,312	\$5,054,728
PWRX	British Columbia Power Exchange	\$1,351,613	-\$345,586	\$1,006,027
PSE1	Puget Sound Energy	\$580,147	-\$23,836	\$556,310
PXC1	California Power Exchange	\$706,683	-\$411,434	\$295,249
AZUA	City of Azusa	\$185,848	-\$11,208	\$174,640
CALP	Calpine Energy Services	\$123,472	\$0	\$123,472
GLEN	City of Glendale	\$63,195	-\$7,395	\$55,800
APX1	Automated Power Exchange, Inc	\$47,032	-\$2,090	\$44,942
VERN	City of Vernon	\$10,805	\$0	\$10,805
CPS1	Citizens Power Sales	\$4,777	-\$3	\$4,774
RVSD	City of Riverside	\$571	-\$142	\$428
PASA	City of Pasadena	\$723	-\$582	\$141
ECH1	Dynegy Power Marketing, Inc.	\$24	\$0	\$24
NES1	Reliant Energy Services, Inc.	\$24	\$0	\$24
PORT	Portland General Electric Company	\$1,095	-\$1,345	-\$250
BPA1	Bonneville Power Administration	\$207,081	-\$233,416	-\$26,335
APS1	Arizona Public Service Company	\$2,041	-\$30,518	-\$28,477
		\$62,735,373	-\$3,143,162	\$59,592,212

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**Table 7. Total Gains from Sellback of Ancillary Services by Year
(through May 2002)**

SC Id	Name	1999	2000	2001	2002	Total
CRLP	Coral Power, LLC		\$9,494,024	\$7,598,690	\$21,372	\$17,114,085
SETC	Sempra Energy Trading	\$3,424	\$4,778,006	\$8,278,596		\$13,060,026
AEI1	Avista Energy Inc		\$128,758	\$11,688,145	\$31,515	\$11,828,418
MID1	Modesto Irrigation District	\$284,938	\$11,056	\$10,157,276		\$10,453,270
EPMI	ENRON Power Marketing Inc	\$8,753	\$5,096,893			\$5,105,646
PWRX	British Columbia Power Exchange		\$1,006,027			\$1,006,027
PSE1	Puget Sound Energy		\$556,310			\$556,310
PXC1	California Power Exchange	-\$21,959	\$313,430	\$21,451		\$312,922
AZUA	City of Azusa	-\$5,891	\$44,170	\$136,362		\$174,640
CALP	Calpine Energy Services			\$123,472		\$123,472
BPA1	Bonneville Power Administration	\$80,613	\$5,929			\$86,542
GLEN	City of Glendale		\$28,685	\$27,115		\$55,800
APX1	Automated Power Exchange	\$44,928	\$14			\$44,942
VERN	City of Vernon	\$26	\$8,599	\$2,180		\$10,805
PORT	Portland General Electric		\$1,095			\$1,095
RVSD	City of Riverside	\$428				\$428
PASA	City of Pasadena	\$107	\$34			\$141
CPS1	Citizens Power Sales	\$96				\$96
ECH1	Dynegy Power Marketing, Inc.	\$24				\$24
NES1	Reliant Energy Services, Inc.	\$24				\$24
APS1	Arizona Public Service	-\$1,787	-\$26,901			-\$28,688
Total		\$393,723	\$21,446,128	\$38,013,287	\$52,887	\$59,906,025

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**Table 8. Compliance Rate of Enron
 with Ancillary Services Energy Instructions**

Month	Awarded AS Capacity MWs	Incremental AS Energy Instructions		Non-Compliance Adjustments			Non-Compliance Rate	
		#	MWs	#	MWs	Amount	#	MWs
Jan-00	21,101			-	-	-		
Feb-00	28,160			-	-	-		
Mar-00	32,741			-	-	-		
Apr-00	16,194			-	-	-		
May-00	27,680			-	-	-		
Jun-00	35,335	142	4,413	16	1,229	\$920,756.82	11%	28%
Jul-00	30,944	198	6,150	3	70	\$ 7,972.75	2%	1%
Aug-00	31,682	392	10,106	8	115	\$ 6,161.20	2%	1%
Sep-00	23,860	303	8,126	3	22	\$ 755.74	1%	0%
Oct-00	16,998	20	446	1	12	\$ 62.08	5%	3%
Nov-00	8,341	101	2,069	3	29	\$ 1,068.94		
Dec-00	6,754	190	3,279	-	-	-		
2000	126,931	1344	34,592	34	1,480	\$936,777.53	3%	4%
Jan-01	50	2	50	-	-	-		
Feb-01	-	-	-	-	-	-		
Mar-01	-	-	-	-	-	-		
Apr-01	-	-	-	-	-	-		
May-01	-	-	-	-	-	-		
Jun-01	-	-	-	-	-	-		
Jul-01	348	1	49.90	-	-	-		
Aug-01	1,590	4	18.27	3	4	\$ 49.07	75%	21%
Sep-01	-	-	-	-	-	-		
Oct-01	-	-	-	-	-	-		
Nov-01	-	-	-	-	-	-		
Dec-01	-	-	-	-	-	-		
2001	1,988	7	118	3	4	\$ 49.07	43%	3%

Data on non-compliance provided by ISO Compliance Department.

7. Scheduling of Counterflows on Out-of-Service Lines ('Wheel-Out')

Background

Another type of scheduling practice identified in the Enron memos is where a scheduling coordinator submits schedules and/or adjustment bids across a tie point that has been de-rated to zero capacity in hopes of getting paid for providing a counter-flow schedule that will need to be cut by ISO in real time. This practice was apparently referred to as 'wheel-out' by Enron traders.

The ISO's Day ahead and Hour Ahead congestion management program (CONG) does not allow currently allow the ISO to reject or cancel schedules across a tie point that has been de-rated to zero transmission capacity. Instead, when a tie point de-rated to zero capacity, the ISO sets the available capacity for the tie point in the CONG software to approximately zero.¹⁰ When the CONG software is run, the software adjusts schedules as necessary to achieve the result of a net zero scheduled flow across the tie point. For example, if schedules are submitted that create a net flow in one direction, the CONG software will seek to offset this flow by accepting adjustment bids for counterflows in the opposite direction and/or reduce initial scheduled flows based on adjustment bids).

When a tie point is de-rated, a market notice is sent to market participants to notify them of the de-rate. Market participants also can access forecasts of transmission usage and line and equipment outages that cause de-rating of lines on the OASIS system. For an outage or de-rate, they can access the start time, an anticipated end time, and a reason for the outage or de-rate. They also have information on status changes to outages or de-ratings.

With the information available on OASIS and through market notices, scheduling coordinators have the opportunity to submit a schedule to provide counter-flow across the tie point or to be adjusted in the direction of the counter-flow (generally in the hour-ahead market) to relieve congestion on the tie point. In the case where the tie point was de-rated to zero capacity, there will be congestion in the hour-ahead (and day-ahead if the duration of the de-rate is long enough) congestion markets. Any SCs providing counter-flow schedules to relieve this congestion are paid counter-flow revenues.

In real-time, when a tie-point is de-rated to zero, the ISO effectively removes this tie-point from the transmission system by canceling all schedules on the tie-point during the final real time inter-tie checkout just prior to each operating hour. However, any congestion charges and payments associated with the Day ahead and Hour ahead congestion management process described above are not cancelled or reversed from the ISO settlement system.

¹⁰ In practice, the available capacity for lines that are out is set to .03 MW (rather than zero), in order to facilitate computation by the CONG software in a more timely manner.

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As noted in the Enron memos, this creates a potential gaming opportunity, in that when a tie point is known to be out of service, an SC may submit schedules and adjustment bids in an effort to create counterflow schedules on tie for which they can earn congestion revenues, knowing that these schedules will be cancelled by the ISO in real time. In 1999, the ISO proposed modifying its congestion management software to reject all schedules on any line that is out of service prior to the congestion management process. However, this modification was not made since the PX opposed such a modification, due to the fact that modification of the ISO's software would create a conflict with the PX's software. In addition, it should be noted that every SCs can defend against this gaming opportunity by simply not scheduling on lines that are out of service and/or submitting adjustment bids on any schedules that would cause those schedules to be cancelled if significant congestion charges exceeded a level specified by the SC. Finally, it should be noted that not all counterflow schedules on tie lines that are out of service may be attributable to intentional gaming, since an SC may schedule or submit adjustment bids on a line prior to notification of the line outage and fail to cancel these after notification of outage occurs.

Analysis of Market Impacts

Tie lines that were out-of-service prior to the Day Ahead and/or Hour Ahead congestion management process were identified by summing up all net final scheduled flows on each time line, and selecting those lines with net final flows of approximately zero.¹¹ Final counterflow schedules on out-of-service lines are comprised of schedules submitted directly by SCs, as well as any adjustments made through the ISO's congestion management process based on adjustment bids submitted by SCs for each schedule that were accepted by the congestion management software (CONG).

This set was further screened to include only ties on which congestion payments/credit occurred, as indicated by a positive congestion price.

The general formula for calculating the gains from providing counter-flow schedules across tie points that have been de-rated to zero for any hour is as follows:

$$\text{Counterflow Payment} = MW_{DA} * CC_{DA} + (MW_{HA} - MW_{DA}) * CC_{HA}$$

where

MW_{DA} is the final scheduled MW after the day-ahead congestion market
 MW_{HA} is the final scheduled MW after the hour-ahead congestion market
 CC_{DA} is the day-ahead congestion charge (or credit), and
 CC_{HA} is the hour-ahead congestion charge (or credit).

¹¹ This approach was necessary since the ISO system does not include a database with the historical ratings of each tie-point for each hour that was used in the congestion management process. In practice, as noted in the previous footnote, the available capacity for lines that are out of service is set to .03 MW (rather than zero), in order to facilitate computation by the CONG software in a more timely manner.

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Since schedules that are covered by Existing Transmission Contracts (ETCs) neither pay nor receive congestion revenues, schedules submitted under ETCs were identified and removed from this stage of the analysis.¹²

Table 9 provide a summary of revenues earned from counterflows on out-of-service tie-points by all SCs that gained over \$50,000 from such counter-flow schedule over the 2000-2002 period examined in this analysis.¹³ As shown in Table 1, over 96% of revenues from counterflow schedules on out-of-service tie-points over the 2000-20002 can be attributed to the five SCs listed in Table 1.

**Table 9. Counterflow Revenues on Out-of-Service Tie Points
 April 1998 – June 2002**

SC_ID	Company	1998	1999 *	2000	2001	2002	Total
ECH1	Electric Clearinghouse, Inc	\$0	\$247,224	\$1,874,516			\$2,121,740
PWRX	British Columbia Power Exchange	\$0	\$430,375	\$738,644		\$267,446	\$1,436,465
SETC	Sempra Energy Trading Corporation	\$0	\$2,500	\$476,038	\$223,887	\$152,257	\$854,682
CRLP	Coral Power, LLC	\$0	\$167	\$53,938	\$119,298	\$298,291	\$471,694
EPMI	Enron Energy Services, Inc.	\$0	\$5,788	\$225,075	\$92,066		\$322,929
	All Other SCs	\$6	\$1,362,456	\$16,674			\$1,379,137
Total		\$6	\$2,048,510	\$3,384,885	\$478,397	\$733,942	\$6,645,741

* Schedules covered by ETCs during 1999 were estimated based on scheduling trends by each SC over each tiepoint during the 2000-2002 period for which full ETC data were available.

Of the \$3.389 million in congestion revenues shown in Table 1 for the year 2000, \$3.35 million were gained from a five-hour outage across the Four Corners (FCORNR_5_PSUEDO) tie point within the El Dorado branch group on the 28th of May, 2000.

DMA staff also reviewed data in the ISO's outage logging system (SLIC) to attempt to determine the extent to which tie-line outages had been schedules or known in advance of the Day Ahead market, so that SCs could have avoided submitted schedules and/or adjustment bids on these tie-points. The following criteria were used to identify schedules that may have been "avoidable" based on information about when tie-points went out-of-service:

¹² The ISO information system does not save the data required to identify specific tie-point schedules covered by ETC's prior to February 2000. Therefore, prior to this time, schedules that are likely to have been submitted under ETCs were identified and removed from the analysis based on the historical scheduling by each SC on each tie-point during the 2000-20002 period for which ETC data were available.

¹³ The 2000-2002 period was used since prior to this period full data were not available from the ISO scheduling system on which schedules were submitted under ETCs and therefore did not earned counterflow revenues.

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- 1) Schedules first submitted in the Day Ahead market were flagged as "Avoidable" if SLIC records indicate that approval of the outage occurred before 10am two days prior to the operating day of the schedule. Thus, Day Ahead schedules/bids were flagged as "Avoidable" if they were submitted on tie-points on which outages were approved a full 24 hours prior to the close of the Day Ahead market.
- 2) Schedules first submitted in the Hour Ahead market were flagged as "Avoidable" if SLIC records indicate that approval of the outage occurred before the earlier of (a) 12 midnight of the Operating Day of the schedule, or (b) 6 hours before the start of the Operating hour. In two days prior to the operating day of the schedule. Thus, Hour Ahead schedules/bids were flagged as "Avoidable" if they were submitted on tie-points on which outages were approved at least 3 hours prior to the Hour Ahead Market (which is run 3 hours prior to each operating hour).
- 3) If SLIC records indicate and outage occurred after the Hour Ahead market (i.e. less than 3 hours before an Operating hour), the schedules was flagged as "Unavoidable".
- 4) All other schedules were classified as "Indeterminate", to reflect the fact that its could not be determined whether or not it is likely that participants could or were likely to have been aware that a tie-point was out of service when the SC submitted the schedules (or could have cancelled its schedules once the SC became aware of the outage) .

Results of this analysis, which are summarized in Table 10 below, indicate that information in SLIC do not provide sufficient information to assess whether most schedules on out-of-service tie-points were avoidable or not. Based on this review of SLIC records, only about 10% of the congestion revenues paid for counterflows on out-of-service tie-points during the 2000-2002 period were identified as being "avoidable".

**Table 10. Counterflow Revenues on Out-of-Service Tie Points by Category
 (Avoidable vs. Unavoidable Schedules on Open Ties)**

	2000	2001	2002	Total
Indeterminate	\$3,442,997	\$244,144	\$521,167	\$4,208,308
Avoidable	\$43,191	\$221,757	\$212,775	\$477,724
Unavoidable		\$12,496		\$12,496
Total	\$3,486,188	\$478,397	\$733,942	\$4,698,528

The ISO is considering the option of filing a Tariff Amendment to modify its congestion management procedures/software so that once a path is rated at zero all schedules will simply be rejected.

8. Ricochet

The definition of ricochet schedules or "megawatt laundering" provided in the Enron memos and (subsequently included in the Commission's Request for Admissions) is narrow in that it includes only one type of "ricochet" or "megawatt laundering": i.e. *exporting power from the PX to another entity, for a fee, in order to resell the same energy back into the ISO's real time market.* Under this scenario, if the energy was re-imported and resold back into the ISO market by a second entity, the ISO generally does not have the information to identify the schedules and transactions involved in such an arrangement.¹⁴

However, it should be noted that "ricochet schedules" or "megawatt laundering" are terms that have also been used to refer to a number of other potential strategies:

- Export of power from the PX for resale in the ISO's real time market by the same entity (without reselling and repurchasing this energy from another entity for a fee). With this approach, a Schedule Co-ordinator may simply export power purchased through the PX to its "portfolio" of resources/schedules in other control areas, and then resell power back into California out of the same portfolio of resources.
- Export of power from an SC's own resource portfolio within the ISO system for resale in the ISO's real time market. With this approach, an Schedule Co-ordinator may simply export power from its overall "portfolio" of resources/schedules within the ISO system to another control areas, and then resell power back into California. This could be done without or without reselling and repurchasing this energy from another entity for a fee.

In addition, "ricochet" schedules or "megawatt laundering" are terms that commonly used to describe scheduling strategies that not simply aimed at selling power in the real time market rather than Day Ahead market. The ISO has commonly considered the definition of these terms to encompass strategies aimed at circumventing "hard" price cap limits, as well as the cost reporting and potential refund obligations associated with sales over the \$250/\$150 "soft caps" that took effect shortly after the Enron memos were written. Several different strategies that involve "ricochet" schedules or "megawatt laundering" include the following:

- Circumvention of the \$250 Hard Price Cap During late November/early December 2000. While "hard" price caps were in effect in the ISO's real time

¹⁴ The only information that could be used to identify such transactions would be "e-tags" or "NERC-tags" submitted with schedules. E-tags must be reviewed manually, and are only available in hard-copy for the 200-2001 period. In addition, e-tags may not provide a definitive, clear record of such arrangements.

market (until December 8, 2000), "ricochet" schedules or "MW-laundering" were terms also used to describe potential attempts to circumvent these hard caps by exporting power and seeking to sell power back to the ISO "out-of-market" (OOM) at prices that might exceed the price caps. Throughout the summer and fall of 2000, the ISO monitored potential "MW-laundering" by entities making out-of-market sales of imports to the ISO, but found that OOM sales were very rarely made at prices in excess of the ISO's real time price cap. However, starting in the second half of November 2000, the ISO began needing to purchase significant quantities of imports out-of-market at prices in excess of the \$250 hard cap in effect at that time. During the first week of December, the volume of energy offered into the ISO's formal real time market decreased and the volume of imports purchased out-of-market at prices in excess of the \$250 price cap increased to the point where most real time energy was being imported through out-of-market purchases. During these few weeks, analysis of exports and imports provides strong evidence that the \$250 hard cap in effect was circumvented by suppliers through "ricochet" schedules or "MW-laundering".

- Circumvention of the Cost Reporting and Refund Obligations for Sales to the ISO Under the \$250/\$150 Soft Cap. While "soft" price caps were in effect in the ISO's real time market (from December 8, 2000 through June 20, 2001), "ricochet" schedules or "MW-laundering" were terms also used to describe potential attempts to circumvent the cost reporting and potential refund obligations by exporting power and seeking to sell power back to the ISO as an import. While real time energy sales from generation sources within the ISO are linked to specific resources, sales of imports to the ISO are not linked to specific generating sources. Thus, the ISO believes that "ricochet" schedules or "MW-laundering" strategies were employed as a way for suppliers to disguise the true source and cost basis of sales of real time energy in excess of the \$250/\$150 "soft caps" while these "soft caps" were in effect.
- Circumvention of the Cost Reporting, Refund Obligations and Credit Uncertainty by Selling to CERS. Starting in latter part of January 2000, many sellers began refusing to sell to the ISO directly, so that the State California (through CERS) began purchasing significant quantities of imports out-of-market in order to help meet the "net short" position of the State's investor owned utilities. Thus, suppliers had an incentive to export power for sale directly to CERS (for re-import to the ISO system) in order to ensure immediate payment. Exporting for sale to CERS also provided the advantage that these sales circumvented the cost reporting and potential refund obligations associated with sales directly to the ISO. Under the Commission's July 25, 2001 Order on refunds for this period, sales made through CERS were not made subject to refund, so that, in retrospect, this strategy has so far proven to be a successful strategy for avoiding refund obligations.

DMA staff have developed queries to identify export/import schedules that could be part of each of these strategies by identifying the "overlap" between the quantity of exports

scheduled by each SC on a Day Ahead and Hour Ahead basis, and the quantity of imbalance real time energy imports sold by the same SC to the ISO (through real time market and out-of-market sales) and, starting on January 17, 2001 through CERS. Results of this analysis require further verification, which has not been completed at this time due to staffing constraints, but can be provided upon request if Commission staff view this as relevant to their investigation.

9. Selling Non-firm as Firm Energy

ISO Operations has not identified any specific instances where it has become aware of any imports of non-firm energy being scheduled as a firm imports. This practice is not allowed under current WSCC rules, but presumably could occur if all control areas are not vigilant in check out procedures and/or do not ensure that firm exports are backed by the necessary operating reserves.

10. Scheduling Energy to Collect Congestion Charges

The specific gaming opportunity identified in the Enron memos (i.e. when congestion charges are higher than the price cap in effect in the real time energy market) has occurred on a very limited basis (only about 50 times) since 1998.

A more general type of scheduling practice described in the Enron memos is where scheduling coordinators submit schedules in the Day-Ahead and/or Hour-Ahead congestion markets, providing counter-flow on a congested path. These schedules receive congestion charges, which are ultimately paid by scheduling coordinators with schedules in the congested direction, as counter-flow revenue in the day-ahead and/or hour-ahead congestion markets. Under current ISO scheduling and settlement practices, SCs may subsequently cut the counter-flow schedules just prior to real-time, but still receive the counter-flow revenues for schedules submitted in the Day-Ahead and/or Hour-Ahead congestion markets.

This creates a gaming opportunity, in that SCs may earn congestion revenues for counterflow schedules in the Day Ahead and Hour Ahead markets, and then cancel these schedules prior to real time. The practice of cutting non-firm schedules was proscribed by the ISO under a Market notice issued under the MMIP on July 21, 2000 banning this practice, and does not appear to have occurred since a market notice was issued. However, a similar gaming opportunity continued to exist insofar as the same basic strategy could be employed by cutting wheel-through schedules and/or firm energy schedules.

It should be noted that not all counterflow schedules cut in real time represent gaming. Wheel through schedules, for instance, may be cancelled if the SC is unable to the procure generations and/or transmission to deliver the "import" leg of a wheel through the ISO system. Similarly, an outage within the ISO system may decrease the overall supply of energy within and SC's portfolio, and require the cutting of an export schedule

in order to avoid and imbalance in the SC's supply and demand schedules. In some cases, the ISO may need to curtail an export due to a de-rate on a tie-line occurring after the Hour Ahead congestion management market is ended.¹⁵ However, the description of the reason for each counterflow schedule that is cut in real time that is available in logs kept by ISO Grid Operators and Real Time Schedulers is typically not sufficient to determine the precise reason for the cut, and whether the cut could be due to gaming or not.

Analysis of Impacts

Total congestion revenues paid for counterflow schedules that were cut prior to real time were assessed based on real time schedule changes made after the Hour Ahead market recorded in the BITS database. The analysis included all counterflow schedules which earned congestion revenues in the Day Ahead or Hour Ahead markets where the final real time schedule was less than the final Hour Ahead schedule. However, schedules that were cut due to tie-points being out of service were analyzed separately (see section on "Wheel Out" gaming strategy), and were therefore not included in this analysis.

Since Hour Ahead schedules may only be partially cut, and may represent a combination of Day Ahead and Hour Ahead congestion revenues, the following two equations were used to calculate the amount of congestion revenues paid for schedules that were cut in real time.

If the Hour Ahead Schedule was equal to the Day Ahead schedule (so that the SC only earned counterflow revenues in the Day Ahead market), the following equation was used:

$$\text{Counterflow Payment} = (MW_{DA} - MW_{RT}) \times CC_{DA}$$

If the Hour Ahead Schedule was greater than the Day Ahead schedule (so that the SC may have earned counterflow revenues in both the Day Ahead and Hour Ahead markets), the following equation was used:

$$\text{Counterflow Payment} = (MW_{DA} - MW_{RT}) \times CC_{DA} + (MW_{HA} - MW_{DA}) \times CC_{HA}$$

Finally, if the Hour Ahead Schedule was less than the Day Ahead schedule (and was subject to the Hour ahead congestion charge for the reduction in its counterflow schedule), the following equation was used:

$$\text{Counterflow Payment} = (MW_{HA} - MW_{RT}) \times CC_{HA}$$

¹⁵ However, when de-rates occur, the ISO would typically not cut a schedule that is providing a counterflow on a tie-line, since this would exacerbate congestion on the de-rated path.

Where:

MW_{DA} is the final scheduled MW after the Day-Ahead congestion market
 MW_{HA} is the final scheduled MW after the Hour-Ahead congestion market
 MW_{RT} is the final scheduled MW after the real time checkout process
 CC_{DA} is the day-ahead congestion charge (or credit), and
 CC_{HA} is the hour-ahead congestion charge (or credit).

DMA staff also reviewed operating logs (SLIC) for indications of whether each cut was made by the ISO due to an outage on a tie-point or by the SC for some other reason. In cases where operating logs provided an indication that either the ISO or SC cut schedule, these were classified accordingly. In cases where no assessment could be made as to the cause of the cut, the schedule was classified separately.

Table 11 summarizes result of this analysis for each SC for the period from January 2000 through June 2002. As shown in Table 11, total congestion revenues paid for counterflow scheduled that were cut in real time totaled just over \$3 million over this two and one half year period. ISO records indicate that only about 8% of these revenues represent counterflow schedules cut by the ISO due to a de-rate on a tie-point.¹⁶ About \$1.1 million these revenues represent counterflow schedules cut by the SC for various reasons. Operating records did not provide any information on the reason for the remaining \$1.6 million in counterflow schedules cut. Thus, total congestion revenues paid for counterflow schedules that do not appear to be cut by the ISO totaled just over \$2.7 million over this two and one half year period. Table 12 shows a breakdown of this \$3 million for each SC by year.

¹⁶ The most typical scenario was that an outage or de-rate on a tie-point cause the source of a wheeling schedule to be cut, so that the export leg of the wheel that was providing the counterflow on another tie-point also needed to be cut by the ISO.

**Table 11: Counter-flow Revenues from Cutting Schedule in Real-time
January 2000 through June 2002**

	Cut by ISO (A)	Cut by SC (B)	Unknown (C)	Total Not Cut by ISO (B + C)
San Diego Gas and Electric	\$2,242	\$340,333	\$321,195	\$661,528
Morgan Stanley Capital Group	\$0	\$426,788	\$214,659	\$641,447
Sempra Energy Trading Corporation	\$166,473	\$155,300	\$391,999	\$547,300
Coral Power, LLC	\$30,004	\$112,904	\$84,760	\$207,664
British Columbia Power Exchange Corporation	\$45,567	\$9,893	\$129,313	\$139,206
Enron Energy Services, Inc.	\$2,815	\$46,244	\$85,039	\$131,282
Avista Energy Inc	\$0	\$0	\$99,975	\$99,975
Pacific Gas and Electric Company	\$7,571	\$1,440	\$75,731	\$77,171
American Electric Power Service Corp	\$0	\$0	\$58,193	\$58,193
Duke Energy Trading and Marketing, L.L.C.	\$0	\$17,306	\$34,263	\$51,569
Southern Company Energy Marketing, L.P.	\$0	\$4,946	\$31,598	\$36,544
Cargill-alliant, LLC	\$5,198	\$20,113	\$809	\$20,921
Idaho Power Company	\$0	\$0	\$23,652	\$23,652
Puget Sound Energy	\$0	\$0	\$14,523	\$14,523
Dynegy	\$0	\$0	\$9,751	\$9,751
PGE Energy Services (PGES)	\$7,539	\$0	\$9,304	\$9,304
Calpine Corporation	\$0	\$4,376	\$3,515	\$7,891
Southern California Edison Company	\$10,761	\$0	\$7,310	\$7,310
Sierra Pacific Power Company	\$0	\$0	\$6,391	\$6,391
Idaho Power Company	\$0	\$0	\$3,199	\$3,199
TEMU	\$0	\$0	\$2,955	\$2,955
Modesto Irrigation District	\$0	\$0	\$2,150	\$2,150
Salt River Project	\$0	\$0	\$1,793	\$1,793
City of Glendale	\$0	\$0	\$1,542	\$1,542
Arizona Public Service Company	\$0	\$0	\$1,380	\$1,380
Williams Energy Services Corporation	\$0	\$0	\$1,174	\$1,174
PacificCorp	\$0	\$0	\$609	\$609
EPME	\$0	\$0	\$511	\$511
Constellation Power Service	\$0	\$0	\$465	\$465
Southern California Edison Company	\$0	\$0	\$414	\$414
Pacific Gas and Electric Company (PGEU)	\$0	\$46	\$0	\$0
Bonneville Power Administration	\$359	\$0	\$0	\$0
City of Vernon	\$224	\$0	\$0	\$0
Grand Total	\$271,214	\$1,139,688	\$1,620,701	\$2,760,390

Notes:

- (A) SLIC records indicate schedule cut by ISO due to line outage.
 (B) SLIC records indicate schedule cut by SC.
 (C) No indication of cause for cut found in SLIC.

Totals include period from January 2000 through June 2002.

Table 12: Counter-flow Revenues from Cut Schedules Compared by SC

SC_ID	Company	2000	2001	2002	Total
SETC	Sempra Energy Trading Corporation	\$382,764	\$134,972	\$196,043	\$713,779
SDGE	San Diego Gas and Electric	\$663,793	\$106		\$663,899
MSCG	Morgan Stanley Capital Group		\$640,963	\$89	\$641,052
CRLP	Coral Power, LLC	\$115,436	\$47,628	\$74,606	\$237,670
PWRX	British Columbia Power Exchange Corporation	\$75,381	\$28,164	\$81,854	\$185,399
EPMI	Enron Energy Services, Inc.	\$82,593	\$51,505		\$134,098
AEI1	Avista Energy Inc		\$99,977		\$99,977
PORT	Portland General Electric	\$75,822			\$75,822
SCEM	Southern Company Energy Marketing, L.P.	\$16,744	\$8,164	\$41,958	\$66,866
DETM	Duke Energy Trading and Marketing, L.L.C.	\$51,577		\$12,931	\$64,508
AEPS	American Electric Power Service Corp	\$58,193			\$58,193
	Other SCs	\$59,114	\$7,815	\$43,364	\$110,293
Total		\$1,581,417	\$1,019,294	\$450,845	\$3,051,556

EXHIBIT NO. ISO-3

Addendum to October 4, 2002 Report on Analysis of Trading and Scheduling Strategies Described in Enron Memos:

Revised Results for Analysis of Potential Circular Schedules ("Death Star" Scheduling Strategy)

January 17, 2003

Background

On October 4, 2002, the California Independent System Operator ("ISO") issued a report prepared by the Department of Market Analysis, entitled "Analysis of Trading and Scheduling Strategies Described in Enron Memos". This report was provided to regulatory and law enforcement agencies on a confidential basis. On January 7, 2003, the ISO released the report publicly and posted it on the ISO's website.

As noted in the ISO's report, the purpose of the report was twofold: (1) to indicate the potential magnitude of the extent to which the strategies outlined in the Enron memos may have been employed by Enron and other entities, and (2) to identify specific schedules and transactions that could provide a starting point for further investigation by various regulatory and law enforcement entities involved in review and litigation related to the practices outlined in the Enron memos. Since the analysis was designed to assess the potential magnitude of these strategies and provide a starting point for further analysis based on additional information not available to the ISO, the analysis was intentionally designed to "cast a broad net", and identify all market activity that could be indicative of the strategies outlined in the Enron memos. As indicated throughout the report and to the regulatory and law enforcement entities, the results of the ISO's analysis must be combined with additional information in order to identify specific instances in which the scheduling and trading strategies outlined in the Enron memos were employed by Enron or other entities.

Following release of the October 4 Report to regulatory and law enforcement entities, Market Investigations staff have continued to verify and refine the computer programs used to identify market activity that may be reflective of the practices outlined in the Enron memos and quantify the potential financial impact of these practices. As part of this work, several refinements have been made to the program used to calculate congestion revenues earned by import/export schedules that could potentially be indicative of the "Death Star" trading strategy. This addendum provides revised results of Table 2 in the October 4 report (p.11), and provides a more detailed description of the methodology and modifications used in this analysis.¹

Overview of Methodology

¹ None of the refinements leading to revision of results for the "Death Star" strategy are applicable to analysis of two other strategies analysis included in the October 4 report that include the calculation of congestion revenues ("Scheduling of Counterflows on Out-of-Service Lines", p.24, and "Scheduling Energy to Collect Congestion Charges", p.30). Calculations for these strategies are significantly less complex, and have been rechecked to ensure accuracy.

The "Death Star" scenario described in the Enron memos is an example of what the ISO refers to as a "circular schedule", or a series of energy schedules that appear as an import and export through the ISO control area, but actually include additional schedule(s) outside the ISO control area which form a closed "loop" of scheduled energy with no specific physical beginning (source) or end (sink). (See more detailed discussion in October 4 report.) Thus, the type of circular schedule described as the Death Star strategy would appear in ISO scheduling records simply as an import and export from the ISO control area (earning congestion revenues by creating a counterflow), with the "return" portion of the schedule being outside the ISO control area.

Like the analysis in the October 4 report, the analysis of potential circular scheduling in this report continues to be intentionally designed to "cast a broad net", and identify all export/import schedules for which additional information may be collected to identify any circular schedules such as those described under the Death Star strategy. The analysis identifies potential circular schedules based on these two basic characteristics of such schedules that may be detected in ISO data: (1) an import and export of approximately the same amount of energy by a Scheduling Coordinator ("SC") during the same hour, which (2) generate net congestion payments for the SC due to counterflows created on one or more paths. Thus, while all combinations of import/export schedules that earn congestion revenues by creating a counterflow are clearly not circular schedules, these key characteristics may be used to identify export/import schedules that may be part of a circular schedule submitted for purposes of earning congestion revenues.

Provided below is a more detailed description of the algorithm used to perform this analysis:

1. First, for each SC, the program matches import and export schedules for the same operating hour submitted for approximately the same quantity (within a small tolerance for rounding). This matching is done separately for final Day Ahead Schedules and final Hour Ahead Schedules.
2. Congestion payments and charges for each pair of import/export schedules are then calculated based on the scheduled amount of capacity (MW), and the congestion prices and direction on each congestion path the import/export schedules would create a scheduled flow. For example, for a pair of schedules representing an 25 MW import into NP15 over COI and an 25 MW export from SP15 on Palo Verde, congestion charges/payments would be calculated for a 25 MW flow in the north-to-south direction on COI, Path 15, Path 26 and Palo Verde.
3. For each pair of import/export schedules, the total net congestion payments were calculated (taking into account all paths over which a flow would earn or be charged congestion charges). Pairs of import/export schedules resulting in positive net congestion revenues during any hour (due to counterflow payments in excess of any congestion charges on other paths) are identified as those that could represent circular schedules submitted in order to earn congestion revenues.

² In addition, circular schedules may be created by "looping" energy back through the ISO control area under a different SC. However, this particular strategy would typically only be profitable if the energy schedule in the congested direction is scheduled by an SC with Existing Transmission Rights (ETCs), so that no congestion charges are incurred for this "return" portion of the circular schedule.

4. Total congestion revenues earned by the schedules identified in Step 3 are summed up. Results of this revised analysis are presented as in Table 2 (Revised), which includes a comparison of revised results with previously results included in the October 4 report.

The revised analysis summarized in this report incorporates three refinements in the computer program used in the initial analysis submitted in the October 4 report.

- Most importantly, the revised program now identifies schedules that would be covered by rights under Existing Transmission Contracts (ETCs), and accounts for the fact that these schedules would not pay congestion charges or earn congestion revenues for any counterflows provided. This step was not included in the initial analysis due to a lack of information needed to link individual schedules to ETCs. Data on ETCs for 1998 through January 2000 continues to be unavailable. However, summary data for 1998-2000 were set to zero for several entities known to have ETCs for similar schedules during subsequent periods for which data were available.
- In addition, in the initial analysis, Path 15 and Path 26 congestion revenues/charges were inadvertently included for schedules between SP15 to the Northwest on the DC inter-tie (NOB). The model was corrected so that Path 15 and Path 26 congestion revenues/charges are not included in calculations for flows on NOB.
- Additionally, a correction in calculations for congestion in the Hour Ahead Market was made.

Finally, it should be noted that minor "double counting" of some congestion revenues may exist in the revised analysis, since the monitoring algorithm can match one import schedule with multiple exports. Out of 270,000 pairs of import/export schedules matched by program, about 6% represent import schedules matched to more than one export schedule of the same quantity submitted by the same SC. Multiple matches are left in the analysis, since each possible combination of import/export schedules may warrant review as part of further investigation. Due to the large number of total records involved, refinements needed to eliminate this minor double counting in summary results in Revised Table 2 could not be completed at this time due to resource limitations. Since such refinements would have a relatively minor impact on overall results, revised results are being presented in order to provide the best available information at this time.

**Table 2 (Revised). Total Congestion Revenues from Counterflows
Created by Import/Export Schedules (Matched by MW Amount) by SC**

	1998	1999	2000	2001	2002	Total	Initial Results (Oct 4 Report)	Notes
Coral Power, LLC			\$ 1,301,168	\$ 2,794,278	\$ 2,291,746	\$ 6,387,191	\$ 3,875,484	
ENRON Power Marketing Inc	\$ -	\$ 84,373	\$ 2,014,174	\$ 3,207,580		\$ 5,306,127	\$ 2,797,548	
Sempra Energy Trading Corporation		\$ 88,062	\$ 1,352,285	\$ 226,438	\$ 465,908	\$ 2,132,693	\$ 1,649,422	
British Columbia Power Exchange			\$ 18,886	\$ 322,559	\$ 1,602,780	\$ 1,942,205	\$ 1,084,673	
Mirant Inc.			\$ 105,070	\$ 318,207	\$ 1,497,791	\$ 1,921,068	\$ 496,337	
Cargill Alliant, LLC			\$ -	\$ 14,289	\$ 972,505	\$ 986,794	\$ 893,278	
Williams Energy Marketing and Trading	\$ -	\$ 508,339	\$ 34,884	\$ 10,074	\$ 190,728	\$ 744,025	\$ 968,283	
Automated Power Exchange, Inc-APX1	\$ -			\$ 732,754	\$ 2,662	\$ 735,416	\$ 682,162	
Calpine Energy Services				\$ 205,071	\$ 378,396	\$ 583,466	\$ 132,360	
PacificCorp	\$ 155,461	\$ 13,145		\$ 27,201	\$ 55,404	\$ 251,211	\$ 524,869	[2]
Duke Energy Trading and Marketing	\$ 19,640	\$ 8,622	\$ 134,366	\$ 1,584	\$ 2,585	\$ 167,198	\$ 215,651	[2]
Idaho Power Company			\$ 4,780	\$ 81,640		\$ 86,420	\$ 669,065	[2]
Modesto Irrigation District		\$ 49,265	\$ 14,304	\$ 19,057	\$ 326	\$ 82,953	\$ 79,929	
Aquila Power Corporation			\$ 75,975			\$ 75,975	\$ 6,288	
Morgan Stanley Capital Group, Inc.				\$ 35,618	\$ -	\$ 35,618	\$ 36,614	
American Electric Power Service		\$ -	\$ -	\$ -	\$ 19,877	\$ 19,877	\$ 19,481	
Automated Power Exchange-APX4				\$ 6,678	\$ 8,357	\$ 15,035	\$ 18,727	
Puget Sound Energy			\$ 3,098			\$ 3,098	\$ 1,815	
Arizona Public Service Company	\$ -	\$ -	\$ 1,174	\$ -	\$ 1,389	\$ 2,563	\$ 126,996	[1]
City of Riverside	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 1,501	[1]
City of Anaheim			\$ 0	\$ 0	\$ -	\$ 0	\$ 150,557	[1]
Grand Total	\$ 175,301	\$ 752,007	\$ 5,058,145	\$ 8,003,028	\$ 7,490,455	\$ 21,478,935	\$ 14,429,041	

NOTES.

Results represent sum of congestion revenues from pairs of import/exports resulting in net positive congestion payment during hour. Thus, results undoubtedly include import/export schedules that do not represent circular schedules or gaming strategies such as "Death Star". For instance, totals would include revenues from a supplier wheeling energy from Southwest to Northwest through ISO control area in the opposite direction of congestion.

Additional information or investigation needed to identify specific schedules that may be circular and/or involve gaming, and to identify any inaccuracies in data and calculations.

Results intended to provide (1) an indication of the upper bound of potential impacts of "Death Star" strategy, and (2) a starting point for further investigation in context of various legal and regulatory activities.

[1] Indicates participants for which change in results are due primarily to inclusion of ETCs in revised results.

[2] Indicates participants for change in revised results are due primarily to correction of payments/charges on NOB. Other changes due to combination of [2] and refined calculation of Hour Ahead congestion payments/charges.

Data for Existing Transmission Rights (ETCs) is not available for 1998 - January 2000.

Therefore, ETC schedules not receiving congestion payments/charges in 1998-99 estimated based on ETC patterns in other years.

Minor "double counting" of some congestion revenues may occur, since monitoring algorithm can match one import schedule with multiple exports. Out of 270,000 pairs of import/export schedules matched by program, about 6% represent import schedules matched to more than one export schedule of the same quantity submitted by the same SC. Multiple matches are left in the analysis, since each possible combination of import/export schedules may warrant review as part of further investigation.

Results do not include potential circular schedules which include schedules made under different Schedule Co-ordinator IDs.

EXHIBIT NO. ISO-4

Enron Power Marketing, Inc., et al.
Docket No. EL03-180-000. *et al*

Exhibit No. ISO-4. Page 1 of 30

**Supplemental Analysis of Trading and Scheduling Strategies
Described in Enron Memos**

**Submitted to Federal Energy Regulatory Commission Staff
in Response to Final Report on Price Manipulation in The Western Market**

by

**Department of Market Analysis
California ISO**

June 2003

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Introduction

This report summarizes additional analysis performed by the California Independent System Operator ("ISO"), Department of Market Analysis ("DMA") on the various trading and scheduling practices outlined in the Enron memos. The report supplements a variety of analyses previously provided by the ISO to Federal Energy Regulatory Commission ("Commission" or "FERC") Staff as part of its investigation of the Western Markets.¹ This updated analysis and report was prepared by the ISO in response to recommendations in the Commission Staff's Final Report on Price Manipulation in the Western Markets ("March 2003 Staff Report"),² and a subsequent request from Commission Staff for additional analysis that may be used in further investigations and disgorgement of profits from individual sellers, as recommended in the March 2003 Staff Report.³

The March 2003 Staff Report found that many trading strategies employed by Enron and other companies were undertaken in violation of market monitoring provisions of the Commission-approved tariffs of the ISO and the California Power Exchange ("PX"), and recommends that the Commission initiate proceedings to require companies to disgorge profits associated with these tariff violations.⁴ The March 2003 Report also recommends that certain Market Participants identified in previous analyses submitted by the ISO to Commission Staff be directed to show cause why their behavior did not constitute violations of the ISO and PX tariffs.⁵ Following the release of the March 2003 Staff Report, Commission Staff also requested assistance from the ISO in developing updated analyses and transaction-specific data for individual Market Participants whose behavior may constitute violations of the ISO and PX tariffs.

The results summarized in this report vary from results in the previous report cited in the March 2003 Staff report for a variety of reasons, as follows:

¹ See, *Analysis of Trading and Scheduling Strategies Described in Enron Memos*, October 4, 2002; and *Addendum to October 4, 2002 Report on Analysis of Trading and Scheduling Strategies Described in Enron Memos: Revised Results for Analysis of Potential Circular Schedules* ("Death Star" Scheduling Strategy) January 17, 2003. Additional data and analyses were also provided in response to data requests issued in the recent 100-day discovery period of the California Refund Proceeding, Docket No. EL00-95, et al., and the Commission's investigation of on Price Manipulation in Western Markets: Fact-finding Investigation of Potential Manipulation of Electric and Natural Gas Prices, Docket No. PA02-2-00.

² *Final Report on Price Manipulation in Western Markets: Fact-finding Investigation of Potential Manipulation of Electric and Natural Gas Prices*, Docket No. PA02-2-00, March 2003 ("March 2003 Staff Report").

³ As indicated in the ISO's initial report on the Enron strategies submitted on October 4, 2002, "the ISO stands ready to provide Commission Staff with additional documentation and analysis of these trading practices and to assist Staff with any aspect of its investigation."

⁴ *March 2003 Staff Report* at ES-2.

⁵ The *March 2003 Staff Report* appears to refer to the first report on Enron strategies submitted to Commission Staff and other legal/regulatory entities on a confidential basis on October 4, 2002 as the "January 6, 2003 Cal ISO Report". The January 6, 2003 date corresponds to the date that the ISO made the October 4, 2002 report public.

- 1) **Limited Time Frame.** Previous analyses by the ISO covered the time period from 1998 through 2002. However, the March 2003 Staff Report indicates that any disgorgement of profits would only cover activities during the period of January 1, 2000 through June 21, 2001, and that these disgorgements would be in addition to the refunds resulting from the California Refund Proceedings.⁶ Therefore, the updated analysis summarized in this report covers the period of January 1, 2000 through June 21, 2001, and also provides subtotals for two periods: a *pre-refund* period from January 1 through October 1, 2000, and a *refund* period from October 2, 2000 through June 21, 2001.
- 2) **Additional Trading Practices.** Previous analyses by the ISO did not include a comprehensive analysis of the extent to which all Market Participants may have employed two of the major trading practices outlined in the Enron memos: Overscheduling of Load ("Inc'ing Load" or "Fat Boy"), and Ricochet (of "MW Laundering"). This report includes a more comprehensive analysis of these strategies.
- 3) **Additional Information Provided by Market Participants.** Several Market Participants have contacted the ISO and/or FERC to offer additional information, provide explanations, and/or correct data upon which previous analyses were based. This report incorporates those data corrections and other information to the extent that they could be verified by the ISO. For example, several Market Participants identified a limited number of Schedules or transactions that were miscoded with the incorrect identity of the Market Participant represented by the Schedule or transaction, or that were cut due to system conditions in the ISO or a neighboring control area. DMA has incorporated all of the verifiable changes and suggests that any further explanations by Market Participants be provided directly to the Commission in the context of any further investigation or show cause orders.
- 4) **Analytical Refinements/Corrections.** As noted in the ISO's previous reports, the ISO's analysis was intentionally designed to "cast a broad net", and identify all market activity that could be indicative of the strategies outlined in the Enron memos. Following release of the October 4 Report to regulatory and law enforcement entities, DMA has reviewed and refined its analysis, as reflected in this report.

In addition to the methodological descriptions and summary results presented in this report, DMA is providing detailed data files that identify the specific transactions, Schedules and Meter Data underlying this analysis. These data are being provided to allow further analysis and response to these results by Commission Staff as well as individual Market Participants.

⁶ March 2003 Staff Report at ES-2.

Finally, several important caveats regarding the scope of the analysis provided in this report should be noted.

- The ISO's analysis is limited to the specific strategies and methodologies outlined in the Enron memos as specifically described in this report. For example, the data and methodology employed in this report cannot identify the extent to which "Ricochet" or "MW Laundering" may have been employed by two or more participants. In those strategies, the Energy may have been exported and then re-imported under two different Schedule Coordinator identities, and the data would reflect no relationship between those transactions.
- The ISO's analysis is limited in two respects: it is based only on the data and other information available the ISO; and is constrained by the time and resources of DMA to devote to this analysis.
- While this report estimates potential revenues received as a result of different practices, it does not analyze the total market impacts of different practices, or other profits that individual Market Participants may receive as a result of the indirect and cumulative impact of these strategies on overall market prices and outcomes. For example, practices such as Ricochet and Overscheduling of Load represent ways to withhold supply from the forward markets (such as the PX Day-Ahead market) and to exercise market power in real time. In addition to raising prices in California's wholesale markets, these strategies would have also increased prices in future time periods by increasing the expectation of higher prices. The analyses in this report clearly do not incorporate the overall costs and profits associated with such broader market impacts. As noted in the ISO's filings in recent FERC proceedings, "it is virtually if not absolutely impossible to disentangle the effects of the various strategies engaged in by disparate sellers in order to assign discrete market effects and discrete ill-gotten gains to each instance of each seller's implementation of each strategy," since "the effects were simply too interwoven and too cumulative, both within an hour and over time."⁷
- Finally, while DMA has sought to "screen out" transactions based on additional data and analysis, the summary results in this report are provided for all Market Participants, including those with a relatively small number of transactions and potential revenues from the strategies in the Enron memos. In general, the ISO believes that the volume of transactions and potential revenues identified for individual Market Participants in this report provides an indicator of the potential that these transactions represent intentional trading behavior such as described in the Enron memos (i.e. the smaller the volume of transactions and potential revenues identified for individual participants, the lower the likelihood that transactions represent intentional trading behavior such as that described in the Enron memos). In view of this, we continue to recommend that the results of the report be combined with other information collected through other investigative

⁷ *Responsive Filing of the California Independent System Operator*, EL00-95-069, et al., March 20, 2003, page 8. <http://www1.caiso.com/docs/2003/03/21/2003032109052124535.pdf>

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proceedings, and that some minimum threshold be applied in any further investigation of the activities.

I. Overscheduling Load ("Inc'ing Load", "Fat Boy")

The ISO's previous reports on the Enron strategies only included summary data on the degree of overscheduling of Load by Enron in 2000-2001. This report includes a more detailed analysis and summary of overscheduling of Load by all Market Participants in the January 2000 – June 2001 time period. The analysis includes several measures of the degree of overscheduling, ranging from total hours and MWs of overscheduling to the approximate amount of Imbalance Energy payments received from the ISO due to this overscheduling. However, it should be noted that, due to data and resource limitations, this additional analysis does not consider the market impacts of this strategy as a means of exercising market power by withholding Energy from the Day-Ahead Energy markets. As noted in the recent filings by the ISO, while the ISO believes the "Fat Boy" strategy had numerous detrimental impacts on the market and system reliability, the ISO believes these overall impacts are highly interwoven with other strategies for exercising market power and manipulating market outcomes.⁸

Methodology

The following sections provide a step-by-step summary of the methodology used to assess the degree of overscheduling by different Market Participants.

1. Provide and Format Load Schedule Data

The various final market Load Schedules (Day-Ahead Preferred, Day-Ahead Revised Preferred, and Hour-Ahead Preferred) in the *Load_sch* file for each hour and interval were combined to create a file with a single record for each hour and interval for each Schedule Coordinator at each Load point (or *Load ID*). For hours prior to ten-minute settlements (e.g. before September 1, 2000), this Load Schedule file was created on an hourly level. For the period after ten-minute settlements was implemented, hourly Load data were converted into a 10-minute interval format (i.e. each hourly Load Schedule value was divided by six, and the resulting value was used to create six records for each hour, representing the six ten-minute intervals within each hour). This conversion was done to allow Load Schedule data to be merged with Meter Data, and to calculate payments for uninstructed Energy based on 10-minute interval prices, as is done in the actual ISO settlement system.

2. Merge Load Schedules with Metered Load Data

The Load Schedule data file, created as described above, was then merged with metered Load readings in the Settlement system (*ss_measurements*, *ss_10min_measurements*), by Scheduling Coordinator, date, hour, Load ID, and, when applicable, 10-minute interval.⁹ As noted above, for the time period prior to 10-minute

⁸ See ISO filings referenced in Footnote 7.

⁹ In the *Load_sch* table, the scheduling coordinator ID is the *sc_id* field, the date is the *opr_dt* field, the hour is the *opr_hr* field, the market type is the *mkt_type* field, the cong run type (e.g. preferred, revised

settlements (e.g. before September 1, 2000), matches were conducted at the hourly level; for the period after 10-minute settlement was implemented, Load Schedule and Meter Data were merged by hour and interval.

3. Aggregate Load Schedules and Meter Data by Congestion Zone

Load IDs were then matched to Congestion zone,¹⁰ and then subsequently summed by Scheduling Coordinator, Congestion zone, date, hour, and interval,¹¹ to determine each Scheduling Coordinator's total hourly or interval-level zonal Schedule and meter readings. This level of aggregation was performed in order to allow transmission losses and Imbalance Energy charges/payments to be calculated for each Congestion zone based on zonal real time Energy prices in the same manner as the ISO settlement system.

Some special aggregations were made to account for the fact that during some periods Market Participants scheduled Demand under different Scheduling Coordinator IDs (SC_IDs) than those under which Load data were being metered, resulting in a mismatch of Load Schedules and corresponding Meter Data. These are summarized below.

- (1) Data for January 19 and January 20, 2001 were excluded from the calculation for all Scheduling Coordinators due to scheduling confusion resulting from the shut down of the PX.
- (2) From January 21, 2001 forward, Load Schedules, meter readings and transmission losses were summed for the following SC IDs: PXC3, PCG1, and PCGB. This was done to account for mismatches between the SC IDs for the Load Schedules and the corresponding metered Loads that occurred during the transition of Pacific Gas & Electric Company ("PG&E") from scheduling through the PX to being their own Scheduling Coordinator.
- (3) From April 2001 forward, data were summed for the following SC IDs: PGAB and PGAE. This was done to account for mismatches between the SC IDs

preferred run) is the *sch_class* field, and the Load ID is the *Load_id* field. In the *ss_measurements* and *ss_10min_measurements* table, the scheduling coordinator ID is the *short_name* field, the date is the *trade_int* field, the hour is the *trade_hr* field, and the Load ID is the *lctn_id* field. Additionally, in the *ss_10min_measurements* table, the interval is indicated in the *subhour_int* field. See the field description tables included with the source data files.

¹⁰ The ZP-26 Congestion zone was not created until February 1, 2000, so Load IDs in ZP-26 prior to February 1, 2000 should be reassigned to the SP-15 Congestion zone.

¹¹ The PX, prior to its bankruptcy, used the PXC1 Scheduling Coordinator ID to schedule all Investor Owned Utility ("IOU") Load. Thus, it is difficult to separate out each IOU's Load from within all PXC1 Load. As a proxy, when the Scheduling Coordinator ID was PXC1, we identified the Utility Distribution Company ("UDC") area the Load point was within, and rewrote the *sc_id* as "PXC1 / " and the UDC area (e.g. PG&E, Southern California Edison Company ("SCE"), or San Diego Gas and Electric Company ("SDG&E")) to identify roughly which company's Load that would be.

- for the Load Schedules and the corresponding metered Loads that resulted from a change in PG&E utility services' SC IDs during this period.
- (4) Between April 6 and 30, 2001, data for two SC IDs (COTB and COTP) were summed to account for mismatches between the SC IDs for the Load Schedules and the corresponding meters resulting from a change in SC IDs for the California Oregon Transmission Project.
 - (5) Duke Energy Marketing and Trading Load Schedules for December 7, 2000, HE 14 through HE 22 were removed from the analysis due to information identified in their responsive testimony in EL00-95-075, indicating that Load was scheduled during these two hours at the request of, or at least with the approval of the ISO. Removal of these Schedules resulted in Duke Energy's elimination from the Load overscheduling results.
 - (6) Load Schedules at the GOLETA_2_V200LD Load point submitted through the PX were reassigned to Reliant Energy Services (NES1) due to information provided to the ISO that NES1 was scheduling Load at that point under the SC ID for the PX (PXC1).

4. Calculate Transmission Losses

One reason ISO Market Participants may overschedule Load by about 3% is to account for Generation produced to compensate for transmission losses that otherwise would be assessed to Generation resources as part of the ISO settlement process.¹² In order to incorporate expected Generation transmission losses into the analysis of Load scheduling, transmission losses during the ISO settlement process were estimated and incorporated into subsequent steps of this analysis.

In order to calculate zonal transmission losses for supply resources, Generation units and tie points were mapped into ISO Congestion zones (for interties, by ISO injection zone). We then obtained Final Hour-Ahead Generation Schedules from the *Generation_sch* table and interchange Schedules from the *I_interchange_sch* table.¹³ We also obtained the calculated Generation Meter Multipliers (GMM) for each Generation unit, date, and hour, and the Tie Meter Multipliers (TMM) for each intertie, date, and hour.

¹² For example, if an SC has exactly 100 MW of Load and generates exactly 100 MW of Generation, transmission losses associated with the SC's 100 MWs of Generation assessed during the ISO settlement process (which typically average about 3%) would typically result in the SC being charged for about 3 MW of negative uninstructed Energy (representing Imbalance Energy needed to compensate for 3% losses on Generation). The SC could avoid these charges by submitting a schedule for 103 MW of Load and then providing 103 MW of Generation. Under this scenario, the SC would have 100 MW of metered Demand and 100 MW of Generation (after losses), representing an uninstructed deviation of zero in the ISO's settlement process.

¹³ For PXC1, import losses were not considered because it was impossible to determine which imports were intended to serve which utility's Load.

For Generation resources within the ISO control area, the meter multipliers were then applied in the following fashion. Two values were developed:

- The final Hour-Ahead Schedule (MW) without the GMM; and
- The final Hour-Ahead Schedule (MW) with the GMM applied, e.g. $FinMW * GMM$.

Transmission losses for these resources (T_{Loss}) were then calculated based on the difference between these two values. As indicated in Step 7, in the event that estimated transmission losses were less than 3% using the above methodology, we assumed minimum transmission losses of 3% in order to avoid potential underestimation of transmission losses due to data errors.

For Interchange Schedules (representing imports and exports), the net interchange over a tie was calculated for each SC, date and hour by taking the sum of all imports and exports scheduled over each tie (i.e. based on final Hour-Ahead import/export Schedules). The TMM was then applied to this net import/export Schedule yielding two values:

- The final net Hour-Ahead interchange Schedule MW without the TMM; and
- If final net Hour-Ahead interchange Schedule MW was an import,¹⁴ then the final net Hour-Ahead interchange Schedule MW with the TMM applied, e.g. $FinMW * TMM$; otherwise, just $FinMW$.

Losses for Demand associated with export from the ISO system (T_{Loss}) were then calculated based on the difference between these two values.

After September 1, 2000, the two values were divided by six so that the values were uniformly distributed over six intervals.

Losses were then merged with zonal Load Schedules and meter readings by date, hour, interval, SC, and Congestion zone.

5. Calculate Imbalance Energy Charges/Payments for Deviations from Scheduled Load

Real time Energy prices were then merged into the set, and the following were calculated for each date, hour, interval (if applicable), SC, and Congestion zone:

For the pre-ten-minute settlement period (before September 1, 2000), an estimate of the Imbalance Energy price¹⁵ was calculated:

$$((HA-Meter) - T_{Loss}) * ZnEnergyPrc, \text{ if } \Delta(HA-Meter) \geq 0,$$

¹⁴ Note that according to the *I_interchange_sch* table's conventions, imports are a negative MW value.

¹⁵ This calculation is only intended as an estimate of the uninstructed Energy settlement calculation; full accuracy requires calculation of metered Generation along with schedules, calculation of ramping Energy, etc., which were not replicated here.

$\Delta(HA-Meter) * ZnEnergyPrc$, if $\Delta(HA-Meter) < 0$,

where $\Delta(HA-Meter)$ is the difference between the final zonal Hour-Ahead Load Schedule and the metered Load quantity

$TLoss$ is the zonal transmission loss for that scheduling coordinator

$ZnEnergyPrc$ is the hourly zonal Imbalance Energy price.

For the post-ten-minute settlement period (after September 1, 2000), the price was calculated:

$(\Delta(HA-Meter) - TLoss) * ZnDecPrc$, if $\Delta(HA-Meter) \geq 0$,

$\Delta(HA-Meter) * ZnIncPrc$, if $\Delta(HA-Meter) < 0$,

where

$\Delta(HA-Meter)$ is the difference between the final zonal Hour-Ahead Load Schedule and the metered Load quantity

$TLoss$ is the zonal transmission loss for that scheduling coordinator

$ZnIncPrc$ is the zonal incremental Imbalance Energy price for the specified interval, and

$ZnDecPrc$ is the zonal decremental Imbalance Energy price for the specified interval.

6. Calculate Hourly Level Load Data for ISO System

Final Load Schedules, metered Load readings, transmission losses, and the estimated uninstructed deviation settlement amount for each Congestion zone were then summed for each Market Participant over the entire ISO system by date and hour.

7. Application of Potential Threshold for Hourly Overscheduling

A threshold value for overscheduling of Load, representing the level below which any overscheduled Load may be assumed to be due to forecast error and/or allowances for transmission losses, was calculated for each hour for each Market Participant based on the maximum of:

- 10% of the difference between the final Hour-ahead Load Schedule and actual metered Demand, plus estimates of transmission losses (see Step 4 above);
- 13% of final Hour-Ahead Load scheduled¹⁶; or
- 25 MW

The minimum absolute value of 25 MW used in setting the threshold represents the minimum block that is most commonly used to trade and schedule Energy. This was included as an alternative minimum threshold to account for a scenario in which a Market Participant may have "rounded up" Demand Schedules as much as 25 MW to balance Energy that needed to be procured in minimum increments of 25 MW.

8. Calculation of Different Measures of Overscheduling

The final stage of this analysis involved the calculation of a variety of different measures of overscheduling by individual participants based on hourly results. These measures include the following:

1. Hours of Load Overscheduling (with and without threshold level)
2. Average MWs of Load overscheduled during hours of overscheduling (with and without threshold level)
3. Average Load overscheduled as a percentage of total Load during hours of overscheduling (with and without threshold level)
4. Total payments for overscheduled Load during hours of overscheduling (with and without threshold level).¹⁷

¹⁶ As previously noted, a value of 13% (representing 10% plus a minimum of 3% transmission losses) was used in the event that calculated transmission losses were less than 3%. This was included to avoid underestimation of transmission losses in the event of any data errors

¹⁷ For this analysis, if a Market Participant's total aggregate system-level Load deviation was less than zero (e.g. on a system-level, if a Scheduling Coordinator was a buyer in the Imbalance Energy market), then the estimated uninstructed deviation settlement was set at zero. This reflects the fact that during hourly settlement before September 1, 2000, these Scheduling Coordinators would actually have paid for Energy at the Imbalance Energy price. After September 1, 2000, since the decremental Energy price was typically less than the incremental Energy price if Energy was decremented in a zone, Scheduling Coordinators would also have paid for Energy at some price between the maximum incremental Energy price and the minimum decremental Energy price. In any event, these Scheduling Coordinators would be excluded from the threshold filter, since on a system level, they underscheduled.

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Results

Results of this analysis are summarized in Tables 1 through 3.

Table 1. Overscheduling of Load (pre-refund Period)

ID	Total Number of Hours	Number of Hours where Over Threshold	Pct. Hours Over Threshold	Average Metered Load when Over Threshold	Average MW Overscheduled when Over Threshold	Average Load Deviation % when Over Threshold	Sum of MW Overscheduled when Over Threshold	Total Estimated Unrecr. Energy Payment when Over Threshold
EPMI	6,599	4,324	66%	785	343	45%	1,483,090	\$215,829,088
PWRX	5,055	2,590	51%	157	256	162%	661,999	\$118,717,742
PETP	2,353	2,046	87%		244		499,951	\$73,570,487
SCEM	3,726	3,097	83%		154		477,015	\$89,454,119
APX1	6,599	3,674	56%	213	142	67%	520,005	\$61,198,406
SETC	6,576	3,288	50%	25	144	583%	474,001	\$60,257,635
HFET	1,536	1,437	94%		222		318,894	\$49,008,313
PGAE *	6,599	1,191	18%	1,017	215	21%	256,534	\$25,601,170
CRLP	3,623	2,225	61%	42	81	193%	180,617	\$21,200,264
CAPP	6,247	2,158	35%	1	125	18030%	270,478	\$13,925,705
ECH1	6,599	1,446	22%	44	72	163%	104,572	\$10,995,036
NCPA	6,502	1,087	17%	38	57	150%	61,918	\$8,499,350
RVSD	6,599	1,462	22%	230	55	24%	79,729	\$7,499,638
APS1	6,599	1,086	16%	134	58	43%	62,800	\$7,386,903
NES1	6,599	766	12%	0	92	27588%	70,337	\$6,353,080
NEI1	5,759	780	14%	563	118	21%	90,286	\$5,620,760
PGES	4,008	1,337	33%	399	128	32%	170,892	\$5,477,717
SRP1	6,599	820	12%	432	89	21%	72,961	\$5,314,333
ANHM	6,599	677	10%	316	73	23%	49,409	\$4,452,106
PXC1 / SDGE *	6,599	72	1%	1,852	300	16%	21,612	\$2,313,812
VERN	6,599	131	2%	148	50	34%	6,555	\$1,781,632
SCE1	6,599	87	1%	5	182	3397%	14,088	\$1,744,610
WESC	6,570	624	9%	0	70	15888%	43,697	\$1,646,287
PASA	6,599	340	5%	169	36	21%	12,226	\$1,165,754
AZUA	6,599	150	2%	39	30	75%	4,468	\$747,416
PXC1 / SCE *	6,599	35	1%	6,602	1,007	15%	35,246	\$724,175
LGE1	3,648	208	6%	527	104	20%	21,698	\$647,565
COTP	6,599	3	0%		998		2,993	\$492,247
IEPI	6,599	173	3%	168	33	17%	5,676	\$149,747
PXC1 / PGAE *	6,599	23	0%	7,134	1,221	17%	28,065	\$134,307
WAMP	6,599	47	1%	105	33	32%	1,558	\$124,732
PAC1	6,599	7	0%	32	26	60%	181	\$25,358
IPC1	6,599	23	0%	15	31	209%	712	\$22,468
SCL1	6,599	1	0%	4	25	696%	25	\$756

* Results for PGAE and SCE1 include Schedules submitted by other entities through PG&E and SCE as their Schedule Coordinator, respectively. The ISO does not have data to clearly identify which Schedules/Meter Data correspond to Market Participants other than PG&E and SCE.

Similarly, results for the PX (PXC1) were disaggregated by the utility distribution system in which Load IDs were located (PG&E, SCE or SDGE). Therefore, these results include Schedules/metering data for these utilities as well as other entities.

Table 2. Overscheduling of Load (Refund Period)

ID	Total Number of Hours	Number of Hours where Over Threshold	Pct. Hours Over Threshold	Average Metered Load when Over Threshold	Average MW Overscheduled when Over Threshold	Average Load Deviation % when Over Threshold	Sum of MW Overscheduled when Over Threshold	Total Estimated Uninstr. Energy Payment when Over Threshold
EPMI	6,240	1,692	27%	880	461	52%	779,460	\$117,198,791
PWRX	2,809	1,379	49%	169	455	269%	628,049	\$90,530,475
SCEM	2,133	1,565	73%		256		400,403	\$52,640,866
PETP	1,621	1,410	87%		257		363,009	\$50,162,622
SETC	4,481	1,364	30%		250		340,655	\$49,186,574
APX1	6,240	1,566	26%	148	207	140%	329,976	\$42,937,678
HFET	857	856	100%		226		193,667	\$27,852,560
PGAB / PGAE *	4,055	839	21%	1,352	299	22%	250,731	\$16,031,412
ECH1	6,240	1,004	16%	46	88	191%	88,131	\$12,486,729
PXC1	80	80	100%		1,125		89,999	\$12,267,851
CRLP	6,240	884	14%	33	79	238%	70,010	\$9,049,845
PGAE	2,185	177	8%	1,190	211	18%	37,286	\$7,622,510
NCPA	6,240	752	12%	34	64	187%	48,022	\$7,416,476
PXC1 / SDGE *	2,881	203	7%	1,443	259	18%	52,507	\$5,145,092
NES1	6,240	462	7%	0	87	8485825%	39,978	\$4,794,661
RVSD	6,240	1,195	19%	175	39	22%	48,172	\$3,143,020
SRP1	5,017	226	5%	456	95	21%	21,411	\$3,078,979
PXC1 / PCG1 *	3,623	153	4%	7,785	1,341	17%	205,195	\$2,665,302
ANHM	6,240	583	9%	262	59	23%	34,481	\$2,142,580
PSE1	48	48	100%		150		7,200	\$1,705,367
NE11	6,240	264	4%	151	40	26%	10,481	\$1,857,619
WAMP	6,240	126	2%	117	33	28%	4,164	\$904,080
SDG3	3,359	36	1%	1,568	270	17%	9,729	\$670,814
PASA	6,240	54	1%	126	44	35%	2,373	\$373,685
PXC1 / SCE *	4,474	9	0%	6,743	829	14%	6,358	\$358,550
PAC1	3,123	25	1%	26	91	348%	2,267	\$324,679
APS1	6,240	75	1%	84	30	35%	2,227	\$280,344
SEL1	6,240	49	1%	33	30	92%	1,491	\$161,646
VERN	6,240	77	1%	113	37	33%	2,879	\$153,694
WESC	5,911	68	1%		42		2,878	\$128,036
CAPP	5,856	28	0%	13	27	213%	747	\$111,231
APX3	3,089	19	1%	47	52	109%	966	\$88,712
EPPS	3	2	67%		66		135	\$9,407
AZUA	6,240	1	0%	9	29	308%	29	\$2,979
IPC1	6,240	2	0%	9	26	279%	52	\$297
AEPS	1	1	100%		25		25	\$0
SCE1	6,240	146	2%	5,438	1,046	19%	152,743	(\$676,776)

* Results for PGAE and SCE1 include Schedules submitted by other entities through PG&E and SCE as their Schedule Coordinator, respectively. The ISO does not have data to clearly identify which Schedules/Meter Data correspond to Market Participants other than PG&E and SCE.

Similarly, results for the PX (PXC1) were disaggregated by the utility distribution system in which Load ids were located (PG&E, SCE or SDGE). Therefore, these results include Schedules/metering data for these utilities as well as other entities.

Table 3. Overscheduling of Load (January 1, 2000 – June 19, 2001)

ID	Total Number of Hours	Number of Hours where Over Threshold	Pct. Hours Over Threshold	Average Measured Load when Over Threshold	Average MW Overscheduled when Over Threshold	Average Load Deviation % when Over Threshold	Sum of MW Overscheduled when Over Threshold	Total Estimated Unrec. Energy Payment when Over Threshold
EPMI	12,839	6,018	47%	797	378	47%	2,262,550	\$333,027,879
PWRX	7,884	3,989	50%	181	325	201%	1,290,048	\$208,248,217
PETP	3,974	3,456	87%		250		862,960	\$123,733,109
SCEM	5,859	4,662	80%		188		877,418	\$122,094,985
SETC	11,057	4,652	42%	25	175	708%	814,657	\$108,444,209
APX1	12,839	5,270	41%	193	181	84%	849,980	\$104,136,083
HFET	2,393	2,293	96%		224		512,561	\$76,860,873
PGAE *	8,784	1,368	16%	1,039	215	21%	293,820	\$33,223,679
CRLP	9,883	3,109	32%	39	81	209%	250,828	\$30,250,109
ECH1	12,839	2,450	19%	45	79	174%	192,703	\$23,481,764
PGAB / PGAE *	4,055	839	21%	1,352	299	22%	250,731	\$18,031,412
NCPA	12,742	1,839	14%	36	60	164%	109,941	\$15,915,826
CAPP	12,103	2,186	18%	1	124	12460%	271,225	\$14,038,936
PXC5	80	80	100%		1,125		89,999	\$12,267,851
NES1	12,839	1,228	10%	0	90	42978%	110,316	\$11,147,720
RVSD	12,839	2,657	21%	205	47	23%	125,901	\$10,842,658
SRP1	11,616	1,048	9%	437	80	21%	94,372	\$8,391,312
APS1	12,839	1,181	9%	131	56	43%	65,027	\$7,667,247
PXC1 / SDGE *	9,480	275	3%	1,550	270	17%	74,119	\$7,458,804
NEI1	11,999	1,044	9%	459	97	21%	100,767	\$7,278,379
ANHM	12,839	1,280	10%	291	67	23%	83,889	\$8,584,688
PGES	4,008	1,337	33%	399	128	32%	170,892	\$5,477,717
PGEC *	3,623	153	4%	7,785	1,341	17%	205,195	\$2,665,302
VERN	12,839	208	2%	133	45	34%	9,434	\$1,935,726
WESC	12,481	692	6%	0	67	15270%	46,576	\$1,772,323
PSE1	48	48	100%		150		7,200	\$1,705,367
PASA	12,839	394	3%	183	37	23%	14,600	\$1,539,439
PXC1 / SCE *	11,073	44	0%	6,631	991	15%	43,804	\$1,082,724
SCE1 *	12,839	233	2%	3,409	718	21%	186,842	\$1,067,834
WAMP	12,839	173	1%	114	33	29%	5,722	\$1,028,812
AZUA	12,839	151	1%	39	30	76%	4,496	\$750,394
SDG3	3,359	38	1%	1,568	270	17%	9,729	\$670,814
LGE1	3,648	208	6%	527	104	20%	21,698	\$847,585
COTP	11,012	3	0%		998		2,993	\$482,247
PAC1	9,722	32	0%	27	76	279%	2,447	\$350,037
SEL1	10,353	49	0%	33	30	92%	1,491	\$161,648
IEPI	9,480	173	2%	188	33	17%	5,676	\$149,747
PXC1 / PGAE *	10,896	23	0%	7,134	1,221	17%	28,085	\$134,307
APX3	3,089	19	1%	47	52	108%	986	\$88,712
IPC1	12,839	25	0%	14	31	213%	764	\$22,786
EPPS	3	2	67%		68		135	\$9,497
SCL1	10,273	1	0%	4	25	696%	25	\$756
AEPS	1	1	100%		25		25	\$0

* Results for PGAE and SCE1 include Schedules submitted by other entities through PG&E and SCE as their Schedule Coordinator, respectively. The ISO does not have data to clearly identify which Schedules/Meter Data correspond to Market Participants other than PG&E and SCE.

Similarly, results for the PX (PXC1) were disaggregated by the utility distribution system in which Load ids were located (PG&E, SCE or SDGE). Therefore, these results include Schedules/metering data for these utilities as well as other entities

Company Names (for Tables 1 through 3)

ID	NAME
AEPS	American Electric Power Service Corporation
ANHM	City of Anaheim
APS1	Arizona Public Service Company-APS1
APX1	Automated Power Exchange, Inc-APX1
APX3	Automated Power Exchange Inc-APX3
APX4	Automated Power Exchange-APX4
AZUA	City of Azusa
BAN1	City of Banning
CALP	Calpine Energy Services
CAPP	California Polar Power Brokers LLC
CDWR	California Department of Water Resources
CERS	California Department of Water Res.
COTB	CA-OR Transmission Project
COTP	CA-OR Transmission Project
COTP / COTB	CA-OR Transmission Project
CPSC	Constellation Power Source Inc.
CRLP	Coral Power, LLC
DETM	Duke Energy Trading and Marketing, L.L.C.
ECH1	Dynegy Power Marketing, Inc.
EPMI	ENRON Power Marketing Inc
EPPS	El Paso Power Services Company
ESRC	Edison Source
HFET	HAFSLUND ENERGY TRADING L.L.C.
IEPI	Illinova Energy Partners, Inc
IPC1	Idaho Power Company
LGE1	Louisville Gas and Electric Company
NCPA	Northern California Power Agency
NEI1	NewEnergy Inc.
NES1	Reliant Energy Services, Inc.
PAC1	PacificCorp
PAC3	PacificCorp-Green
PASA	City of Pasadena
PETP	PG&E Energy Trading Power, L.P.
PGAB / PGAE	Pacific Gas and Electric Company
PGAE	Pacific Gas and Electric Company
PGES	PG & E Energy Services
PSE1	Puget Sound Energy
PWRX	British Columbia Power Exchange
PXC1 / PGAE	PX (Pacific Gas & Electric Company Region)
PXC1 / SCE	PX (Southern California Edison Region)
PXC1 / SDGE	PX (San Diego Gas & Electric Region)
PXC3	California Power Exchange 3 - PG&E
PXC3 / PCG1 / PCGB	Pacific Gas and Electric Company
PXC5	California Power Exchange 5
RVSD	City of Riverside
SCE1	Southern California Edison Company
SCEM	Mirant
SCL1	Seattle City Light
SDG3	San Diego Gas & Electric, Merchant
SDG4	San Diego Gas and Electric, Merchant
SDGE	San Diego Gas and Electric Company
SEL1	Strategic Energy, LLC
SETC	Sempra Energy Trading Corporation
SRP1	Salt River Project
VERN	City of Vernon
VSYN	VIASYN, INC
WAMP	Western Area Power Administration
WESC	Williams Energy Marketing and Trading
WRDG	Western Area Power Admin.-Redding

II. Circular Schedules ("Death Star")

The purpose of this report — like previous related reports — has been to provide an indication of the potential magnitude to which the "Death Star" strategy outlined in the Enron memos may have been employed by Market Participants, and to identify specific Schedules and transactions that could provide a starting point for further investigation and potential legal and regulatory actions related to the practices outlined in the Enron memos. As such, the methodology developed by DMA and the resulting analysis was intentionally designed to "cast a broad net" and to identify all market activity that could be indicative of the "Death Star" strategy. DMA has continued to review and refine its calculation of Congestion revenues earned by import/export Schedules that could potentially be indicative of the "Death Star" trading strategy, as documented in a revised analysis posted on the ISO website on January 17, 2003.¹⁸

Methodology

The "Death Star" scenario described in the Enron memos is an example of what the ISO refers to as a "circular" Schedule, or a series of Energy Schedules that appear as import and export Schedules through the ISO control area, but actually include additional Schedule(s) outside the ISO control area which form a closed "loop" of scheduled Energy with no specific, physical, beginning (source) or end (sink). Thus, the type of circular Schedule described under the "Death Star" strategy would appear in ISO Scheduling records simply as an import and export from the ISO control area (earning Congestion revenues by creating a counterflow), with the "return" portion of the Schedule being outside the ISO control area.¹⁹

The potential frequency and financial gains from circular Schedules were analyzed by identifying import/export Schedules (of equal quantities) by the same SC that generated Congestion revenues from counter-flows on inter-ties and/or internal paths within the ISO. This approach may underestimate circular Schedules since the analysis only includes import/export Schedules that can be matched because they are of (approximately) equal quantities by the same SC. For instance, the strategy could also be employed by a single SC using more than two Schedules (e.g. two 50 MW import Schedules on two different ties, paired with a 100 MW export Schedule on a third tie). In addition, it could be employed by two or more SC's (e.g. a 50 MW import Schedule by one SC, coupled with an inter-SC trade to another SC, who then exports all or part of the amount transferred from the other SC). The methodology used in this study does not capture either of these two types of strategies (non-equal capacity and inter-SC trading). At the same time, such matching would also include "non-circular"

¹⁸ Addendum to October 4, 2002 Report on Analysis of Trading and Scheduling Strategies Described in Enron Memos: Revised Results for Analysis of Potential Circular Schedules ("Death Star" Scheduling Strategy) January 17, 2003.

¹⁹ In addition, circular Schedules may be created by "looping" Energy back through the ISO control area under a different SC. However, this particular strategy would typically only be profitable if the Energy schedule in the congested direction is scheduled by an SC with Existing Transmission Rights ("ETR"s), so that no Congestion charges are incurred for this "return" portion of the circular Schedule.

wheeling Schedules (or other combinations of export/import Schedules) which may have a distinct physical source and sink outside the ISO control area.

The analysis of potential circular scheduling in this report is designed to identify all export/import Schedules which may, based on the information available to the ISO, be circular Schedules such as those described under the "Death Star" strategy. This analysis identifies potential circular Schedules based on two basic characteristics of such Schedules that may be detected in ISO data: (1) an import and export of approximately the same amount of Energy by a SC during the same hour, which (2) generate net Congestion payments for the SC due to counterflows created over one or more paths. Thus, while all combinations of import/export Schedules that earn Congestion revenues by creating a counterflow are clearly not circular Schedules, these key characteristics may be used to identify export/import Schedules that may be part of a circular Schedule submitted for purposes of earning Congestion revenues.

There are instances where a single import (export) Schedule will be paired with more than one export (import) Schedule due to the matching algorithm employed in the methodology. Only one of these multiple pairs is simultaneously feasible and the ISO has no means for determining which of these pairs may have been intended by the SC. In the case where multiple pairings are generated by the algorithm, the pair with the highest net gain from Congestion counter-flow payments less any Congestion charges is selected to be included in the final tabulation. This selection is made on returns only and is done specifically to avoid double counting when tabulating the extent to which this strategy was employed and the potential gains that result. The selection of one pair from multiple pairings does not exclude any of the paired schedules that were not selected for inclusion in the final tabulation from the pool of schedules that may have been executed in the manner of the "Death Star" strategy.

Provided below is a more detailed description of this analysis:

1. First, for each SC, the import and export Schedules are matched for the same operating hour submitted by the same SC for approximately the same quantity (within a small tolerance for rounding). This matching is done separately for final Day-Ahead Schedules and final Hour-Ahead Schedules.
2. Congestion payments and charges for each pair of import/export Schedules are then calculated based on the scheduled amount (MW), and the Congestion prices and direction the import/export Schedules would create a scheduled flow on each Congestion path. We then identify Schedules that would be covered under ETC rights, and account for the fact that these Schedules would not pay Congestion charges or earn Congestion revenues for any counter-flows provided. Any pair of Schedules for which one leg of the pair was covered by an ETC is excluded from the final tabulation. For example, for a pair of Schedules representing an 25 MW import into NP15 over COI and a 25 MW export from SP15 on Palo Verde (with no ETC's on either leg of the pair), Congestion charges/payments would be calculated for a 25 MW flow in the north-to-south direction on COI, Path 15, Path 26 and Palo Verde.

3. For each pair of import/export Schedules, the total net Congestion payments were calculated (taking into account all paths over which a flow would be earned or be charged Congestion charges). Pairs of import/export Schedules resulting in positive net Congestion revenues during any hour (due to counterflow payments in excess of any Congestion charges on other paths) are identified as those that could represent circular schedules submitted in order to earn Congestion revenues.
4. Total Congestion revenues earned by the Schedules identified in Step 3 are summed. In cases where one leg of a circular Schedule was paired with more than one counterpart leg, the pairing that yielded the highest net gain was selected to be included in the tabulation of gains and capacity scheduled under this strategy.
5. Finally, pairs of import/export Schedules representing less than 1 MW and/or \$1 in counterflow revenues were screened out of the analysis. These Schedules appear to result from rounding that occurs in the ISO Congestion Congestion Management system.

**Table 4. Total Congestion Revenues from Counterflows
Created by Import/Export Schedules (Matched by MW Amount)**

ID	Company	Pre-refund Period	Refund Period	Total
EESI	Enron Energy Services, Inc.	\$1,783,157	\$379,328	\$2,162,485
CRLP	Coral Power, LLC	\$337,982	\$1,213,017	\$1,550,999
SETC	Sempra Energy Trading Corporation	\$348,020	\$900,377	\$1,248,397
APX	Automated Power Exchange, Inc	\$0	\$726,099	\$726,099
SCEM	Southern Company Energy Marketing, L.P.	\$95,419	\$9,650	\$105,069
DETM	Duke Energy Trading and Marketing, L.L.C.	\$10,600	\$85,381	\$95,981
IPC	Idaho Power Company	\$1,980	\$81,393	\$83,373
AQPC	Aquila Power Corporation	\$75,975	\$0	\$75,975
WESC	Williams Energy Services Corporation	\$4,972	\$35,115	\$40,087
BCHA	British Columbia Power Exchange Corporation	\$1,882	\$29,574	\$31,456
MID	Modesto Irrigation District	\$10,059	\$4,245	\$14,304
SCEC	Southern California Edison Company	\$10,200	\$1,380	\$11,580
PGE	Portland General Electric	\$5,750	\$0	\$5,750
CPCO	Calpine Corporation	\$0	\$4,376	\$4,376
PSE	Puget Sound Energy	\$0	\$2,982	\$2,982
APS	Arizona Public Service Company	\$1,174	\$0	\$1,174
HFET	Hatslund Energy Trading, LLC	\$425	\$0	\$425
		\$2,687,595	\$3,472,917	\$6,160,512

Note: Includes all import/export combinations by the same SC (matched by MW amount) that earned net Congestion revenues from counterflows on interties and internal ISO paths. The ISO does not have sufficient information to determine if these Schedules represent actual physical sources and sinks that mitigated congestion, or are the type of "circular" Schedule without physical source and sink, such as the Death Star scheme described in the Enron memos.

III. Ancillary Services Buyback ("Get Shorty")

The Enron memo describes two distinct gaming "strategies" in the A/S markets:

1. Taking advantage of systematic differences in the Day-Ahead and Hour-Ahead Market prices for A/S by selling A/S in the Day-Ahead Market and buying them back, when possible, at a lower price in the Hour-Ahead Market.
2. Selling A/S in the Day-Ahead Market from imports for which resources are not actually available (with the intent to "buy back" these A/S in the Hour-Ahead Market at a lower price).

Methodology

Total gains by each SC from selling back Ancillary Services in the Hour-Ahead Market were calculated based on the difference in Day-Ahead/ Hour-Ahead Market prices for each MW sold back by each SC in the Hour-Ahead Market. Any losses from the sellback of A/S capacity at prices that were higher than Day-Ahead prices were included in the analysis to reflect the fact that the "sellback" strategy was not always successful. However, this analysis shows that gains from sellback of A/S far outweigh any losses, suggesting that SCs employing this trading strategy were highly successful at anticipating when the Hour-Ahead Market prices would be lower than the Day-Ahead Market prices.²⁰

Results

Table 5 summarizes these results for each SC by time period (pre-refund and refund), in terms of both gross and net gains from sellback of A/S. As noted in the October 4, 2002 Report, the ISO does not have information that could be used to determine the extent to which A/S capacity sold in the Day-Ahead Market and then "sold back" in the Hour-Ahead Market was not actually available or could not have been provided.

²⁰ As compared to previous drafts of this report, the "Get Shorty" figures in this report reflect additional filtering to omit transactions with trivial buy-back quantities ($\leq 1\%$ of DA procurement) and buy-back transactions that may have been initiated by the ISO in response to changes in branch group capacity or a decrease in the maximum amount of A/S that could be purchased from resources outside the control area. In both these cases, the curtailment by the ISO will be *pro rata*, so the same percent cut would apply to all schedules affected on a branch group. To capture these two circumstances, records were omitted if (1a) all DA A/S schedules on that branch group were curtailed in the HA market and (1b) there was more than one DA A/S schedule on that branch group -or- (2) if there were multiple buy-backs on the same branch group with the same percent of capacity purchased back in the HA market. For the entire period from January 1, 2000, through June 21, 2001, imposing these filters on the transactions resulted in a decrease in transactions from 14,275 to 9,421 and a decrease in potential net gains from \$47.2 million to \$27.8 million.

**Table 5: Sellback of Ancillary Services
Pre-refund Period (January 1-October 1, 2000)**

ID	Name	Gains	Losses	Net Gains
CRLP	Coral Power LLC	\$6,010,809	-\$481,212	\$5,529,597
MID	Modesto Irrigation District	\$4,692,758	-\$75,725	\$4,617,034
AVEI	Avista Energy Inc	\$4,260,564	-\$55,176	\$4,205,388
SETC	Sempra Energy Trading Corporation	\$3,701,719	-\$117,636	\$3,584,084
BCHA	British Columbia Power Exchange Corporation	\$120,569	-\$15,076	\$105,493
AZUA	City of Azusa	\$90,789	-\$218	\$90,571
GCPD	Grant County PUD	\$35,550	-\$7,395	\$28,155
TCEP	Tuscon Electric Power	\$23,679	-\$1,713	\$21,966
EESI	Enron Energy Services Inc.	\$6,383	\$0	\$6,383
IPC	Idaho Power Company	\$2,085	\$0	\$2,085
VERN	City of Vernon	\$1,940	\$0	\$1,940
LDWP	Los Angeles Water and Power	\$15,858	-\$52,702	-\$36,844

**Table 6: Sellback of Ancillary Services
Refund Period (October 2, 2000 – June 21, 2001)**

ID	Name	Gains	Losses	Net Gains
EESI	Enron Energy Services Inc.	\$4,266,400	-\$140,857	\$4,125,543
SETC	Sempra Energy Trading Corporation	\$3,742,655	-\$314,587	\$3,428,068
CRLP	Coral Power LLC	\$1,479,020	-\$30,815	\$1,448,205
PSE	Puget Sound Energy	\$500,309	-\$23,753	\$476,556
BCHA	British Columbia Power Exchange Corporation	\$271,072	-\$213,770	\$57,302
AZUA	City of Azusa	\$42,800	\$0	\$42,800
MID	Modesto Irrigation District	\$21,714	\$0	\$21,714
TCEP	Tuscon Electric Power	\$16,714	-\$110	\$16,605
AVEI	Avista Energy Inc	\$20,049	-\$4,458	\$15,591
GLEN	City of Glendale	\$12,188	\$0	\$12,188
IPC	Idaho Power Company	\$11,564	\$0	\$11,564
LDWP	Los Angeles Water and Power	\$12,964	-\$4,661	\$8,304
VERN	City of Vernon	\$7,268	\$0	\$7,268
PSNM	Public Service Company of New Mexico	\$869	\$0	\$869
PASA	City of Pasadena	\$29	\$0	\$29
APX	Automated Power Exchange Inc	\$14	\$0	\$14
BPA	Bonneville Power Administration	\$707	-\$1,360	-\$654

**Table 7: Sellback of Ancillary Services
(January 1, 2000 – June 21, 2001)**

ID	Name	Gains	Losses	Net Gains
SETC	Sempra Energy Trading Corporation	\$7,444,374	-\$432,222	\$7,012,152
CRLP	Coral Power LLC	\$7,489,829	-\$512,027	\$6,977,802
MID	Modesto Irrigation District	\$4,714,472	-\$75,725	\$4,638,747
AVEI	Avista Energy Inc	\$4,280,613	-\$59,634	\$4,220,979
EESI	Enron Energy Services Inc.	\$4,272,783	-\$140,857	\$4,131,926
PSE	Puget Sound Energy	\$500,309	-\$23,753	\$476,556
BCHA	British Columbia Power Exchange Corporation	\$391,641	-\$228,846	\$162,795
AZUA	City of Azusa	\$133,589	-\$218	\$133,371
TCEP	Tuscon Electric Power	\$40,393	-\$1,823	\$38,571
GCPD	Grant County PUD	\$35,550	-\$7,395	\$28,155
IPC	Idaho Power Company	\$13,648	\$0	\$13,648
GLEN	City of Glendale	\$12,188	\$0	\$12,188
VERN	City of Vernon	\$9,208	\$0	\$9,208
PSNM	Public Service Company of New Mexico	\$869	\$0	\$869
PASA	City of Pasadena	\$29	\$0	\$28
APX	Automated Power Exchange Inc	\$14	\$0	\$14
BPA	Bonneville Power Administration	\$707	-\$1,360	-\$654
LDWP	Los Angeles Water and Power	\$28,822	-\$57,362	-\$28,540

**Table 8: Net Gains From Sellback of Ancillary Services
(January 1, 2000 – June 21, 2001)**

ID	Name	Pre-refund Period	Refund Period	Total
SETC	Sempra Energy Trading Corporation	\$3,428,088	\$3,584,084	\$7,012,152
CRLP	Coral Power LLC	\$1,448,205	\$5,529,597	\$6,977,802
MID	Modesto Irrigation District	\$21,714	\$4,617,034	\$4,638,747
AVEI	Avista Energy Inc	\$15,591	\$4,205,388	\$4,220,979
EESI	Enron Energy Services Inc.	\$4,125,543	\$6,383	\$4,131,926
PSE	Puget Sound Energy	\$476,556	\$0	\$476,556
BCHA	British Columbia Power Exchange Corporation	\$57,302	\$105,493	\$162,795
AZUA	City of Azusa	\$42,800	\$90,571	\$133,371
TCEP	Tuscon Electric Power	\$16,605	\$21,966	\$38,571
GCPD	Grant County PUD	\$0	\$28,155	\$28,155
IPC	Idaho Power Company	\$11,564	\$2,085	\$13,648
GLEN	City of Glendale	\$12,188	\$0	\$12,188
VERN	City of Vernon	\$7,268	\$1,940	\$9,208
PSNM	Public Service Company of New Mexico	\$869	\$0	\$869
PASA	City of Pasadena	\$28	\$0	\$28
APX	Automated Power Exchange Inc	\$14	\$0	\$14
BPA	Bonneville Power Administration	-\$654	\$0	-\$654
LDWP	Los Angeles Water and Power	\$8,304	-\$36,844	-\$28,540

IV. Scheduling of Counterflows on Out-of-Service Lines ('Wheel-Out')

Background

Another type of scheduling practice identified in the Enron memos is where an SC submits Schedules and/or Adjustment Bids across a tie point that has been de-rated to zero capacity in hopes of getting paid for providing a counter-flow Schedule that will need to be cut by ISO in real time. This practice was apparently referred to as 'wheel-out' by Enron traders.

The ISO's Day-Ahead and Hour-Ahead Congestion Management program ("CONG") does not currently allow the ISO to reject or cancel Schedules across a tie point that has been de-rated to zero transmission capacity. Instead, when a tie point is de-rated to zero capacity, the ISO sets the available capacity for the tie point in the CONG software to approximately zero.²¹ When the CONG software is run, the software adjusts Schedules as necessary to achieve the result of a net zero scheduled flow across the tie point. For example, if Schedules are submitted that create a net flow in one direction, the CONG software will seek to offset this flow by accepting Adjustment Bids for counterflows in the opposite direction and/or reduce initial scheduled flows based on Adjustment Bids).

When a tie point is de-rated, a market notice is sent to Market Participants to notify them of the de-rate. Market Participants also can access forecasts of transmission usage and line and equipment outages that cause de-rating of lines on the ISO's OASIS system. For an outage or de-rate, they can access the start time, an anticipated end time, and a reason for the outage or de-rate. They also have information on status changes to outages or de-ratings.

With the information available on OASIS and through market notices, SCs have the opportunity to submit a Schedule to provide counter-flow across the tie point or to be adjusted in the direction of the counter-flow (generally in the Hour-Ahead Market) to relieve Congestion on the tie point. In the case where the tie point was de-rated to zero capacity, there will be Congestion in the Hour-Ahead (and Day-Ahead if the duration of the de-rate is long enough) Congestion markets. Any SCs providing counter-flow Schedules to relieve this Congestion are paid counter-flow revenues.

In real-time, when a tie-point is de-rated to zero, the ISO effectively removes this tie-point from the transmission system by canceling all Schedules on the tie-point during the final real time inter-tie checkout just prior to each operating hour. However, any Congestion charges and payments associated with the Day-Ahead and Hour-Ahead

²¹ In practice, the available capacity for lines that are out is set to .03 MW (rather than zero), in order to facilitate computation by the CONG software in a more timely manner.

Congestion Management process described above are not cancelled or reversed from the ISO settlement system.

As noted in the Enron memos, this creates a potential gaming opportunity, in that when a tie point is known to be out of service, an SC may submit Schedules and Adjustment Bids in an effort to create counterflow schedules on tie for which they can earn Congestion revenues, knowing that these Schedules will be cancelled by the ISO in real time. Finally, it should be noted that not all counterflow Schedules on tie lines that are out of service may be attributable to intentional gaming, since an SC may schedule or submit Adjustment Bids on a line prior to notification of the line outage and fail to cancel these after notification of outage occurs.

Methodology

Tie lines that were out-of-service prior to the Day-Ahead and/or Hour-Ahead Congestion Management process were identified by summing up all net final scheduled flows on each time line, and selecting those lines with net final flows of approximately zero.²² Final counterflow Schedules on out-of-service lines are comprised of Schedules submitted directly by SCs, as well as any adjustments made through CONG.

This set was further screened to include only ties on which Congestion payments/credit occurred, as indicated by a positive Congestion price.

The general formula for calculating the gains from providing counter-flow Schedules across tie points that have been de-rated to zero for any hour is as follows:

$$\text{Counterflow Payment} = MW_{DA} * CC_{DA} + (MW_{HA} - MW_{DA}) * CC_{HA}$$

where

MW_{DA} is the final scheduled MW after the Day-Ahead Congestion Market
 MW_{HA} is the final scheduled MW after the Hour-Ahead Congestion Market
 CC_{DA} is the Day-Ahead Congestion charge (or credit), and
 CC_{HA} is the Hour-Ahead Congestion charge (or credit).

Since schedules that are covered by ETCs neither pay nor receive Congestion revenues, Schedules submitted under ETCs were identified and removed from this stage of the analysis.

Summary results provided in Table 9 of the ISO's October 4, 2002 report included all SCs with gains over \$50,000 from counterflow Schedules on out-of-service ties over the

²² This approach was necessary since the ISO system does not include a database with the historical ratings of each tie-point for each hour that was used in the Congestion Management process. In practice, as noted in the previous footnote, the available capacity for lines that are out of service is set to .03 MW (rather than zero), in order to facilitate computation by the CONG software in a more timely manner.

1998-2002 period covered in that report. (October 4 Report, p. 24). For this report, two modifications have been made which have the effect of changing overall results:

- As with all results in this report, the analysis is limited to the period from January 1, 2000 through June 19, 2001, which is the subject of further investigation by FERC staff.
- In addition, DMA has conducted further review of ISO data in order to determine if the Market Participants' Schedules or Adjustment Bids changed noticeably in a way that would indicate they may have indeed been seeking to exploit the tie line outage in order to earn counterflow revenues for Schedules that they knew would need to be cancelled in real time. For example, Attachment 1 to this report provides a summary of changes that were detected in scheduling and bidding behavior shortly before and during a line outage on the Four Corners branch group on May 27-28, 2000.²³ If no such change was detected in the Market Participants' Schedules and/or Adjustment Bids, the incident was screened from the analysis.

Table 9 provides a summary of this revised analysis.

**Table 9. Counterflow Revenues on Out-of-Service Tie Points
January 1, 2000 – June 19, 2001**

ID	Name	Pre-Refund	Refund Period	Total
		Period		
ECH1	Dynegy Power Marketing	\$1,876,571		\$1,876,571
PWRX	British Columbia Power Exchange Corporation	\$789,491		\$789,491
SETC	Sempra Energy Trading Corporation	\$485,895		\$485,895
EPMI	Enron Energy Services, Inc.	\$225,075		\$225,075
CRLP	Coral Power, LLC	\$53,938		\$53,938
DETM	Duke Energy Trading and Marketing, L.L.C.	\$33,558		\$33,558
Total		\$3,464,528	\$0	\$3,464,528

Of the \$3.465 million in Congestion revenues shown in Table 1 for the pre-refund period, about \$3.35 million were gained from a five-hour outage across the Four Corners (FCORNR_5_PSUEDO) tie point within the El Dorado branch group on May 27-28, 2000.

²³ Attachment 1 was previously submitted to FERC in the 100-day discovery process in the Refund Proceeding.

V. Ricochet

As noted in our October 4 report, "ricochet schedules" or "megawatt laundering" refer to a variety of scheduling and trading practices. For this report, we have included analysis of the one general form of "ricochet schedules" or "megawatt laundering": export of power from an SCs resource portfolio within the ISO system on a Day-Ahead or Hour-Ahead basis, and a resale of power back into the ISO system in real time (through either a sale in the ISO Real Time Market or an out-of-market sale). We focus on this specific definition since this can be quantified using ISO records based on the "overlap" between Day-Ahead/Hour-Ahead exports and real time imports by an individual SC during the same hour. As noted in the introduction to this report, the data and methodology employed in this analysis do not identify the extent to which Ricochet or "MW Laundering" may have been employed by two or more SCs, so that Energy may have been exported and then re-imported under two different SC_IDs, since the ISO does not have information to perform such analysis.

Methodology

The analysis identifies, on an hourly basis for each SC, the maximum quantity of Energy that could be exported from within the ISO system on a Day-Ahead or Hour-Ahead basis, and then sold back into the ISO system in real time (through either a sale in the ISO Real Time Market or an out-of-market sale). Specifically, the analysis calculates this based on the lesser of ²⁴:

- (a) the net quantity exported from the ISO control area to the Northwest or Southwest, either through purchases in the PX Day-Ahead Market or through the non-PX portion of the SC's portfolio (physical resources or inter-sc trades); and
- (b) the quantity imported into the ISO control area in real-time to the Northwest or Southwest, either through the Imbalance Energy market, or balancing Energy and ex post price ("BEEP") stack, or through out-of-market procurement.

This analysis is performed on a zonal/regional level for each SC to account for the physical constraints associated with moving electricity from the Southwest to the Northwest (or *vice versa*) outside the California ISO control area. For example, potential "Ricochets" from the Southwest are calculated by comparing net exports from the ISO's southern zone (SP15) to control areas bordering the ISO in the Southwest to real time imports to the ISO system from the Southwest. Similarly, potential "Ricochets" from the Northwest are calculated by comparing net exports from the ISO northern zone (NP15) and NOB (the only transmission line connecting SP15 with the Northwest), to real time imports back into the ISO system from the Northwest.

²⁴ Specifically, the Energy that can be shifted between these forward and real time markets, or 'laundered', is calculated using the following formula:

MW = Minimum(BEEP_Import + OOM_Import, PX_Net_Exports + Other_Net_Exports).

Results

The results of this analysis are summarized in Table 10, which depicts the total MWs imported as real time Energy that may have been exported in Day-Ahead/Hour-Ahead Schedules by this same SC.

It should be noted that this includes no economic analysis of potential profits from "Ricochet" sales. Analysis of revenues earned from "Ricochet" Schedules could not be completed due to the limited time and data available to DMA. For instance, another way in which Market Participants benefited from ricochet schedules was to collect counterflow revenues for exports scheduled in the Day-Ahead or Hour-Ahead Market when Congestion existed in the import direction. In addition, as previously noted in this report, ricochet Schedules also represent a means of withholding supply from the forward markets (such as the PX Day-Ahead Market) and exercising market power in real time. To the extent that ricochet Schedules were employed to spike prices in California's wholesale markets during one time period, these strategies would have also increased prices in future time periods by increasing the expectation of higher prices. The analyses in this report clearly do not incorporate the overall costs and profits associated with such broader market impacts.²⁵

**Table 10. Potential Real Time Energy Imports
Exported in Day-Ahead/Hour-Ahead Schedules (MW)**

ID	Name	Jan 1, 2000 - Oct 1, 2000	Oct 2, 2000 - June 21, 2001	Total (MW)
PSE	Puget Sound Energy	140,304	148,479	288,783
PAC	PacificCorp	132,393	35,537	167,930
APS	Arizona Public Service Company	97,239	12,944	110,183
BCHA	British Columbia Power Exchange Corporation	40,748	58,648	99,396
EESI	Enron Energy Services Inc.	25,388	23,232	48,620
SETC	Sempra Energy Trading Corporation	34,738	6,865	41,603
IPC	Idaho Power Company	0	36,681	36,681
BPA	Bonneville Power Administration	15,879	6,828	22,707
AVEI	Avista Energy Inc	3,592	16,184	19,777
AQPC	Aquila Power Corporation	15,357	0	15,357
SRVP	Salt River Project	8,648	1,858	10,506
LDWP	Los Angeles Water and Power	1,975	7,882	9,857
PGE	Portland General Electric	5,406	4,368	9,775
PSNM	Public Service Company of New Mexico	2,427	25	2,452
WESC	Williams Energy Services Corporation	520	1,380	1,900
GLEN	City of Glendale	0	1,388	1,388
DETM	Duke Energy Trading and Marketing, L.L.C.	0	1,350	1,350
SCEM	Southern Company Energy Marketing, L.P.	673	328	1,001

²⁵ The summary results presented in Table 10 represent only those Market Participants who showed potential real-time imports from forward export schedules that exceeded 1,000 MW in sum across both time periods.

VI. Scheduling Energy to Collect Congestion Charges ("Cut Counter flows")

A more general type of scheduling practice described in the Enron memos is where SCs submit schedules in the Day-Ahead and/or Hour-Ahead Congestion Markets, providing counter-flows on a congested path. These Schedules receive Congestion charges, which are ultimately paid by SCs with Schedules in the congested direction, as counter-flow revenue in the Day-Ahead and/or Hour-Ahead Congestion Markets. Under current ISO scheduling and settlement practices, SCs may subsequently cut the counter-flow Schedules just prior to real-time, but still receive the counter-flow revenues for Schedules submitted in the Day-Ahead and/or Hour-Ahead Congestion Markets.

This creates a gaming opportunity, in that SCs may earn Congestion revenues for counterflow schedules in the Day-Ahead and Hour-Ahead Markets, and then cancel these Schedules prior to real time. The practice of cutting non-firm Schedules was proscribed by the ISO on July 21, 2000 in accordance with the Market Monitoring and Information Protocol Section of the ISO Tariff and does not appear to have occurred since that time. However, a similar gaming opportunity continued to exist insofar as the same basic strategy could be employed by cutting wheel-through Schedules and/or firm Energy Schedules.

Not all counterflow Schedules cut in real time represent gaming. Wheel through Schedules, for instance, may be cancelled if the SC is unable to procure Generation and/or transmission to deliver the "import" leg of a wheel through in the ISO system. Similarly, an outage within the ISO system may decrease the overall supply of Energy within an SC's portfolio, and require the cutting of an export Schedule in order to avoid an imbalance in the SC's supply and Demand Schedules. In some cases, the ISO may need to curtail an export due to a de-rate on a tie-line occurring after the Hour-Ahead Congestion Management market has ended.²⁶ However, the logged reason each counterflow Schedule is cut in real time is typically not sufficient to determine the precise reason for the cut, and whether the cut could be due to gaming or not.

Methodology

Total Congestion revenues paid for counterflow Schedules that were cut prior to real time were assessed based on real time Schedule changes made after the Hour-Ahead Market as recorded in the BITS database (used to track any import/export changes made after the close of the Hour-Ahead Market). The analysis included all counterflow Schedules that earned Congestion revenues in the Day-Ahead or Hour-Ahead Markets where the final real time Schedule was less than the final Hour-Ahead Schedule. However, Schedules that were cut due to tie-points being out of service were analyzed separately (see section on "Wheel Out" gaming strategy), and were therefore not included in this analysis.

²⁶ However, when de-rates occur, the ISO would typically not cut a Schedule that is providing a counterflow on a tie-line, since this would exacerbate Congestion on the de-rated path.

Since Hour-Ahead Schedules may only be partially cut, and may represent a combination of Day-Ahead and Hour-Ahead Congestion revenues, the following two equations were used to calculate the amount of Congestion revenues paid for schedules that were cut in real time.

If the Hour-Ahead Schedule was equal to the Day-Ahead Schedule (so that the SC only earned counterflow revenues in the Day-Ahead Market), the following equation was used:

$$\text{Counterflow Payment} = (MW_{DA} - MW_{RT}) \times CC_{DA}$$

If the Hour-Ahead Schedule was greater than the Day-Ahead schedule (so that the SC may have earned counterflow revenues in both the Day-Ahead and Hour-Ahead markets), the following equation was used:

$$\text{Counterflow Payment} = (MW_{DA} - MW_{RT}) \times CC_{DA} + (MW_{HA} - MW_{DA}) \times CC_{HA}$$

Finally, if the Hour-Ahead Schedule was less than the Day-Ahead schedule (and was subject to the Hour-Ahead Congestion charge for the reduction in its counterflow schedule), the following equation was used:

$$\text{Counterflow Payment} = (MW_{HA} - MW_{RT}) \times CC_{HA}$$

Where:

MW_{DA} is the final scheduled MW after the Day-Ahead Congestion Market
 MW_{HA} is the final scheduled MW after the Hour-Ahead Congestion Market
 MW_{RT} is the final scheduled MW after the real time checkout process
 CC_{DA} is the Day-Ahead Congestion charge (or credit), and
 CC_{HA} is the Hour-Ahead Congestion charge (or credit).

DMA also reviewed ISO operating logs for indications of whether each Schedule cut was made by the ISO due to an outage on a tie-point or by the SC for some other reason. Cases where operating logs indicated that the ISO cut the Schedule were screened from the results.

Cut Schedules earning less than \$10 in counter flow revenues or less than 1 MW were also excluded from the analysis.

Cut Schedules from Market Participants that provided satisfactory and verifiable explanations for cut Schedules were also removed from the analysis.

Results

Table 11 summarizes the results of this analysis for each SC for the period from January 2000 through June 2001. As shown in Table 11, total Congestion revenues paid for counter flow schedules that were cut in real time identified in this analysis totaled just over \$1.4 million over this 18-month period. .

Table 11: Counter-flow Revenues from Cut Schedules Compared by SC

ID	Company	pre Refund	Refund	Total
MSCG	Morgan Stanley Capital Group		\$633,415	\$633,415
SETC	Sempra Energy Trading Corporation	\$201,671	\$198,319	\$399,990
CRLP	Coral Power, LLC	\$17,356	\$95,470	\$112,826
EPMI	Enron Energy Services, Inc.	\$72,070	\$7,428	\$79,497
PWRX	British Columbia Power Exchange/Powerex	\$28,777	\$17,495	\$46,273
AEPS	American Electric Power Service Corp	\$45,240		\$45,240
DETM	Duke Energy Trading and Marketing, L.L.C.		\$41,701	\$41,701
SCEM	Southern Company Energy Marketing, L.P.		\$20,273	\$20,273
PSE1	Puget Sound Energy	\$17,044	\$48	\$17,092
ECH1	Dynegy Power Marketing Inc.	\$14,980		\$14,980
PORT	Portland General Electric	\$1,440	\$11,257	\$12,698
CALP	Calpine Corporation		\$4,376	\$4,376
EPPS	El Paso Power Services Company		\$4,084	\$4,084
MID1	Modesto Irrigation District	\$2,150		\$2,150
IPC	Idaho Power Company		\$2,060	\$2,060
TEMU	TransAlta Energy Marketing (US)		\$1,801	\$1,801
WESC	Williams Energy Services Corporation	\$609		\$609
Total		\$401,337	\$1,037,728	\$1,439,065

EXHIBIT NO. ISO-5 –
PROVIDED IN CD-ROM FORMAT AND LABELED AS
PROTECTED MATERIALS,
NOT AVAILABLE TO COMPETITIVE
DUTY PERSONNEL

EXHIBIT NO. ISO-6 –
PROVIDED IN CD-ROM FORMAT AND LABELED AS
PROTECTED MATERIALS,
NOT AVAILABLE TO COMPETITIVE
DUTY PERSONNEL

EXHIBIT NO. ISO-7

**California Independent System Operator Corporation
Technical Supplement to Source Data
Provided Pursuant to the June 25, 2003 FERC Orders
to Show Cause Concerning Gaming and/or Anomalous Market Behavior,
Docket Nos. EL03-137-000, et al., and EL03-180-000, et al**

July 15, 2003

On June 25, 2003, the Federal Energy Regulatory Commission ("FERC") issued two Orders to Show Cause Concerning Gaming And/Or Anomalous Market Behavior in Docket Nos. EL03-137-000, et al., and EL03-180-000, et al. Pursuant to those Orders, and the Notice of Extension of Time issued on July 11, 2003 in Docket Nos. EL03-180-000, et al, the California Independent System Operator Corporation ("ISO") is providing to the Identified Entities all of the specific transaction data for each of the Gaming Practices discussed in the ISO Report, including an explanation of the screen that it used to identify the transactions in question.

This document complies with FERC's directive and provides a guide for locating and assembling the source data underlying the ISO's analysis of Enron-style trading and scheduling practices so that Market Participants¹ named in the June 25 FERC Order can respond and perform their own analysis using data reflecting their transactions. The methodology, "screens", and selected summary results of the ISO's analysis have been previously provided in the ISO's report titled "Supplemental Analysis of Trading and Scheduling Strategies Described in Enron Memos" released in June 2003 ("ISO's June Report"). The source data and work files associated with the ISO's June Report are being provided on two CDs included with this document. Attachment A to this document provides a listing of all source data and work files being provided with this document, and identifies the specific CD and directory in which each of these source data and work files can be found. Attachment B provides a listing and explanation of each field in each of these files.

I. Overscheduling Load

A detailed description of the methodology, data and screens used in the ISO's analysis of this strategy, is provided on pages 5 through 14 of the ISO's June Report. Attachments to this supplemental document provide detailed descriptions of the data contained in the source and work files associated with the ISO's analysis of overscheduling load.

II. Circular Schedules

A detailed description of the ISO's analysis of this strategy is provided on pages 15 through 17 of the ISO's June Report. The files "CF_Field Descriptions.xls" and "Death

¹ Capitalized terms that are not defined herein are used in the sense given in the master Definitions Supplement, Appendix A to the ISO Tariff.

Star Field Descriptions.xls" provide a more detailed description of the data contained in the source and work files associated with the ISO's analysis of circular schedules. All Interchange Schedule details are contained in the *I_interchange_sch* table, including initial (pre-Congestion Management) and final MW values, import/export indicators, Energy type of the Schedule, and tie point.

MW values for Schedules after the close of the Hour-Ahead market are contained in two places:

- For the pre-September 2000 period, information is contained within the *I_interchange_sch* table as mkt_type "R" records. In the absence of an "R" record, the Schedule was left unchanged after the close of the Hour-Ahead Market. If an "R" record exists with a non-zero hrly_mw value, then the Schedule was changed after the close of the Hour-Ahead Market to the fin_mw value.
- Starting September 1, 2000, the MW values for all Schedules after the close of the Hour-Ahead Market are contained in the *CAL_ISO_4_HAM_Sch* tables. In the absence of a record in the *HAM_Sch* tables corresponding to a non-zero final Hour-Ahead Schedule, the Schedule is deemed to have been cut after the Hour-Ahead Market.

For identification of Schedules using Existing Contracts ("ETCs") information is contained in the *Source_sink_interchg* table. The hrly_mw value in the *Source_sink_interchg_etc* table contains the total amount of the ETC reservation for the Schedule.

Interchange Schedules can be linked to the ISO internal zone, external zone, branch group, and geographical region by the *Bg_tp_zn_cz_region* table.

Branch group Congestion prices are contained in the *Cong_prc* tables, with a positive final flow value indicating scheduled flows in the import direction and a negative value indicating scheduled flows in the export direction. Note that for Path 15 and Path 26, the import direction is from south to north.

III. Ancillary Service Buy-back

A detailed description of the ISO's analysis of this strategy is provided on page 18 of the ISO's June Report. The files "A/S Buy-back Field Descriptions.xls" and "Buy-back Field Descriptions.xls" provide a more detailed description of the data contained in the source and work files associated with the ISO's analysis of this practice.

All pairs of Day-Ahead/Hour-Ahead Schedules where a buy-back occurred are provided in the table *as_price_quantity*. This table contains final Day-Ahead and Hour-Ahead quantities of Ancillary Services procured as well as the Market Clearing Price. All data needed to calculate gains from the buy-back practice are provided in this table.

As noted in footnote 20 of the ISO's June Report, three screens were used to filter out sellback transactions.

- 1) If all Day-Ahead A/S Schedules on a specific branch group were curtailed in the Hour-Ahead Market (and there was more than one Day-Ahead A/S Schedule on that branch group), then all sellbacks of resources on that branch group during that hour were screened from the analysis. This screen was designed to filter out cases in which A/S Schedules over inter-ties may have been curtailed due to limits on imports of A/S imposed by the ISO.
- 2) If there were multiple sellbacks on the same branch group with the same percent of capacity purchased back in the Hour-Ahead Market from each A/S Schedule on that branch group, then all sellbacks of resources on that branch group during that hour were screened from the analysis. This screen was designed to filter out cases in which A/S Schedules over inter-ties may have been curtailed due to limits on imports of A/S imposed by the ISO.
- 3) If the quantity of the Hour-Ahead sell-back for an individual A/S Schedule did not exceed 1% of the original Day-Ahead procurement (for each A/S resource Schedule, not the entire A/S portfolio of the Scheduling Coordinator ("SC")), then the Schedules with this sell-back were screened from the analysis. This screen was designed to filter out minor reductions in Day-Ahead A/S Schedules that may appear in Hour-Ahead Market data for several reasons, such as rounding by the market software.

Provided below is a summary of additional information needed to replicate these screens.

- The table *cal_iso_4_imp_sch2*, found in the Source Data folder to the MW Laundering/Ricochet strategy provides all A/S Schedules across the ties. This table can be used in the calculation of filters (1) and (2) described above.
- The table *bg_to_tp* is included to allow mapping of A/S purchases across inter-ties to their corresponding branch group (using the *tie_point* field to link tables).
- No additional information is required to employ the third filter ($\leq 1\%$) described above.

Note that if the table *cal_iso_1_as* from the 100-day discovery proceeding is used, the MW and bid price values for Non-spinning Reserve in that table are incorrect and must be replaced with the corresponding values from the *cal_iso_4_gen_sch2* and *cal_iso_4_imp_sch2* tables, also from the 100-day discovery proceeding.

IV. Wheel Out

A detailed description of the ISO's analysis of this strategy is provided on pages 21 through 23 of the ISO's June Report.

Calculations for the "Wheel Out" strategy used the same source data as the circular Scheduling strategy, with particular attention paid to the change in the MW value of the Import/export Schedule after the close of the Hour-Ahead Market. Thus, field descriptions of various files provided under the circular scheduling strategy provide a more detailed description of the data contained in the source and work files associated with the ISO's analysis of the "Wheel Out" strategy.

Calculations of Congestion charges for each Schedule were performed in the same fashion as with circular scheduling. A preliminary screen to determine whether a tie-point was derated to zero in all of the markets was created by calculating the sum of the MW values of all interchange Schedules on each tie point. Results of the zero-rated path determination are provided in the *ZeroRatedpaths_00_02.xls* spreadsheet. If the sum of all interchange Schedules on each tie point was between -0.05 and 0.05, then the tie was further checked in the Scheduling and Logging for ISO California ("SLIC") database to determine if the tie was, in fact, out of service or under a full scheduling limitation. Results of that check are contained within the working file *WheelOut_FERCWorksheet.xls*.

The file *WheelOut_FieldDescriptions.xls* and field descriptions provided under the Circular Schedules strategy provides a more detailed description of the data contained in the source and work files.

V. Ricochet/Megawatt Laundering

A detailed description of the ISO's analysis of this strategy is provided on pages 21 through 23 of the ISO's June Report.² As noted in previous ISO reports, the ISO interprets the terms "ricochet schedules" and "megawatt laundering" as referring to a variety of scheduling and trading practices. The ISO's June Report included summary results for only one general form of these scheduling/trading practices. In addition, as noted in previous ISO reports, the ISO's analysis does not include "megawatt laundering" that may have occurred by exporting and importing by two different entity identifications.³

² Results provided with this document reflect the following changes in the methodology described in the ISO's June Report. (1) Rather than restricting analysis of the potential "overlap" between exports and imports by each SC to a regional level (i.e., the Southwest and Northwest), this analysis is based on total export/imports between the ISO Controlled Grid and neighboring Control Areas. This refinement was made to ensure that results included potential "ricochet" and "MW laundering" that involved transfers of Energy exported from the ISO Controlled Grid between different Control Areas or regions (such as from the Southwest to the Northwest using transmission of Los Angeles Department of Water and Power) prior to being re-imported to the ISO. (2) The analysis in the ISO's June Report was also corrected to include real time imports made by entities through the California Power Exchange Corporation ("PX") as an SC, which were significant for several entities, such as British Columbia Power Exchange Corporation. (3) Entities with minimal levels of total potential overlap between exports and real time imports (< 5,000 MWh) were screened out of the analysis.

³ For example, the ISO's analysis would not generally capture cases in which one entity exported Energy under its PX or ISO participant identifier, and another entity imported Energy in real time under a different PX or ISO participant identifier. The one exception to this is the analysis which includes OOM

- Data and work files being provided with this document include source data, work files and summary results that may be used to assess a variety of different scheduling/trading practices in the general category of "ricochet schedules" and "megawatt laundering". Figures 1 through 3 summarize results of three such scheduling/trading practices within the ISO's understanding of the general category of "ricochet schedules" and "megawatt laundering". Figure 1 shows summary results of all potential overlap between Day-Ahead/Hour-Ahead exports from ISO Controlled Grid and real time imports based on the basic methodology described in the ISO June Report.
- Figure 2 shows results for the same analysis, expanded to include real time imports made by entities through Out-Of-Market ("OOM") sales to CERS.
- Figure 3 shows summary results of potential overlap between Day-Ahead/Hour-Ahead exports from the ISO Controlled Grid and OOM sales of real time Energy directly to the ISO at prices in excess of the \$750/\$500/\$250 "hard caps" that were in effect until December 2000.

import sales through California Energy Resources Scheduling ("CERS"), which the ISO is generally able to track back to the entity selling the energy through CERS.

Table 1. Potential Real Time Energy Imports Exported in Day-Ahead/Hour-Ahead Schedules (MW)
(Excludes OOM Imports through CERS)

ID	Company Name	Jan - Apr 2000	May - Oct 1, 2000	Oct 2, 2000 - Jun 21, 2001	Total
BCHA	British Columbia Power Exchange Corporation	0	140,543	147,116	287,659
PSE	Puget Sound Energy	0	139,196	136,854	275,052
PAC	PacificCorp	0	206,101	32,894	238,995
APS	Arizona Public Service Company	0	97,078	14,144	111,222
IPC	Idaho Power Company	0	51,507	40,070	91,578
EEBI	Enron Energy Services, Inc.	1	35,980	4,863	40,844
PGE	Portland General Electric	0	15,285	11,152	26,437
SETC	Sempra Energy Trading Corporation	86	21,781	3,923	25,790
AVEI	Avista Energy Inc	0	11,082	14,041	25,124
BPA	Bonneville Power Administration	0	15,879	6,828	22,707
WEBC	Williams Energy Services Corporation	50	1,241	21,080	22,371
AQPC	Aquila Power Corporation	2,105	18,084	0	18,189
LDWP	Los Angeles Water and Power	0	3,099	8,071	11,140
SRVP	Salt River Project	0	8,848	1,858	10,706
PSNM	Public Service Company of New Mexico	0	6,594	628	7,221

Table 2. Potential Real Time Energy Imports Exported in Day-Ahead/Hour-Ahead Schedules (MW)
(Includes OOM Imports through CERS)

ID	Company Name	Jan - Apr 2000	May - Oct 1, 2000	Oct 2, 2000 - Jun	Total
BCHA	British Columbia Power Exchange Corporation	0	140,543	21,280	565,155
PSE	Puget Sound Energy	0	139,198	414,811	278,052
PAC	PacificCorp	0	208,101	135,854	239,210
WEBC	Williams Energy Services Corporation	50	1,241	33,108	195,440
APS	Arizona Public Service Company	0	97,078	184,148	151,878
IPC	Idaho Power Company	0	51,507	34,801	91,578
EESI	Enron Energy Services, Inc.	1	35,980	4,993	40,954
SETC	Sempra Energy Trading Corporation	88	21,781	16,280	38,117
AVEI	Avista Energy Inc	0	11,082	15,377	28,459
PGE	Portland General Electric	0	15,285	11,182	26,437
BPA	Bonneville Power Administration	0	15,879	6,828	22,707
AQPC	Aquila Power Corporation	2,105	16,084	0	18,189
LDWP	Los Angeles Water and Power	0	3,089	8,303	11,432
SRVP	Salt River Project	0	8,848	1,858	10,506
PSNM	Public Service Company of New Mexico	0	6,594	628	7,221
SCEM	Southern Company Energy Marketing, L.P.	0	1,375	4,082	5,457

**Table 3. Potential OOM Energy Imports at Prices Over ISO "Hard Cap"
 Exported in Day-Ahead/Hour-Ahead Schedules (MW)
 (Through December 8, 2000)**

ID	Company Name	Jan - Apr 2000	May - Oct 1, 2000	Oct 2 - Dec. 8, 2000	Total
BCHA	British Columbia Power Exchange Corporation	0	0	40,401	40,401
PSE	Puget Sound Energy	0	0	10,906	10,906
PAC	PacificCorp	0	0	5,071	5,071
AVEI	Avista Energy Inc	0	0	2,991	2,991
LDWP	Los Angeles Water and Power	0	300	2,359	2,659
PGE	Portland General Electric	0	0	1,368	1,368
IPC	Kahlo Power Company	0	0	1,214	1,214
SRVP	Salt River Project	0	0	848	848
APS	Arizona Public Service Company	0	300	524	824
DETM	Duke Energy Trading and Marketing, L.L.C.	0	0	120	120
PSNM	Public Service Company of New Mexico	0	0	25	25
EESE	Enron Energy Services, Inc.	0	0	5	5

As indicated in the ISO's June Report, the two key sources of data used in the ISO's analysis of the Megawatt Laundering/Ricochet strategy are net exports from the ISO Control Area and real-time imports into the ISO Control Area. Provided below is a detailed description of how the source of these data being provided with this document can be utilized to replicate the ISO's analysis:

- **Net Exports from the ISO Control Area:** The *px_trans* table can be used to construct the Day-Ahead imports to and exports from the ISO Control Area through the PX Day-Ahead Market. The table *px_mat_eff* allows mapping of PX affiliate ID's to ISO affiliate ID's. Use records where the *resource_type* field is equal to 'Export' and 'Import'. For net exports from the ISO Control Area not through the PX, use the fields *l_ha_mw* and *e_ha_mw* from the *cal_iso_4_imp_sch2* table. The tables *ma_bg_to_region* and *bg_to_tp* can be used to identify the location of the import or export.
- **Real-time Imports into the ISO Control Area - BEEP:** Real-time Energy imports through the ISO Real-Time Market are taken from the *bp_se*, *bp_sp*, *bp_ns*, and *bp_rp* fields from the *cal_iso_4_imp_sch2* table. The ISO affiliate identification can be recovered from records in this table that show Energy procured from the PX by extracting the PX affiliate identification from the *interchg_id* field and converting it to an ISO affiliate identification using the *px_mat_eff* table.
- **Real-time Imports into the ISO Control Area - OOM:** Imports through OOM purchases made by the ISO are taken from the *iso_oom* table. Imports through OOM purchases made by CERS are taken from the *cers_oom_data* table. The *interchg_id* field from the *iso_oom* and *cers_oom_data* tables and the *sc_id_mat_eff* table will aid in identifying the ISO master affiliate identification for records in these tables where that identification is not already complete.

Additional tables with source data are included to provide prices and other portfolio information that may be relevant in determining whether the Megawatt Laundering/Ricochet strategy was employed.

The files "MW Laundering Field Descriptions.xls", "MWL_Field Descriptions.xls", and "Field Descriptions.xls" provide a more detailed description of the data contained in the source and work files.

VI. Cut Counterflow

A detailed description of the ISO's analysis of this strategy is provided on pages 26 through 28 of the ISO's June Report.

As with analysis of the Wheel Out strategy, calculations for the Cut Counterflow Schedules strategy used the same data as the Circular Schedules strategy. Particular emphasis was placed on the Schedule changes after the close of the Hour-Ahead Market. Schedules that were determined to have been reduced after the close

of the Hour-Ahead Market and were originally scheduled in a direction against Congestion (e.g., counterflow) were subsequently screened through the ISO's SLIC database to determine whether the ISO initiated the curtailment for reliability reasons, the SC cut the Schedule due to procurement difficulties, or the Schedule was reduced for other reasons.

The cut counterflow Schedules and results from the SLIC screen are kept in the CutCounterflows_FERCworksheet.xls worksheet. The file entitled "CutSchedules_FieldDescriptions.xls" and field descriptions provided under the Circular Schedules strategy provide a more detailed description of the data contained in the source and work files.

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Technical Supplement - Attachment A

Directory of Source Data and Working Files Provided on Disk 1 and Disk 2

Directory of Source Data and Working Files Provided on DISK 1 and DISK 2

DISK 1

Directory of Disk 1\Ancillary Service Buy-back - Get Shorty\Source Data

BG to TP.csv	Branch Group - Tie Point Mapping Table
(see also AS Buy-back Data and Tables.xls).txt	Place-holder and note
Buy-back Field Descriptions.xls	Field Description Tables
AS_Price_Quantity.csv	Ancillary Service Price/Quantity Table

Directory of Disk 1\Ancillary Service Buy-back - Get Shorty\Work Files

AS Buy-back Data and Tables.xls	Summary tables and supporting work file data
AS Buy-back Field Descriptions.xls	Field descriptions for work file

Directory of Disk 1\Circular Schedules - Death Star\Source Data

BG_REGION_ZONE.csv	Branch Group - Region - Zone Mapping Table
BG_TO_TP.csv	Branch Group - Tie Point Mapping Table
BG_TP_SW_CK_REGION.csv	Branch Group-Tie Point-Region-Zone Table
CAL_ISO_4_HAM_Sch_00Q3.zip	Real-time schedule Data, 2000 Q3 after 9/1/00
CAL_ISO_4_HAM_Sch_00Q4.zip	Real-time schedule Data, 2000 Q4
CAL_ISO_4_HAM_Sch_01Q1.zip	Real-time schedule Data, 2001 Q1
CAL_ISO_4_HAM_Sch_01Q2.zip	Real-time schedule Data, 2001 Q2
Circular Schedule Field Descriptions.xls	Field Description Tables
CONG_PRC.zip	Congestion Prices
CONTRACTS IN USAGES ETC.zip	Existing Rights Encumbrances by Branch Group
I_INTERCHANGE_SCH_2000Q1.zip	Day-Ahead, Hour-Ahead, and Real-time schedules 00Q1
I_INTERCHANGE_SCH_2000Q2.zip	Day-Ahead, Hour-Ahead, and Real-time schedules 00Q2
I_INTERCHANGE_SCH_2000Q3.zip	Day-Ahead, Hour-Ahead, and Real-time schedules 00Q3
I_INTERCHANGE_SCH_2000Q4.zip	Day-Ahead and Hour-Ahead schedules 2000 Q4
I_INTERCHANGE_SCH_2001Q1.zip	Day-Ahead and Hour-Ahead schedules 2001 Q1
I_INTERCHANGE_SCH_2001Q2.zip	Day-Ahead and Hour-Ahead schedules 2001 Q2
SC_ID_MST_AFF.csv	Scheduling Coordinator-Holding Affiliate Mapping
SOURCE_SIDE_INTERCHG_ETC.zip	Existing Rights Interchange Scheduling

Directory of Disk 1\Circular Schedules - Death Star\Work Files

Death Star Period Gains by SC.xls
Counterflow Gains 00-01.xls
Death Star Field Descriptions.xls
Death Star Data.xls
CF_Field Descriptions.xls
Counterflow_Gains_summary.xls

Death Star Gains by period, SC
Counterflow Congestion revenues
Death Star Data Field Descriptions
Suspected Circular Counterflow schedules
Counterflow Gains Field Descriptions
Counterflow Gains Summary

Directory of Disk 1\CutCounterflows\Source Data

See Circular Schedules for Source Data.txt

Directory of Disk 1\CutCounterflows\Work Files

CutSchedules_FieldDescriptions.xls
Counterflow Non-firm Gains_Euron.xls
CutCounterflows_FERCWorksheet.xls
Cut_Schedules_fina_alloes1.xls

Cut counterflows (FERC Worksheet) Field Description
Euron Non-firm gains
Cut Counterflow schedules
Cut Counterflow schedules (intermediate worksheet)

Directory of Disk 1\NW Laundering - Niccohet\Source Data

BG TO TP.xls
BNEP_STACK_IMP.sip
CAL_ISO_4_Gen_Sch2_00Q1.sip
CAL_ISO_4_Gen_Sch2_00Q2.sip
CAL_ISO_4_Gen_Sch2_00Q3.sip
CAL_ISO_4_Gen_Sch2_00Q4.sip
CAL_ISO_4_Gen_Sch2_01Q1.sip
CAL_ISO_4_Gen_Sch2_01Q2.sip
CAL_ISO_4_Impr_Sch2_00Q1.sip
CAL_ISO_4_Impr_Sch2_00Q2.sip
CAL_ISO_4_Impr_Sch2_00Q3.sip
CAL_ISO_4_Impr_Sch2_00Q4.sip
CAL_ISO_4_Impr_Sch2_01Q1.sip
CAL_ISO_4_Impr_Sch2_01Q2.sip
CAL_ISO_SUPP_INTERNL_INTERCHG_00Q1.sip
CAL_ISO_SUPP_INTERNL_INTERCHG_00Q2.sip
CAL_ISO_SUPP_INTERNL_INTERCHG_00Q3.sip
CAL_ISO_SUPP_INTERNL_INTERCHG_00Q4.sip
CAL_ISO_SUPP_INTER_SC_TRADES_00Q4.sip

Branch Group - Tie Point Mapping Table
Import bids from BNEP stack
Generation Schedules 2000 Q1
Generation Schedules 2000 Q2
Generation Schedules 2000 Q3
Generation Schedules 2000 Q4
Generation Schedules 2001 Q1
Generation Schedules 2001 Q2
Interchange Schedules 2000 Q1
Interchange Schedules 2000 Q2
Interchange Schedules 2000 Q3
Interchange Schedules 2000 Q4
Interchange Schedules 2001 Q1
Interchange Schedules 2001 Q2
Inter-SC trades 2000 Q1
Inter-SC trades 2000 Q2
Inter-SC trades 2000 Q3
Inter-SC trades 2000 Q4 before 11/10/2000
Inter-SC trades 2000 Q4 after 11/10/2000

CAL_ISO_SUPP_INTER_SC_TRADES_01Q1.zip
CAL_ISO_SUPP_INTER_SC_TRADES_01Q2.zip
CHRS_OOM_DATA.zip
Field Descriptions.xls
GEN_UNIT.zip
ISO_OOM.zip
ISO_PRC_1.zip
ISO_PRC_2.zip
ISO_Price_Cap.zip
IMP_UNIT.xls
MS_BO_TO_REGION.xls
MW Laundering Field Descriptions.xls
PX_Const_Price.zip
PX_MST_AFF.xls
PX_Trans.zip
PX_UNC_PRC.zip
SC_ID_MST_AFF.xls

Directory of Disk 1\MW Laundering - Ricochet\Work Files

Launder Data (10 Jul 2003).xls
MWL_Field Descriptions.xls
Potential Capacity Laundered (Rev 10 July 2003).xls

Directory of Disk 1\Wheel Out\Source Data

See Circular Schedules for Source Data.txt

Directory of Disk 1\Wheel Out\Work Files

WheelOut_FieldDescriptions.xls
Zero rated paths_00_02.xls
Zero rated paths_detm.xls
WheelOut_FERCWorksheet.xls

Inter-SC trades 2001 Q1
Inter-SC trades 2001 Q2
Data for CHRS OOM purchases
Field description for some tables
Generating unit information
Data for ISO OOM purchases
ISO incremental prices (up to 01-Sep-2000)
ISO incremental prices (01-Sep-2000 fwd)
Price caps
Import location information
Maps branch group to region
Field description for some tables
PX day-ahead constrained market price
Maps PX affiliate to ISO affiliate
PX day-ahead transactions
PX day-ahead unconstrained market price
Maps ISO SC_ID to master affiliate

Data used in summary tables
Field descriptions for Launder Data table
Summary tables for Megawatt Laundering

Wheel Out (FERC Worksheet) Field Descriptions
Zero rated paths, 2000-2002
DFTM schedules on 5/28/2000
Wheel Out (FERC Worksheet)

DISK 2

Directory of Disk 2\Load Overscheduling - Fat Boy\Source Data

bg_cs_zone_region.xls
 bg_tp_cs_zone_region.xls
 exp_mkt_info_00q1.zip
 exp_mkt_info_00q2.zip
 exp_mkt_info_00q3.zip
 generation_sch_00q1.zip
 generation_sch_00q2.zip
 generation_sch_00q3.zip
 generation_sch_00q4.zip
 generation_sch_01q1.zip
 generation_sch_01q2.zip
 i_interchange_sch_00q1.zip
 i_interchange_sch_00q2.zip
 i_interchange_sch_00q3.zip
 i_interchange_sch_00q4.zip
 i_interchange_sch_01q1.zip
 i_interchange_sch_01q2.zip
 load_exclusion_list.xls
 load_id_zone.xls
 Load Overscheduling Field Descriptions.xls
 load_sch_00q1.zip
 load_sch_00q2.zip
 load_sch_00q3.zip
 load_sch_00q4.zip
 load_sch_01q1.zip
 load_sch_01q2.zip
 rt_exp_mkt_info_00q3.zip
 rt_exp_mkt_info_00q4.zip
 rt_exp_mkt_info_01q1.zip
 rt_exp_mkt_info_01q2.zip
 ss_measurements_00q1.zip
 ss_measurements_00q2.zip
 ss_measurements_00q3.zip
 ss_10min_measurements_00q3.zip
 ss_10min_measurements_00q4.zip
 ss_10min_measurements_01q1.zip
 ss_10min_measurements_01q2.zip
 tie_gmw_00q1.zip

Branch group - zone - region mapping table
 Branch group-tie point-zone-region mapping table
 Hourly ex-post prices, 2000 Q1
 Hourly ex-post prices, 2000 Q2
 Hourly ex-post prices, 2000 Q3, until 9/1/2000
 Generation Schedules, 2000 Q1
 Generation Schedules, 2000 Q2
 Generation Schedules, 2000 Q3
 Generation Schedules, 2000 Q4
 Generation Schedules, 2001 Q1
 Generation Schedules, 2001 Q2
 Interchange Schedules, 2000 Q1
 Interchange Schedules, 2000 Q2
 Interchange Schedules, 2000 Q3
 Interchange Schedules, 2000 Q4
 Interchange Schedules, 2001 Q1
 Interchange Schedules, 2002 Q1
 Load ID exclusion list (for curtailable load)
 Load ID - congestion zone mapping
 Field Descriptions
 Load Schedules, 2000 Q1
 Load Schedules, 2000 Q2
 Load Schedules, 2000 Q3
 Load Schedules, 2000 Q4
 Load Schedules, 2001 Q1
 Load Schedules, 2001 Q2
 10-minute imbalance energy prices, 2000 Q3
 10-minute imbalance energy prices, 2000 Q4
 10-minute imbalance energy prices, 2001 Q1
 10-minute imbalance energy prices, 2001 Q2
 Hourly resource meter readings, 2000 Q1
 Hourly resource meter readings, 2000 Q2
 Hourly resource meter readings, 2000 Q3
 10-minute resource meter readings, 2000 Q3
 10-minute resource meter readings, 2000 Q4
 10-minute resource meter readings, 2001 Q1
 10-minute resource meter readings, 2001 Q2
 Tie Meter Multipliers, 2000 Q1

tie_gen_00q2.sip
tie_gen_00q3.sip
tie_gen_00q4.sip
tie_gen_01q1.sip
tie_gen_01q2.sip
udg_gen_ids.xls
udg_load_ids.xls
unit_gen_00q1.sip
unit_gen_00q2.sip
unit_gen_00q3.sip
unit_gen_00q4.sip
unit_gen_01q1.sip
unit_gen_01q2.sip

Tie Meter Multiplier, 2000 Q2
Tie Meter Multiplier, 2000 Q3
Tie Meter Multiplier, 2000 Q4
Tie Meter Multiplier, 2001 Q1
Tie Meter Multiplier, 2001 Q2
UDC Generation ID mapping (for PZ period)
UDC Load ID mapping (for PZ period)
Generation Meter Multiplier, 2000 Q1
Generation Meter Multiplier, 2000 Q2
Generation Meter Multiplier, 2000 Q3
Generation Meter Multiplier, 2000 Q4
Generation Meter Multiplier, 2001 Q1
Generation Meter Multiplier, 2001 Q2

Directory of Disk 2\Load Overscheduling - Fat Boy\work files

LO Field Descriptions.xls

Load Overscheduling Tables.xls

load_sc_system_00q1.sip
load_sc_system_00q2.sip
load_sc_system_00q3.sip
load_sc_system_00q4.sip
load_sc_system_01q1.sip
load_sc_system_01q2.sip

Aggregated SC Systemside Load Field Description Summary Tables

Aggregated SC Systemside Load, 2000 Q1
Aggregated SC Systemside Load, 2000 Q2
Aggregated SC Systemside Load, 2000 Q3
Aggregated SC Systemside Load, 2000 Q4
Aggregated SC Systemside Load, 2001 Q1
Aggregated SC Systemside Load, 2001 Q2

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Technical Supplement - Attachment B

**Field Descriptions for Tables Provided on Disk 1 and Disk 2
that Contain Source Data**

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**Ancillary Service Buy-back,
A/k/a "Get Shorty"**

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Field Name	Description
OPR_DT	Operation date.
OPR_HR	Operation hour.
SC_ID	Schedule Coordinator Identification.
MST_AFF	Master Business Affiliate.
UNIT_ID	Unit Identification.
TIE_POINT	The point Identification.
INTERCHG_ID	Interchange Identification.
MKT_TYPE	Market type (D=DA and H=HA).
AS_TYPE	Ancillary service type.
FIN_MW	Final procured MW.
BID_PRC	Bid price.
MCP	Market clearing price.

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Field Name	Description
BRANCH_GRP	Branch Group of which Tie Point is a part of
TIE_POINT	Tie Point

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Field Name	Field Description
year_month	Operating month (YYYY.MM)
OPR_DT	Operating date
OPR_HR	Operating hour
MST_AFF	Master affiliate identification
SC_ID	Scheduling coordinator identification
UNIT_ID	Unit identification
TIE_POINT	The point identification
INTERCHG_ID	Interchange identification (for A/S capacity scheduled across external tie points)
AS_TYPE	Ancillary service type (restricted to Spin (SP), Non-spin (NS), and Replacement (RP) Reserve)
da_fin_mw	Final MW procured in the day-ahead market
da_price	Market clearing price in the day-ahead market
da_fin_cost	Cost of final MW procured in the day-ahead market ($da_fin_mw * da_price$)
ha_fin_mw	Final MW procured in the hour-ahead market (< 0 indicates A/S buy-back)
ha_price	Market clearing price in the hour-ahead market
ha_fin_cost	Cost of final MW procured in the hour-ahead market ($ha_fin_mw * ha_price$)
fin_mw	Net final MW procured ($da_fin_mw + ha_fin_mw$)
fin_cost	Net cost of final MW procured ($da_fin_cost + ha_fin_cost$)
gains	Gains from the A/S buyback strategy (formula)
losses	Losses from the A/S buyback strategy (formula)

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**Circular Schedules,
A/k/a "Death Star"**

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Field Name	Description
BRANCH_GRP	Branch Group
REGION_2	External region branch group connects to
ZONE_ID	Internal ISO congestion zone branch group injects into

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Field Name	Description
BRANCH_GRP	Branch Group of which Tie Point is a part of
TIE_POINT	Tie Point

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Field Name	Description
BRANCH_GRP	Branch Group
ZONE	Internal ISO congestion zone branch group injects into
CZ	External Congestion zone branch group connects to
REGION	External region branch group connects to
TIE_POINT	The Point

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Field Name	Description
OPR_DT	Operation date.
OPR_HR	Operation hour.
SC_ID	Scheduling coordinator identification.
IE_TYPE	'I' = Import, 'E' = export.
BRANCH_GRP	Branch group identification.
TIE_POINT	Tie point.
INTERCHG_ID	Interchange identification.
R_REC_TYPE	Record type ('R' = post hour-ahead).
RT_FIN_MW2	Final schedule in MW.

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Field Name	Description
OPR_DT	Operation date.
OPR_HR	Operation hour.
MKT_TYPE	Market type ('D' = day-ahead and 'H' = hour-ahead).
BRANCH_GRP	Branch Group
TIE_POINT	Tie Point
CNGS_PRC	Congestion Price
FINAL_FLOW_MW	Final Scheduled Flow on the Branch Group after the run of the congestion management software

Field Name	Description
OPR_DT	Operation date.
OPR_HR	Operation hour.
MKT_TYPE	Market type ('D' = day-ahead and 'H' = hour-ahead).
SCH_CLASS	'P' = Preferred Schedule; 'R' = Revised Preferred Schedule
SC_ID	Scheduling coordinator identification.
USAGE_ID	Usage identification of contract rights usage
USAGE_TYPE	E' = Existing Contract Right
CONTRACT_REF_CHAIN	List of valid contract references associated with Usage ID
CONTRACT_REF	Contract Reference Number for Capacity MW
CONTRACT_TYPE	'Y' = schedule was adjusted during the congestion management process.
PRIORITY	Scheduling Priority
BRANCH_GRP	Branch Group upon which contract rights reside
FROM_CNCS_ZONE	Source Congestion Zone
TO_CNCS_ZONE	Sink Congestion Zone
CAPACITY_MW	Contract Capacity MW for the given contract reference number
ADJ_MW	Adjusted MW for Capacity reservation
FIN_MW	Final MW for Capacity Reservation
VALID_STATUS	Validity Status
USER_COMMENTS	Comment field.
REC_NO	Record number.
STLMT_DATE	Settlement date.
STLMT_FLG	Settlement flag.
UPD_DATE	Updated date.
UPD_USER	Updated by user.
REC_STAT	
ORIG_MW	

Field Name	Description
SC_ID	Scheduling coordinator identification.
OPR_DT	Operation date.
OPR_HR	Operation hour.
MKT_TYPE	Market type ('D' = day-ahead and 'H' = hour-ahead).
IE_TYPE	'I' = Import, 'E' = Export.
TIE_POINT	Tie point.
INTERCHG_ID	Interchange identification.
ENGY_TYPE	Energy type ('FIRM' = Firm, 'NFRM' = Non-firm, 'WHEEL' = Wheeling, 'DYN' = Dynamic, 'CSPN' = Spinning Reserve Capacity, 'CNSPN' = Non-spinning Reserve Capacity, 'CRPLC' = Replacement Reserve Capacity).
EXT_CNTRL_ID	External control identification.
CONTRACT_REF	Contract reference number.
CONTRACT_TYPE	Contract type.
PRIOR_TYPE	OT (Unused)
SCH_CLASS	Schedule Class: 'P' = Preferred Schedule; 'R' = Revised Preferred Schedule
WSCC_TAG	WSCC tag.
SCHED_ID	Miscellaneous information
POST_ADJ_FLG	Unused
LOSS_CMP_FLG	Unused
CNGS_MGT_FLG	'Y' = congestion management was required in the area of this schedule.
CNGS_MGT_ADJ	'Y' = schedule was adjusted during the congestion management process.
HRLY_MW	Initial preferred schedule.
ADJ_MW	Interim schedule after first run of congestion management.
FIN_MW	Final schedule after last run of congestion management.
NO_OF_SEG	Number of bid segments submitted.
REC_STAT	
MW1	Adjustment capacity from bid segment #1.
MW2	Adjustment capacity from bid segment #2.
MW3	Adjustment capacity from bid segment #3.
MW4	Adjustment capacity from bid segment #4.
MW5	Adjustment capacity from bid segment #5.
MW6	Adjustment capacity from bid segment #6.
MW7	Adjustment capacity from bid segment #7.
MW8	Adjustment capacity from bid segment #8.
MW9	Adjustment capacity from bid segment #9.

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Field Name	Description
MW10	Adjustment capacity from bid segment #10.
MW11	Adjustment capacity from bid segment #11.
PR1	Bid price for adjustment bid segment #1.
PR2	Bid price for adjustment bid segment #2.
PR3	Bid price for adjustment bid segment #3.
PR4	Bid price for adjustment bid segment #4.
PR5	Bid price for adjustment bid segment #5.
PR6	Bid price for adjustment bid segment #6.
PR7	Bid price for adjustment bid segment #7.
PR8	Bid price for adjustment bid segment #8.
PR9	Bid price for adjustment bid segment #9.
PR10	Bid price for adjustment bid segment #10.
PR11	Bid price for adjustment bid segment #11.
CAP_RES_PRC	For CSPN, CNSPN, CRPLC, the hourly capacity reservation price
RAMP_RATE	Unit Ramp Rate
MIN_TO_SYNC	Minutes to Synchronize following notification
USER_COMMENTS	Comment field.
REC_NO	Unused
STLMT_DATE	Settlement Date
STLMT_FLG	Processed in Settlement System
UPD_DATE	Updated Date
UPD_USER	Update User ID
CONTINGENCY_FLG	For CSPN, CNSPN, contingency flag ('Y' = keep for reserve capacity).

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Field Name	Description
SC_ID	Scheduling coordinator identification.
MST_AFF	Master Affiliate Identification
MST_AFF_NAME	Master Affiliate name

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Field Name	Description
OPR_DT	Operation date.
OPR_HR	Operation hour.
MKT_TYPE	Market type ('D' = day-ahead and 'H' = hour-ahead).
SCH_CLASS	'P' = Preferred Schedule; 'R' = Revised Preferred Schedule
SC_ID	Scheduling coordinator identification.
TIE_POINT	The Point of Interchange
INTERCHG_ID	Scheduling Interchange Identification
USAGE_ID	Usage Identification of contract rights usage
CONTRACT_REF_CHAIN	List of valid contract references associated with Usage ID
	Energy Type of Interchange Schedule; FIRM = Firm Schedule, NFRM = Nonfirm schedule, WHEEL =
	Wheeling schedule, DYN = Dynamic schedule
ENGY_TYPE	Wheeling schedule, DYN = Dynamic schedule
PRIORITY	Scheduling Priority
FROM_CNGB_ZONE	Source Congestion Zone
TO_CNGB_ZONE	Sink Congestion Zone
HRLY_MW	Initial Reservation Schedule at start of congestion management run
ADJ_MW	Adjustments to initial reservation schedule
FIN_MW	Final ETC Reservation schedule
VALID_STATUS	Validity Status
USER_COMMENTS	Comment field.
REC_NO	Record number.
STLMT_DATE	Settlement date.
STLMT_FLG	Settlement flag.
UPD_DATE	Updated date.
UPD_USER	Updated by user.
REC_STAT	
ORIG_MW	

Field Name	Description
SC_ID	Scheduling coordinator identification.
OPR_DT	Operation date.
OPR_HR	Operation hour.
tie_point_imp	Tie point - Import.
tie_point_exp	Tie point - export.
Interchg_id_imp	Interchange identification - Import.
Interchg_id_exp	Interchange identification - export.
MKT_TYPE	Market type ('D' = day-ahead and 'H' = hour-ahead).
engy_type_imp	Energy type ('FIRM' = Firm, 'NFRM' = Non-firm, 'WHEEL' = Wheeling, 'DYN' = Dynamic).
engy_type_exp	Energy type ('FIRM' = Firm, 'NFRM' = Non-firm, 'WHEEL' = Wheeling, 'DYN' = Dynamic).
EXT_CNTRL_ID	External control identification.
CONTRACT_TYPE	Contract type.
SCHED_ID	Miscellaneous information
branch_grp_imp	Branch group of Import schedule.
branch_grp_exp	Branch group of export schedule.
conga_prc_imp	Congestion price on branch group of Import schedule.
cong_a_prc_exp	Congestion price on branch group of export schedule.
hfty_mw_imp	Initial preferred schedule - Import.
adj_mw_imp	Interim schedule after first run of congestion management - Import.
fin_mw_imp	Final schedule after last run of congestion management - Import.
fin_mw_da_imp	If mkt_type is not equal to 'D' then the Final schedule after the second day-ahead run of congestion management - Import. Otherwise, blank.
hfty_mw_exp	Initial preferred schedule - export.
adj_mw_exp	Interim schedule after first run of congestion management - export.
fin_mw_exp	Final schedule after last run of congestion management - export.
fin_mw_da_exp	If mkt_type is not equal to 'D' then the Final schedule after the second day-ahead run of congestion management - export. Otherwise, blank.
cm_chain_imp	Contract Reference Number chain, if applicable - Import
cm_chain_exp	Contract Reference Number chain, if applicable - export
elo_mw_imp	Existing Transmission Contract capacity reservation - Import.
elo_mw_exp	Existing Transmission Contract capacity reservation - export.
elo_mw_da_imp	Existing Transmission Contract capacity reservation during the DA market - Import.
elo_mw_da_exp	Existing Transmission Contract capacity reservation during the DA market - export.
from_place_imp	Region Imported from.
to_place_imp	Zone Imported to.

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Field Name	Description
from_place_exp	Zone exported from.
to_place_exp	Region exported to.
pivot_region	Common region / zone.
final_flow_mw_tp	Not used.
final_flow_mw_bg	Not used.
mw1_lmp	Adjustment capacity from bid segment #1 - import.
mw2_lmp	Adjustment capacity from bid segment #2 - import.
mw3_lmp	Adjustment capacity from bid segment #3 - import.
mw4_lmp	Adjustment capacity from bid segment #4 - import.
mw5_lmp	Adjustment capacity from bid segment #5 - import.
mw6_lmp	Adjustment capacity from bid segment #6 - import.
mw7_lmp	Adjustment capacity from bid segment #7 - import.
mw8_lmp	Adjustment capacity from bid segment #8 - import.
mw9_lmp	Adjustment capacity from bid segment #9 - import.
mw10_lmp	Adjustment capacity from bid segment #10 - import.
mw11_lmp	Adjustment capacity from bid segment #11 - import.
pr1_lmp	Bid price for adjustment bid segment #1 - import.
pr2_lmp	Bid price for adjustment bid segment #2 - import.
pr3_lmp	Bid price for adjustment bid segment #3 - import.
pr4_lmp	Bid price for adjustment bid segment #4 - import.
pr5_lmp	Bid price for adjustment bid segment #5 - import.
pr6_lmp	Bid price for adjustment bid segment #6 - import.
pr7_lmp	Bid price for adjustment bid segment #7 - import.
pr8_lmp	Bid price for adjustment bid segment #8 - import.
pr9_lmp	Bid price for adjustment bid segment #9 - import.
pr10_lmp	Bid price for adjustment bid segment #10 - import.
pr11_lmp	Bid price for adjustment bid segment #11 - import.
mw1_exp	Adjustment capacity from bid segment #1 - export.
mw2_exp	Adjustment capacity from bid segment #2 - export.
mw3_exp	Adjustment capacity from bid segment #3 - export.
mw4_exp	Adjustment capacity from bid segment #4 - export.
mw5_exp	Adjustment capacity from bid segment #5 - export.
mw6_exp	Adjustment capacity from bid segment #6 - export.
mw7_exp	Adjustment capacity from bid segment #7 - export.
mw8_exp	Adjustment capacity from bid segment #8 - export.

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Field Name	Description
mw9_exp	Adjustment capacity from bid segment #9 - export.
mw10_exp	Adjustment capacity from bid segment #10 - export.
mw11_exp	Adjustment capacity from bid segment #11 - export.
pr1_exp	Bid price for adjustment bid segment #1 - export.
pr2_exp	Bid price for adjustment bid segment #2 - export.
pr3_exp	Bid price for adjustment bid segment #3 - export.
pr4_exp	Bid price for adjustment bid segment #4 - export.
pr5_exp	Bid price for adjustment bid segment #5 - export.
pr6_exp	Bid price for adjustment bid segment #6 - export.
pr7_exp	Bid price for adjustment bid segment #7 - export.
pr8_exp	Bid price for adjustment bid segment #8 - export.
pr9_exp	Bid price for adjustment bid segment #9 - export.
pr10_exp	Bid price for adjustment bid segment #10 - export.
pr11_exp	Bid price for adjustment bid segment #11 - export.
P15_PRC	Congestion price on Path 15.
P15_DIR	Direction of congestion on Path 15.
P26_PRC	Congestion price on Path 26.
P26_DIR	Direction of congestion on Path 26.
final_flow_mw_bg_imp	Final schedule on the entire branch group of the import schedule.
final_flow_mw_bg_exp	Final schedule on the entire branch group of the export schedule.
game	Scheduled direction of flow (from zone to zone).
TP_Gains_imp	Gains from counterflow revenue at the tie point. Calculated as congestion price at the branch group times the scheduled flow across the tie point (day-ahead market) or change from the day-ahead schedule (hour-ahead market). Positive indicates gain (from counter-flow revenues) and negative indicates cost (from congestion charges). Import direction
TP_Gains_exp	Gains from counterflow revenue at the tie point. Calculated as congestion price at the branch group times the scheduled flow across the tie point (day-ahead market) or change from the day-ahead schedule (hour-ahead market). Positive indicates gain (from counter-flow revenues) and negative indicates cost (from congestion charges). Export direction
P15_Gains	Indicates cost (from congestion charges). Export direction
	Gains from counterflow revenue on Path 15. Calculated as congestion price on the path times the scheduled flow across the path (day-ahead market) or change from the day-ahead schedule (hour-ahead market). It is assumed that all the capacity in the circulating schedule will cross Path 15. Positive indicates gain (from counter-flow revenues) and negative indicates cost (from congestion charges).

Field Name	Description
P28_Gains	Gains from counterflow revenue on Path 28. Calculated as congestion price on the path times the scheduled flow across the path (day-ahead market) or change from the day-ahead schedule (hour-ahead market). It is assumed that all the capacity in the circulating schedule will cross Path 28. Positive indicates gain (from counter-flow revenues) and negative indicates cost (from congestion charges).
Total_Gains_AL_ETC	Total gains from counterflow revenue = TP_Gains_imp + P15_Gains + P28_Gains + TP_Gains_exp. Assumes that if one or more legs in a transaction utilize ETC capacity, the entire schedule utilized ETC capacity, and consequently zeroes out congestion charges for the entire transaction.
Data_Set	Indicates whether there were duplicate pairings for the import leg of the schedule pair, export leg of the schedule pair, both legs of the schedule pair, or neither leg of the schedule pair.
Keep_Flag	=1 indicates that schedule pair was used in tabulation of summary results. =0 indicates there were duplicate pairings for one or more of the schedules in the pair and another pairing was used in the tabulation of summary results.
NOB_Flag	=1 indicates that one leg of the circular schedule was scheduled on the Nevada-Oregon Border (NOB) DC intertie.

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Description	
Field Name	Date
OPR_DT	Hour
OPR_HR	Schedule co-ordinator ID
SC_ID	Type of scheduling records existing in system used in analysis (D=Day ahead, H=Hour Ahead, R=Real time)
REC_TYPE	Type of schedule Cancelled (I= Import, E=Export)
IE_TYPE	Branch group of cancelled schedule
BRANCH_GRP	Tie point of cancelled schedule
TIE_POINT	Interchange ID of cancelled schedule
INTERCHG_ID	Energy Type
ENGY_TYPE	Flag whether schedule is subject to Congestion Management in DA
DA_CNGBS_MGT_FLG	Flag whether schedule was subject by Congestion Management in DA
DA_CNGBS_MGT_ADJ	Initial Schedule (Day Ahead Schedule)
DA_HRLY_MW	Amount of schedule adjustment in DA
DA_ADJ_MW	Final Schedule (Day Ahead Schedule)
DA_FIN_MW	Congestion Price (Day Ahead)
DA_CNGBS_PRC	Congestion Price (Day Ahead)
DA_BG_FIN_MW	Final Branch Group MW usage in DA
DA_CFlow	DA counterflow direction
HA_CNGBS_MGT_FLG	Flag whether schedule is subject to Congestion Management in HA
HA_CNGBS_MGT_ADJ	Flag whether schedule was subject by Congestion Management in HA
HA_HRLY_MW	Initial Schedule (Hour Ahead Schedule)
HA_ADJ_MW	Amount of schedule adjustment in HA
HA_FIN_MW	Final Schedule (Hour Ahead Schedule)
HA_CNGBS_PRC	Congestion Price (Hour Ahead)
HA_BG_FIN_MW	Final Branch Group MW usage in HA
HA_CFlow	HA counterflow direction
RT_CNGBS_MGT_FLG	Unused
RT_CNGBS_MGT_ADJ	Unused
RT_HRLY_MW	Initial Schedule (Real time checkout)
RT_ADJ_MW	Unused
RT_FIN_MW	Final Schedule (Real time checkout)
Zero_Type	Zero Tie type
sc_id2	Modified SC Id
MST_AFF_NAME	Name of entity

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Field Name	Description
Game_Type	D=0 H>R: DA schedule is zero, with a deduction from HA to real-time; D<H>R: No reduction from DA to
R_Gotten_Gain	HA, with reduction from HA to real-time
Game_Category	counterflow revenues earned from schedule cut in real time
opr_yr	Zero TP: Scheduling on an open Interlie; Main Gain: Reducing a counterflow schedule between the Hour-
opr_yr_mo	Ahead and Real-time
	year
	year and month

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Cut Counter-flow Schedules

Field Name	Description
OPR_DT	Date
OPR_HR	Hour
SC_ID	Schedule co-ordinator ID
	Type of scheduling records existing in system used in analysis (D=Day ahead, H=Hour Ahead, R=Real time)
REC_TYPE	Type of schedule Cancelled (I= Import, E=Export)
IE_TYPE	Type of schedule Cancelled (I= Import, E=Export)
BRANCH_GRP	Branch group of cancelled schedule
TIE_POINT	Tie point of cancelled schedule
INTERCHG_ID	Interchange ID of cancelled schedule
ENGY_TYPE	Energy Type
DA_CNCS_MGT_FLG	Flag whether schedule is subject to Congestion Management in DA
DA_CNCS_MGT_ADJ	Flag whether schedule was subject by Congestion Management in DA
DA_HRLY_MW	Initial Schedule (Day Ahead Schedule)
DA_ADJ_MW	Amount of schedule adjustment in DA
DA_FIN_MW	Final Schedule (Day Ahead Schedule)
DA_CNCS_PRC	Congestion Price (Day Ahead)
DA_BG_FIN_MW	Final Branch Group MW usage in DA
DA_CFlow	DA counterflow direction
HA_CNCS_MGT_FLG	Flag whether schedule is subject to Congestion Management in HA
HA_CNCS_MGT_ADJ	Flag whether schedule was subject by Congestion Management in HA
HA_HRLY_MW	Initial Schedule (Hour Ahead Schedule)
HA_ADJ_MW	Amount of schedule adjustment in HA
HA_FIN_MW	Final Schedule (Hour Ahead Schedule)
HA_CNCS_PRC	Congestion Price (Hour Ahead)
HA_BG_FIN_MW	Final Branch Group MW usage in HA
HA_CFlow	HA counterflow direction
RT_CNCS_MGT_FLG	Unused
RT_CNCS_MGT_ADJ	Unused
RT_HRLY_MW	Initial Schedule (Real time checkout)
RT_ADJ_MW	Unused
RT_FIN_MW	Final Schedule (Real time checkout)
sc_id2	Modified SC Id
MST_AFF_NAME	Name of entity
	D=0 H>R: DA schedule is zero, with a deduction from HA to real-time; D=H>R: No reduction from DA to HA, with reduction from HA to real-time
Sched_Type	

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Field Name		Description
Gains		counterflow revenues earned from schedule out in real time
opr_yr		year
opr_yr_mo		year and month
SLIC Comments		Comments (if any) from SLIC log
Curtail Status		1=ISO Cut, 2=SC Cut, 3=unknown
SLIC LOG present?		1=SLIC log found and reviewed
Period		1=pre-refund, 2= refund period
Other explanations		Other explanations
Drop		1=screened from summary results

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**Megawatt Laundering,
A/k/a "Ricochet"**

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Field Name	Description
BRANCH_GRP	Branch Group of which Tie Point is a part of
TIE_POINT	Tie Point

<u>Field Name</u>	<u>Description</u>
OPR_DT	Operation date.
OPR_HR	Operation hour.
UNIT_ID	Unit Identification.
SC_ID	Scheduling coordinator Identification.
DA_MW	Final schedule after the day-ahead congestion markets are run.
HA_MW	Final schedule after the hour-ahead congestion markets are run.
D_RU_B	Day-ahead Regulation Up capacity bid.
D_RU_P	Price of day-ahead Regulation Up capacity bid.
D_RU_F	Day-ahead Regulation Up capacity procured.
D_RD_B	Day-ahead Regulation Down capacity bid.
D_RD_P	Price of day-ahead Regulation Down capacity bid.
D_RD_F	Day-ahead Regulation Down capacity procured.
D_SP_B	Day-ahead Spinning Reserve capacity bid.
D_SP_P	Price of day-ahead Spinning Reserve capacity bid.
D_SP_F	Day-ahead Spinning Reserve capacity procured.
D_NS_B	Day-ahead Non-spinning Reserve capacity bid.
D_NS_P	Price of day-ahead Non-spinning Reserve capacity bid.
D_NS_F	Day-ahead Non-spinning Reserve capacity procured.
D_RP_B	Day-ahead Replacement Reserve capacity bid.
D_RP_P	Price of day-ahead Replacement Reserve capacity bid.
D_RP_F	Day-ahead Replacement Reserve capacity procured.
H_RU_B	Hour-ahead Regulation Up capacity bid.
H_RU_P	Price of Hour-ahead Regulation Up capacity bid.
H_RU_F	Hour-ahead Regulation Up capacity procured.
H_RD_B	Hour-ahead Regulation Down capacity bid.
H_RD_P	Price of Hour-ahead Regulation Down capacity bid.
H_RD_F	Hour-ahead Regulation Down capacity procured.
H_SP_B	Hour-ahead Spinning Reserve capacity bid.
H_SP_P	Price of Hour-ahead Spinning Reserve capacity bid.
H_SP_F	Hour-ahead Spinning Reserve capacity procured.
H_NS_B	Hour-ahead Non-spinning Reserve capacity bid.
H_NS_P	Price of Hour-ahead Non-spinning Reserve capacity bid.
H_NS_F	Hour-ahead Non-spinning Reserve capacity procured.
H_RP_B	Hour-ahead Replacement Reserve capacity bid.
H_RP_P	Price of Hour-ahead Replacement Reserve capacity bid.

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Field Name	Description
H_RP_F	Hour-ahead Replacement Reserve capacity procured.
SCH_CHG	Approximation of real-time schedule change for RMR units.
SE_INC_B	Capacity bid as Incremental Supplemental Energy.
SE_DEC_B	Capacity bid as decremental Supplemental Energy.
BP_SP	Energy dispatched from Spinning Reserve capacity procured.
BP_NS	Energy dispatched from Non-spinning Reserve capacity procured.
BP_RP	Energy dispatched from Replacement Reserve capacity procured.
BP_SE	Energy dispatched from Supplemental Energy bid.
M_GEN	Gross metered generation.

Field Name	Description
OPR_DT	Operation date.
OPR_HR	Operation hour.
SC_ID	Scheduling coordinator identification.
TIE_POINT	The point.
INTERCHG_ID	Interchange identification.
L_DA_MW	Final import schedule after the day-ahead congestion management is run.
E_DA_MW	Final export schedule after the day-ahead congestion management is run.
L_HA_MW	Final import schedule after the hour-ahead congestion management is run.
E_HA_MW	Final export schedule after the hour-ahead congestion management is run.
I_HAM_MW	Final import schedule after adjustments to the final the hour-ahead import schedule is set.
E_HAM_MW	Final export schedule after adjustments to the final the hour-ahead export schedule is set.
D_SP_B	Day-ahead Spinning Reserve capacity bid.
D_SP_P	Price of day-ahead Spinning Reserve capacity bid.
D_SP_F	Day-ahead Spinning Reserve capacity procured.
D_NS_B	Day-ahead Non-spinning Reserve capacity bid.
D_NS_P	Price of day-ahead Non-spinning Reserve capacity bid.
D_NS_F	Day-ahead Non-spinning Reserve capacity procured.
D_RP_B	Day-ahead Replacement Reserve capacity bid.
D_RP_P	Price of day-ahead Replacement Reserve capacity bid.
D_RP_F	Day-ahead Replacement Reserve capacity procured.
H_SP_B	Hour-ahead Spinning Reserve capacity bid.
H_SP_P	Price of Hour-ahead Spinning Reserve capacity bid.
H_SP_F	Hour-ahead Spinning Reserve capacity procured.
H_NS_B	Hour-ahead Non-spinning Reserve capacity bid.
H_NS_P	Price of Hour-ahead Non-spinning Reserve capacity bid.
H_NS_F	Hour-ahead Non-spinning Reserve capacity procured.
H_RP_B	Hour-ahead Replacement Reserve capacity bid.
H_RP_P	Price of Hour-ahead Replacement Reserve capacity bid.
H_RP_F	Hour-ahead Replacement Reserve capacity procured.
SE_INC_B	Capacity bid as Incremental Supplemental Energy.
SE_DEC_B	Capacity bid as decremental Supplemental Energy.
BP_SP	Energy dispatched from Spinning Reserve capacity procured.
BP_NS	Energy dispatched from Non-spinning Reserve capacity procured.
BP_RP	Energy dispatched from Replacement Reserve capacity procured.
BP_SE	Energy dispatched from Supplemental Energy bid.

Field Name	Description
SC_ID	Scheduling coordinator identification.
OPR_DT	Operation date.
OPR_HR	Operation hour.
MKT_TYPE	Market type ('D' = day-ahead and 'H' = hour-ahead).
TRADING_SC	Source Scheduling Coordinator
PNT_OF_INTRC	Point (Zone) of interchange
CONTRACT_REF	Contract Reference Number
CNGS_MGT_ADJ	'Y' = schedule was adjusted during the congestion management process.
SCH_CLASS	'P' = Preferred Schedule; 'R' = Revised Preferred Schedule
	'EN' = Energy; 'NS' = Non-spin; 'SP' = Spin; 'RU' = Regulation Up; 'RD' = Regulation Down; 'ON' =
	Obligation Non-spin
SCHED_TYPE	Initial preferred schedule.
HPLY_MW	Interim schedule after first run of congestion management.
ADJ_MW	Final schedule after last run of congestion management.
FIN_MW	Contract MW for the given contract reference number
CONTRACT_MW	
REC_STAT	
USER_COMMENTS	Comment field.
REC_NO	Record number.
STLMT_DATE	Settlement date.
STLMT_FLG	Settlement flag.
UPD_DATE	Updated date.
UPD_USER	Updated by user.

Field Name	Description
SC_ID	Scheduling coordinator identification.
OPR_DT	Operation date.
OPR_HR	Operation hour.
MKT_TYPE	Market type ('D' = day-ahead and 'H' = hour-ahead).
TRADING_SC	Source Scheduling Coordinator
PNT_OF_INTRC	Point (Zone) of interchange
SCHED_TYPE	'EN' = Energy; 'NS' = Non-spin; 'SP' = Spin; 'RU' = Regulation Up; 'RD' = Regulation Down
TYPE_OF_INTRC	'F' = Fixed trade; 'G' = Variable trade - Generation; 'L' = Variable trade - Load
DIRECTION	'S' = Send; 'R' = Receive
SCH_CLASS	'P' = Preferred Schedule; 'R' = Revised Preferred Schedule
CONTRACT_REF	Contract Reference Number
CNGS_MGT_ADJ	'Y' = schedule was adjusted during the congestion management process.
CNGS_MGT_FLG	'Y' = congestion management was required in the area of this schedule.
CNGS_ZONE	Zone identification.
HRLY_MW	Initial preferred schedule.
ADJ_MW	Interim schedule after first run of congestion management.
ADJ_NET_MW	
FIN_MW	Final schedule after last run of congestion management.
FIN_NET_MW	
CONTRACT_MW	Contract MW for the given contract reference number
TRANSFER_MW	Hourly preferred transfer MW value specified for the returned resource (variable trades) that include either a UNIT_ID or a LOAD_ID
TRANSFER_MW_MAX	The maximum hourly transfer MW value needed for variable trades that include either a UNIT_ID or a LOAD_ID
NO_OF_SEG	Number of bid segments submitted.
NO_OF_RET_PRY_SEG	
MW1	Adjustment capacity from bid segment #1.
MW2	Adjustment capacity from bid segment #2.
MW3	Adjustment capacity from bid segment #3.
MW4	Adjustment capacity from bid segment #4.
MW5	Adjustment capacity from bid segment #5.
MW6	Adjustment capacity from bid segment #6.
MW7	Adjustment capacity from bid segment #7.
MW8	Adjustment capacity from bid segment #8.
MW9	Adjustment capacity from bid segment #9.

Field Name	Description
MW10	Adjustment capacity from bid segment #10.
MW11	Adjustment capacity from bid segment #11.
PR1	Bid price for adjustment bid segment #1.
PR2	Bid price for adjustment bid segment #2.
PR3	Bid price for adjustment bid segment #3.
PR4	Bid price for adjustment bid segment #4.
PR5	Bid price for adjustment bid segment #5.
PR6	Bid price for adjustment bid segment #6.
PR7	Bid price for adjustment bid segment #7.
PR8	Bid price for adjustment bid segment #8.
PR9	Bid price for adjustment bid segment #9.
PR10	Bid price for adjustment bid segment #10.
PR11	Bid price for adjustment bid segment #11.
RET_MW1	
RET_MW2	
RET_MW3	
RET_MW4	
RET_MW5	
RET_MW6	
RET_MW7	
RET_MW8	
RET_MW9	
RET_MW10	
RET_PR1	
RET_PR2	
RET_PR3	
RET_PR4	
RET_PR5	
RET_PR6	
RET_PR7	
RET_PR8	
RET_PR9	
RET_PR10	
UPD_DATE	Updated date.
UPD_USER	Updated by user.

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Field Name	Description
STLMT_DATE	Settlement date.
STLMT_FLG	Settlement flag.
REC_NO	Record number.
USER_COMMENTS	Comment field.
REC_STAT	

Field Name	Description
UNIT_ID	Unique Resource ID
MST_AFF	Master Affiliate ID of the Generation unit
MST_AFF_NAME	Master Affiliate of the Generation unit
OWNER	Owner
ZONE_ID	Zone within which the generation unit is located
UTYPE	Generation Type: HY= Hydro, TH=Thermal, GEO=Geothermal, OTHER=Other type
GROUP_ID	
PRIOR_TYPE	Indicates whether output is classified as Reliability Must-Run, Regulatory Must-Run, or Must-Take
UDC	Associated Utility Distribution Co
PSEUDO_UNIT	Field indicating whether a generation resource is a "pseudo generation unit" used for scheduling power and self-provided ancillary services for governmental entities with existing interconnection agreements and contracts with IOUs
P_MAX	Dependable Generation Capacity of a Generation Resource. Pseudo Units have a value of 999 assigned to Pmax; filter them out.
MAX_MW	Nameplate capacity
MIN_MW	Minimum Generating Capacity
MIN_AGC	AGC Capability
VOC	Variable Operating and Maintenance Cost
F_O_R	Forced Outage Rate
NOX	Level of NOx emissions
ZONE_DT1	Starting Date
ZONE_DT2	Ending Date
UNIT_CATEGORY	Major Unit: PGA generating facilities which primarily provide electricity; Muni Unit: generation owned by federal, state and municipal agencies; QF: PURPA "qualifying facilities", including industrial cogeneration, small hydro, and renewable generation
MW1	Top of Segment 1 of Heat Rate Curve
MW2	Top of Segment 2 of Heat Rate Curve
MW3	Top of Segment 3 of Heat Rate Curve
MW4	Top of Segment 4 of Heat Rate Curve
MW5	Top of Segment 5 of Heat Rate Curve
MW6	Top of Segment 6 of Heat Rate Curve
MW7	Top of Segment 7 of Heat Rate Curve
MW8	Top of Segment 8 of Heat Rate Curve
MW9	Top of Segment 9 of Heat Rate Curve

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<u>Field Name</u>	<u>Description</u>
MW10	Top of Segment 10 of Heat Rate Curve
MW11	Top of Segment 11 of Heat Rate Curve
HR1	Heat Rate of Segment 1 of Heat Rate Curve
HR2	Heat Rate of Segment 2 of Heat Rate Curve
HR3	Heat Rate of Segment 3 of Heat Rate Curve
HR4	Heat Rate of Segment 4 of Heat Rate Curve
HR5	Heat Rate of Segment 5 of Heat Rate Curve
HR6	Heat Rate of Segment 6 of Heat Rate Curve
HR7	Heat Rate of Segment 7 of Heat Rate Curve
HR8	Heat Rate of Segment 8 of Heat Rate Curve
HR9	Heat Rate of Segment 9 of Heat Rate Curve
HR10	Heat Rate of Segment 10 of Heat Rate Curve
HR11	Heat Rate of Segment 11 of Heat Rate Curve
MONO_INC_HR1	Heat Rate of Segment 1 of Monotonically Increasing HR Curve
MONO_INC_HR2	Heat Rate of Segment 2 of Monotonically Increasing HR Curve
MONO_INC_HR3	Heat Rate of Segment 3 of Monotonically Increasing HR Curve
MONO_INC_HR4	Heat Rate of Segment 4 of Monotonically Increasing HR Curve
MONO_INC_HR5	Heat Rate of Segment 5 of Monotonically Increasing HR Curve
MONO_INC_HR6	Heat Rate of Segment 6 of Monotonically Increasing HR Curve
MONO_INC_HR7	Heat Rate of Segment 7 of Monotonically Increasing HR Curve
MONO_INC_HR8	Heat Rate of Segment 8 of Monotonically Increasing HR Curve
MONO_INC_HR9	Heat Rate of Segment 9 of Monotonically Increasing HR Curve
MONO_INC_HR10	Heat Rate of Segment 10 of Monotonically Increasing HR Curve
MONO_INC_HR11	Heat Rate of Segment 11 of Monotonically Increasing HR Curve

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Field Name	Description
DIM_TIE_POINT	Counter
TIE_POINT	Tie Point
BRANCH_GRP	Branch Group
ZONE_ID	Internal ISO congestion zone branch group injects into
FROM_ZONE	External Congestion zone branch group connects to
FROM_REGION	External region branch group connects to
ZONE_DT1	Start Date
ZONE_DT2	End Date

Field Name	Description
OPR_DT	Operation date.
OPR_HR	Operation hour.
TIE_POINT	Tie point.
INTERCHG_ID	Interchange identification.
UNIT_ID	Unit identification.
SC_ID	Scheduling coordinator identification.
MST_AFF	Master business affiliate identification.
PRICE	Price for OOM / OOS transaction.
MWH	Energy from OOM / OOS transaction.
COST	Cost (PRICE * MWH). Note that this value can be misleading for circulation or exchanges.
ZONE	Zone identification.
SYSTEM	System of source energy (internal or external to the ISO control area)
REASON	Reason for purchasing out-of-market or out-of-sequence.
MARKET	OOM / OOS code (MAR, SEQ,)
MISC_INFO	Comment field.
RT_PRICE	Real-time hourly ex-post MCP.
INSTR_TYPE	OSSE: Out of Sequence Imbalance Energy Supplemental; OSSP: Out of Sequence Imbalance Energy Spin; OSNS: Out of Sequence Imbalance Energy Non-Spin; OSRR: Out of Sequence Imbalance Energy Replacement Reserve; OSRCNG: Out of Sequence Inter-Zonal Congestion;
REASON_FLAG	Indicator if a record was corrected
REASON_CORRECTION_EXPLANATION	Comment field for correction
FROM_TIME	Start time for energy from OOM / OOS transaction.
TO_TIME	End time for energy from OOM / OOS transaction.
PATH	
ZONE_ID	Congestion Zone

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Field Name
OPR_DT
OPR_HR
ISO_PRICE_CAP

Description
Operation date.
Operation hour.
ISO Price Cap

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Field Name	Description
BRANCH_GRP	Branch Group
REGION	External region branch group connects to

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Field Name	Description
OPR_DT	Operation date.
OPR_HR	Operation hour.
ZONE_ID	Congestion Zone
PRC_PX_C	Constrained PX Clearing Price

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Field Name
PARTICIPANT
MST_AFF2
Participant_Long_Name
Description
Participant
Master Affiliate Identification
Name of Participant

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Field Name	Description
OPR_DT	Operation date.
OPR_HR	Operation hour.
MKT_TYPE	Market type ('D' = day-ahead and 'H' = hour-ahead).
PARTICIPANT	Participant
DEMAND_SUPPLY	'D' = Demand, 'S' = Supply
RESOURCE_NAME	Resource Name
RESOURCE_TYPE	Resource Type: Import, Export
SCHED_MW	Scheduled MW
zone_id	Congestion Zone
GLOBAL_RESOURCE	Resource ID, e.g. Interchange ID
E_ID	PX Market Clearing Price
PX_MCP	MW
MW	Month
month	

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Field Name	Description
SC_ID	Scheduling coordinator identification.
MST_AFF	Master Affiliate identification
MST_AFF_NAME	Master Affiliate name

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Field Name	Description
OPR_DT	Operation date.
OPR_HR	Operation hour.
TIE_POINT	The point.
INTERCHG_ID	Interchange identification.
SC_ID	Scheduling coordinator identification.
ENERGY_TYPE	Energy type (supp, spn, non-spn, replacement).
BID_MW	Capacity bld into BEEP Stack.
BID_PRICE	Bld price.
OUT_MW	Dispatched capacity.

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Field Name	Description
OPR_DT	Operation date.
OPR_HR	Operation hour.
TIE_POINT	The point.
INTERCHG_ID	Interchange Identification.
UNIT_ID	Generating unit Identification.
SC_ID	Schedule coordinator Identification.
met_all	Master business affiliate Identification.
era_bought_from	CERS trading partner.
price	Transaction price.
mwh	Transaction energy.
cost	Transaction cost.
zone	Congestion zone Identification.
system	System (internal / external).
reason	Reason for transaction.
market	MAR => OOM.
misc_info	

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Field Name	Description
OPR_DT	Operation date.
OPR_HR	Operation hour.
OPR_MI	Operation minute.
ZONE_ID	Congestion zone identification.
ISO_INC_PRC	ISO real-time incremental price.
ISO_DEC_PRC	ISO real-time decremental price.

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Field Name

OPR_DT
OPR_HR
PROD_TYPE
ZONE_ID
PRICE

Description
Operation date.
Operation hour.
Indicates incremental or decremental energy.
Congestion zone identification.
ISO real-time price (alimulated hourly weighted average incremental or decremental price).

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Field Name	Description
OPR_DT	Operation date.
OPR_HR	Operation hour.
PROD_TYPE	Indicates incremental or decremental energy.
ZONE_ID	Congestion zone identification.
PRICE	ISO real-time price (simulated hourly weighted average incremental or decremental price).

Field Name	Description
OPR_DT	Operation date
OPR_HR	Operation hour
net_aff	Master affiliate
PX_imp_MW	Import MW directly to PX (DA & HA)
PX_imp_Cost	Cost of Import MW directly to PX (DA & HA)
PX_exp_MW	Export MW directly from PX (DA & HA)
PX_exp_Cost	Cost of export MW directly from PX (DA & HA)
DA_FROM_PX	DA MW purchased from PX (in control area)
DA_TO_PX	DA MW sold to PX (in control area)
DA_FROM_OTHER	DA MW inter-so trade from other SC (in control area)
DA_TO_OTHER	DA MW inter_sc trade to other SC (in control area)
HA_FROM_PX	HA MW purchased from PX (in control area)
HA_TO_PX	HA MW sold to PX (in control area)
HA_FROM_OTHER	HA MW inter-so trade from other SC (in control area)
HA_TO_OTHER	HA MW inter_sc trade to other SC (in control area)
HA_GEN_MW	Final HA schedule for generation in control area
AS_GEN_ENGY_BID	Energy bid by units in control area through A/S capacity awarded
SUP_GEN_ENGY_BID	Supplemental energy bid by units in control area
AS_GEN_ENGY_DISP	Energy dispatched through energy bids by units in control area from A/S capacity awarded
SE_GEN_ENGY_DISP	Supplemental energy dispatched through supplemental energy bid by units in control area
L_HA_MW	Final HA schedule for imports from outside control area
E_HA_MW	Final HA schedule for exports from outside control area
AS_imp_ENGY_BID	Energy bid by resources outside the control area through A/S capacity awarded
SUP_imp_ENGY_BID	Supplemental energy bid by resources outside the control area
AS_imp_ENGY_DISP	Energy dispatched through energy bids by resources outside the control area from A/S capacity awarded
SE_imp_ENGY_DISP	Supplemental energy dispatched through supplemental energy bid by resources outside the control area
BEEP_MW_LE_CAP	Beep MW dispatched at bid price <= price cap (imports only)
BEEP_MW_GT_CAP	Beep MW dispatched at bid price > price cap (imports only)
BEEP_COST_GT_CAP	Cost of Beep MW dispatched at bid price > price cap (imports only)
BEEP_PRC_GT_CAP	Average price of Beep MW dispatched at bid price > price cap (imports only)
oom_gen_mwh	Net OOM purchases by ISO from generators within control area
oom_gen_pro	Average price of net OOM purchases by ISO from generators within control area
oom_imp_mwh	Import OOM purchases by ISO from outside control area

Field Name**Description**

oom_leo_imp_pro	Average price of Import OOM purchases by ISO from outside control area
oom_leo_imp_giscap_mwh	Import OOM purchases by ISO from outside control area where OOM price > price cap
oom_leo_imp_giscap_pro	Average price of Import OOM purchases by ISO from outside control area where OOM price > price cap
oom_leo_exp_mwh	Export OOM sales / transactions by ISO from outside control area
oom_leo_exp_pro	Average price of export OOM sales / transactions by ISO from outside control area
oom_cera_gen_mwh	Net OOM purchases by CERS from generators within control area
oom_cera_gen_pro	Average price of net OOM purchases by CERS from generators within control area
oom_cera_imp_mwh	Import OOM purchases by CERS from outside control area
oom_cera_imp_pro	Average price of Import OOM purchases by CERS from outside control area
oom_cera_imp_giscap_mwh	Import OOM purchases by CERS from outside control area where OOM price > price cap
oom_cera_imp_giscap_pro	Average price of Import OOM purchases by CERS from outside control area where OOM price > price cap
oom_cera_exp_mwh	Export OOM sales / transactions by CERS from outside control area
oom_cera_exp_pro	Average price of export OOM sales / transactions by CERS from outside control area
PX_CP	Simple average of PX constrained market clearing price
leo_imp_pro	Simple average of ISO incremental market clearing price
PRICE_CAP	ISO imbalance energy price cap
MIDC_PRC	Spot energy price at Mid-columbia hub
COB_PRC	Spot energy price at California-Oregon Border hub
PV_PRC	Spot energy price at Palo Verde Border hub
AVG_HUB_PRC	Simple average of three regional hub prices

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**Scheduling on a Zero-rated Path,
A/k/a "Wheel Out"**

Field Name	Description
OPR_DT	Date
OPR_HR	Hour
SC_ID	Schedule co-ordinator ID
REC_TYPE	Type of scheduling records existing in system used in analysis (D=Day ahead, H=Hour Ahead, R=Real time)
IE_TYPE	Type of schedule Cancelled (I= Import, E=Export)
BRANCH_GRP	Branch group of cancelled schedule
TIE_POINT	The point of cancelled schedule
INTERCHG_ID	Interchange ID of cancelled schedule
ENRG_TYPE	Energy Type
DA_CNGS_MGT_FLG	Flag whether schedule is subject to Congestion Management in DA
DA_CNGS_MGT_ADJ	Flag whether schedule was subject by Congestion Management in DA
DA_HRLY_MW	Initial Schedule (Day Ahead Schedule)
DA_ADJ_MW	Amount of schedule adjustment in DA
DA_FIN_MW	Final Schedule (Day Ahead Schedule)
DA_CNGS_PRC	Congestion Price (Day Ahead)
DA_BG_FIN_MW	Final Branch Group MW usage in DA
DA_CFlow	DA counterflow direction
HA_CNGS_MGT_FLG	Flag whether schedule is subject to Congestion Management in HA
HA_CNGS_MGT_ADJ	Flag whether schedule was subject by Congestion Management in HA
HA_HRLY_MW	Initial Schedule (Hour Ahead Schedule)
HA_ADJ_MW	Amount of schedule adjustment in HA
HA_FIN_MW	Final Schedule (Hour Ahead Schedule)
HA_CNGS_PRC	Congestion Price (Hour Ahead)
HA_BG_FIN_MW	Final Branch Group MW usage in HA
HA_CFlow	HA counterflow direction
RT_CNGS_MGT_FLG	Unused
RT_CNGS_MGT_ADJ	Unused
RT_HRLY_MW	Initial Schedule (Real time checkout)
RT_ADJ_MW	Unused
RT_FIN_MW	Final Schedule (Real time checkout)
Zero_Type	
sc_id2	Modified SC id
MGT_AFF_NAME	Name of entity

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Field Name	
Sched_Type	Description
Gains	D=0 H=Pt DA schedule is zero, with a deduction from HA to real-time; D+H=Pt: No reduction from DA to HA, with reduction from HA to real-time
opr_yr	counterflow revenues earned from schedule cut in real time
opr_yr_mo	year
SLIC Comments	year and month
Screened	Comments (if any) from SLIC log
	Screened from summary results if no change in bidding/scheduling detected.

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**Overscheduling of Load,
A/k/a "Fat Boy"**

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Field Name	Description
BRANCH_GRP	Branch Group
ZONE	Internal ISO congestion zone branch group injects into
CZ	External Congestion zone branch group connects to
REGION	External region branch group connects to

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Field Name	Description
BRANCH_GRP	Branch Group
ZONE	Internal ISO congestion zone branch group injects into
CZ	External Congestion zone branch group connects to
REGION	External region branch group connects to
TIE_POINT	Tie Point

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Field Name	Description
OPR_DT	Operation date.
OPR_HR	Operation hour.
CNGS_ZONE	Internal Congestion Zone
MW	Acknowledged MW
PRICE	Hourly Ex-Post Energy Price

Field Name**Description**

SC_ID	Scheduling coordinator identification.
OPR_DT	Operation date.
OPR_HR	Operation hour.
MKT_TYPE	Market type ('D' = day-ahead and 'H' = hour-ahead).
UNIT_ID	Unit identification.
SCH_CLASS	'P' = Preferred Schedule; 'R' = Revised Preferred Schedule
POST_ADJ_FLG	Unused
RAMP_RATE	Unit Ramp Rate
NO_OF_SEG	Number of bid segments submitted.
CNGS_MGT_FLG	'Y' = congestion management was required in the area of this schedule.
CNGS_MGT_ADJ	'Y' = schedule was adjusted during the congestion management process.
CONTRACT_REF	Contract reference number.
MW1	Adjustment capacity from bid segment #1.
MW2	Adjustment capacity from bid segment #2.
MW3	Adjustment capacity from bid segment #3.
MW4	Adjustment capacity from bid segment #4.
MW5	Adjustment capacity from bid segment #5.
MW6	Adjustment capacity from bid segment #6.
MW7	Adjustment capacity from bid segment #7.
MW8	Adjustment capacity from bid segment #8.
MW9	Adjustment capacity from bid segment #9.
MW10	Adjustment capacity from bid segment #10.
MW11	Adjustment capacity from bid segment #11.
PR1	Bid price for adjustment bid segment #1.
PR2	Bid price for adjustment bid segment #2.
PR3	Bid price for adjustment bid segment #3.
PR4	Bid price for adjustment bid segment #4.
PR5	Bid price for adjustment bid segment #5.
PR6	Bid price for adjustment bid segment #6.
PR7	Bid price for adjustment bid segment #7.
PR8	Bid price for adjustment bid segment #8.
PR9	Bid price for adjustment bid segment #9.
PR10	Bid price for adjustment bid segment #10.
PR11	Bid price for adjustment bid segment #11.
HRLY_MW	Initial preferred schedule.

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Final Net MW

ADJ_MW

FIN_MW

ADJ_NET_MW

FIN_NET_MW

HRLY_GROSS_MW

USER_COMMENTS

Interim schedule after first run of congestion management.
Final schedule after last run of congestion management.
Net Adjusted Schedule
Final Net Schedule
Hourly Gross Schedule
Comment field.

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Field Name	Description
SC_ID	Scheduling coordinator identification.
OPR_DT	Operation date.
OPR_HR	Operation hour.
MKT_TYPE	Market type ('D' = day-ahead and 'H' = hour-ahead).
IE_TYPE	'I' = Import, 'E' = Export.
TIE_POINT	Tie point.
INTERCHG_ID	Interchange identification.
ENGY_TYPE	Energy type ('FIRM' = Firm, 'NFRM' = Non-firm, 'WHEEL' = Wheeling, 'DYN' = Dynamic, 'OSPN' = Spinning Reserve Capacity, 'CNSPN' = Non-spinning Reserve Capacity, 'CRPLC' = Replacement Reserve Capacity).
EXT_CNTRL_ID	External control identification.
CONTRACT_REF	Contract reference number.
CONTRACT_TYPE	Contract type.
PRIOR_TYPE	OT (Unused)
SCH_CLASS	Schedule Class: 'P' = Preferred Schedule; 'R' = Revised Preferred Schedule
WSCC_TAG	WSCC tag.
SCHED_ID	Miscellaneous information
POST_ADJ_FLG	Unused
LOSS_CMP_FLG	Unused
CNGS_MGT_FLG	'Y' = congestion management was required in the area of this schedule.
CNGS_MGT_ADJ	'Y' = schedule was adjusted during the congestion management process.
HRLY_MW	Initial preferred schedule.
ADJ_MW	Interim schedule after first run of congestion management.
FIN_MW	Final schedule after last run of congestion management.
NO_OF_SEG	Number of bid segments submitted.
REC_STAT	
MW1	Adjustment capacity from bid segment #1.
MW2	Adjustment capacity from bid segment #2.
MW3	Adjustment capacity from bid segment #3.
MW4	Adjustment capacity from bid segment #4.
MW5	Adjustment capacity from bid segment #5.
MW6	Adjustment capacity from bid segment #6.
MW7	Adjustment capacity from bid segment #7.
MW8	Adjustment capacity from bid segment #8.
MW9	Adjustment capacity from bid segment #9.

Field Name	Description
MW10	Adjustment capacity from bid segment #10.
MW11	Adjustment capacity from bid segment #11.
PR1	Bid price for adjustment bid segment #1.
PR2	Bid price for adjustment bid segment #2.
PR3	Bid price for adjustment bid segment #3.
PR4	Bid price for adjustment bid segment #4.
PR5	Bid price for adjustment bid segment #5.
PR6	Bid price for adjustment bid segment #6.
PR7	Bid price for adjustment bid segment #7.
PR8	Bid price for adjustment bid segment #8.
PR9	Bid price for adjustment bid segment #9.
PR10	Bid price for adjustment bid segment #10.
PR11	Bid price for adjustment bid segment #11.
CAP_RES_PRC	For CSPN, CNSPN, CRPLC, the hourly capacity reservation price
RAMP_RATE	Unit Ramp Rate
MIN_TO_SYNC	Minutes to Synchronize following notification
USER_COMMENTS	Comment field.
REC_NO	Unused
STLMT_DATE	Settlement Date
STLMT_FLG	Processed in Settlement System
UPD_DATE	Updated Date
UPD_USER	Update User ID
CONTINGENCY_FLG	For CSPN, CNSPN, contingency flag ('Y' = keep for reserve capacity).

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Field Name
LOAD_ID

Description

Specific Load IDs excluded from tabulation because of special unit characteristics, e.g. dispatchable/curtailable load resources; in order to properly account for these resources, BEEP dispatches would also need to be factored in. Rather than unnecessarily complicate work, the decision was made to exclude these IDs.

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Field Name	Description
LOAD_ID	Load ID
CNIGS_ZONE_RAW	Congestion Zone the unit is located within.

• NOTE: for Units in ZP-28, there will be duplicate records in this table, one for ZP-28 and one for SP-15, due to the fact that ZP-28 was carved out of the SP-15 zone on 1 February 2000. In order to use this data, you'll need to extract those duplicates and, if before 1 February 2000, replace ZP-28 with SP-15.

Field Name Description

SC_ID	Scheduling coordinator identification.
OPR_DT	Operation date.
OPR_HR	Operation hour.
MKT_TYPE	Market type ('D' = day-ahead and 'H' = hour-ahead).
LOAD_ID	Load identification.
SCH_CLASS	'P' = Preferred Schedule; 'R' = Revised Preferred Schedule
BID_FLG	'Y' = Schedule is for bid nomination
CONTRACT_REF	Contract reference number.
CNGS_MGT_FLG	'Y' = congestion management was required in the area of this schedule.
POST_ADJ_FLG	Unused
CNGS_MGT_ADJ	'Y' = schedule was adjusted during the congestion management process.
GRID_CONTR_REF	Unused
GRID_CONTR_MW	Unused
NO_OF_SEG	Number of bid segments submitted.
MW1	Adjustment capacity from bid segment #1.
MW2	Adjustment capacity from bid segment #2.
MW3	Adjustment capacity from bid segment #3.
MW4	Adjustment capacity from bid segment #4.
MW5	Adjustment capacity from bid segment #5.
MW6	Adjustment capacity from bid segment #6.
MW7	Adjustment capacity from bid segment #7.
MW8	Adjustment capacity from bid segment #8.
MW9	Adjustment capacity from bid segment #9.
MW10	Adjustment capacity from bid segment #10.
MW11	Adjustment capacity from bid segment #11.
PR1	Bid price for adjustment bid segment #1.
PR2	Bid price for adjustment bid segment #2.
PR3	Bid price for adjustment bid segment #3.
PR4	Bid price for adjustment bid segment #4.
PR5	Bid price for adjustment bid segment #5.
PR6	Bid price for adjustment bid segment #6.
PR7	Bid price for adjustment bid segment #7.
PR8	Bid price for adjustment bid segment #8.
PR9	Bid price for adjustment bid segment #9.
PR10	Bid price for adjustment bid segment #10.

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Field Name	Description
PR11	Bid price for adjustment bid segment #11.
HRLY_MW	Initial preferred schedule.
ADJ_MW	Interim schedule after first run of congestion management.
FIN_MW	Final schedule after last run of congestion management.
ADJ_NET_MW	Net Adjusted Schedule
FIN_NET_MW	Final Net Schedule
HRLY_GROSS_MW	Hourly Gross Schedule
USER_COMMENTS	Comment field.

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Field Name	Description
OPR_DT	Operation date.
OPR_HR	Operation hour.
RT_INTERVAL	Sub-hour Interval
CNGS_ZONE	Internal Congestion Zone
ZN_INC_PRC	Zonal 10-minute Incremental Imbalance Energy Price
ZN_DEC_PRC	Zonal 10-minute Decremental Imbalance Energy Price
INC_MWH	Acknowledged Zonal 10-minute Incremental Imbalance Energy Quantity
DEC_MWH	Acknowledged Zonal 10-minute Decremental Imbalance Energy Quantity

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Field Name	Description
SC_ID	Scheduling coordinator identification.
TRADE_INT	Trade date.
TRADE_HR	Trade hour
SUBHOUR_INT	Sub hour interval
LCTN_ID	Location identification, e.g. Load identification.
UNALLOC_QTY	Metered Quantity

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Field Name	Description
SC_ID	Scheduling coordinator identification.
TRADE_INT	Trade date.
TRADE_HR	Trade hour
LCTN_ID	Location identification, e.g. Load identification.
UNALLOC_QTY	Metered Quantity

Field Name	Description
TIE_POINT	Tie Point
OPR_DT	Operation date.
OPR_HR	Operation hour.
TIE_GMW	Calculated Forecasted Generation Meter Multiplier on the Inter tie

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Description
Utility distribution company identification
Unit identification

Field Name
UDC_ID
UNIT_ID

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Description	
UDC_ID	Utility distribution company identification
LOAD_ID	Load Point Identification

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Field Name	Description
UNIT_ID	Unit Identification
OPR_DT	Operation date.
OPR_HR	Operation hour.
UNIT_GMM	Calculated Forecasted Generation Meter Multiplier for the generation unit

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Field Name	Description
OPR_DT	Operation date.
OPR_HR	Operation hour.
SC_ID	Scheduling coordinator identification.
LOAD_SCH_MW_D_P	Sum of Load Schedules in the Day-Ahead Preferred Market
LOAD_SCH_MW_D_R	Sum of Load Schedules in the Day-Ahead Revised Preferred Market
LOAD_SCH_MW_H_P	Sum of Load Schedules in the Hour-Ahead Preferred Market
M_LOAD	Sum of Metered Load
H_M_LOAD_DELTA	LOAD_SCH_MW_H_P - M_LOAD
INC_MWH	Zonal Acknowledged Incremental Energy
DEC_MWH	Zonal Acknowledged Decremental Energy
INC_COST	Total cost of Zonal Acknowledged Incremental Energy
DEC_COST	Total cost of Zonal Acknowledged Decremental Energy
LOSS	Sum of Transmission losses
EST_UNINSTR_STLMT	Estimated Uninstructed energy Settlement Amount, as described in the Methodology document.
MONTH	Month.
YEAR	Year.
OVERSCH_THRSH_LVL	Overbidding Threshold level, as described in the Methodology document
LOAD_DEV	H_M_LOAD_DELTA/M_LOAD; if M_LOAD = 0, then H_M_LOAD_DELTA/0.01.
OVERSCH_FLG	if H_M_LOAD_DELTA > 0, then 1; else 0.
OVERTHRSH_FLG	if H_M_LOAD_DELTA > OVERSCH_THRSH_LVL, then 1; else 0.
CASE	if Pre-Refund Period: 1, if Refund Period: 2

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**Two (2) CD-ROMs
Containing Confidential Information
Redacted**

CERTIFICATE OF SERVICE

In accordance with the order issued by the Presiding Administrative Law Judge I hereby certify that I have this day served the foregoing document, except for the CD-ROM attachments designated as Protected Materials, by posting an electronic copy on the Listserv for this proceeding, as maintained by the Commission.

Dated at Washington, DC, on this 16th day of January, 2004.



Michael Kunselman