Perkins Coie

1120 N.W. Couch Street, Tenth Floor
Portland, OR 97209-4128
PHONE: 503.727.2000
FAX: 503.727.2222
www.perkinscoie.com

James M. Van Nostrand
PHONE: (503) 727-2162
FAX: (503) 346-2162
EMAIL: JVanNostrand@perkinscoie.com

August 10, 2007

VIA E-MAIL AND OVERNIGHT DELIVERY

Public Utility Commission of Oregon
Attention: Filing Center
550 Capitol St NE #215
Salem OR 97308-2148

Re: ***Docket UM 1002 – Wah Chang, Petitioner v. PacifiCorp, Respondent***
PacifiCorp's Supplemental Exhibit Replacing Exhibit WC//1136

Dear Sir or Madam:

During the hearings on Tuesday, August 7, Wah Chang offered its exhibit WC/1136, consisting of pages 1, 2, 33 and 34 of the testimony of Richard D. Tabors on behalf of PGE in a proceeding before the Federal Energy Regulatory Commission, Docket Nos. EL02-114-000 and EL02-115-001. PacifiCorp objected to the entry of the exhibit on the grounds that it was incomplete and failed to provide the context in which the testimony was offered. Judge Power overruled the objection and allowed the exhibit to be admitted, but indicated that PacifiCorp would be permitted to supplement the exhibit as necessary to provide the complete testimony as well as indicate the context in which the testimony was offered. Enclosed as proposed Exhibit PacifiCorp/73 is the complete text of the testimony of Richard D. Tabors, as well as the FERC Order Initiating Investigation in Docket No. EL02-114-000 and Order Approving Uncontested Partial Settlement in Docket Nos. EL02-114-000, EL02-114-006, EL02-115-001 and EL02-115-007. PacifiCorp offers this exhibit as a replacement for Exhibit WC/1136.

Very truly yours,

James M. Van Nostrand

cc: Service List
ALJ Patrick Power

24878-0008/LEGAL13465543.1

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UM 1002

WAH CHANG, Petitioner, v. PACIFICORP, Respondent.	**HEARING EXHIBIT**

Supplemental Exhibit Replacing Exhibit WC/1136

UNITED STATES OF AMERICA 100 FERC ¶ 61,186
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Pat Wood, III, Chairman;
William L. Massey, Linda Breathitt,
And Nora Mead Brownell.

Portland General Electric Company
Enron Power Marketing, Inc.

Docket No. EL02-114-000

ORDER INITIATING INVESTIGATION, AND ESTABLISHING HEARING PROCEDURES AND REFUND EFFECTIVE DATE

(Issued August 13, 2002)

1. In this order we are initiating an investigation into instances of possible misconduct by two Enron Corporation affiliates: Enron Power Marketing, Inc. (EPMI) and Portland General Electric Company (Portland) (collectively, Enron) to determine whether the misconduct occurred and, if so, to determine remedies, including possibly refunds and/or revocation of Portland's and/or Enron's market-based rate authority.

2. As discussed below, we will set the possible misconduct for hearing and establish a refund effective date under section 206 of the Federal Power Act (FPA), 16 U.S.C. § 824e (1994), to provide for refunds should the hearing indicate that they are warranted.

Background

3. On February 13, 2002, the Commission directed a Staff fact-finding investigation into whether any entity manipulated short-term prices in electric energy or natural gas markets in the West or otherwise exercised undue influence over wholesale prices in the West for the period January 1, 2000 forward.[1]

4. On May 8, 2002, in accord with the Commission's directive, Commission Staff issued a data request concerning various trading strategies of sellers of wholesale

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[1]Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices, 98 FERC 61,165 (2002) (February 13 Order).

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electricity and/or ancillary services in the United States portion of the Western System Coordinating Council during 2000-2001. Among the sellers to whom the data request was sent are public utilities who were granted market-based rate authority by this Commission based on a finding that they lacked market power and there was no evidence of affiliate abuse or reciprocal dealing.

5. On June 4, 2002, the Commission issued an order[2] finding that Portland and others had failed to cooperate with the Commission investigation and ordered those companies to show cause why their authority to charge market-based rates should not be revoked as a result of their failure to comply with the Commission-ordered investigation.

Discussion

6. In a Commission Staff initial report, being publicly released concurrently with this order,[3] Commission Staff states that it has obtained preliminary evidence of possible violations by Portland and Enron (specifically, EPMI) of their codes of conduct and the Commission's standards of conduct. Codes of conduct govern, among other things, a power marketer's relationship with its traditional public utility affiliates, including limitations on its ability to sell power at market-based rates to its affiliate with captive customers and the pricing of sales of non-power goods and services between the affiliates. In addition, any sharing of information between Portland and Enron must be simultaneously disclosed to the public. The Commission reviews and accepts codes of conduct and market-based rate tariffs as part of the power marketer's application for market-based rate authority.

7. Standards of conduct are contained in the Commission's regulations[4] and generally require that the employees of a transmission provider engaged in transmission system operations function independently of those employees engaged in the wholesale

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[2]Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices, 99 FERC ¶ 61,272 (2002) (Show Cause Order).

[3]Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices, Initial Report on Company-Specific Separate Proceedings and Generic Reevaluations; Published Natural Gas Price Data; and Enron Trading Strategies, Docket No. PA02-2-000, August , 2002. This report is available on the Commission's website at: http://www.ferc.gov/electric/bulkpower/pa02-2/pa02-2.htm

[4]18 C.F.R. § 37.4 (2002).

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merchant function (and also of employees engaged in the wholesale merchant function of any of the transmission provider's affiliates). For example, the standards of conduct require that employees of Portland's transmission function act independently of employees of Portland's merchant function and of employees of EPMI's merchant function.

8. Preliminary evidence, taken from transcripts of recorded telephone conversations, indicates that Portland and Enron knowingly engaged in transactions that may constitute violations of the standards of conduct and/or the companies' codes of conduct and/or market-based rate tariffs.

9. For example, in the transcripts, an Enron employee explains to a Portland employee that they cannot buy and sell energy directly, but must use a non-affiliated utility as a middle man. There is also evidence that Portland employees believed that the requests they were receiving from their affiliates were improper. For example, when two Portland transmission function employees are discussing an Enron request for such a three-party arrangement, one reports that a third employee thinks the arrangement is not legal. In another instance, a Portland transmission function describes the three-party arrangement as "a scam." In addition, Portland has failed to properly post data related to sales to Enron for a significant amount of transactions.

10. This information supports further investigation. We will accordingly initiate a separate proceeding to investigate possible violations by Portland and Enron (specifically, EPMI) of their codes of conduct or market-based rate tariffs and the Commission's standards of conduct, and the imposition of any appropriate remedies.

11. Staff's initial on-site investigation in Portland, Oregon, identified questionable transactions with affiliates. Subsequently, in April 2002, Portland contacted the Commission's enforcement staff and conducted informal discussions about this matter. Issues concerning these affiliate transactions are included in the proceeding we are now initiating.

12. As noted above, in the Show Cause Order, the Commission found that Portland had failed to cooperate with the investigation initiated in the February 13 Order and ordered Portland to show cause why its market-based rate authority should not be revoked. In response to the Show Cause Order, Portland provided information that was largely limited to the previously identified transactions involving Enron. Accordingly, as part of the hearing ordered herein, we will set for hearing the issue of whether Portland has in fact provided all relevant information in the investigation and what the appropriate

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remedies for any failure should be, including whether Portland's market-based rate authority should be revoked.

13. In cases where, as here, the Commission institutes a section 206 investigation on its own motion, section 206(b) requires that the Commission establish a refund effective date that is no earlier than 60 days after publication of notice of the Commission's investigation in the Federal Register, and no later than five months subsequent to expiration of the 60-day period. In order to give maximum protection to consumers, we will establish the refund effective date at the earliest date allowed, [5] 60 days after publication of notice of initiation of the Commission's investigation in Docket No. EL02-114-000 in the Federal Register.

14. Section 206(b) also requires that if no final decision is rendered by the refund effective date or by the conclusion of the 180-day period commencing upon initiation of a proceeding pursuant to section 206, whichever is earlier, the Commission shall state the reasons why it has failed to do so and shall state its best estimate as to when it reasonably expects to make such a decision. To implement that requirement, we will direct the presiding judge to provide a report to the Commission 15 days in advance of the refund effective date or the conclusion of the 180-day period, whichever is earlier, in the event the presiding judge has not by the earlier of those two dates certified to the Commission: (1) a settlement which, if accepted, would dispose of the proceeding; or (2) an initial decision. The judge's report, if required, shall advise the Commission of the status of the investigation and provide an estimate of the expected date of certification of a settlement or an initial decision.

The Commission orders:

(A) Pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by section 402(a) of the Department of Energy Organization Act and the Federal Power Act, particularly section 206 thereof, and pursuant to the Commission's Rules of Practice and Procedure and the regulations under the Federal Power Act (18 C.F.R., Chapter I), a public hearing shall be held in Docket No. EL02- -000, concerning the matters discussed in the body of this order.

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[5] See, e.g., Canal Electric Company, 46 FERC ¶ 61,153, reh'g denied, 47 FERC ¶ 61,275 (1989).

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(B) The Secretary shall promptly publish a notice of the Commission's initiation of the proceeding in Docket No. EL02-114-000 in the Federal Register.

(C) The refund effective date in Docket No. EL02-114-000 will be 60 days following publication in the Federal Register of the notice discussed in Ordering Paragraph (B) above.

(D) A presiding judge to be designated by the Chief Judge shall convene a conference in this proceeding to be held within approximately fifteen (15) days of the date the Chief Judge designates the presiding judge, at a hearing room of the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, D.C. 20426. Such conference shall be held for the purpose of establishing a procedural schedule. The presiding judge is authorized to establish procedural dates and to rule on all motions (except motions to dismiss), as provided in the Commission's Rules of Practice and Procedure.

(E) The presiding judge shall advise the Commission, no later than 15 days prior to the refund effective date, in the event that the presiding judge has not by that date certified to the Commission a settlement which, if accepted, would dispose of the proceeding or issued an initial decision, as to the status of the proceeding and the best estimate of when the proceeding will be disposed of by the presiding judge.

By the Commission.

(S E A L)

Linwood A. Watson, Jr.,
Deputy Secretary.

Exhibit No. PGE-23

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Portland General Electric Company	**)**	**Docket No. EL02-114-000**
Enron Power Marketing, Inc.	**)**	**Docket No. EL02-115-001**

DIRECT TESTIMONY

OF

PORTLAND GENERAL ELECTRIC COMPANY

Richard D. Tabors

February 24, 2003

Portland General Electric Company
Docket No. EL02-114-000
Docket No. EL02-115-001

Summary of the Testimony Of Richard D. Tabors

In his testimony, Dr. Richard D. Tabors evaluates the potential impact on electricity markets in California of particular transactions undertaken by Enron Power Marketing, Inc. ("EPMI"), associated with the EPMI's trading strategy referred to as "Death Star." The testimony consists of two major parts. In the first part, Dr. Tabors provides general economic analysis of the Death Star strategy and explains the role of the transactional elements of Death Star from the point of view of the economics of energy trading. In the concluding part of his testimony, Dr. Tabors provides, by an example, a qualitative evaluation of the impact of the Death Star strategy on electricity consumers in California.

Based on the analysis carried out in his testimony, Dr. Tabors clearly demonstrates that the so-called "Death Star" strategy caused no harm to the operations of the California electricity market. Moreover, this strategy benefited electricity consumers in the state of California. The strategy consisted of EPMI submitting a series of transaction schedules that had the effect of giving the CAISO access to additional transmission facilities that the CAISO then was able to use to relieve congestion between Northern and Southern California. In addition, it provided incremental capacity at certain congested external scheduling points, predominantly at the California-Oregon Border (COB). This incremental transmission capability was from physical transmission rights that EPMI had purchased from LADWP under long-term contract. EPMI was paid an appropriate amount for the congestion relief that it created.

Finally, Dr. Tabors concludes that it is unreasonable to assess financial penalties on the basis of harm allegedly caused by the Death Star strategy, because the latter was not harmful. On the contrary, it was beneficial.

Direct Testimony of Richard D. Tabors

I. Introduction

Q. Dr. Tabors, please state for the record your name, occupation, and business address.

A. My name is Richard D. Tabors. I am president of Tabors Caramanis & Associates ("TCA"). Our offices are located at 50 Church Street, Cambridge, MA 02138. I am also a Senior Lecturer at Massachusetts Institute of Technology ("MIT") in the Technology and Policy Program in the School of Engineering.

Q. Please describe your general background in electric power systems.

A. I have thirty years of experience in electric power systems as a consultant, researcher and lecturer. My experience has been in the areas of planning, regulating and most recently restructuring electric markets. My background of particular relevance to this proceeding is summarized below and outlined in detail in Exhibit No. PGE-24.

Q. Please describe your specific experience with the restructuring of wholesale electric markets.

A. As Assistant Director of the Laboratory for Electromagnetic and Electronic Systems ("LEES") at the Massachusetts Institute of Technology between 1984 and 1996, I led numerous research and development projects on electric systems markets and planning. This included work with several colleagues on the development of the concepts of Spot Pricing and the theory of spatial spot pricing upon which Locational Marginal Pricing is based. I have co-authored 5 books on different aspects of energy and environment and numerous professional articles regarding energy markets and power systems. I am now, with a co-author, under contract to complete a text on electric power markets with Kluwer Academic Press.

Since founding TCA in 1989, the majority of my consulting has been related to restructuring of electric markets. From 1991 to 1995, I was a member of the consulting team advising the National Grid Company in the U.K. on commercial practices of a stand-alone transmission company operating in a deregulated wholesale market. Since 1994 I have been advising clients on a range of restructuring related issues in the United States, at both the federal and state level. In that role, I have testified before the Federal Energy Regulatory Commission ("Commission") as well as before regulatory agencies in California, Maine, Maryland, Massachusetts, New Jersey, Wisconsin and Alberta (Canada). In those cases my clients have included state Attorney General offices, utilities and marketers.

My work on issues in wholesale generation markets throughout the US includes a series of analyses for clients on the cause and impact of the Midwest price spikes in the summer of 1998 and an analysis of alternative auction methods for the California Power Exchange. Through work at both TCA and at MIT, I have completed a number of studies of real-time (electricity) pricing and customer response to real time prices.

Q. **What is the purpose of your testimony in this proceeding?**

A. TCA has been retained by Portland General to evaluate the potential impact on electricity markets in California of particular transactions undertaken by Enron

Power Marketing, Inc. ("EPMI"), and the extent to which those transactions are associated with the EPMI trading strategy referred to as "Death Star." The ultimate objective of my testimony is to carefully analyze the Death Star strategy and assess whether the transactions carried out to implement that strategy caused any harm to consumers in California and in other areas of the WECC.

Q. **Please summarize your conclusions.**

A. Although we do not have sufficient information to know for certain that the services Portland General provided EPMI were part of a larger Death Star strategy, for purposes of my analysis I assumed that those transactions were indeed a part of that strategy as described in various internal Enron documents that now have become public. Nevertheless, a thorough analysis of the Death Star strategy described in my testimony clearly demonstrates that this strategy caused no harm to the operations of the California electricity market. Moreover, this strategy benefited electricity consumers in the state of California. The strategy consisted of EPMI submitting a series of transaction schedules that had the effect of giving the CAISO access to additional transmission facilities that the CAISO then was able to use to relieve congestion between Northern and Southern California. In addition, it provided incremental capacity at certain congested external scheduling points, predominantly at the California-Oregon Border ("COB"). This incremental transmission capability was from physical transmission rights that EPMI had purchased from LADWP under long-term contract. EPMI was paid an appropriate amount for the congestion relief that it created.

To be more specific, I concluded that the Death Star was an economically sound strategy because:

- it helped the CAISO to relieve congestion in forward markets;
- congestion was relieved because the CAISO gained access to additional transmission capacity (in the examples that I use, 24 MW from LADWP) that would not otherwise have been available to it;
- it improved the efficiency of unit commitment in the CAISO system;
- the payment EPMI collected through this strategy was fair and based on the market value of the transmission service it provided;
- the societal benefit of Death Star was either equal to or, more likely, *greater than* the payment received by EPMI;
- Death Star caused no harm and most likely benefited the operations of the California electricity market in real-time.

Q. How did the Death Star transactions provide the CAISO access to additional transmission for relieving congestion between Northern and Southern California?

A. I provide a much more detailed explanation of the Death Star strategy later in my testimony, but a brief summary might be helpful at this point. EPMI had purchased, from Los Angeles Department of Water and Power ("LADWP"), long-term firm point-to-point transmission rights from the California-Oregon Border ("COB") into Southern California. When EPMI submitted a schedule with LADWP for delivery of 24 MW of power into Southern California at the Palo Verde scheduling point, LADWP was put on notice that 24 MWs of its transmission capacity should be set aside for the purpose of that delivery. Simultaneously EPMI submitted to CAISO a schedule for a northbound counter-flow from Palo Verde to COB. That put CAISO on notice that because of that 24 MW south to north counter-flow, the CAISO would have access to an additional 24 MW of north to south transmission. To the CAISO this meant that it could schedule an additional 24 MW of lower cost power in Northern California and schedule delivery of that power into the congested Southern California zone. Thus as a result of schedules submitted by EPMI, LADWP set aside transmission capacity for delivery of 24 MW of power from north to south and the CAISO effectively received access to that transmission capacity. That in turn, allowed the CAISO to alter its generation schedule and therefore reduce generation costs in California. In sum, congestion between Northern and Southern California was relieved and EPMI was paid an appropriate fee for that congestion relief.

Q. **What information have you examined for the purpose of this proceeding to analyze EPMI's Death Star strategy?**

A. I have examined the following documents and data sources:

- The December 6 and December 8, 2000 memoranda from Christian Yoder and Stephen Hall to Richard Sanders (further referenced as Yoder-Hall memos, Exhibit No. S-20);
- The memorandum from Gary Fergus and Jean Fitzell to Richard Sanders with no date (Exhibit No. S-20);
- The analysis of the Death Star trading strategy presented in the testimony of Barry Sullivan in this proceeding (Exhibit No. S-19);

- The Forney Perpetual Loop Schematics (Exhibit No. S-21);
- The Driscoll Memo to the Portland Shift (Exhibit No. S-21);
- The Report on Enron's Trading Strategies prepared by the California Independent System Operator (CAISO) Dated October 4, 2002 ("CAISO Report") included as a part of Exhibit No. PGE-25 to this testimony;
- The Supplement to the CAISO Report dated January 7, 2003 specifically addressing the Death Star strategy also included as a part of Exhibit No. PGE-25 to this testimony;
- Work papers accompanying the CAISO Report and the supplement to this report;
- Historical market data obtained from the CAISO through data requests furnished in this proceeding.

Q. **Are your conclusions in agreement with those made by the CASIO in its report?**

A. Yes, for the most part. According to the CAISO October 4, 2002 report, Death Star "... may have the effect of reducing congestion charges in the Day Ahead and Hour Ahead market by, in effect, allowing the CAISO's congestion management model to 'divert' energy scheduled by other SCs over the congested path over the transmission lines outside the CAISO system over which the circular schedule is made." In other words, at least from the perspective of the forward market, the CAISO concluded that the Death Star was not harmful and was likely beneficial. The CAISO report raised some theoretical concerns with respect to the possible impact of Death Star on operations in the Real-time Market

("RTM"). As I explain later in this testimony, those concerns are not material when compared to the benefits of transactions like Death Star. Moreover, essentially the same concerns arise with all multi-party transactions that import or export power into or out of California.

Q. Is your testimony coordinated with that of others?

A. Yes, my testimony has been developed and coordinated with that of Professor Judith Cardell and Mr. Joseph R. Taylor. Prof. Cardell's testimony provides a description of the physics of transmission and a discussion of specific elements of the California electricity market relevant to the Death Star strategy. Prof. Cardell's testimony lays the foundation for understanding how a market participant could utilize physical transmission assets within California that are outside of the control of the CAISO and I support her testimony on those issues. In my opinion, understanding the physical and structural idiosyncrasies of transmission in California is key to understanding the Death Star strategy. Mr. Taylor provides a detailed discussion of the trading practices in use by traders in the Pacific Northwest and their relevance to the trading pattern seen in the Death Star strategy.

Q. How is the balance of your testimony organized?

A. The balance of my testimony consists of two sections.

In the first section, I provide a general economic analysis of the Death Star strategy and explain the role of the transactional elements of Death Star from the point of view of the economics of energy trading.

In the second section, I provide, by an example, a qualitative evaluation of the impact of the Death Star strategy on electricity consumers in California.

Q. Do you testify on any quantitative analysis of the impact of the Death Star?

A. Not at this time. Due to the delay in the CAISO's response to Portland General data requests, I did not have sufficient time to complete my quantitative analyses. Thus, I would like to reserve the right to file testimony on that issue as soon as all of the data have been received and the data analyzed.

II. The Economics of the Death Star Strategy

Q. Dr. Tabors, how would you define EPMI's Death Star trading strategy?

A. Death Star was a set of simultaneous scheduled transactions across several paths forming a loop along elements of the WSCC transmission grid. The financial objective of Death Star was to collect congestion payments on the transmission grid administered by the CAISO in exchange for giving the CAISO access to additional physical transmission capacity. That capacity was controlled by EPMI and was available for the transfer of energy from Northern to Southern California.

Q. What source of information did you primarily rely upon in formulating that definition?

A. Primarily I relied upon the Forney Perpetual Loop schematics included in this testimony as Exhibit No. PGE-26 and also on the Driscoll memo included as Exhibit No. PGE-27.

Q. Which electricity markets in California did the Death Star strategy affect?

A. The predominant impact of the Death Star strategy was upon the forward, Hour-Ahead market, but it is likely that it also had a positive impact in real-time.

Q. Please describe the simultaneous transactions forming the Death Star loop.

A. Let us use as a point of departure the Forney Perpetual Loop Schematics presented on Exhibit No. PGE-26. This loop appears to consist of two major elements. The first element, which is outside of California, depicts the flow from the California-Oregon Border ("COB") to John Day ("JD"), back to COB and then from COB to Palo Verde ("PV"). The second element, which is inside California, depicts the counter-flow (presented as a dashed line) from PV to COB.

Thus it appears from that diagram that the power flows in a loop. The handwriting on Exhibit No. PGE-26 states, "No MW's flow, just call in schedules," and it makes you think that by implementing these call-in schedules EPMI could collect congestion relief payments for the counter-flow in perpetuity. Later in my testimony I will explain why this is not the case.

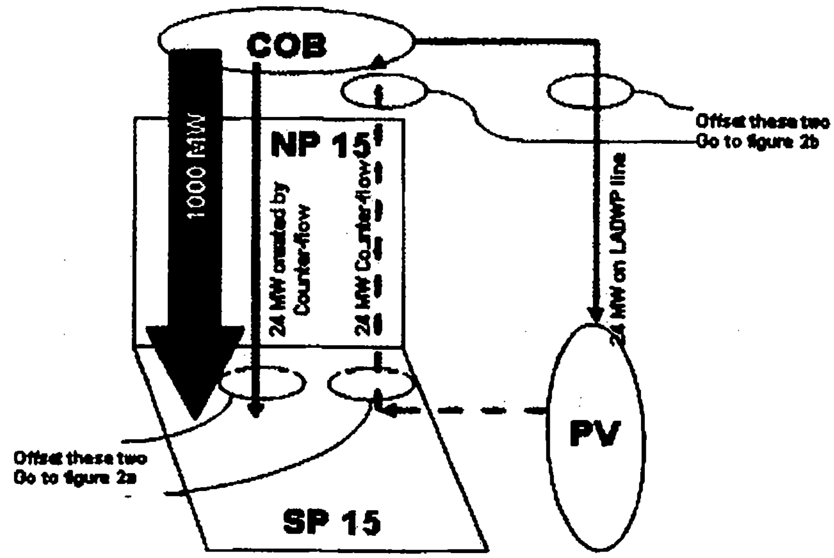
Q. **Does this diagram represent an accurate and comprehensive representation of the Death Star strategy?**

A. As far as it goes it does. The document that we are using represents notes taken by a trader and therefore contains the elements of the strategy necessary for that trader to implement the strategy. In this sense the notes represent the information that the trader needed to know. However, to understand the economics of Death Star, this schematic needs to be augmented.

Q. **What should be added to the Forney schematic?**

A. We should add the very central aspect of the California system, the source of revenues in the Death Star strategy, namely the congested transmission path linking Northern California with Southern California. I have attached as Figure 1

Figure 1
Augmented Forney Loop Diagram



the same looped diagram but have added two arrows leading from COB through Northern California to Southern California. The first wide blue arrow, marked as 1000 MW, represents the portion of the transmission system interface between Northern and Southern California (Path 15 and Path 26) that is controlled by the CAISO. This wide arrow marked "1000 MW" reflects the approximate level of north to south transmission capacity within the CAISO's control. The wide arrow points north to south. This is the direction in which net power flows were moving on that system at the times in question. The second narrow blue arrow pointing south, marked as "24 MW created by counter-flow" represents the incremental capacity north to south on the transmission system. This incremental capacity was created by 24 MW of the south to north counter-flow schedule that was a part of the Death Star strategy. On this diagram, the 24 MW counter-flow is shown as a red dash line directed south to north from PV to COB. The green solid line from COB south to PV represents physical transmission capacity rights EPMI purchased from LADWP on transmission facilities outside of CAISO control.

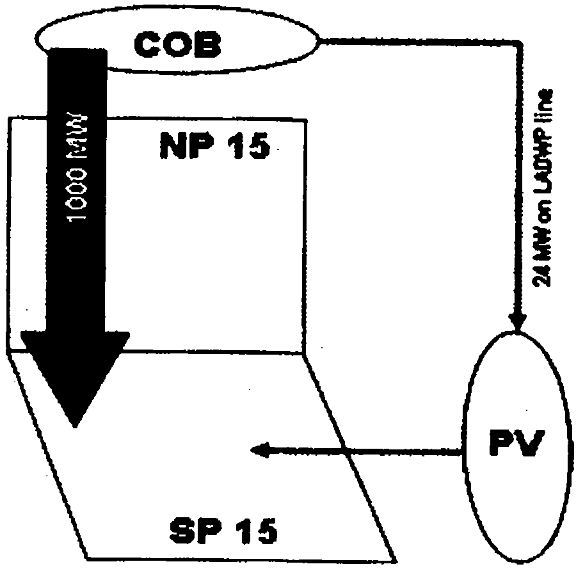
Q. Why is it necessary to show the center 24 MW arrow?

A. This center narrow blue arrow reflects the effect of a counter-flow. As explained by Prof. Cardell, counter-flows increase capacity available on a line. When the CAISO accepts a *south to north* counter-flow schedule (depicted on Fig. 1 as a red dash line), it accounts for it by increasing by an equal amount the *north to south* transfer capability of the transmission system within its control.

Q. But would not this south to north counter-flow and an incremental flow from north to south offset each other?

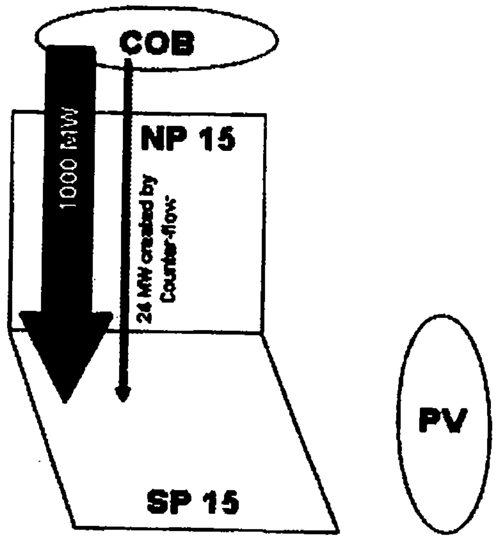
A. As I explained above, the 24 MW counter-flow scheduled by EPMI would create 24 MW of additional transmission capacity going north to south. The CAISO can take advantage of this new transmission capacity by scheduling additional flow of 24 MW into the congested Zone SP15. As Mr. Taylor and Prof. Cardell point out, control area operators often will net out schedules submitted in opposite directions. Thus, one way in which an operator might view these transactions is depicted in Figure 2a which shows Figure 1 redrawn with two 24 MW schedules over the CAISO facilities netted against each other. Because those schedules net to zero, they are no longer shown on Figure 2a.

Figure 2a
Death Star: View 1 Scheduled Net Flow
Counter-flow offsets incremental flow



There is a second and equally valid way to depict the net effect of Death Star schedules. Another diagram (Figure 2b) again shows Figure 1 redrawn, but this time the 24 MW counter-flow, scheduled by EPMI is netted against the 24 MW flow from North California (COB) to Southern California scheduled by EPMI over its transmission rights on LADPW facilities. Again, since these two schedules net to zero, they are not shown on Figure 2b.

Figure 2b
Death Star: View 2 Capacity added to CAISO System
Counter-flow offsets flow on LADWP line



I must stress again that Figures 2a and 2b are equivalent to each other and to the diagram on Figure 1. Therefore, each of them provides an accurate representation of the Death Star strategy. What is significant is that each of these figures demonstrates how Death Star transactions allow congestion into Southern California to be relieved by allowing the transmission of 24 additional MW from Northern to Southern California.

BEGIN PROTECTED MATERIAL

END PROTECTED MATERIAL

Q. Dr. Tabors, from the standpoint of theoretical economics or market theory, was this a reasonable transaction?

A. Yes, it was. EPMI paid for the use of the asset (to LADWP), then turned this asset over for the CAISO to schedule. For this EPMI received an agreed upon compensation. As with all market transactions, EPMI took the risk that the product it offered would not be purchased, e.g., a risk that market conditions would not allow it to recover its incurred transaction costs.

Q. You mentioned earlier that the term "perpetual loop" mischaracterizes this strategy. Why is that so?

A. To answer this question, let us first ask ourselves another question. If the Death Star strategy was a perpetual money-making machine, why did EPMI schedule counter-flow for only 24 MW as opposed to scheduling a counter-flow for a much larger quantity, say 100 MW? The answer is that the level of the counter-flow was not arbitrary. It was tied to the physical asset supporting that counter-flow, the available capacity of the transmission line EPMI leased from LADWP. This so-called money making machine was in fact the means of providing the CAISO with congestion relief service in exchange for the market value of congestion net of transaction costs. As Prof. Cardell explained, a counter-flow not supported by a physical asset is neither physically nor financially viable. Similarly to machines that are claimed to have perpetual motion – which, of course, contradict the basic laws of physics – the perpetual money-making loop contradicts the basic laws of economics. Both seem to entertain our imagination yet both are equally impossible.

Q. Why did a strategy that was relatively simple and seemingly beneficial to California consumers require such a complicated set of transactions utilizing facilities outside of the system managed by the CASIO?

A. There are two major reasons underlying the need for such a complicated set of transactions. First, the LADWP transmission line used by EPMI is physically a part of the transmission grid in the state of California but is outside of the system controlled by the CAISO. As such it is not available to be used as a part of the CAISO congestion management analytic system.

Second as is discussed in greater detail later, the historical trading practice that emerged well before the California market was deregulated precluded any transactions occurring between Northern and Southern California that did not use entirely "within California" transmission facilities or control points.

Q. Please explain the importance of the fact that the transmission capacity

EPMI contracted from LAWPD was outside of the CASIO control.

A. This is important for two reasons. First, EPMI, as a holder of physical rights on transmission outside of the CAISO's control, could receive congestion relief payments only by scheduling a counter-flow in combination with paired import and export schedules. There was no other way in the forward market to be paid for the use of this line for congestion relief.

Second, as Prof. Cardell explained in her testimony, another mechanism for receiving congestion payments in CAISO market is to acquire Firm Transmission Rights ("FTRs"). However, the CAISO does not control the entire California transmission system. Only transmission capacity that is within CAISO control is available in the FTR market. The LADWP line, for instance, is outside of this market. If this transmission capacity were within the CAISO control, and had EPMI had the FTRs for this 24/MW, it would not have needed to enter such a complicated system of transactions to be paid the congestion value between COB and SP15. It simply could have purchased FTRs for that capacity and received the same congestion payment as other holders of similar FTRs.

Q. **When they relieved congestion, would EPMI receive the same congestion payment as holders of FTR rights?**

A. Yes, for each transmission segment between COB and SP15 both EPMI (for the Death Star transactions) and holders of FTRs for that segment would receive identical per-MWH congestion payments. However, unlike EPMI, FTR holders would not have to incur the transaction costs associated with moving power throughout the entire set of elements outside of the CAISO system. Moreover, by engaging in Death Star transactions, EPMI increased transmission capacity available to the CAISO for managing congestion by bringing additional transmission capacity to the CAISO. FTR holders merely collected their congestion payments, and they provide no incremental capacity.

Q. **Could you identify on which transmission segments EPMI was eligible to collect congestion charges for the counter-flow associated with the Death Star schedule?**

A. Assuming that the counter-flow was scheduled from Mead or Palo Verde to Malin ("COB"), EPMI could receive payment for relieving congestion and/or be charged congestion costs, depending on the direction in which particular transmission elements were binding. Relevant transmission paths identified by the CAISO in its October 4, 2002 report included Path 15, Path 26, transmission leading to the export scheduling point at Malin from Zone NP15, and transmission leading from the import point at either Palo Verde or Mead to Zone SP15.

Q. **Were FTRs available on all those transmission segments?**

A. No. It is my understanding that no FTRs were available on Path 15 and no auction for such FTRs was conducted. However, FTRs were available on other transmission segments.

Q. **Why didn't EPMI simply use its rights on the LADWP path from COB to Southern California to schedule exports from Northern California and import into Southern California instead of using the LADWP path combined with the additional legs in Oregon?**

A. As introduced earlier, it has never been possible to directly schedule the export of energy from Northern California to COB and into Southern California over facilities that now are controlled by the CAISO and were previously controlled by California Investor-Owned Utilities. Traders call this type of transaction (see testimony of Joseph R. Taylor) "bouncing" power off of the south side of the COB hub. Bouncing power off of the south side of the COB hub has never been permitted due to scheduling protocols historically used in California. These restrictive protocols existed well before the initiation of the CAISO structure and simply were carried forward from the time when Pacific Gas & Electric Company (PG&E) controlled the south side of the COB hub.

Transaction operators outside California do not have similar restrictions in their scheduling protocols. Consequently, bouncing power off of the north side of COB became a well recognized practice among traders on the WECC system. It was known among traders as a COB HUB transaction and existed well before the CAISO market was put in place. As Mr. Joseph R. Taylor explains in his testimony in this proceeding, a COB HUB transaction would typically occur when the power is scheduled from a Northwest control area source such as Puget Sound Energy, with an ultimate sink in another Northwest control area, such as PacifiCorp. The transaction path would, however, go through COB. In reality, these transactions usually boil down to using COB (or other hubs) as a convenient location to purchase and resell power. These types of trades are typical in the Pacific Northwest and, as Mr. Taylor testifies, they were the topic of workshops for traders learning how to schedule these transactions.

While bouncing power off COB was typical and legitimate north of California, such transactions were not allowed south of COB. As Mr. Taylor testified, PG&E and then the CAISO always required power to sink north of COB before it could return to California. That it was not (and still is not) possible to "bounce" off of the south side of COB has meant that any transactions initiated in Northern California that were destined to end up in Southern California through a route that was outside of the control areas (and control) of the old investor owned utilities (now the CAISO) had to sink in the Northwest with a different utility from which it then could be resold and brought back to COB for transfer to Southern California. This circuitous route was and remains an inefficient means of transacting.

Thus, this practice prevented EPMI from sending power directly from COB to PV. To comply with this rule, EPMI had to find a sink north of COB before it could move power to its final destination, i.e., Zone SP15.

Q. **Is there anything wrong with a COB hub transaction south of COB?**

A. No. There is nothing wrong with this transaction electrically or economically. It is simply an archaic rule that the CAISO inherited from the old days when the system was controlled by IOUs.

BEGIN PROTECTED MATERIAL

END PROTECTED MATERIAL

Q. **In your opinion, when we look at the entire set of transactions said to be Death Star transactions, those between EPMI and the CASIO and those outside of the CASIO system, is this a circular transaction strategy?**

A. Death Star transactions appear circular because the sink for power imported from Northern California coincides with the source of power exported to Southern California. That apparent circularity, however, does not result in a circular flow of power. The augmented diagram on Figure 1 explains that fact, as do the two equivalent representations of Death Star transactions depicted on Figures 2a and 2b. None of those flow diagrams are circular and all show the non-circular representation of the net energy flow from Northern to Southern California that Death Star provided.

Q. **The Yoder-Hall memo states that in the Death Star strategy no energy is put into the grid or taken off. Is this statement correct?**

A. This statement is incorrect in one sense and correct in another.

Q. **In what sense is this statement incorrect?**

A. As I explained earlier, the objective of the Death Star strategy was not to add to or take power off the CAISO system. Instead, the objective was to provide the CAISO system with (and be paid for) additional transmission capacity across a constrained part of the CAISO system. That objective was achieved. The net effect of that transaction was to provide 24 MW of incremental transmission capacity to the CAISO for delivery of power from Northern California to

Southern California. In sum, the transaction had a beneficial impact on the flow of power in the system.

Q. **In what sense is this statement correct?**

A. It is correct in the sense that EPMI did not inject new power (e.g., bring generation resources) into the system. EPMI did, however, bring another valuable resource, incremental transmission capacity between the constrained zones. This allowed the CAISO to adjust its schedules for dispatch of generation in Northern and Southern California so that additional power was scheduled to flow into Southern California.

III. The Impact of the Death Star Strategy on Consumers

Q. Why do you believe that the Death Star strategy was beneficial to California consumers?

A. The Death Star strategy helped to relieve congestion in the forward market because it increased a transactional or scheduled flow of power from North to South.

Consider two scenarios resulting in two alternative schedules developed by the CAISO. In the first scenario we assume that EPMI schedules no counter-flow with the CAISO. In the second scenario, EPMI schedules 24 MW of counter-flow from Southern to Northern California. Let us assume in the first scenario that the CAISO has a total of 1000 MW of transmission capacity on the path separating Northern and Southern California. Let us further assume that the entire 1000 MW are committed and the path is congested, resulting in a congestion price of $20/MWH in the congestion market. The difference in prices effective for loads in the Zone SP15 and NP15 prices is $20/MWH. This transmission congestion price indicates that the CAISO has had to accept some expensive bids for generation located in Southern California (which, in the California market, are called "adjustment" bids) and, furthermore, that the CAISO has had to turn down some less expensive generation in Northern California.

Q. Your description of the California adjustment market is significantly different from that of the FERC standard market design. Can you briefly describe these differences?

A. Yes, there are a number of differences that characterize the structure of California congestion pricing relative to that in the FERC Standard Market Design, but only one is significant in analyzing the benefits and costs of the Death Star strategy. Within California, congestion and the congestion market are separate from the energy market. In the Standard Market Design, the energy price is for delivered energy, i.e. the combination of energy and congestion. The California congestion market is based on generators and demand providing incremental and decremental bids that the CAISO then can use to bring on and/or reduce demand and supply on the two sides of a constraint. The result of the California structure and that of the SMD is the same but the method of arrival at the solution in California is less familiar than that of the SMD. As a result, the discussion that follows explains the benefits of Death Star using the SMD structure, i.e., one in which the locational (zonal in this case) price of energy is for delivered energy. The cost of congestion, then, is the difference between the cost of delivered energy in the two zones. While this is the very same outcome of the California market, the mechanism for achieving the outcome is different.

Q. **Given your discussion above, please explain the basis for the congestion price of $20/MWH in your example.**

A. To understand the source of the $20/MWH of congestion charge, imagine that the most expensive generating unit scheduled in the NP15 zone offers supply at $40/MWH. This is the marginal generator in NP15. Effectively it sets the price of energy for consumers in NP15 at $40/MWH. The most expensive generator scheduled to run in the SP15 zone offers supply at $60/MWH. This is the marginal generator in SP15. Effectively it sets the price of energy for consumers in SP15 at $60/MWH. Thus in the first scenario, the difference in those effective zonal prices equals $20/MWH = $60/MWH - $40/MWH.

Q. **Please continue.**

A. Consider now the second scenario in which EPMI schedules 24 MW in counter-flow with the CAISO. This signals to the CAISO that it could effectively use 24 MW more transmission capacity than in the first scenario. Thus, the total transmission capacity from Northern California to Southern California becomes 1024 MW. As a result, compared to the first scenario, the CAISO would be able to schedule an additional 24 MW of relatively inexpensive generation in Northern California and ratchet down 24 MW of relatively expensive generation in Southern California.

Q. **Will this change the congestion cost?**

A. Possibly, but not necessarily. In our example this depends on whether adding the 24 MW in transmission capacity would change the marginal generator in at least one zone. If the marginal generators are still the same as in the first scenario, the price difference between SP15 and NP15 would remain unchanged as would the congestion price.

Q. **If there is no change in congestion cost, is there a societal benefit from the counter-flow?**

A. Yes there is. The counter-flow reduces generation costs in California. An expensive generator in Zone SP15 generates 24 MW less resulting in cost reduction in SP15 of $60/MWH times 24 MW. A less expensive generator in the NP15 generates 24 MWH more resulting in cost increase in that zone of

$40/MWH times 24 MWH. The net impact is that the overall cost of generation purchased by the CAISO to serve California load is reduced by $20/MWH ($60/MWH - $40/MWH) times 24 MW, or $480 per hour.

Q. **How does this benefit relate to the congestion payment to EPMI?**

A. In this particular example, the societal benefit from congestion relief caused by the counter-flow would exactly equal the congestion payment to EPMI for scheduling the counter-flow.

Q. **In your example can the counter-flow change the congestion costs?**

A. Yes, and only to the benefit of California consumers. It is important to note that the counter-flow could only further reduce congestion costs. It could never increase them. Indeed, since less generation is being scheduled in Southern California, the price of the marginal generating unit in SP15 could only decrease to a price less than $60/MWH, e.g., $59/MWH. Since more generation is being scheduled in Northern California, the price of the marginal unit in NP15 could only increase to a price greater than $40/MWH, e.g., to $41/MWH. If this were to happen, the resulting congestion price would be reduced from $20/MWH to only $18/MWH ($59/MWH - $41/MWH) and the congestion payment to EPMI would be only $432 per hour ($18/MWH times 24MW). However, the societal benefits from congestion relief will be much bigger than the payment to EPMI.

Q. **How do you estimate societal benefits from congestion relief in this case and why will they be greater than the congestion payment to EPMI?**

A. The societal benefits would now consist of two parts, savings in generation costs and savings in payments to FTR holders. Savings in generation costs will be approximately $432 per hour[1]. Assuming 1000 MW held in FTRs, a $2/MWH reduction in congestion costs would result in a $2000 per hour reduction in payments to FTR holders. Thus, the overall societal benefit of the counter-flow would be at least $2432 per hour, which in this example exceeds the payment to EPMI of $432 per hour. Thus, in this example, the societal benefit is over five times more than EPMI's compensation.

Q. **Did the Death Star strategy relieve congestion in the forward market?**

A. Yes. In the forward market when the desired usage of the transmission system exceeds the capacity within the CAISO's control, congestion exists on the CAISO system. It is important to note that this would not necessarily be congestion due to physical limitations of the entire California grid. The congestion may merely be on that portion of the grid over which the CAISO can schedule transactions. When the Death Star strategy increases the capacity of transmission available to the CAISO's control, it necessarily relieves congestion in the forward market.

Q. **Please describe the impact of the Death Star strategy in the Real-Time market.**

A. As Prof. Cardell explained in her testimony, the Real-Time (RT) market deals with physical operation of the system. This is not the same as the scheduled transactions of the forward market. In particular, the physical loading of transmission (based on laws of physics that state that energy on a transmission network flows along the path of least resistance, i.e., not based on contract path) is different from the use of that transmission scheduled by the CAISO in the forward

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1 This is a conservative estimate. In fact savings in generation costs would be within the range from $432

market. This is the case because the CAISO controls only a part of the transmission system and, as I discussed earlier, has limited direct knowledge of how much transmission capacity non-CAISO transmission owners will use in real time. In fact, the CAISO is able to schedule transactions over residual capability on the total transmission system beginning 40 minutes before the hour, which was 20 minutes after the close of the hour-ahead market, the last of the forward markets to close. As a result, it is possible that when transmission was congested in the forward market, there was no physical congestion on the entire system, and hence no congestion cost, in the real-time market. Therefore, when the Death Star relieved congestion in the forward market, it did not necessarily relieve congestion in the real-time market.

Q. **If we assume that Death Star relieved congestion only in the forward market but did not relieve congestion in the real-time market, would it still be beneficial for consumers?**

A. Yes it is beneficial for two reasons. First, forward market settlements are financially binding: costs resulting from forward schedules will be borne by consumers. Therefore, relieving congestion in the forward market is beneficial to them, because it reduces costs consumers otherwise would be obligated to pay. Second, under all conditions, the Death Star strategy also benefited the California system in Real-Time.

Q. **Why did Death Star benefit the California system in the Real-Time market?**

A. It benefited the Real-Time market because it gave the CAISO assured control of a

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to $480 per hour.

larger portion of the transmission grid. That control reduced the CAISO's uncertainty with respect to the amount of transmission capacity outside of its control to which it might have access in real time. Greater certainty can only improve the efficiency of the CAISO's operations as well as the reliability of the system controlled by the CAISO. Facing lower uncertainty, the CAISO could more efficiently control physical generation and manage transmission congestion.

Q. Did Death Star cause any harm?

A. I am not aware of any harm caused by the Death Star strategy. Moreover, I am not aware of any harm caused by the Death Star strategy during any of the 17 days identified by Portland General[2]. To the best of my knowledge, there were no price spikes, blackouts or declared Stage 1 or 2 emergencies on any of the 17 days identified by Portland General.

Q. You stated earlier that the CASIO in its October 4, 2002 report expressed two concerns with respect to the impact of Death Star on real-time market operations. What is the first concern?

A. The Report states 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 CAISO's congestion model and power flows under a full network model, power may not (and often does not) actually flow as scheduled."

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[2] Those 17 days of transactions between Portland General and EPMI are specified in Exhibit S-15, p. 12 of

While I agree with this conclusion, this has nothing to do with Death Star. This discrepancy existed regardless of whether or not the Death Star strategy was implemented. The CAISO admitted this point in response to a Portland General data request (Portland General/ISO-24). Moreover, as I explained earlier, with Death Star, this discrepancy is less than without it. This should not be a matter of concern for the CAISO Grid Operations.

Q. **What is the second concern?**

A. The Report states 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 counter-flow 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."

Again, this is not due to Death Star. Indeed, the same concern applies to any counter-flow scheduled with the CAISO. As stated in the CAISO October 4, 2002 Report, "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 sum, the CAISO does not know the return path of what the CAISO calls a circular schedule or even whether there is such a return path. Therefore, from the Grid Operations perspective, all counter-flows are the same. Moreover, I disagree that the counter-flow based on a circular schedule in which the source and a sink coincide poses a greater reliability risk than a counter-flow in which the source and sink are different. The major reliability concern for the Death Star schedule is an outage or deration on the LADWP line. When the source and the sink are different, the reliability could be compromised due to the generator outage at the source, inability of the load to accept power at the sink, a line outage leading from the source, or a line outage leading to the sink. In general, a counter-flow based on a non-circular schedule involves a greater number of physical elements, and the probability for those schedules to be cut is higher than for Death Star schedules.

Q. Did Portland General attempt to obtain a further explanation of this concern from the CASIO?

A. Yes. Responding to the Data Request Portland General/ISO-23, CAISO stated, "If the ISO needs to mitigate congestion on a tie point by cutting or reducing an import or export schedule, that forms one 'leg' of a circular schedule, the cutting or reducing of this 'leg' may have a direct unpredictable and adverse consequence on the ISO ability to manage reliability since this 'leg' constitutes, on paper, the source or sink of another import or export schedule on the ISO system."

Q. **Do you believe that this is a valid concern?**

A. No. If the CAISO needs to reduce an export or import to relieve congestion, it should reduce the schedule that makes that tie point congested. This does not apply to the counter-flow schedule such as a Death Star schedule, which is in the opposite direction of the congestion. There is simply no need to reduce either export or import associated with the counter-flow.

Q. **Did you review the testimony of Mr. Movish on behalf of the City of Tacoma and Tacoma Power?**

A. Yes I did. Mr. Movish mischaracterized the Death Star strategy by stating that it was designed to create revenue by creating congestion and being paid by the CAISO to relieve that congestion. As I explained in detail, Death Star did not create congestion. On the contrary, it helped to relieve congestion.

Q. **Do you agree with Mr. Movish that the objective of Death Star was to raise electricity prices in California?**

A. No. Mr. Movish offered no basis for this claim he made on page 12, lines 5-6, of his testimony. Again, as I explained, the Death Star helped to reduce prices by relieving congestion, not to raise them.

Q. **Do you agree with Mr. Movish that the Death Star strategy had a potential to place at risk the operational integrity of the entire western region?**

A. No. Mr. Movish offered no basis for this claim he made on page 12, lines 8-10, of his testimony. Again, as I explained, the Death Star could only improve the operational efficiency of the CAISO by giving it control over a larger portion of the transmission grid ahead of time.

Q. **Do you agree that Mr. Movish has accurately estimated that Death Star events occurred on 259 days?**

A. No. However, I will address this issue in the context of my quantitative analysis I intend to file at a later date.

Q. **Do you agree with Mr. Movish or with Mr. Merola, who testified on behalf of the California Public Utility commission and attorney general of California, that Portland General should refund money for participating in Death Star?**

A. No. I completely disagree with their recommendations. As I have demonstrated, Death Star caused no harm. Instead it benefited consumers in California. The magnitude of that benefit most likely will exceeded the compensation EPMI received from the Death Star strategy. There is simply no basis for seeking any refund from Portland General in this case.

Q. **Was Portland General the only entity that allowed EPMI to carry out the northern leg of Death Star transactions?**

A. No. It is my understanding that, in implementing its various Death Star transactions, EPMI obtained assistance from the City of Redding, the Northern California Power Agency (NCPA) and PacifiCorp. Exhibit No. PGE-30 shows the memorandum describing the so-called "Red Congo" strategy involving Redding, which appears to be the functional equivalent of the Death Star transaction. Exhibit No. PGE-31 shows diagrams similar to the Forney Schematic but involving NCPA. Finally, as Mr. Taylor explained in his testimony, PacifiCorp discovered how to move power from the Malin bus at COB to the Captain Jack bus at COB without the need to sink energy in the North. PacifiCorp performed over 40 GWH (or about 20 times larger than the volume of transactions at issue in this proceeding) of these transactions for EPMI and other parties. These transactions with PacifiCorp apparently began in July of 2000, about a month after EPMI stopped using Portland General's services for the transaction at issue in this proceeding.

Q. **Did Portland General provide similar services to parties other than EPMI?**

A. Yes. As Mr. Taylor explained in his testimony, Portland General assisted the Modesto Irrigation District and Sempra with similar transactions. Most notably, Portland General frequently assisted the CAISO in transactions around the COB HUB that were functionally equivalent to Death Star and that helped the CAISO to relieve congestion. In those transactions Portland General agreed to the CAISO's request to function as a non-California sink. Portland General helped CAISO to move nearly 42 GWH from NOB and to the COB HUB.

Q. **Does this conclude your testimony?**

A. Yes it does.

105 FERC ¶ 61,302
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Pat Wood, III, Chairman;
Nora Mead Brownell, and Joseph T. Kelliher.

Portland General Electric Company
Enron Power Marketing, Inc.

Docket Nos. EL02-114-000, EL02-114-006, EL02-115-001 and EL02-115-007

ORDER APPROVING UNCONTESTED PARTIAL SETTLEMENT

(Issued December 18, 2003)

1. On September 26, 2003, Portland General Electric Company (Portland), Federal Energy Regulatory Commission Trial Staff (Staff), the People of the State of California, ex rel. Bill Lockyer, Attorney General (California AG), the California Public Utilities Commission (CPUC), the City of Tacoma Washington (Tacoma), the Oregon Public Utility Commission (Oregon PUC), Enron Power Marketing, Inc. (EPMI), Industrial Customers of Northwest Utilities (ICNU), and Blue Heron Paper Company (Blue Heron) (collectively the parties) filed an Offer of Settlement and an Agreement and Stipulation (Settlement) resolving all issues in the above proceedings pertaining to Portland.[1] On October 16, 2003, both Staff and Tacoma filed comments supporting the Settlement. No reply comments were filed. On November 10, 2003, the Presiding Judge certified the Settlement as an uncontested partial settlement to the Commission.

2. The subject Settlement is in the public interest and is hereby approved. The Commission's approval of this Settlement does not constitute approval of, or precedent regarding, any principle or issue in this proceeding. The Commission retains the right to investigate the rates, terms, and conditions under the just and reasonable and not

[1] This Settlement constitutes a complete settlement of the issues designated for investigation by the Commission, so far as Portland is concerned. Because the Settlement leaves for litigation elsewhere the issues designated for investigation by the Commission, so far as EPMI is concerned, this can only be deemed a "partial" settlement in this proceeding.

unduly discriminatory or preferential standard of Section 206 of the Federal Power Act, 16 U.S.C. § 824e (2000).

3. This order terminates Docket Nos. EL02-114-000, EL02-114-006, EL02-115-001, and EL02-115-007.

By the Commission. Commissioner Brownell dissenting in part with a separate statement attached.

(S E A L)

Magalie R. Salas,
Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Portland General Electric Company Enron Power Marketing, Inc.	Docket Nos. EL02-114-000, EL02-114-006, EL02-115-001, and EL02-115-007

(Issued December 18, 2003)

Nora Mead BROWNELL, Commissioner *dissenting in part*:

1. As I explained in my separate statement in Midwest Independent Transmission System Operator, Inc., 105 FERC ¶ 61,073 (2003), I can no longer support making our acceptance of settlement agreements subject to a Commission reservation of authority to make future revisions under the just and reasonable standard, as opposed to the Mobile-Sierra public interest standard--unless, of course, the agreement itself includes language requesting such a reservation. If the Commission has objections to a settlement, we should articulate them when we first review it, instead of approving the settlement with the cloud of uncertainty that we might make subsequent changes under a lower-than-public-interest standard after market participants have come to rely on it. Therefore, I would have accepted this agreement without reserving the option of revisiting it under a just and reasonable standard.

Nora Mead Brownell

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UM 1002

WAH CHANG, Petitioner, v. PACIFICORP, Respondent.	CERTIFICATE OF SERVICE

I certify that I have this day served PacifiCorp's Supplemental Exhibit Replacing Exhibit WC/1136 (Exhibit PacifiCorp/73), upon all parties of record in this proceeding by mailing a copy properly addressed as shown below and by electronic mail pursuant to OAR 860-013-0070, to the following parties or attorneys of parties:

Richard H. Williams
Milo Petranovich
Lane Powell Spears Lubersky LLP
Suite 2100
601 S.W. Second Avenue
Portland, OR 97204
Email: williamsr@lanepowell.com
petranovichm@lanepowell.com

Paul Graham
Assistant Attorney General
Department of Justice
Regulated Utility & Business Section
1162 Court St. NE
Salem, OR 97301-4096
Email: paul.graham@state.or.us

Perkins Coie LLP
1120 N.W. Couch Street, Tenth Floor
Portland, OR 97209-4128
Phone: 503.727.2000
Fax: 503.727.2222

Natalie Hocken
Vice President and General Counsel
Pacific Power
825 NE Multnomah, #2000
Portland, OR 97232
Email: natalie.hocken@pacificorp.com

DATED: August 15, 2007.

PERKINS COIE LLP

By ______________________________
James M. Van Nostrand, OSB No. 79428
Christopher L. Garrett, OSB No. 03100
Attorneys for PacifiCorp

Perkins Coie LLP
1120 N.W. Couch Street, Tenth Floor
Portland, OR 97209-4128
Phone: 503.727.2000
Fax: 503.727.2222