

**FINAL REPORT ON
PRICE MANIPULATION IN WESTERN MARKETS**

**FACT-FINDING INVESTIGATION OF
POTENTIAL MANIPULATION OF
ELECTRIC AND NATURAL GAS PRICES**

DOCKET NO. PA02-2-000



**Prepared by the Staff of the
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Executive Summary

Overview

This Report is the culmination of a yearlong effort by Commission Staff to determine whether and, if so, the extent to which California and Western energy markets were manipulated during 2000 and 2001. While Staff found significant market manipulation, this evidence does not alter the Commission's original conclusion, set forth in its December 15, 2000 Order, that significant supply shortfalls and a fatally flawed market design were the root causes of the California market meltdown.

The underlying supply-demand imbalance and flawed market design greatly facilitated the ability of certain market participants to engage in manipulation. In addition, the ability to pass through gas prices in electric power prices provided no check on gas buyers' willingness to pay.

For the first 2 years of its operation, the California market performed well and saved the state's customers billions of dollars. Only after the Pacific Northwest could no longer provide abundant supplies of low-cost hydropower to the regional market did the negative effects of too little infrastructure and poorly designed market rules adversely affect customers' bills.

A key conclusion of this Report is that markets for natural gas and electricity in California are inextricably linked, and that dysfunctions in each fed off one another during the crisis. Spot gas prices rose to extraordinary levels, facilitating the unprecedented price increase in the electricity market. Dysfunctions in the natural gas market appear to stem, at least in part, from efforts to manipulate price indices compiled by trade publications. Reporting of false data and wash trading are examples of efforts to manipulate published price indices. This Report makes recommendations for conditions the Commission should impose to ensure that price indices represent better barometers of actual prices.

In a related finding, Staff concludes that large-volume, rapid-fire trading by a single company, in what was incorrectly assumed to be a liquid market, substantially increased natural gas prices in California. To compensate for this, Staff reiterates the recommendation of its August 2002 Initial Report, which called for the Commission to alter the natural gas pricing methodology employed in the California

Refund Proceeding. Using Staff's recommended producing area plus transportation price, instead of published price indices, while accounting for scarcity and keeping electricity providers whole for the actual prices they paid for natural gas, would result in larger refunds to California.

This Report finds that many trading strategies employed by Enron and other companies were undertaken in violation of antigaming provisions of the Commission-approved tariffs for the Cal ISO and Cal PX. Staff recommends the Commission initiate proceedings to require guilty companies to disgorge profits associated with these tariff violations. This disgorgement would affect activities beginning January 1, 2000 through June 21, 2001, and not just those during the October 2, 2000 through June 21, 2001 refund period. These disgorgements would be in addition to the refunds resulting from the California Refund Proceeding.

A central mandate in undertaking this Staff fact-finding investigation was to determine whether the dysfunctional spot market for electricity had an impact on the forward prices reflected in long-term power supply agreements. The Staff's analysis finds that spot prices influenced forward prices negotiated during the January 1, 2000 through June 21, 2001 crisis period. The influence is greatest for contracts with 1- to 2-year terms.

Staff concludes that EnronOnline (EOL), which gave Enron proprietary knowledge of market conditions not available to other market participants, was a key enabler of wash trading. This created a false sense of market liquidity, which can cause artificial volatility and distort prices. Enron's informational trading advantage on EOL was lucrative; the company took large positions and was an active, successful speculator. Staff estimates Enron's speculative profits from EOL exceeded \$500 million in 2000 and 2001. These speculative profits in financial instruments allowed Enron to sustain trading losses in physical trading. Staff further finds that Enron manipulated thinly traded physical markets to profit in financial markets. The Report recommends that the Commission prohibit the use of one-to-many trading platforms such as EOL and explicitly prohibit wash trading.

Staff concludes that prices in the California spot markets were affected by economic withholding and inflated bidding. Staff finds this violated the antigaming provisions of the Cal ISO and Cal PX tariffs and recommends proceedings to require disgorgement of profits associated with these inflated prices. This investigation did not address physical withholding of generation, an issue the Commission is addressing separately.

The balance of this executive summary discusses in greater detail the findings and recommendations in the body of this Report.

Background

On February 13, 2002, in Docket No. PA02-2-000, the Commission directed Staff to investigate whether any entity, including but not limited to Enron or any of its affiliates, manipulated short-term prices for electric energy or natural gas in the West or otherwise exercised undue influence over these prices and whether this resulted in unjust and unreasonable rates in long-term power sales contracts.

In August 2002, Staff released its Initial Report in Docket No. PA02-2-000.¹ In that Report, Staff recommended the initiation of various company-specific proceedings² to further investigate possible misconduct and recommended several generic changes to market-based tariffs to prohibit the deliberate submission of false information or the deliberate omission of material information, and to provide for the imposition of both refunds and penalties for violations. Staff also concluded that the most widely used published price indices were compiled without adequate standards or controls, were subject to attempted manipulation, could not be independently verified, and should not be used for setting the market-clearing prices in the California Refund Proceeding. Accordingly, Staff recommended the use of producing-area natural gas prices plus transportation. Finally, Staff analyzed the now infamous Enron trading strategies and found many of them to be forms of gaming based on price manipulation and the falsification of information.

Overall Organization and Primary Objectives of the Final Report

This Final Report achieves a multitude of objectives, many of which were listed in the Initial Report. It begins with two core objectives: to provide the Commission with our analysis of whether spot power prices in the West were just and reasonable in 2000–2001 and whether spot power prices adversely affected long-term power prices. While the Commission has already held that spot electric prices were unjust

¹The Initial Report is available on the Commission's Web site at www.ferc.gov/electric/bulkpower/pa02-2/Initial-Report-PA02-2-000.pdf.

²These proceedings, which are currently pending before the Commission, are Docket Nos. EL03-113-000, EL03-114-000, and EL03-115-000.

and unreasonable, its refund methodology hinges on the use of a competitive gas input cost. Therefore, the first four chapters of this Report are dedicated to this critical gas issue and the fifth chapter addresses the correlation of spot electric prices to long-term electric prices. The remaining chapters address the other critical issues that help to explain the gas and electric markets in 2000 and 2001.

This Report reflects the views of Staff only. It has not been considered or adopted by the full Commission. In addition, whenever this Report concludes that prices were or appear to have been manipulated, it does so in the context of determining whether rates were unjust and unreasonable under the Federal Power Act or the Natural Gas Act or whether persons may have violated tariffs or regulations under those acts. Those acts do not require that intent be proven in order to make a determination that rates are or were unjust and unreasonable or that a person violated tariffs or regulations under those acts.

Chapter I: Context of the Gas and Electric Markets in the West

In this chapter, Staff provides essential background and context of the gas and electric markets in the West during 2000–2001. We analyze many factors that affected prices, including reduced hydro output, supply/demand imbalance, flawed market rules, illiquidity at a key gas trading point, stringent pipeline balancing rules, low gas storage levels, and pipeline constraints. We conclude that the electric and gas markets were so inextricably interrelated that their dysfunctions fed off each other.

Spot Gas Prices Reached Extraordinary Levels and Were Used to Set Clearing Prices for the Entire Electric Spot Market

The crucial conclusions of this chapter are that spot gas prices reflected extraordinary basis differentials that far exceeded the cost of transportation and that the effects of these inflated gas prices were greatly magnified because they were used to compute clearing prices paid by most California wholesale buyers for spot power. In Chapters II to IV we examine the causes in more detail.

Chapter II: Topock Was Illiquid—A Single Company Substantially Increased Prices

In this chapter, we conclude that Reliant engaged in a high-volume, rapid-fire trading strategy to purchase its physical spot gas needs at Topock. Reliant often bought and sold many times its needs in quick bursts, which significantly increased the price of gas in that market. We describe this as “churning” and define its characteristics later in the chapter. We use this term even though it has other connotations in securities or futures trading because it gives the best visual image of Reliant’s behavior. Reliant’s churning enabled it to reduce the overall cost of the gas it actually needed. Through its churning, Reliant profited by selling gas at or near the top of the price climb it caused. Reliant was often such a large presence at Topock (e.g., for the 3-month period from December 2000 to February 2001, nearly 50 percent of the spot gas trades at Topock on EOL were with Reliant) that its trading strategy moved the entire market price. Our analysis shows that the price of gas would have been lower by about \$8.54/MMBtu in December 2000 and by about \$1.69/MMBtu over the 9 months of the California Refund Proceeding absent Reliant’s churning. These inflated gas prices significantly influenced index prices and the clearing prices paid by most California wholesale buyers for spot power.

Staff concludes that these gas prices are not the result of competitive conditions and would not produce just and reasonable electric prices in the California Refund Proceeding. In Chapter IV of this Report, we recommend alternative gas prices for the Commission’s consideration in the California Refund Proceeding.

Recommendations To Amend Gas Marketing Certificates and Generic Proceeding

Reliant’s churning did not violate the blanket certificate under which it sold gas because Section 284.402 of the regulations contains no explicit guidelines or prohibitions. We recommend that Sections 284.284 and 284.402 of the regulations be amended to provide explicit guidelines or prohibitions for trading natural gas under Commission blanket certificates. We also suggest a generic proceeding to develop appropriate reporting and monitoring requirements for sellers of gas under Commission certificates.

Chapter III: Traders Attempted To Manipulate Price Indices Through False Reporting

Market participants provided false reports of natural gas prices and trade volumes to industry publications. These publications used the reports to compile price indices, and false reporting became epidemic. Five major traders (Williams, Dynegy, AEP, CMS, and El Paso Merchant Energy) have admitted that their employees falsified information provided to *Gas Daily* and *Inside FERC*, the most influential and relied-upon compilers of natural gas price indices. The false reporting included fabricating trades, inflating the volume of trades, omitting trades, and adjusting the price of trades.

The predominant motives for reporting false information were to influence reported gas prices, to enhance the value of financial positions or purchase obligations, and to increase reported volumes to attract participants by creating the impression of more liquid markets. Market participants that sold power in California, or that were affiliated with such sellers, also had incentives to manipulate reported prices because the clearing price set for power was based, in part, on natural gas spot prices.

Many traders acknowledged that false reporting was done openly in the industry. Some traders believed that the periodicals that prepared the indices were able to distinguish between fictional and accurate reports, but the Staff was unable to confirm that the periodicals could discern fictional trades and eliminate them from the index calculation. The widespread false reporting led Staff to conclude that reported prices did not reliably reflect market activity and, accordingly, that reported prices should not provide the basis for setting spot power clearing prices in the California Refund Proceeding.

Recommendations for Changes in the Reporting Process

Staff recommends various changes to the price reporting process. These changes will eliminate the ability and incentive of those reporting the data to manipulate the indices and will improve the price calculation methods.

- ◆ Only data that can be audited and verified by the Commission or other agencies can be used to construct the natural gas or electric price index.

- ◆ Data sent to firms publishing natural gas or electric price indices must be provided by the risk management office of the company, not the trading desk or a trader, and must be certified by the chief risk officer.
- ◆ The Commission should consider conditioning all electric market-based rate authorizations and blanket gas marketing certificate authorities on the companies providing complete, accurate, and honest information to any entity that publishes the price indices.
- ◆ The Commission should consider conditioning all electric and natural gas market-based rate authorizations on retaining all relevant data and information needed to reconstruct a published price index for a period of 3 years.
- ◆ Any published natural gas or electric price indices for Commission-jurisdictional transactions (e.g., pipeline tariff rates, market-based electric sales) must be subject to audit to ensure the accuracy of the data going in and the calculations themselves.
- ◆ The Commission should consider encouraging standard product definitions for published natural gas and electricity price indices and standard methodologies for calculating the price indices.

Certain Companies Must Demonstrate That They Currently Have Sound Procedures in Place

Staff recognizes the importance of accurate price indices in the overall health of competitive energy markets. The companies discussed at length in this chapter are significant participants in the U.S. electricity and natural gas markets. In order for the published price indices to be accurate and credible, firms publishing such indices must receive complete and accurate information from these companies. As such, Staff recommends that the following companies be required to demonstrate that they have corrected their internal processes for reporting trading data to the Trade Press or that they no longer sell natural gas at wholesale:

- ◆ Dynegy
- ◆ Aquila
- ◆ AEP
- ◆ El Paso Merchant Energy
- ◆ Williams
- ◆ Reliant
- ◆ Duke
- ◆ Mirant

- ◆ Coral
- ◆ CMS
- ◆ Sempra Energy Trading

At a minimum, these companies need to show the following:

- ◆ Those employees, including trading desk heads and managers, who participated in manipulations or attempted manipulations of the published price indices have been disciplined.
- ◆ The company has a clear code of conduct in place for reporting price information.
- ◆ All trade data reporting is done by an entity within the company that does not have a financial interest in the published index (preferably the chief risk officer).
- ◆ The company is cooperating fully with any government agency investigating its past price reporting practices.

**Chapter IV: Spot Gas Prices
Were Not the Product of a
Well Functioning
Competitive Market—They
Should be Replaced for the
California Refund
Proceeding**

In this and previous chapters of this Report, Staff concludes that California spot gas prices were artificially high due to market dysfunctions, illiquidity, misreporting, and a rupture causing an abnormal pipeline capacity shortage. The spot gas prices reflected extraordinary basis differentials that far exceeded the cost of transportation and reached levels that would never have been sustained in a competitive market. While some portion of these price levels reflected legitimate scarcity, we cannot calculate the portion attributable to scarcity alone. These inflated gas prices were used in the California Refund Proceeding to compute clearing prices for the entire electric spot power market. While there is no way to precisely replicate the level that spot gas prices would have reached in a competitive market, Staff recommends the use of producing-area prices plus transportation as a proxy for competitively derived gas prices in computing the market-clearing prices in the California Refund Proceeding. Over the 9-month refund period, Staff's proposal would reduce gas costs used in the refund formula by \$7.03 in

southern California and \$4.18 in northern California, or about \$5.60 on average.

Many generators paid these distorted gas prices and fundamental fairness dictates that they be able to recover these costs. Accordingly, Staff also recommends that generators be made whole for the spot gas prices they paid, but that this recovery be on a dollar-for-dollar basis and not part of the market-clearing price.

Staff's proposal would increase the level of the refunds for California.

**Chapter V: Spot Power
Prices Adversely Affected
Long-Term Power Prices**

The vital link between the spot price and forward price for a commodity is the ability to store that commodity. In essence, someone can meet future needs by purchasing the commodity now and storing it for future consumption. As a result, the forward price that someone is willing to pay will approximate the cost of purchasing plus the carrying cost involved with stockpiling. Since the feasibility of storing electricity is very limited, we would expect to see little or no relationship between spot electric prices today and the forward price of electricity. Instead, forward prices should mostly reflect a buyer's expectations of prices in the future. Since natural gas is the marginal fuel in the West, forward gas prices should, in large part, explain forward power prices. Our analysis shows, however, that forward power prices negotiated during 2000–2001 in the western United States were significantly influenced by the then-current spot power prices. This tells us that the trauma of the dysfunctional spot power prices at that time so influenced buyers that they placed great weight on these prices in forming future expectations. The influence of spot prices on forward prices was the greatest for forward contracts with the shortest time to delivery (1-2 years) and varied by location. While Staff has found a statistically significant relationship, the magnitude of the impact is limited (that is, the impact of spot power prices on long-term power prices is clearly not dollar-for-dollar). Rather, a reduction of about one-third in the price of a 2-year forward contract would require a finding that spot power prices were three times above the just and reasonable level.

**Chapter VI: Trading
Strategies, Anomalous
Behavior, Economic
Withholding, and Inflated
Bidding**

In this chapter, we identify various entities that appear to have participated in some Enron price manipulation strategies; entered into profit-sharing arrangements with Enron, which masked Enron's real-market share; engaged in economic withholding; and raised clearing prices through inflated bidding. We also find evidence of price manipulation of the electric price index at Palo Verde and evidence that the spot power prices in the Pacific Northwest were inflated.

Violations of Cal ISO and Cal PX Tariffs

Since 1998, the Cal ISO and Cal PX tariffs have contained Market Monitoring and Information Protocols (MMIP). The MMIP include antigaming and anomalous market behavior provisions that identify various abuses and misconduct, such as taking unfair advantage of market rules, excessive pricing or bidding, and behavior not consistent with competitive markets, to the detriment of the efficiency of customers in the Cal ISO and Cal PX markets.

The Cal ISO and Cal PX initially submitted the MMIP (along with other protocols) for informational purposes only on October 31, 1997. The Commission, however, found that the protocols, including the MMIP, "govern a wide range of matters which traditionally and typically appear in agreements that should be filed with and approved by the Commission."³ Therefore, the Commission accepted the protocols, including the MMIP, for filing, and directed the Cal ISO and Cal PX to post the protocols on their Internet sites and to file the complete protocols pursuant to Section 205 of the Federal Power Act within 60 days of the Cal ISO's Operations Date.⁴ The Cal ISO and the Cal PX made that compliance filing on June 1, 1998. Accordingly, the MMIP has been part of the Cal ISO and Cal PX filed rate schedules since the Cal ISO's Operations Date (April 1, 1998).

Because of the fact that Part 2 of the MMIP specifically enumerates suspect practices, that Section 7.3 of the MMIP authorizes the Cal ISO to impose "sanctions and penalties" or to refer matters to the Commission for appropriate sanctions or penalties, and that the MMIP

³*Pacific Gas and Electric Co., et al.*, 81 FERC ¶ 61,320 at 62,470-471 (1997).

⁴*Id.*

is part of the Cal PX's and Cal ISO's rate schedules on file with the Commission, Staff concludes that entities that transact through the Cal PX or Cal ISO and engage in such enumerated practices are in violation of those filed rate schedules. The stated objectives of the MMIP are to identify abuses of market power by giving particular scrutiny to a list of abusive practices and misconduct and to take corrective action, including sanctions and penalties. In Staff's view, the identified misconduct remains a violation of the Cal ISO's and Cal PX's filed rate schedules even if such formal procedures as referral outlined in the MMIP did not occur. The Commission can enforce a rate schedule on file even when there are processes in that rate schedule which, had they been used, would have assisted the Commission. Ultimately, the Commission can enforce a tariff with or without the assistance of a complaint or referral.

Orders To Show Cause

We conclude that many of these behaviors violated the Cal ISO and Cal PX tariffs and recommend that these entities be ordered to show cause why they should not disgorge revenues and why market-based authorizations should not be revoked. This disgorgement would be in addition to the refunds in the California Refund Proceeding.

Spot Power Prices in the Pacific Northwest Appear Inflated

Staff analysis of actual transaction data for the period January 2001 to June 2001 indicates that spot power prices in the Pacific Northwest appear to be excessive, as were spot power prices in the California portion of the integrated Western market.

Recommendation for Further Pacific Northwest Proceedings

Staff recommends that this Report and, in particular, the conclusions herein related to the Pacific Northwest spot power prices, be remanded to the Administrative Law Judge in Docket No. EL01-10-000.

Chapter VII: Wash Trading on EOL Created a False Impression of Liquidity

Wash trades were common on EOL across many products and locations. In fact, EOL often posted its willingness to buy and sell at the same price. This invited counterparties to wash trades, and these trades created a false sense of liquidity, which can distort prices.

Enron also manipulated prices on EOL by having affiliates on both sides of certain wash-like trades. This created artificial price volatility and raised prices.

Ban Wash Trading and Prohibit Reporting of Affiliate Trades to Indices

Staff recommends that the Commission establish specific rules banning any prearranged trades that wash and prohibiting the reporting of affiliate trades to industry indices.

Chapter VIII: Enron's Trading Practices on EOL Were Lucrative

EOL's one-to-many platform provided no transparency to the market. However, EOL provided Enron with a huge information advantage that Enron used to earn large profits.

EOL was not simply a conduit for transactions earning a moderate but steady profit on the spread between what it paid and what it sold. In fact, EOL took large positions and was an active, successful speculator. Enron used the information advantage acquired from its central position in physical markets to earn large speculative profits in financial products—more than \$500 million in 2000 and 2001. Enron could sustain trading losses in the thinner physical markets as the cost to gain its information edge, which enabled it to earn large net profits.

Condition Market-Based Rates and Blanket Gas Certificates

We recommend that market-based rates and blanket gas certificates be conditioned to require sellers who use electronic platforms to use only those platforms with certain transparency and monitoring attributes. As discussed in this chapter and Chapter IX, Staff recommends that these platforms employ various monitoring tools, such as a churn alarm, to detect a large amount of buying and selling in a short timeframe.

Staff also recommends that information about all trigger events, e.g., identity of the market participants and the transaction data, be made available to the Commission through a real-time data feed.

**Chapter IX: Enron
Manipulated Thin Physical
Markets for Profit in
Financial Markets**

Financial energy products are used to hedge risk on physical energy products, and the two are interrelated. Physical transaction prices dictate the pricing of financial products, i.e., financial products derive their value from the underlying physical market. The depth and liquidity of financial energy markets are far greater than those of physical markets.

The relationship between financial and physical energy products and the relatively thinner and less liquid physical markets provides opportunities to manipulate the physical markets and profit in the financial markets. This is true regardless of whether the manipulation in the physical market raises or lowers prices for the physical commodity.

This Report analyzes an experiment by Enron to test a manipulation strategy and an actual manipulation by Enron using EOL. Enron manipulated the price of physical gas upward, then downward. Although the price change in the physical markets was only about \$0.10/MMBtu, Enron profited due to the effect that this small change in the physical price had on its large financial position. Enron earned more than \$3 million from this manipulation.

Show Cause Why the Commission Should Not Revoke Enron's Gas Marketing Certificate

We recommend that the Commission issue an order directing Enron to show cause why it should not have its blanket gas marketing certificate revoked.

**Chapter X: Allegations That
Williams Cornered the
Market in Southern California
Gas Are Unsubstantiated**

Staff investigated allegations that Williams Energy Marketing & Trading Company cornered the natural gas market in California in January 2001. Based on the data, information, and documents reviewed, Williams purchased natural gas in amounts roughly

equivalent to its needs and had a small share of the natural gas demand. The allegations that Williams cornered the natural gas market in southern California for January 2001 are unsubstantiated.

Details of Staff Recommendations

Below we identify in one comprehensive list the specifics of Staff's recommendations for the Commission's consideration in addressing the issues arising out of this investigation. Staff recommends that the Commission:

- ◆ Amend Sections 284.284 and 284.402 of the regulations to provide explicit guidelines or prohibitions for trading natural gas under Commission blanket certificates. (Chapters II and IX)
- ◆ Consider a generic proceeding to develop appropriate reporting and monitoring requirements for sellers of natural gas under the Commission's blanket certificates. (Chapters II and IX)
- ◆ Condition all electric market-based rates and natural gas blanket marketing certificates on the companies providing complete, accurate, and honest information to any entity that publishes the price indices. (Chapter III)
- ◆ Condition all electric market-based rates and natural gas blanket marketing certificates on retaining all relevant data and information needed to reconstruct a published price index for a period of 3 years. (Chapter III)
- ◆ Require that any published price indices for Commission-jurisdictional transactions (e.g., pipeline tariff rates, market-based electric sales) must be subject to audit to ensure the accuracy of the data going in and the calculations themselves. (Chapter III)
- ◆ Require that only actual trade data be used to construct the price indices. (Chapter III)
- ◆ Require that data sent to firms publishing price indices be provided by the risk management office of the company, not the trading desk or a trader, and be certified by the chief risk officer. (Chapter III)
- ◆ Encourage standard product definitions for published natural gas and electricity price indices and standard methodologies for calculating the price indices. (Chapter III)
- ◆ Require Dynegy, Aquila, AEP, El Paso Merchant Energy, Williams, Reliant, Duke, Mirant, Coral, CMS, and Sempra Energy

Trading to demonstrate that they no longer sell natural gas at wholesale or that:

- Those employees, including trading desk heads and managers, who participated in manipulations or attempted manipulations of the published price indices have been disciplined.
- The company has a clear code of conduct in place for reporting price information.
- All trade data reporting is done by an entity within the company that does not have a financial interest in the published index (preferably the chief risk officer).
- The company is cooperating fully with any government agency investigating its past price reporting practices. (Chapter III)
- ◆ Use producing-area prices plus transportation as a proxy for competitively derived gas prices in computing the market-clearing prices in the California Refund Proceeding. (Chapter IV)
- ◆ Allow generators, many of which paid high gas prices, to recover these costs on a dollar-for-dollar basis, but not as part of the market-clearing price. (Chapter IV)
- ◆ For contracts that are subject to a just and reasonable standard of review in the ongoing consolidated complaint proceedings,⁵ the Commission should send this analysis to the Administrative Law Judges to use as seen fit to resolve the complaints. (Chapter V)
- ◆ Conclude that the Cal ISO and Cal PX tariff antigaming and anomalous market behavior provisions identify various abuses and misconduct, such as taking unfair advantage of market rules, excessive pricing or bidding, and behavior not consistent with competitive markets; that these provisions authorize the imposition of sanctions and penalties by the Commission; that these provisions are part of the Cal ISO and Cal PX rate schedules on file; and that entities that engaged in the identified practices violated the Cal ISO and Cal PX filed rate schedules. (Chapter VI)
- ◆ Conclude that the Commission can enforce a rate schedule on file on its own motion without complaint or referral. (Chapter VI)

⁵Consolidated proceeding: *Nevada Power Company and Sierra Pacific Power Company v. Enron Power Marketing, Inc., El Paso Merchant Energy, and American Electricity Power Services Corporation; Nevada Power Company v. Morgan Stanley Capital Group, Calpine Energy Services, Reliant Energy Services, and Mirant Americas Energy Marketing, L.P.; Southern California Water Company v. Mirant Americas Energy Marketing, L.P.; and Public Utility District No. 1, Snohomish County, Washington v. Morgan Stanley Capital Group, Inc.*—Docket Nos. EL02-28-000, EL02-33-000, EL02-38-000, EL02-29-000, EL02-30-000, EL02-32-000, EL02-34-000, EL02-39-00, EL02-43-000, and EL02-56-000.

- ◆ Apply these provisions in issuing and implementing various show cause orders. (Chapter VI)
- ◆ Explicitly prohibit the use of false information as a condition for granting all market-based rate authorizations and blanket gas marketing certificates and add this condition to all open access transmission tariffs. (Chapter VI)
- ◆ Direct certain market participants identified in the January 6, 2003 Cal ISO Report⁶ to show cause why their behavior did not constitute gaming in violation of the Cal ISO and Cal PX tariffs, with disgorgement of unjust profits associated with the violations or other appropriate remedies. (Chapter VI)
- ◆ Direct AES/Williams, Dynegy/NRG, Mirant, Reliant, BPA, LADWP, Idaho Power, Powerex, and Enron to show cause why their prices from May to October 2000 did not constitute economic withholding or inflated bidding in violation of the antigaming and anomalous market behavior provisions in the Cal ISO and Cal PX tariffs, with disgorgement of unjust profits associated with the violations or other appropriate remedies. (Chapter VI)
- ◆ Issue an order to Enron and the entities with whom it jointly engaged in the Enron trading strategies⁷ (both public utilities and governmental entities) to show cause why this did not constitute gaming in violation of the Cal ISO and Cal PX tariffs, with disgorgement of unjust profits associated with the violations or other appropriate remedies. (Chapter VI)
- ◆ Issue an order for Enron to show cause why its market-based rate authorization and its blanket gas marketing certificate authority should not be revoked. (Chapters VI and IX)

⁶Sempra/San Diego Gas and Electric; Morgan Stanley Capital Group; Coral Power, LLC; Powerex Corporation; Enron Power Marketing, Inc.; Enron Energy Services Inc.; Avista Energy Inc.; Pacific Gas and Electric Company; American Electric Power Services Corporation; Duke Energy Trading and Marketing; Mirant; Cargill-Alliant, LLC; Idaho Power Company; Puget Sound Energy; Dynegy; PGE Energy Services; Calpine Corporation; Modesto Irrigation District; City of Glendale, California; Arizona Public Service Company; Williams Energy Services Corporation; PacifiCorp; Automated Power Exchange; Bonneville Power Administration; Portland General Electric; Los Angeles Department of Water and Power; Aquila; Southern California Edison; Citizens Power Sales; Constellation Power Service; Sierra Pacific; Azusa; Riverside; Pasadena; Vernon; Salt River Project; and Reliant.

⁷Energy West; Montana Power Company; Puget Sound Power and Lighting Company; Powerex Corporation; City of Redding, California; City of Glendale, California; Colorado River Commission; Las Vegas Cogeneration; Washington Water Power Company (later named Avista); Valley Electric Association; Public Service of New Mexico; Grant Public Utility District; Grays Harbor Paper Company; Modesto Irrigation District of Northern California; and TOSCO.

- ◆ Order all jurisdictional entities to file any agreements with other entities that have any of the characteristics of the Enron joint partnership arrangements within 30 days. (Chapter VI)
- ◆ Order Reliant and BP Energy to show cause why their authorities to sell power at market-based rates should not be revoked by the Commission due to manipulation of electricity prices at Palo Verde. (Chapter VI)
- ◆ Remand this Report and, in particular, the conclusions herein related to the Pacific Northwest spot power prices, to the Administrative Law Judge in Docket No. EL01-10-000. (Chapter VI)
- ◆ Establish specific rules banning any form of prearranged wash trading and prohibiting the reporting of any affiliate trading activities through industry indices. (Chapter VII)
- ◆ Condition blanket gas marketing certificates, as well as electric market-based rates, to require that sellers who use trading platforms use only those trading platforms that agree to provide the Commission with full access to trade reporting and order book information for the trading systems and agree to adhere to appropriate monitoring requirements. (Chapters VII, VIII, and IX)
- ◆ Recommend that Congress consider giving direct authority to a Federal agency to ensure that electronic trading platforms for wholesale sales of electric energy and natural gas in interstate commerce are monitored and provide market information that is necessary for price discovery in competitive energy markets. (Chapters VII, VIII, and IX)
- ◆ State that the allegations that Williams Energy Marketing & Trading Company cornered the natural gas market in California in January 2001 are unsubstantiated. (Chapter X)
- ◆ Reevaluate the “simultaneous offer” rule that it uses to discipline affiliate transactions to ensure that it is effective and verifiable. (Initial Report)
- ◆ Require that all market-based rate tariffs include a specific prohibition against the submission of false information or the omission of material information to the Commission or to an entity such as an independent system operator, a regional transmission organization, or an approved market monitor. (Initial Report)
- ◆ Recommend that Congress expand the Commission’s civil penalty authority that applies to jurisdictional companies that violate Commission orders, regulations, or tariffs. (Initial Report)

I. Manipulations in the California Natural Gas Spot Markets Forced Upward Pressure on Wholesale Electric Prices

California experienced extraordinarily high wholesale electric prices from the summer of 2000 through the winter of 2000–2001. High natural gas prices in California from the summer of 2000 through the winter of 2000–2001, in combination with accelerated electric demand, generation failures, flawed regulation, and transmission constraints combined to create these extraordinary wholesale electric prices. Gas-fired generation units, particularly peaking units, were often reliant on the spot gas market, due in part to policies of the California Public Utilities Commission (CPUC) that restricted their ability to enter into long-term contracts for natural gas. Operators of gas-fired generation units in California who paid higher spot market gas costs consequently raised their bids in the wholesale spot electric market. The effect of relatively inefficient generators (i.e., those with high heat rates), whose bids set the market price for all sellers, was to increase the impact of higher gas prices on wholesale electric prices.

Higher gas prices increased the revenues owed to power sellers and ultimately severely affected the state's electric customers.

While soaring demand for natural gas and flawed electric power market rules were the primary drivers of high gas prices, spot market manipulations contributed significantly. High wholesale electric prices were partially the result of specific behavior inimical to the efficient operation of a liquid and transparent competitive market.

Staff concludes that commodity trading in gas, particularly in southern California in the roughly 9-month period beginning in the summer of 2000, affected the very high electric prices. This conclusion is particularly germane to the methodology the Commission established in its July 25, 2002 Order to calculate potential refunds due to customers in the organized markets operated by the California ISO and the California PX for the period October 2, 2000 through June 20, 2001.¹ In that Order, the Commission established a mitigated price based on the marginal cost of the last unit dispatched to meet load in the California ISO's real-time market based on a daily spot gas price, as published in Financial Times Energy's *Gas Daily* publication.

We conclude that reliance on published spot market prices for natural gas at California delivery points is inappropriate for calculating

¹See *San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Service*, 96 FERC ¶ 61,120 at 61,499, 61,516-517 (2001).

market-clearing power prices. In particular, these published prices reflect anomalous outcomes and manipulative activities not associated with a competitive market. Accordingly, they should not provide the basis for potential refunds to electric customers.

Sellers of wholesale power obtained prices that were augmented in an amount greater than the addition of higher gas input costs alone because, as indicated above, the market clearing price was set by the marginal (i.e., least efficient) unit. Thus, while sellers may have incurred higher spot market input costs for their gas-fired generation units, they obtained wholesale electric prices that magnified the effect of these higher gas costs because all generators were paid a single clearing price. Use of published gas index prices would result in a windfall to sellers if the published spot market prices for natural gas were used in the refund methodology.² Gas costs that were inflated by conditions not associated with competitive markets should not provide a source of profit to wholesale power sellers. Staff urges a different methodology for calculating electric prices for this period of market dysfunction.

Spot Market Natural Gas Prices at California Borders Were Extraordinarily High

Sharply higher gas costs beginning in the summer of 2000 and extending through the winter of 2000–2001 exacerbated already dire conditions for electric customers in California. Increased gas consumption pressured prices upward. Gas consumed for electric generation in California increased by 44 percent from May 2000 through October 2000, as compared to 1999 levels during the same period. In the entire West, the increase was 46 percent.³ California's electric sector used 1.1 Tcf of gas in 2000, a 22-percent increase over consumption in 1999.⁴ Total annual gas-fired generation in California

²Stated alternatively, since many sellers of wholesale power obtained electricity from relatively efficient generating units, these sellers realized a net producers' surplus; i.e., the difference between the minimum price at which the seller would be willing to sell power and the amount for which it actually sold. See Varian, Hal R., *Intermediate Microeconomics* (New York: W.W. Norton & Co., 1987), pp. 262–263. In a competitive market, producer surplus is a justified return earned by more efficient suppliers. However, because input prices were inflated due in part to manipulation, the associated producer surplus was also artificially inflated and hence the portion due to manipulation is unjustified. Staff cannot calculate the portion of the prices due to manipulation.

³Electric Power Monthly, Energy Information Administration, January 2001.

⁴Electric Power Annual, Energy Information Agency, p. 8 (Internet pagination).

rose by 31.7 percent in 2000, as compared to 1999 levels.⁵ As noted above, gas-fired generators were willing to incur increased costs because they could pass these costs through in the form of higher charges for their outputs. Inefficient gas-fired units were called on by the California ISO to run to avoid power blackouts and this resulted in higher wholesale electric prices.

Higher demand was not the only driver of higher gas prices. In the August 2002 Initial Report, the Staff observed that spot market prices at the Southern California Border were detached from production basin prices; this indicates that transportation constraints contributed to a scarcity of gas supply relative to demand in the area, contributing to higher gas costs for California customers. Since the Commission regulates the maximum rate for transportation of natural gas by interstate pipelines, given sufficient interstate pipeline capacity and sufficient storage utilization, the cost of gas at the California border should not have significantly exceeded the production basin price of the gas plus the interstate transportation charge, unless scarcity and nonregulatory factors drove the imbalance.⁶

⁵“U.S. Natural Gas Markets: Mid-Term Prospects for Natural Gas Supply,” Energy Information Administration (December 2001), p. 13 (Internet pagination).

⁶As the Commission has explained, its jurisdiction to regulate the prices charged by sellers of natural gas is subject to statutory limitations:

The Natural Gas Policy Act of 1978 (NGPA) and the Natural Gas Wellhead Decontrol Act substantially narrowed the Commission’s Natural Gas Act (NGA) jurisdiction over sales for resale, with the Wellhead Decontrol Act removing all “first sales” from the Commission’s NGA jurisdiction as of January 1, 1993. First sales include all sales other than those by interstate or intrastate pipelines, LDCs, or their affiliates. In addition, Section 3(b) of the NGA provides that all sales of gas imported from countries with free trade agreements, such as Canada and Mexico, have first sale status even when sold by pipelines, LDCs, or affiliates. The end result of these various statutory provisions is that the only sales the Commission currently has jurisdiction to regulate are those for resale of domestic gas by pipelines, LDCs, or their affiliates.

Reporting of Natural Gas Sales to the California Market, 95 FERC ¶ 61,262 at 61,929 (2001) (footnotes omitted). In addition, in 1992, the Commission directed pipelines to separate their transportation and commodity sales services. See Order No. 636, FERC Stats. & Regs., Regulations Preambles (January 1991 to June 1996) ¶ 30,939 (1992). By unbundling these products, pipelines became more like common carriers. This reform, among others, increased efficiency by creating a largely transparent interstate transportation market in which pipelines were required to treat all shippers equally. According to one authority, natural gas prices have been lower since Federal deregulation of natural gas prices, although the volatility of those prices has increased. “Natural Gas: Analysis of Changes in Market Price,” General Accounting Office, December 2002, p. 10.

California has separate natural gas markets in southern and northern California. The markets are separate because of limits on transportation capacity between the regions and, therefore, prices are often different in the respective regions. In southern California, limited transportation capacity and storage contributed to higher gas prices in the 2000–2001 period than in the prior year. In northern California, fewer transportation constraints, greater storage, and the ability of generators to hold firm transportation capacity resulted in lower spot market prices for natural gas. Although we discuss southern California and northern California natural gas prices and market conditions separately, our overall point is that dysfunctions in both regions render spot prices inappropriate as bases for electric refund calculations.

Most large natural gas customers in southern California, such as electric generation plants, could (1) buy bundled gas at the Southern California Border or (2) buy gas at the San Juan or Permian production basins (located roughly in the Four Corners area and west Texas, respectively) and arrange for transportation of the gas by interstate pipeline to the Southern California Border.⁷ There would have been little reason to pay spot prices at the Southern California Border that exceeded the cost of natural gas purchased in one of the production basins plus the cost of transportation to the border, unless transportation was not readily available.

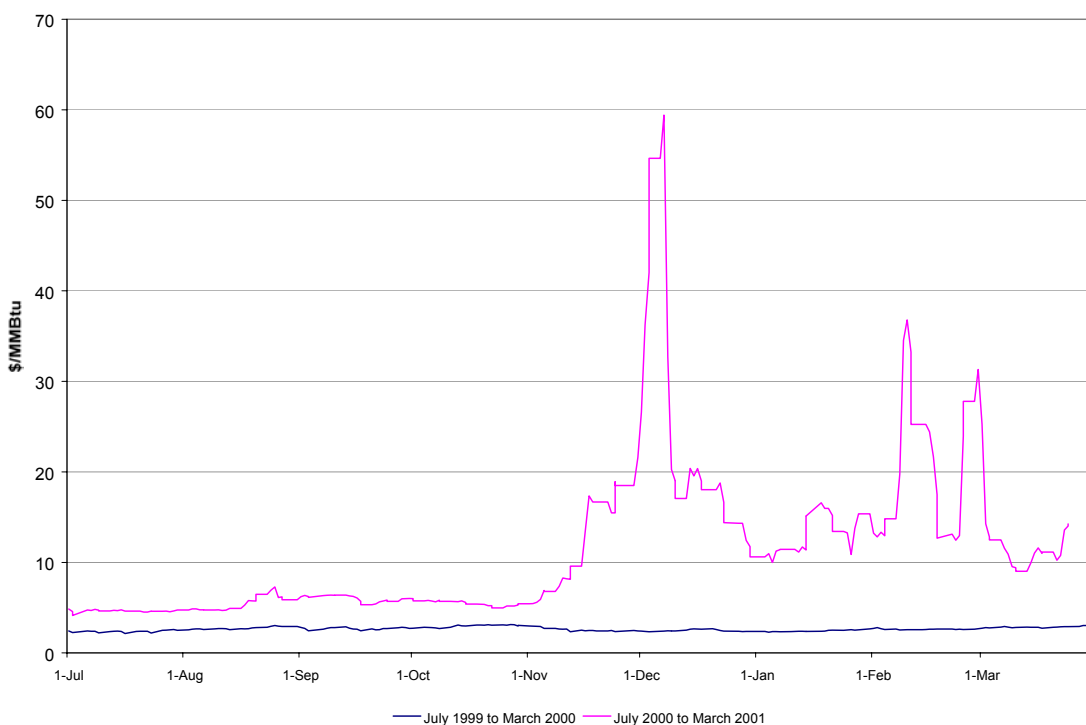
The CPUC's regulation of Southern California Gas Company (SoCalGas) impacted terms under which interstate pipeline capacity was purchased. For example, the CPUC limited SoCalGas to purchasing interstate pipeline capacity necessary to serve its core customers, which did not include independent generators. The CPUC also approved terms of service on SoCalGas' system that, for example, did not provide for firm transportation service on SoCalGas for independent generators. These aspects of the CPUC's regulation did not change the generators' option of buying at a production basin and shipping gas to the border (to the extent that interstate capacity was available) or buying a bundled product at the border. No matter which option generators elected, they would have been able to obtain transportation to their burner tips because, as a rule, SoCalGas delivered gas for shippers that had firm rights on an upstream interstate system or that purchased gas from shippers having firm rights on an upstream system. Williams Energy Marketing & Trading

⁷Approximately 83 percent of the natural gas California consumes is transported from out of state. "U.S. Natural Gas Markets: Mid-Term Prospects for Natural Gas Supply," Energy Information Administration (December 2001), p. 13 (Internet pagination). Thus, traders and customers of natural gas rely principally on out-of-state gas to meet the demands of California users.

Company is an example of a firm that chose both options: To satisfy contracts to supply generators in southern California, it bought producer gas and shipped it to the border and it also purchased bundled gas at the border. Accordingly, the fact that SoCalGas did not offer firm transportation to generators did not affect the generators' basic option of buying at a production basin and transporting to the border or buying bundled supplies.

Natural gas spot prices at the Southern California Border were historically high in the summer of 2000 and the winter of 2000–2001 (see Figure I-1). For example, the price of natural gas for residential customers in California averaged \$12.10/Mcf in January 2001, a 90-percent increase from January 2000.⁸

Figure I-1
Spot Natural Gas Prices at SoCal for the Periods
July 1999 – March 2000 and July 2000 – March 2001



Natural gas spot prices at the Southern California Border were also high relative to Henry Hub prices and the prices at other major trading centers. The persistent basis differentials experienced at the Southern California Border, given the presence of transportation that is rate

⁸“Electricity Shortage in California: Issues for Petroleum and Natural Gas Supply,” Energy Information Administration, June 2001, p. 8 (Internet pagination).

regulated by the Commission, suggest a dysfunctional gas market. Table I-1 presents a range of data at various locations.⁹

Table I-1. Various Delivered Natural Gas Prices

Quarter and Year	Henry Hub	Chicago Citygate	Florida Citygate	New York Citygate	SoCal Citygate	PG&E Citygate
3 rd quarter 2000	4.47	4.56	5.00	4.81	5.28	5.10
4 th quarter 2000	6.41	6.82	6.73	8.07	13.59	12.27
1 st quarter 2001	6.44	6.61	6.85	7.83	15.19	10.28

Figure I-2 depicts the radical decoupling of Henry Hub and SoCal average spot natural gas prices on a monthly average basis. Figure I-3 suggests a rough correlation between production basin and SoCal border prices in the period July 1999 through March 2000. Figure I-4 shows production basin and SoCal border prices for the period July 2000 through March 2001. This shows that prices diverged substantially starting in November 2000.

Prices were also high at the northern California border relative to production basin prices (see Figures I-5 and I-6). Part of the reason for this price differential was that gas from the San Juan basin, normally an attractive source of supply for central California, was diverted to the southern California market because of the high prices for spot gas at the Southern California Border. Accordingly, the price at Pacific Gas and Electric Company (PG&E) citygate reflected the fact that the supply from southern California was less than it had been previously. Increased demand also contributed significantly to the high basin differentials in northern California.

⁹“U.S. Natural Gas Markets: Recent Trends and Prospects for the Future,” Energy Information Agency, May 2001, p. x; RDI GasDat (for PG&E citygate only).

Figure I-2
Monthly Average Spot Gas Prices at Henry Hub and SoCal

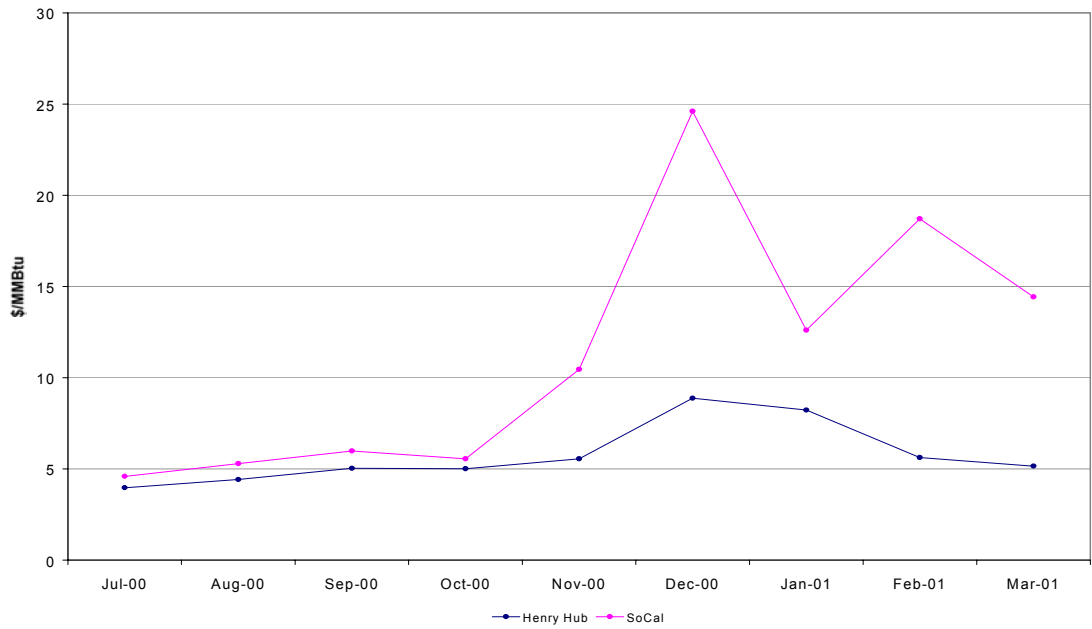


Figure I-3
Daily Spot Natural Gas Prices at Selected Basins and SoCal
July 1999 – March 2000

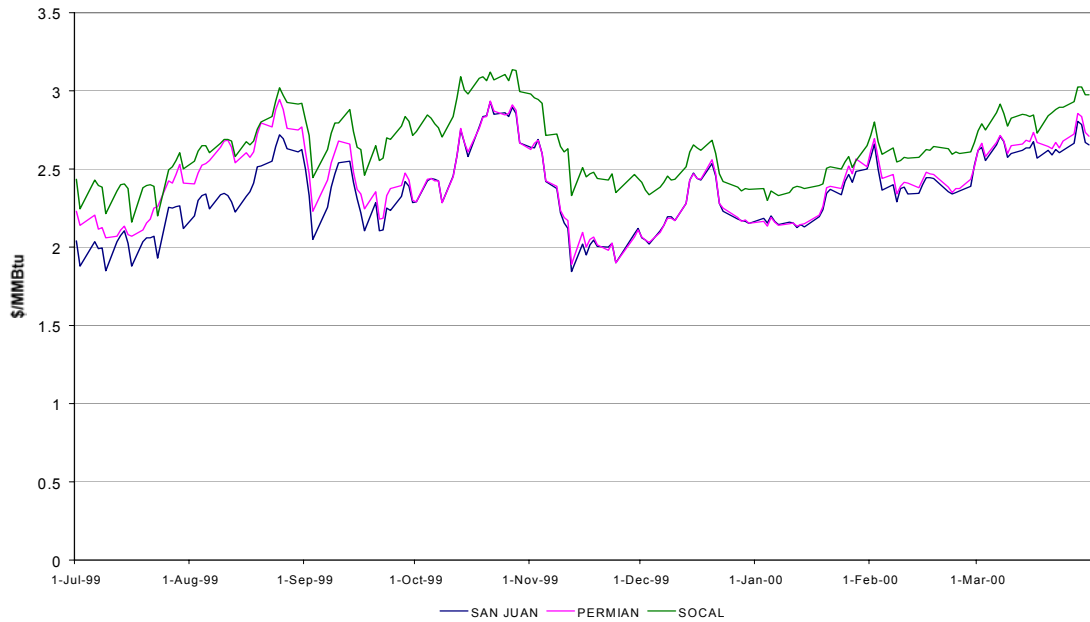


Figure I-4
Daily Gas Prices at Selected Basins and SoCal
July 2000 – March 2001

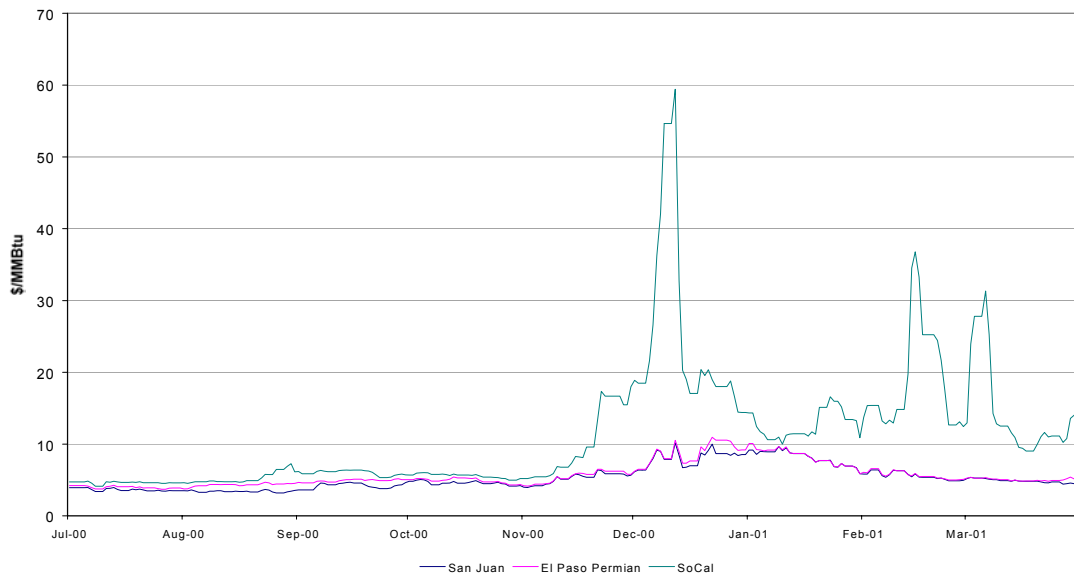


Figure I-5
Daily Natural Spot Gas Prices at Main Canadian Production Point (NOVA (AECO-C)) and PG&E
July 1999 – March 2000

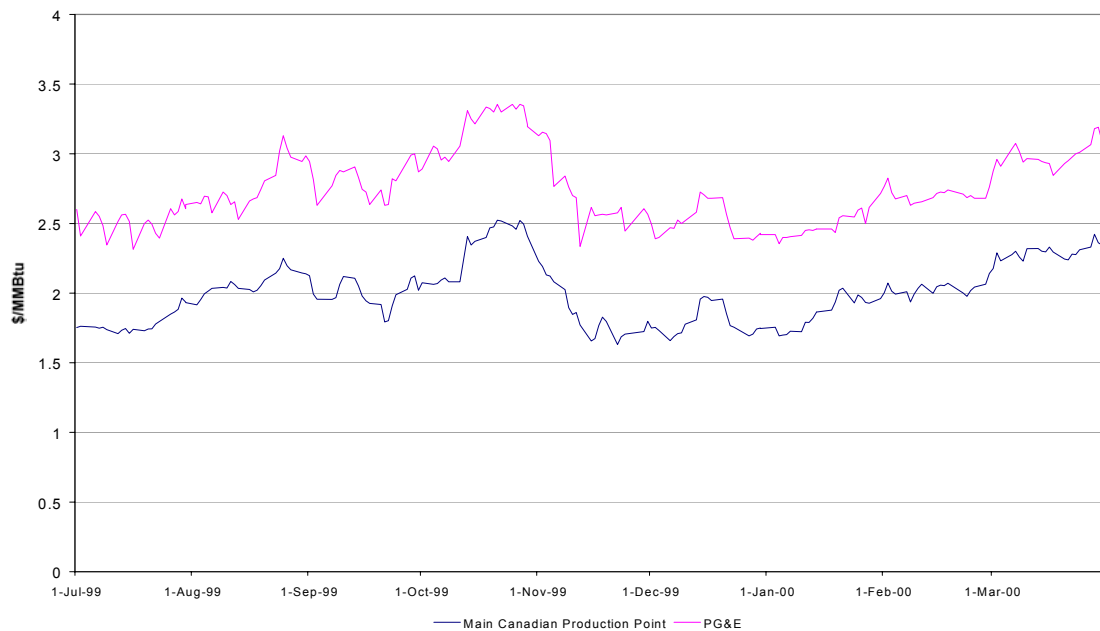
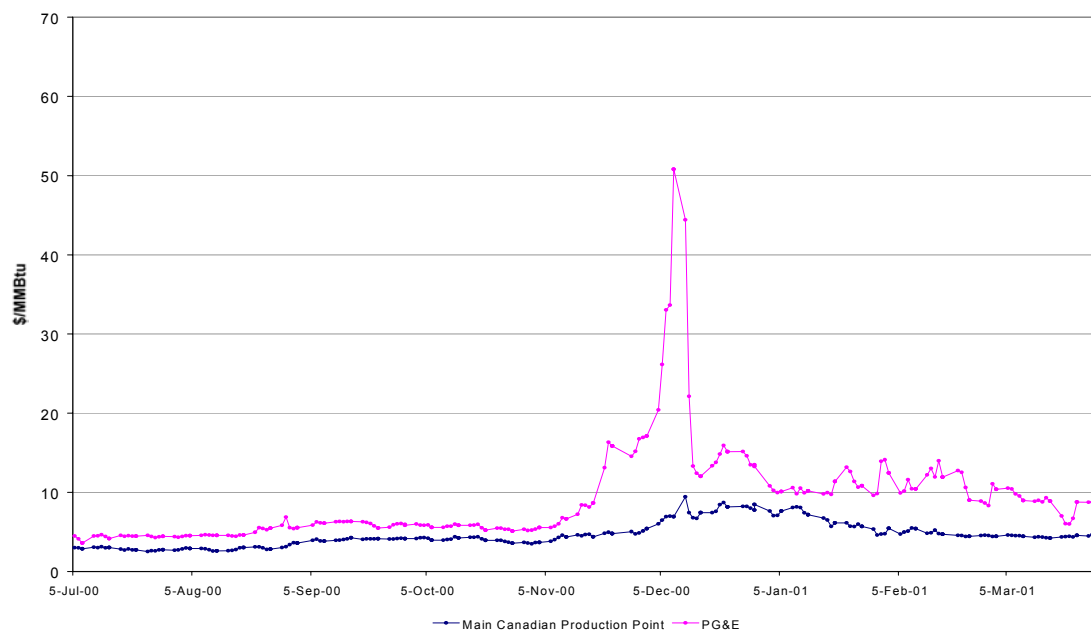


Figure I-6
Daily Spot Natural Gas Prices at Main Canadian Production Point (NOVA (AECO-C)) and PG&E
July 2000 – March 2001



Supply/Demand Imbalance and Flawed Market Rules Drove Wholesale Electric Prices Higher During 2000 and 2001

In November 2000, the Commission determined that the electric market structure and market rules for wholesale sales of electric energy in California were seriously flawed in the summer of 2000.¹⁰ This determination stemmed ineluctably from the wholesale prices in California observed during the preceding half-year. This section surveys the major factors that blighted California's wholesale electric markets from the summer of 2000 through the winter of 2000–2001. Overall, the significant increase in power production costs was triggered by increased demand, significant demand inelasticity, and a scarcity of available generation resources throughout much of the West. Further, California's existing market rules exacerbated conditions by exposing the state's three investor-owned utilities to the volatility of the wholesale spot market without affording them the ability to mitigate price volatility and by promoting underscheduling in the PX.

¹⁰San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services (San Diego), 93 FERC ¶ 61,121 at 61,349 (2000).

Weather Extremes and High Demand

The August 2002 Interim Staff Report noted weather extremes and high demand in California during 2000 and 2001.

From June through August 2000, California experienced one of the hottest summers in 106 years of recordkeeping.¹¹ In November, average temperatures were unusually low. This atypical weather helped drive load growth in California as temperature-sensitive residential customers, in particular, increased their demand. California generators alone produced 414,094 million kWh in 2000, as compared to 383,169 million kWh in 1999.¹²

Reduced snow pack from the winter and lower rainfall in the summer of 2000 reduced western area hydropower output, which California has traditionally relied on to meet its hot-weather peak. Net generation from hydroelectric sources in Washington produced 81 billion kWh in 2000, down from 97 billion kWh in 1999, and net generation from hydroelectric sources in Oregon produced 38 billion kWh in 2000, down from 46 billion kWh in 1999.¹³ On a broader scale, hydroelectric generation in the Northwest was 14 percent lower in 2000 than in 1999, which amounts to a reduction of 46.4 million MWh in total Northwest generation.¹⁴ Within California, reduced hydropower availability forced greater reliance on in-state, gas-fired generation, sourced from units that were generally old and relatively inefficient.

Stepped-up demand and low hydropower increased reliance on gas-fired generation, raising the demand for and the price of spot market gas. As one authority summarized, “[b]etween late 2000 and mid-2001 ... a rapid increase in natural gas demand, brought about by a need to increase electricity output from gas-fired power plants (to compensate for decreased availability of hydropower), also created a tight market for natural gas interstate and intrastate pipeline capacity.”¹⁵ Noting that “[h]igh electricity prices also reflect reduced Northwest hydropower production due to low rainfall and the generally overstressed state of

¹¹Electric Power Annual 2000, Volume I, Preface, Energy Information Administration, p. 6 (Internet pagination).

¹²Net Generation by Census Division and State, 2000 and 1999, Energy Information Administration, p. 2 (Internet pagination).

¹³These were approximately 15-percent declines. Electric Power Annual, Volume I, Preface, Energy Information Administration, p. 10 (Internet pagination).

Washington’s 1997 hydroelectric generation peaked at 104 billion kWh and Oregon’s 1997 hydroelectric generation peaked at 46 billion kWh. Washington and Oregon are California’s principal out-of-state sources for hydroelectric power.

¹⁴“U.S. Natural Gas Markets: Mid-Term Prospects for Natural Gas Supply,” Energy Information Administration (December 2001), p. 13 (Internet pagination).

¹⁵“Natural Gas Transportation—Infrastructure Issues and Operational Trends,” Energy Information Administration (October 2001), p. 15 (Internet pagination).

the western power grid,” one commenter concluded that “much costlier natural gas has in turn helped to drive up the operating cost of electric generation.”¹⁶

Sellers of power necessarily relied on older, relatively inefficient units to meet the higher demand or on peaking units that have relatively high running costs. These units were run more frequently, and stressed more, than they had been in the recent past. Consequently, outages of gas-fired units increased in the summer of 2000 in California as compared to the previous summer. These outages reduced the supply necessary to meet demand. Secretary of Energy Richardson cited “a shortage of currently operational electric generation facilities, a shortage of water used to generate electricity, [and] unusual volatility of electricity and natural gas markets” as reasons supporting his finding of an emergency in California “by reason of the shortage of electric energy.”¹⁷

Notwithstanding the increased demand and reduced availability of hydropower, California exported more power to neighboring states in the summer of 2000 than it did in 1999. For example, August 2000 exports averaged 3,136 MW above the August 1999 level. Higher exports reduced that amount of power bid into the day-ahead market. In August 2000, price caps in California were reduced to \$250/MW, down from \$500/MW in July and early August and \$750/MW in June.¹⁸ The lower price caps motivated sales of bulk power at higher prices outside California, where price caps did not apply.

Higher demand intensified transmission congestion, which in turn contributed to higher wholesale electric prices. While on-peak congestion at the California-Oregon border decreased substantially from the summer of 1999 to the summer of 2000, on-peak congestion north to south on Path 15 increased from 1 percent to 7.9 percent and increased from 0 percent to 29.2 percent on Path 26. Off-peak congestion from south to north on Path 15 also increased from 28.1 percent to 49.6 percent.

¹⁶Cavanagh, R., “Revisiting ‘the Genius of the Marketplace’: Cures for the Western Electricity and Natural Gas Crises,” *The Electricity Journal* (June 2001), pp. 11 and 13.

¹⁷Order Pursuant to Section 202(c) of the Federal Power Act, U.S. Department of Energy (December 14, 2000). See also, Order Pursuant to Section 202(c) of the Federal Power Act, U.S. Department of Energy (January 11, 2001) (citing same reasons).

¹⁸*San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services*, 93 FERC ¶ 61,121 at 61,353 (2000).

**Flawed Market Rules and
Regulatory Policies
Magnified Adverse
Conditions**

California's then-prevailing regulatory scheme forbade much forward contracting by the state's three largest investor-owned utilities (IOUs). The three California IOUs were required to purchase power through the PX with little or no ability to purchase through forward contracts, exposing the utilities to the volatility of the spot market without the ability to mitigate that volatility. Even the generation that was not divested by the three California IOUs could not be used directly to self-supply their retail load. Under the California market design, this retained generation had to be bid into the spot market. The California IOUs were required to buy the output of their resources to supply their retail customers. In its December 15, 2000 Order, the Commission eliminated this aspect of the California market design that required that the IOUs must sell all of their generation into, and buy all of their energy from, the California PX.¹⁹

A second market design flaw was the lack of demand responsiveness. This flaw was exacerbated by a retail rate freeze that insulated residential customers from high wholesale prices, thereby thwarting the ability of price signals to shape and limit demand.

A third major flaw was the underscheduling of load by the three California IOUs. Economic incentives to underschedule tended to increase during high demand periods, which created operational and reliability problems for the Cal ISO and required it to obtain out-of-market energy at high prices. In its December 15, 2000 Order, the Commission established penalties for underscheduling load.

As a result of the conditions and market rules noted above, hourly prices in the PX reached as high as \$750/MWh twice in May and eight times in June; average prices were \$47/MWh in May, \$120/MWh in June, \$106/MWh in July, and \$166/MWh in August.²⁰ These prices were vastly higher than year-ago prices. For example, the monthly average unconstrained market-clearing price for May 2000 in the PX's day-ahead market represented a 100-percent increase over May 1999.²¹

¹⁹San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, 93 FERC ¶ 61,294 (2000).

²⁰San Diego, 93 FERC at 61,353 (citing an ISO source); Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of Summer 2000 Price Abnormalities (2000 Western Markets Staff Report), p. 5-1.

²¹San Diego, 93 FERC at 61,353 (citing a PX source).

Finally, emission compliance costs also increased markedly in the summer of 2000. The cost of credits for complying with nitrous oxide standards rose from approximately \$6 per pound in May 2000 to \$35 per pound in August. Because a combined-cycle gas generator typically emits from 1 to 1.5 pounds of nitrous oxide per MWh, these increased costs were significant.

Gas market rules were also flawed. In particular, the CPUC's rules did not require that storage facilities be filled during the nonpeak season, as discussed in greater detail below. The lack of stored gas in southern California contributed to higher border prices in the winter of 2000–2001.

**Transportation Constraints
and Spot Market
Dysfunctions Contributed
Significantly to Higher Spot
Market Natural Gas Prices at
the California Border**

The disparity in prices between the primary production basins that serve southern California, Permian and San Juan, and the spot market price at Topock, Arizona, near the Southern California Border, suggests that natural gas transportation between these points was constrained.

Three major interstate pipelines serve southern California. Table I-2 indicates the limited choices available to gas purchasers for purchasing gas for resale or consumption in southern California.

Table I-2. Interstate Pipeline Design Capacity to California

Pipeline	Design Capacity to California (MMcf/d)
El Paso Natural Gas Company	3,290
Transwestern Pipeline Company	1,090
Kern River	700
Total Design Capacity	5,080

A rupture occurred on El Paso Natural Gas Company's (El Paso's) pipeline in southeast New Mexico in August 2001; capacity was immediately reduced by approximately 1 Bcf/d for about 2 weeks

following the rupture.²² During the winter of 2000–2001, El Paso operated its pipelines immediately upstream and downstream of the rupture site at reduced pressures pursuant to an Order of the U.S. Department of Transportation.²³ Operation at reduced pressure caused a reduction in El Paso’s capacity in the amount of 270 MMcf/d during this time.²⁴ The loss of capacity was “a major shock to supplies of natural gas in the Western Region, particularly in California, Arizona, and New Mexico.”²⁵ The amount of gas needed to serve 1 million homes is approximately 270 MMcf/d.

High spot prices in southern California were reflected in the willingness of some shippers to pay more than the maximum tariff rate for transportation on pipelines serving southern California.²⁶ The following table provides a barometer of pipeline capacity scarcity. It shows that shippers were able to release capacity on El Paso’s and Transwestern Pipeline Company’s (Transwestern’s) systems above the maximum tariff rate.²⁷

²²“Status of Natural Gas Pipeline System Capacity Entering the 2000–2001 Heating Season,” Energy Information Administration (October 2000), p. xviii (Internet pagination).

²³See Corrective Action Order, issued by the Research and Special Programs Administration of the U.S. Department of Transportation, CPF No. 420001004-H (August 23, 2000).

²⁴El Paso press release, October 23, 2002.

²⁵“Status of Natural Gas Pipeline System Capacity Entering the 2000–2001 Heating Season,” Energy Information Administration (October 2000), p. xviii (Internet pagination).

²⁶In Order No. 637, the Commission temporarily removed the rate ceiling for short-term capacity release transactions. The Commission explained that “[d]uring peak demand periods, when capacity is at a premium, the need to provide shippers with the greatest number of potential options and the most efficient competitive marketplace is crucial. Shippers that most need capacity during periods of scarce supply need a market that can efficiently respond to their demands and provide the capacity they need.” FERC Stats. & Regs, July 1996 – December 2000 ¶ 31,091 at 31,270 (2000). While this provision of Order No. 637 expired on September 30, 2002, 18 C.F.R. § 284.8(i) (2002), it was effective during the winter of 2000–2001.

²⁷San Diego Gas & Electric Company, 95 FERC ¶ 61,264 (2001) (Appendix).

Table I-3. Capacity Releases Above the Maximum Tariff Rate

Month	Pipeline	Amount Released Above Maximum Rate (MMBtu/d) ²⁸
November 2000	El Paso	33,800
December 2000	El Paso	7,000
January 2001	El Paso	12,500
January 2001	Transwestern	7,766
February 2001	El Paso	19,269
March 2001	El Paso	34,566

As the Commission pointed out in an order addressing the data in Table I-3, the volumes of released capacity above the maximum tariff were not large relative to the total capacity serving California.²⁹ Nonetheless, the data provide an indication of the persistence of capacity scarcity because they show that some shippers were willing to pay above-tariff prices to avoid paying high bundled prices at the California border. The volumes of released capacity may have been relatively low, not because a market for capacity above the maximum tariff rate did not exist, but because shippers holding capacity wanted to use it themselves to transport gas to the California border rather than release that capacity to other shippers.

In short, demand for interstate pipeline capacity and capacity from the border into California exceeded supply. Border prices would not have exceeded production basin prices as dramatically as they did had there been sufficient transportation capacity to meet all of the gas demanded by customers in southern California.

Low storage levels contributed to higher prices and greater volatility in the gas market in southern California. If the CPUC rules required that storage facilities be filled, gas supplies would have been increased during the winter of 2000–2001. Shippers use storage during peak periods to supplement interstate pipeline deliveries. Storage levels were historically low approaching and during the winter of 2000–2001. California began the 2000–2001 winter season with 152 Bcf in storage, which was 34 Bcf below the 5-year (1995–1999) average.³⁰ By mid-February 2001, California’s working gas inventories were estimated at less than 70 Bcf, as compared to the 1995–1999 average of 100 Bcf for the end of March.³¹

²⁸An MMBtu is roughly equal to an Mcf.

²⁹San Diego, 95 FERC at 61,934-935.

³⁰“U.S. Natural Gas Markets: Recent Trends and Prospects for the Future,” Energy Information Agency, May 2001, p. 22.

³¹“U.S. Natural Gas Markets: Recent Trends and Prospects for the Future,” Energy Information Agency, May 2001, p. 23.

Storage levels were low for several reasons. First, the Carlsbad rupture caused shippers to draw down storage inventories in August that would otherwise have been available for the winter heating season.³² Second, natural gas prices above the historical average in southern California in the summer of 2000 caused market participants to reduce the amount of gas they put in storage. These market participants believed that gas prices would moderate, permitting them to fill storage later in the season or purchase natural gas on the spot market at lower prices.³³

Additional factors, including higher gas-fired generation output due to low hydropower availability, nuclear plant outages in November 2000, and unusually cold temperatures in November 2000, contributed to the drawdown of storage serving southern California customers.³⁴

Many of the market participants that sold natural gas at the Southern California Border during the winter of 2000–2001 were trading companies that engaged in major business activities outside of California. However, handwritten daily transaction sheets that Southern California Gas Company (SoCalGas), a local distribution company,³⁵ provides each month to the CPUC indicate that SoCalGas profited significantly from border sales at elevated prices. These records show, for example, that for the flow date December 12, 2000, a date on which natural gas prices at the California border were extraordinarily high, SoCalGas purchased gas for approximately \$11 from production area sources and sold gas at Topock for as much as \$65. For the flow dates February 10 through 12, 2001, the days preceding a run-up of border prices, SoCalGas purchased gas at an average price of less than \$14. From February 14 through 16, when gas prices were spiking, SoCalGas sold gas at an average price that exceeded \$30. SoCalGas' ability to store gas suggests the potential for substantial earnings stemming from these transactions. Under a performance-based rates program authorized by the CPUC, a portion of profits derived from trading activity would have been realized by shareholders of SoCalGas' parent company. For the period October

³²“U.S. Natural Gas Markets: Recent Trends and Prospects for the Future,” Energy Information Agency, May 2001, p. 14.

³³This is suggested in part by data for nationwide futures prices for natural gas. “Natural Gas Winter Outlook 2000–2001,” Energy Information Administration, *Natural Gas Monthly*, October 2000, p. xxiii.

³⁴“U.S. Natural Gas Markets: Recent Trends and Prospects for the Future,” Energy Information Agency, May 2001, p. 23. Staff Report to the Federal Energy Regulatory Commission on Northwest Power Markets in November and December 2000, February 1, 2001, pp. 21-22.

³⁵SoCalGas, whose facilities are located solely within the state of California, is a so-called “Hinshaw” pipeline that is exempt from the Commission's jurisdiction under section 1(c) of the Natural Gas Act, 15 U.S.C. 717(c) (1994).

2000 through March 2001, SoCalGas purchased approximately 56,816,000 MMcf for a total of approximately \$626,900,000, or \$11.04/MMcf, and sold at wholesale 12,856,000 MMcf for \$213,640,000, or \$16.60/MMcf. These data show that SoCalGas benefited from higher bundled prices and general volatility during this period. Taken as a whole, SoCalGas' trading activity indicates that profiteers included at least one market participant subject to California's regulatory oversight.

Staff concludes that transportation constraints and spot market dysfunctions contributed significantly to high spot gas prices and that this justifies the substitution of a new methodology for calculating electric prices for this period of market dysfunction that the Staff proposed in Chapter IV.

Market Manipulations Significantly Influenced Reported Spot Prices for Natural Gas in California

The reasons discussed thus far that impeded spot market natural gas prices from adhering to historical norms—supply/demand imbalance, inefficient market rules, and transportation constraints—may be attributed to the intertwining strands of poor market design, ill-timed market conduct, and fortuity. However, two specific activities, (1) trading in anomalous patterns at Topock and (2) false reporting of market transactions to publications for compilation in price indices, reflect deliberate conduct to manipulate market outcomes. These manipulations significantly influenced reported spot prices for natural gas, heaping further aggravation on the already stressed spot market. Because a substantial volume of spot market gas was purchased to fuel electric generation plants in California, the manipulations directly contributed to higher bids by sellers of wholesale power into the PX and ISO spot market and consequently to higher payments made to these sellers. The manipulations of anomalous trading and false reporting fatally undermine published price indices as reliable measures of market activity in a well-functioning market.

Trading in Anomalous Patterns at Topock

Topock is a major delivery point at the junction of El Paso Natural Gas Company's interstate pipeline and Southern California Gas Company's intrastate pipeline. Topock is particularly significant as a trading point because EOL traded gas at this point, which attracted a substantial volume of activity. An analysis of trading data shows that the activity of a single firm's (Reliant Energy Services, Inc. (Reliant))

gas trading significantly influenced spot prices at Topock. The data also show that Reliant benefited from exerting influence on spot prices. Reliant's trading increased spot market natural gas prices on average by about \$8.54/MMBtu in December 2000 and by about \$1.69/MMBtu over the 9 months of the California Refund Proceeding absent Reliant's churning. We explain and document this conclusion in the following section.

False Reporting of Market Transactions to Publications

Evidence continues to accumulate that natural gas trading entities provided false reports to periodicals that published price indices.³⁶ The epidemic of false reporting affected the accuracy of spot prices, including the California burden prices used in the Commission's California refund calculation. While widespread false reporting vitiates the utility of published price indices as a reliable measure of market activity, it has other important implications as well. First, valuation of forward contracts and other price-sensitive instruments is dependent in part on published price indices. Natural gas futures traders use published indices to enter contracts and assess risks. Second, spot prices affected by false reporting affect next-day spot prices, thus impacting the physical market as well. Third, false reporting undermines investor confidence in the ability of the physical gas market to operate successfully.³⁷ We explain and document our conclusions regarding the extent and impact of false reporting in Chapter III.

³⁶For example, on December 18, 2002, the Commodity Futures Trading Commission (CFTC) imposed a \$5 million penalty against Dynegy Marketing and Trade (Dynegy). "Order Instituting Proceedings Pursuant To Section 6(c) and 6(d) of the Commodity Exchange Act, Making Findings and Imposing Remedial Sanctions," CFTC Docket No. 03-03 (December 18, 2002). In its order, the CFTC determined that from 2000 through June 2002, Dynegy knowingly reported false natural gas price and volume information to certain reporting firms in an attempt to skew gas indices relative to various hubs in the United States to Dynegy's financial benefit. As another example, El Paso Corporation acknowledged on December 4, 2002, that Todd Geiger, a vice president at its El Paso Merchant Energy unit, was charged by Federal authorities with knowingly providing inaccurate gas price data to a trade publication. The false trade data were allegedly provided for transactions at Sumas, on the United States-Canada border.

³⁷Credit has largely evaporated, or become very expensive, for power trading companies in the wake of Enron Corporation's collapse and disclosures elsewhere in the sector. In the past year, Allegheny Energy, Inc., American Electric Power, Progress Energy, Inc., and Williams Companies, Inc., among others, have scaled back their trading and Aquila, Inc., CMS Energy Corp., Dynegy, Inc., and El Paso Corporation, among others, have exited trading. "U.S. Utilities Retreating From Energy Trading," Reuters, January 8, 2003.

II. Analysis of Gas Trading Activity in Southern California

Summary

In this chapter we conclude that Reliant Energy Services (Reliant) engaged in a high-volume, rapid-fire trading strategy to purchase its physical spot gas needs at Topock. Reliant often bought and sold many times its needs in quick bursts, which significantly increased the price of gas in that market. We describe this as “churning” and define its characteristics later in this chapter. We use this term even though it has other connotations in securities or futures trading because it gives the best visual image of Reliant’s behavior. Reliant’s churning enabled it to reduce the overall cost of the gas it actually needed. Through its churning, Reliant profited by selling gas at or near the top of the price climb it caused. Reliant was often such a large presence at Topock that its trading strategy moved the entire market price. Our analysis shows that the price of gas would have been lower by about \$8.54/MMBtu in December 2000 and by about \$1.69/MMBtu over the 9 months of the California Refund Proceeding absent Reliant’s churning. These inflated gas prices have been used in the California Refund Proceeding to set the prices that clear the entire electric spot market. This greatly magnifies the effect of Reliant’s actions upon gas prices.

Staff concludes that these gas prices are not the result of competitive conditions and would not produce just and reasonable electric prices in the California Refund Proceeding. Later in this Report, we recommend alternative gas prices for the Commission’s consideration. We also recommend amending the Commission’s blanket certificates to establish guidelines for trading natural gas as well as reporting and monitoring requirements.

Background

During the winter of 2000–2001, the southern California natural gas market experienced high prices, large price swings, and high volumes. Based on findings in the Staff’s Interim Report, we made a detailed investigation of trading activity in the market during this period, focusing on trading on the EnronOnline (EOL) trading platform. We examined trading for all gas products traded on EOL, traded by any counterparty, and traded across all western locations, including both citygate locations as well as basins. We examined trading for spot gas, longer term physical gas transactions, and financial gas products. We found unusual trading patterns associated with Reliant transactions on

the EOL trading platform. Staff, with the assistance of Professor Robert S. Pindyck of MIT and Michael Quinn of Analysis Group/Economics, conducted an investigation into these activities.¹ The results of this analysis are the subject of this chapter.

The firms, individuals, and trading practices highlighted in this chapter contributed to uncertainty and price volatility in gas markets, and ultimately in electricity markets as well. In particular:

- ◆ Analysis of trading data shows that there was often so little liquidity at Topock that Reliant's gas trading significantly influenced spot gas prices at that location.
- ◆ This in turn significantly influenced index prices, which were used to set the market-clearing price in the California Refund Proceeding.
- ◆ Reliant's trading increased spot market gas prices significantly, on average over \$8.54 MMBtu for December 2000.

This chapter examines natural gas trading in southern California from November 2000 through June 2001, focusing on Reliant's activity on the EOL trading platform and on the Topock² location. This is a key point for defining published natural gas price indexes. We provide an in-depth descriptive analysis of Reliant's trading activities, both in terms of actual trades executed and the trading staff, operations, and processes in place. This analysis shows that whenever the market exhibited anomalous patterns (e.g., high prices, price swings, high gross volumes traded), Reliant was typically the most active trader by a variety of measures.

Our analysis also reveals that Reliant's trading activity involved a great deal of churning, i.e., the repeated buying and selling of

¹Robert S. Pindyck is Bank of Tokyo-Mitsubishi Professor of Economics and Finance at MIT's Sloan School of Management. Professor Pindyck is a nationally recognized econometrician with a specialty in energy futures markets. Michael Quinn is a vice president with Analysis Group/Economics. He has a doctorate in Economics from Princeton University. Dr. Quinn specializes in the application of economics to issues in the natural gas and electricity industry, and he has served as an expert on matters involving natural gas transportation and distribution.

²The El Paso Natural Gas pipeline terminates at the California-Arizona border. The two interstate crossings from Arizona into California are at a northern corridor crossing between Topock, Arizona and Needles, California (where El Paso connects to the intrastate systems of both Southern California Gas Company and Pacific Gas and Electric) and at a more southern crossing between Blythe, California and Ehrenberg, Arizona (where El Paso connects to the intrastate system of SoCalGas).

substantial quantities of physical spot gas in a short period of time.³ Reliant's churning generally occurred on trading days during which prices changed significantly—particularly in December 2000. We use econometric analyses to demonstrate the impact of churning on price levels and to estimate counterfactual prices, i.e., the prices that would have prevailed in the absence of Reliant's churning activity.

We also examine the relationship between Reliant's physical trading and financial trading and positions on key dates to determine the extent to which Reliant's financial trading activities may have benefited from its physical trading activities. Disaggregating and analyzing trading data for individual financial traders reveals that the trades of one particular Reliant physical trader benefited Reliant over \$18 million from its financial positions due to its churning.

Descriptive Analysis

Our analysis of EOL trading activity revealed that anomalous trading patterns occurred under the following circumstances:

- ◆ At Topock, a key pricing location for natural gas and, in turn, electricity in California.
- ◆ For next-day gas flow, the product used for the published spot market index prices that affected both gas and electricity prices in California.
- ◆ During the refund period.
- ◆ In Enron's trading with Reliant in proportions far greater than with other counterparties.
- ◆ With the same Reliant trader.

Most notable among these anomalies is the extent to which Reliant's trading activity involved churning through the execution of a large number of trades in both directions (both buys and sells) in a short amount of time—numerous rapid buys and numerous rapid sells. The Reliant trader of physical spot market gas at the California-Arizona border, for entry into the system of Southern California Gas Company

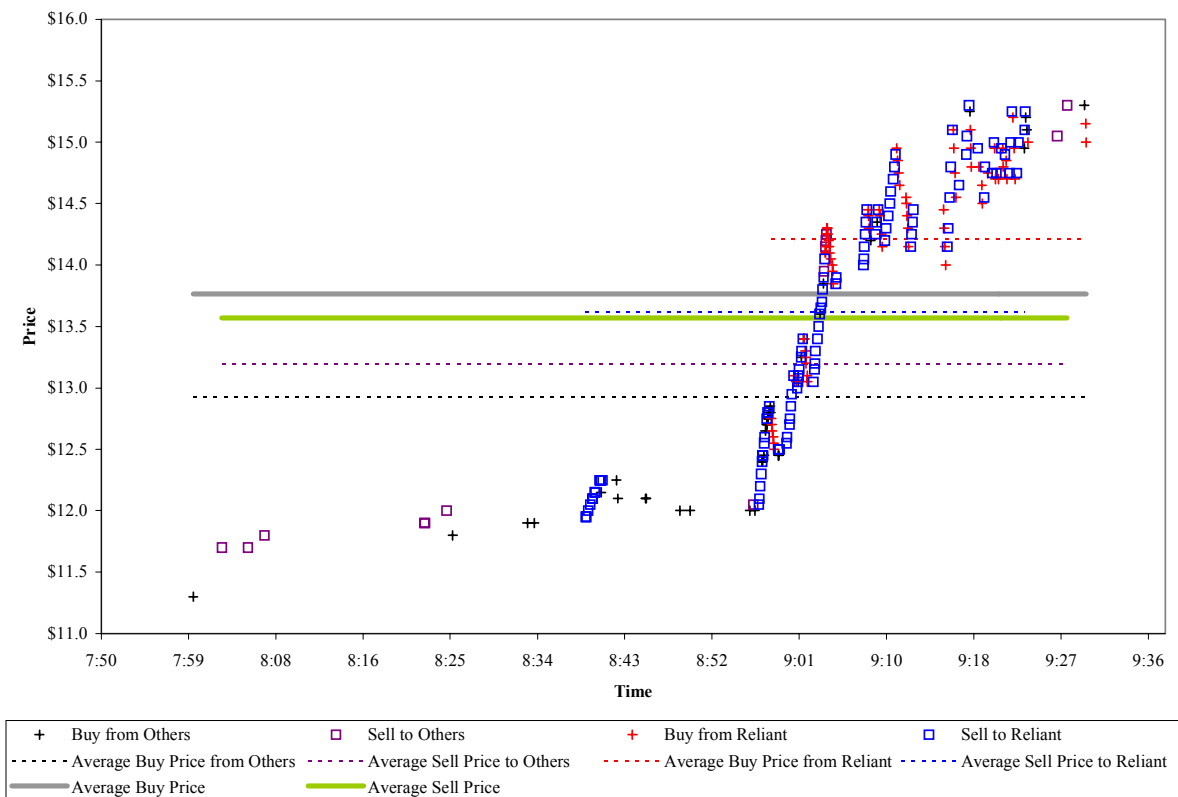
³For the purposes of this report, "churn trading" describes a pattern of gas purchases and sales where: (1) a particular company both buys and sells during the trading interval, so that the company's gross trading volume greatly exceeds its net trading volume; and (2) the company makes a relatively large number of consecutive purchases (or sales) in a short amount of time, often being the only buyer (or seller) during the burst of transactions.

(SoCalGas,⁴ a Sempra company), would frequently buy and sell large quantities of gas within the (at most) 90-minute trading day, finishing with a net position much smaller than gross volume. The most extreme example is the trading activity of January 31 for flow on February 1 (highlighted in the Initial Report). On that day, Reliant bought 1,010,000 MMBtu of gas and sold 730,000 MMBtu, for a net purchase of 280,000 MMBtu. To achieve this, the Reliant trader entered into transactions at the rate of one every 10 seconds over the course of 30 minutes, producing sharp price movements on EOL that all traders would see without knowing the cause. We did not observe any other firm trading in this manner—either in terms of churning buys and sells or rapidly executing a large number of trades.

Figure II-1 depicts trading on Wednesday, January 31, 2001, for gas flow at Topock on February 1, 2001. On this day, 227 trades took place on EOL; more than 75 percent of them were transactions between Reliant and Enron. Each of the 101 blue squares in the figure is a purchase from Enron made by Reliant on EOL. Each of the 73 red crosses is a Reliant sale to Enron. The other 53 trades are between Enron and other counterparties. The first transaction, at 8:00 a.m., is an Enron purchase of 10,000 MMBtu at \$11.30/MMBtu. The last transaction, at 9:30 a.m., is a sale of 10,000 MMBtu from Reliant to Enron for \$15/MMBtu. The grey horizontal line is Enron's average purchase price for the day, and the green line beneath it is Enron's average sale price. Enron loses money for the day trading Topock spot gas. The dotted red line is Reliant's average sale price to Enron, and the dotted blue line beneath it is Reliant's average buy price from Enron. Prices rise slightly during the first hour of trading, from \$11.30 to \$12. Once Reliant begins actively churning, the price rises quickly and steadily, peaking at \$15.30 and closing \$3.70 higher than the price at which it opened.

⁴Throughout this chapter, "SoCalGas" refers to the Southern California Gas Company and "SoCal" refers to gas at the California-Arizona border for entry into the system of SoCalGas.

Figure II-1
Day-Ahead Trades at SoCal
January 31, 2001 for February 1, 2001 Gas

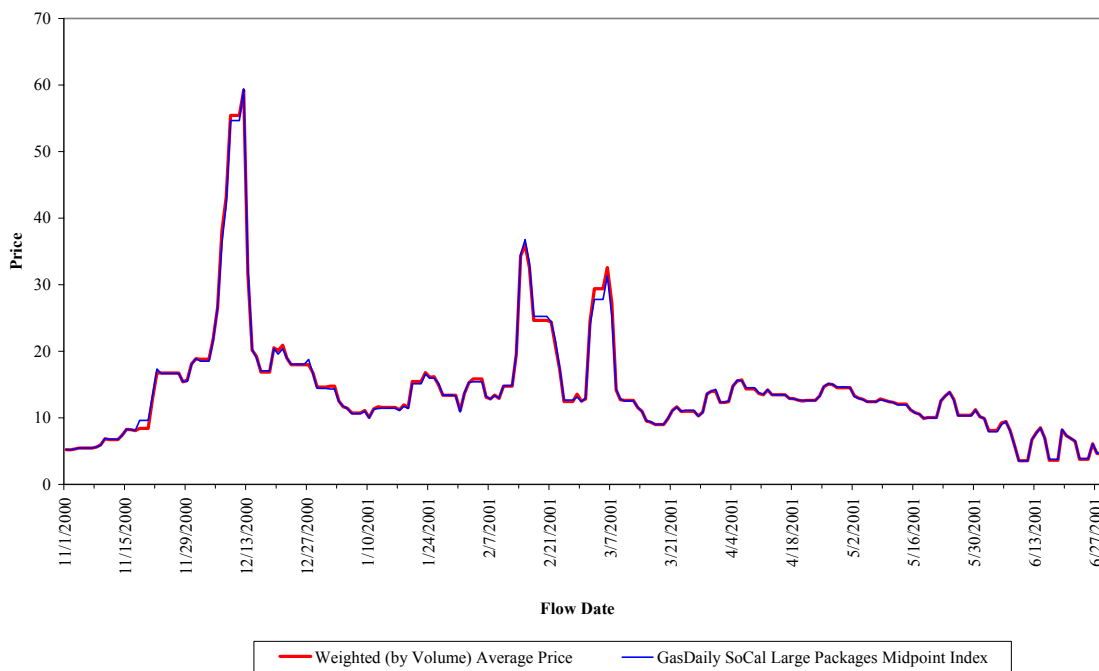


Trading patterns such as those on January 31, 2001 took place a number of times. From an initial review of these trading patterns, it appeared possible that Reliant's trading with Enron may have increased prices, price volatility, and price uncertainty in the entire southern California gas market. That is, Reliant's trading practices with Enron may have caused Enron to change the prices at which it was offering to buy or sell gas at any given time. In contrast, a typical bilateral gas trade—not taking place on EOL—would not necessarily affect the prices at which Enron offered to buy or sell, and thus would not be seen by the whole market as the new market price because the terms of bilateral gas transactions are generally held confidential between the two parties. The public nature of EOL prices is a key factor.

EOL prices closely tracked the reported index prices. Figure II-2 charts spot gas prices at the California border as traded on EOL (Topock and Ehrenberg) and as reported by *Gas Daily*. The correlation

between average EOL prices and the *Gas Daily* midpoint price for SoCal was 0.999 from November 2000 through June 2001.

Figure II-2
EOL Average Price vs. *Gas Daily* Midpoint Price at SoCal
November 2000 – June 2001



Further investigation into Reliant’s risk management, operational, and trading practices uncovered the following key facts:

- ◆ Reliant’s primary SoCal⁵ physical spot market trader worked alone in Los Angeles, while the rest of Reliant’s traders worked together in Houston.
- ◆ The physical spot trading activities of this one trader were affected significantly by a “netting” agreement (described below) that provided a financial incentive to churn, and that would not have been meaningful had there not been “cuts” on El Paso.⁶
- ◆ For its own power plants’ needs, Reliant bought large quantities of gas in the spot market for many days during the refund period, most of it at the constrained Topock point.

⁵The trader dealt in gas for flow on the SoCalGas system.

⁶Throughout this time period, shippers on El Paso’s system frequently did not receive their full nomination of capacity, but were instead cut to some lower amount. Among interstate pipelines, El Paso stands out in terms of the frequency of cuts.

- ◆ The pricing and load forecasting provisions in Reliant's contract with the Los Angeles Department of Water and Power's (LADWP's) nomination practices, and Reliant's risk management practices, all encouraged Reliant to buy spot market gas.

Churn Trading and Netting Arrangement

Reliant and others had a netting arrangement with Enron for dealing with SoCal trades between them. The frequent cuts of nominations from El Paso into SoCalGas's system created potential problems for customers such as Reliant, problems that did not exist when such cuts did not take place. In particular, a customer selling gas might receive cuts in its nominations from El Paso, and such a seller might then cut its counterparties in order of price. This practice is sometimes referred to colloquially as "price majeure." Accordingly, receiving a lower price on a specific transaction might bring with it a lower probability of flow. This concern was especially important to Reliant because it was such a large buyer in the spot market.

The netting arrangement worked as follows: All of Reliant's purchases from Enron were taken together to form a volume-weighted average price. All Reliant sales to Enron were combined in the same way. When there were both sales and purchases, the matching amounts were first netted out against each other and the balance was then settled at the respective average prices. Therefore, the lower-priced transactions were not cut disproportionately. In addition, when there were both sales and purchases, the offsetting or matching amounts would be netted against each other and settled first. Reliant could retain any net profit from the sales even though it was a net buyer and actually owed Enron money overall.

The netting arrangement is not completely transparent. However, as we demonstrate later, whenever Reliant was a net buyer, the netting arrangement gave Reliant a financial incentive to churn. For the period November 2000 to June 2001, Reliant's total profit from the netting agreement was \$8.9 million; the majority of the profit (\$7.3 million) came on days in which Reliant churned.

The highest priced day in market history, December 11, 2000 for December 12 flow, was also the day of the highest profits from netting. Reliant lost money from netting on only 3 of the 24 churn days, and the total amount of losses was less than \$30,000. In contrast, the netting arrangement resulted in a number of days of significant upside for Reliant. Reliant's profits from netting were approximately

\$5 million for December. Virtually all of these profits were in the first 8 days of trading, when market prices rose to all-time highs.

Econometric Analysis

An econometric analysis of the effect of Reliant's trading on market prices showed the following:

- ◆ A clear, robust, and statistically significant relationship—controlling for other factors—between Reliant's churning and prices rising.
- ◆ The price rise generally persisted for a few days before ultimately dissipating.
- ◆ Gas prices in southern California were, on average, more than \$8.54 MMBtu/d higher in December 2000 than they would have been absent Reliant's EOL trading activity.

Reliant was a large and consistent spot gas buyer for both its own needs and those of LADWP. In this regard, Reliant was unlike most of the other firms buying and selling gas for the SoCal area. Reliant's frequent need for large amounts of spot gas, and its lack of storage, may have affected its approach to trading, as Reliant was at risk for the market discovering that Reliant needed a lot of gas on a particular day.

Staff struggled with whether Reliant's trading activities were affected by the level of transparency on EOL, whether some of Reliant's behavior could have been attributed to price discovery, and that Reliant may have been merely "riding the market" and simply profiting from that ride. Such an explanation, however, would have us overlook the enormous share of trading Reliant comprised on many days, the rapid-fire manner in which Reliant frequently bought gas, and the resultant price increases. The volumes and trading pattern simply do not lend themselves to testing the waters for price discovery. Nonetheless, it is possible that prices would have risen by some amount on at least some of the days when Reliant churned, even if it had not churned.

Our econometric analysis clearly establishes a correlation between Reliant's churn trading and higher gas prices. What it does not do—and cannot do by itself—is prove causation. In addressing causation, Staff took into account all of the available information, of which the econometric analysis is but one component. The fact that no other company remotely approached Reliant's size, Reliant's trading

strategy, and the markedly different market behavior on days when Reliant did not churn are all important considerations. When viewed in total, the evidence supports a conclusion that churning caused prices to rise.

Linkages Between Physical and Financial Trading

The investigation for linkages between Reliant's physical and financial trading indicated:

- ◆ Reliant was an active trader of financial gas derivative products in southern California, trading SoCal basis swaps and SoCal balance-of-month "swing" swaps throughout the refund period.⁷
- ◆ One Reliant financial trader made profits of \$23.4 million from December SoCal swaps purchased on November 30, 2000. After this transaction, Reliant's trader of physical spot market gas at the same location then churned for 8 consecutive trading days.
- ◆ About \$18 million of the profits from these financial trades resulted from Reliant's churning.

Investigation of Reliant Trading

The Initial Report⁸ stated that certain gas trading patterns on EOL would be investigated further because a preliminary examination of physical spot gas transactions on EOL identified anomalous trading patterns, in particular with respect to Reliant's trading with Enron.⁹

While it would be imprecise to describe any individual day during this time period as "typical," we present a few summary statistics on average EOL trading levels for SoCal (Topock/Ehrenberg) during the

⁷In a gas "swap," two counterparties execute a trade in which the buyer pays a fixed, known price for some notional quantity of gas and the seller pays a price that will vary with the market price, which will only be known later. Thus, the buyer in a swap transaction is going long and is betting that prices will rise. The seller is betting that prices will fall. These transactions are settled financially, involving no gas delivery. The two types of swaps that we examined are explained below.

⁸*Initial Report on Company-Specific Separate Proceedings and Generic Reevaluations; Published Natural Gas Price Data; and Enron Trading Strategies: Fact Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices*, Docket No. PA02-2-000, prepared by the Staff of the Federal Energy Regulatory Commission, August 2002, pp. 49-51.

⁹The Initial Report did not name Reliant, but referred to it as an unidentified "single counterparty."

period from November 2000 to June 2001. On average, 78 SoCal spot trades per day took place. Of these, 27 were with Reliant and 51 were with all other firms combined. On average, Reliant bought (net) 144,000 MMBtu/d from Enron during this time period, while all other counterparties combined to sell (net) Enron 250,000 MMBtu/d. The *combined* gross trading of counterparties other than Reliant exceeded their net by 70,000 MMBtu/d. Reliant's gross trading exceeded its net trading by more than 100,000 MMBtu/d.

Examples of anomalous trading patterns include:

- ◆ On dozens of occasions, these 2 counterparties traded with each other more than 20 times (up to 174 times) within the (at most) 90-minute trading day. No other firm traded with Enron in this way, either in terms of number of trades or the rate at which transactions would take place. Appendix II-A provides a number of tables, as described below, highlighting Reliant's trading activity on EOL.
- ◆ Reliant was by far the firm most likely to engage in consecutive trades for spot contracts on the EOL system. During one timeframe on January 31, 2001, Reliant made 43 consecutive trades before another firm conducted a trade. Reliant was the only firm to make more than 13 consecutive trades and was the counterparty for 34 of the 40 longest streaks of consecutive trades.
- ◆ Reliant initiated transactions with Enron in bursts unmatched by other counterparties. From November 1, 2000 through June 2001, only once did another firm conduct as many as 10 trades at a single location within a "clock minute" (e.g., 8:51:00 a.m. to 8:51:59 a.m.); Reliant did this 14 times, and was the top trader for 38 of the 40 busiest minutes.
- ◆ Spot market trading for next-day flow from El Paso Natural Gas into SoCalGas at Topock, Arizona, showed unusual activity between Enron and Reliant. As the Initial Report indicated:¹⁰
 - (1) Topock spot market prices are of particular interest because of their impact on actual prices paid for gas and electricity and
 - (2) EOL prices closely tracked reported index prices.

Staff found these patterns troubling because it appeared that Reliant's trading with Enron may have increased prices, price volatility, and price uncertainty to the entire southern California gas market. The market would see the effects of the transactions' pricing through a change in the prices at which Enron would offer to buy and sell gas without knowing that only one trader was causing the change. In contrast, a typical bilateral gas trade—not taking place on EOL—would not be seen by the whole market as the new market price, since

¹⁰Initial Report, pp. 52-55.

the terms of bilateral gas transactions are generally held confidential between the two parties. The public nature of EOL prices is a key factor.

Accordingly, we analyzed in detail:

1. EOL trading activity of gas for delivery into the SoCalGas system, both for physical gas and for financially settled gas derivative transactions that were based on SoCal prices (swaps and basis swaps).
2. Trading activity between Enron and Reliant for Topock spot market gas and for all other western transactions, both physical and financial.
3. Trading activity of the individual traders involved in the anomalous trades.
4. Trading activity of Reliant with all counterparties.

Exploratory Descriptive Analysis

Preliminary analyses examined EOL trading records for 2000 and 2001.¹¹ Staff subsequently narrowed the focus to the period November 2000 to June 2001 for specific analyses (described below). These analyses revealed the unique characteristics of spot trading in southern California and Reliant's trading in particular. The following was determined: the "products" that were most actively traded, the types of prices at which the transactions took place, and the geographic locations where trading was the most active.

By and large, spot gas was the most heavily traded product across all locations. On EOL, spot gas transactions took place at fixed (rather than indexed) prices, and are the types of transactions that allegedly are used for producing the reported daily spot market index prices published by *Gas Daily*, *Natural Gas Intelligence* (NGI), and *Inside FERC*. These daily spot market index prices are used in physical gas contracts tied to indexes and for settling many financial derivative products, such as balance-of-month swing swaps (defined and discussed further below).

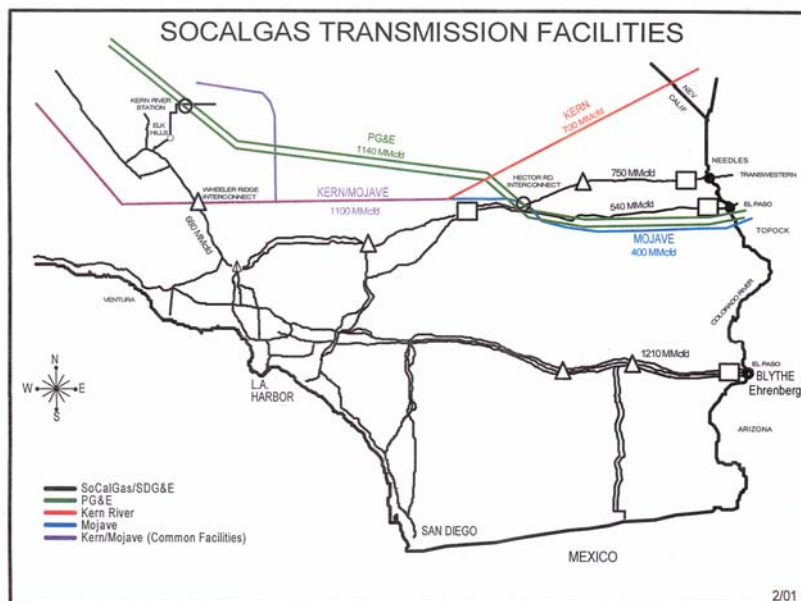
Among the various geographic locations, the California-Arizona border for entry into the SoCalGas system was the most actively traded. On EOL, of the entry points into SoCalGas, Enron offered only Topock until March 2001, when it added Ehrenberg. Another 750,000

¹¹The EOL data we have comprise all physical and financial trades transacted on EOL for the period February 7, 2000 through June 29, 2001 for the western part of the United States. Data for January 2000 are incomplete.

MMBtu/d could enter the SoCalGas system at the terminus of the Transwestern pipeline (at Needles, California). Within California, gas was also traded at Hector Road (the interconnection of Mojave, SoCalGas, and PG&E) and Wheeler Ridge (the interconnection of Kern River and SoCalGas). However, none of these locations were traded on EOL.

The fact that Enron traded only at Topock during December 2000, for example, meant that someone who wanted to buy gas on EOL and deliver it into the SoCalGas system was limited to the constrained Topock location. Only 540,000 MMBtu/d could enter the SoCalGas system at Topock.¹² Another 1,210,000 MMBtu/d could enter at Ehrenberg and Needles. Accordingly, restricting one's trading to Topock could have been a significant limitation.

Figure II-3



¹²Throughout this chapter, volumetric measures of gas pipeline capacity are reported in terms of MMBtus, using an approximation of 1 MMBtu = 1 Mcf.

The bulk of our EOL trading analysis focuses on spot gas traded at the California-Arizona border. Spot market, or swing, gas is typically traded 1 day ahead of its flow date.¹³ For weekends and holidays, gas on EOL was traded in a multiday package—e.g., on Friday a buyer purchases gas for flow on each of Saturday, Sunday, and Monday.

Reliant's SoCalGas Trading on EnronOnline Stands Out

Looking across all western locations where spot market gas was traded on EOL, the volume of gas traded by Reliant with Enron, at Topock in particular, is quite prominent.

Table II-1 covers the period November 1, 2000 through June 2001 and sums the volume of western physical spot market trading activity for the top 15 Enron counterparties on EOL. As the table shows, Reliant had the largest gross trading volumes for all locations combined, and Reliant's Topock volumes alone are more than the second largest counterparty's (Duke) combined EOL activity across all locations. In the EOL data, Topock was also the most active location for El Paso, Dynegy, Aquila, and Williams, in addition to Reliant.

Reliant's head of gas trading explained that Reliant had a risk management policy of buying forward gas to match forward power contracts and relying strictly on spot gas for spot electric sales. Because it was almost entirely in the spot electric market, Reliant relied heavily on spot gas.

¹³Monthly (or longer term) "baseload" gas is a different product. Baseload gas prices are set based on trading in the last week of the month prior to the month of gas flow. For example, "March gas" is priced based on trades during the last week of February. A quantity of March gas, such as 10,000 MMBtu/d, involves the delivery of 10,000 MMBtu each day from seller to buyer.

Table II-1. Top 15 Counterparties by Gross Volume and Top Locations by Gross Volume (EOL, November 1, 2000 – June 30, 2001)

Top 15 Counterparties			Top Locations		
Counterparty	Number of Transactions in All Locations	Gross Volume	Location	Number of Transactions in Location	Gross Volume in Location
Reliant Energy Services, Inc.	4,870	64,395,219	SoCal Topock EPNG	3,412	48,103,388
Duke Energy Trading and Marketing, L.L.C.	3,406	37,245,838	PG&E Ctygte Pool	1,491	16,171,475
El Paso Merchant Energy, L.P.	2,847	29,679,471	SoCal Topock EPNG	668	8,910,324
Dynegy Marketing and Trade	2,459	25,053,591	SoCal Topock EPNG	695	9,534,971
Aquila Energy Marketing Corporation	2,224	22,983,237	SoCal Topock EPNG	585	7,959,234
Enserco Energy, Inc.	2,819	20,787,593	Opal	978	6,965,285
Cook Inlet Energy Supply L.L.C.	2,370	19,991,233	Opal	1,318	10,113,500
BP Energy Company	1,993	16,841,184	Opal	700	5,096,092
Coral Energy Resources, L.P.	1,816	16,548,171	PGT Malin	494	4,461,224
Mirant Americas Energy Marketing, L.P.	1,509	14,103,077	PG&E Ctygte Pool	464	4,654,951
Sempra Energy Trading Corp.	1,288	11,957,743	EPNG SoCal Ehrenberg	250	3,102,500
Calpine Energy Services, L.P.	988	9,113,794	PG&E Ctygte Pool	736	6,579,128
AEP Energy Services, Inc.	880	8,398,119	PG&E Ctygte Pool	291	2,469,500
Williams Energy Marketing & Trading Company	659	6,749,032	SoCal Topock EPNG	242	3,286,000
Enron Energy Services, Inc.	795	6,698,508	PG&E Ctygte Pool	394	3,373,500

Note:

All transactions represent summaries of spot purchases, unless otherwise noted.
All volume traded includes weekends and holidays, unless otherwise noted.

Reliant was also highly active in western gas trading on EOL from a variety of perspectives:

- ◆ From November 1, 2000 through June 2001, Reliant had the 19 busiest days by trading volume (both buys and sells), and 30 of the 40 busiest days. On each of its busiest 3 days, it traded contracts for more than 1,800,000 MMBtu in volume, more than twice the busiest day of any other party. (See Appendix II-A, Table II-A1.)
- ◆ Reliant also had the 8 largest net purchase days in EOL spot trading for western gas from November 1, 2000 through June 2001, 9 of the 10 busiest days, and 32 of the 40 busiest days. (See Appendix II-A, Table II-A2.)
- ◆ Unlike Reliant's dominance on the purchasing side, several firms appear on the list of sellers with the largest net sales days (by net sales volume) in trading of western spot gas on the EOL system from November 1, 2000 through June 2001. (See Appendix II-A, Tables II-A3 and II-A4.) Five firms—SoCalGas (Sempra), El Paso, Dynegy, Duke, and Aquila—appear among the 10 biggest sellers. SoCalGas sold 600,000 MMBtu on November 22, 2000, the biggest single day of net sales. Note that this was the day

before Thanksgiving, so spot contracts sold on this day were for 5 days; SoCalGas's sales of 600,000 MMBtu represent 120,000 MMBtu/d.

- ◆ Reliant purchased more than 6,000,000 MMBtu each month on the spot market from December 2000 through February 2001. These monthly volumes were more than twice the size of the next largest monthly purchases by any other firm. Reliant was the top buyer for 4 of the 5 busiest months for net purchases. (See Appendix II-A, Table II-A5.)
- ◆ From November 1, 2000 through June 2001, Reliant had all of the 30 busiest trading days, defined by number of EOL trades executed for spot gas at Topock or Ehrenberg. The busiest day for a non-Reliant counterparty was March 23, 2001, when El Paso Merchant had 34 trades, the 40th busiest day. (See Appendix II-A, Table II-A6.)

Reliant's Purchases at Topock

From November 1, 2000 through June 2001, both Enron and Reliant frequently made net purchases using spot contracts on EOL that were large relative to the SoCalGas takeaway capacity (540,000 MMBtu/d) at that point. Contrary to statements sometimes made about Enron in general and Enron's EOL trading platform in particular, Enron did not simply act as a middleman matching buyers and sellers on EOL. Quite often, Enron would end a trading day with a substantial net physical purchase and, on some other days, a net sale.

On 39 different occasions, Enron or Reliant purchased more than 270,000 MMBtu/d at Topock (see Table II-2), representing more than half of the pipeline's takeaway capacity at that point. Enron purchased more than 270,000 MMBtu/d on 10 days and Reliant did so on 30 days. On December 12, 2000, both firms purchased more than 270,000 MMBtu/d. The combined purchases of Enron and Reliant exceeded 270,000 MMBtu/d on 29 days. These purchases are listed (in bold) among the 39 shown in Table II-2 below.

Regarding what constitutes a large physical purchase in the spot market, Reliant's head of gas trading stated, "Buying 200,000 for next-day gas is also a big amount for next-day gas."¹⁴ Essentially, on quite a number of days, Reliant (and Enron, to a lesser extent) swamped the market point.

On 2 days during the period, each firm purchased more than 540,000 MMBtu/d, the total SoCalGas takeaway capacity. On these days,

¹⁴Interview with FERC Staff, September 2002.

Reliant's net purchases alone ensured that there would be cuts. Moreover, on 10 days the combined purchases exceeded the total SoCalGas takeaway capacity. Although, along with other customers, Reliant faced cuts in its nominations at Topock, at the same time Reliant was a substantial contributor to the situation there.

Table II-2. EOL Trading Activity in Topock Spot Gas, Days on Which Enron or Reliant Purchased More Than 270,000 MMBtu/d, November 2000 – June 2001

Transaction Date	Net Enron Purchases (MMBtu/day)	Net Reliant Purchases (MMBtu/day)	Combined Purchases (MMBtu/day)
	(1)	(2)	(3) = (1) + (2)
11/2/00	290,000	-45,000	245,000
11/3/00	345,000	-45,000	300,000
11/14/00	340,000	-45,000	295,000
11/27/00	195,000	470,000	665,000
11/28/00	630,000	-45,000	585,000
11/29/00	555,000	130,000	685,000
12/5/00	185,000	289,000	474,000
12/6/00	345,000	177,000	522,000
12/12/00	282,000	410,000	692,000
12/13/00	170,000	557,000	727,000
12/14/00	230,454	322,000	552,454
12/15/00	225,000	452,000	677,000
12/18/00	175,000	460,000	635,000
12/19/00	265,000	270,000	535,000
12/20/00	165,000	380,000	545,000
12/21/00	348,000	215,000	563,000
1/2/01	-80,050	340,000	259,950
1/3/01	-97,500	570,000	472,500
1/4/01	10,000	310,000	320,000
1/5/01	-40,000	340,000	300,000
1/10/01	-35,000	270,000	235,000
1/16/01	-40,000	445,000	405,000
1/17/01	45,000	280,000	325,000
1/22/01	-25,000	380,000	355,000
1/24/01	-15,000	290,000	275,000
1/29/01	321,650	-70,000	251,650
1/31/01	-40,000	280,000	240,000
2/1/01	-80,000	370,000	290,000
2/2/01	-66,000	355,000	289,000
2/7/01	25,000	280,000	305,000
2/12/01	-70,000	410,000	340,000
2/13/01	-97,500	370,000	272,500
2/14/01	-150,000	410,000	260,000
2/15/01	-157,500	330,000	172,500
2/16/01	-100,000	345,000	245,000
2/20/01	-90,000	325,000	235,000
2/21/01	-75,000	305,000	230,000
2/22/01	67,500	390,000	322,500
4/26/01	364,512	-10,000	354,512

Note: Daily totals shown in bold indicate net purchases of more than 270,000 MMBtu/d, representing more than half of the pipeline's capacity. Daily totals shown in bold and boxed indicate net purchases of more than 540,000 MMBtu/d, representing more than the pipeline's total capacity.

Reliant-Enron Churn Trades Sometimes Dominated a Day's Trading

On particularly active days of Reliant SoCal trading, trades between Reliant and Enron sometimes comprised the majority of the day's SoCal trading on EOL. Our subsequent analysis has determined that from November 1, 2000 through June 2001, there were 24 days on which Reliant both bought 100,000 MMBtu/d and sold 100,000 MMBtu/d (referred to as a "churn" day in this chapter) for next-day gas at the California-Arizona border. On the days when this took place, Reliant tended to buy and sell gas in rapid-fire succession. In many cases, this behavior had pronounced effects on prices. This churning by Reliant is something we did not observe for other firms.¹⁵ In Figures II-4 to II-6, we provide representative examples of 3 days of Reliant churning in 2001: January 31, February 2, and June 11.

Figure II-4 depicts trading on Wednesday, January 31, 2001¹⁶ for gas flow at Topock on February 1, 2001. On this day, 227 trades took place (2,240,000 MMBtu); more than 75 percent were transactions between Reliant and Enron. Each of the 101 blue squares in the figure is a purchase from Enron made by Reliant on EOL. Each of the 73 red crosses is a Reliant sale to Enron. The other 53 trades are between Enron and other counterparties (black crosses are Enron purchases from parties other than Reliant and purple squares are Enron sales to parties other than Reliant). The first transaction, at 8:00 a.m., is an Enron purchase of 10,000 MMBtu at \$11.30/MMBtu (from El Paso). The last transaction, at 9:30 a.m., is a sale of 10,000 MMBtu from Reliant to Enron for \$15/MMBtu. The grey horizontal line is Enron's average purchase price for the day, and the green line beneath it is Enron's average sale price. Enron loses money for the day trading Topock spot gas. The dotted red line is Reliant's average sale price to Enron, and the dotted blue line beneath it is Reliant's average buy price from Enron. For the first hour of trading, prices rise slightly, from \$11.30 to \$12. Once Reliant begins actively churning, the price rises quickly and steadily, peaking at \$15.30 (Duke buying from Enron) and closing \$3.70 higher than the price at which it opened.

¹⁵We define churning as days on which Reliant both purchased and sold at least 100,000 MMBtu. It was often the case that Reliant both bought and sold far more than 100,000 MMBtu.

¹⁶Most of the date references are to transaction dates, which typically take place 1 day before gas flow. For weekends and holidays, a transaction date may involve trading of a multiday packet of gas. For example, on Friday, December 8, 2000, a purchase of 10,000 MMBtu of gas on EOL was for flow on each day of December 9 to 11.

In total, Reliant bought 1,010,000 MMBtu of gas and sold 730,000 MMBtu, for a net purchase of 280,000 MMBtu. To achieve this, the Reliant trader entered into transactions at the rate of one every 10 seconds over the course of 30 minutes, producing sharp price movements on EOL that all traders would see without knowing the cause. We did not observe any other firm trading in this manner—either in terms of churning buys and sells or rapidly executing a large number of trades.

Figure II-4
Day-Ahead Trades at SoCal
January 31, 2001 for February 1, 2001 Gas

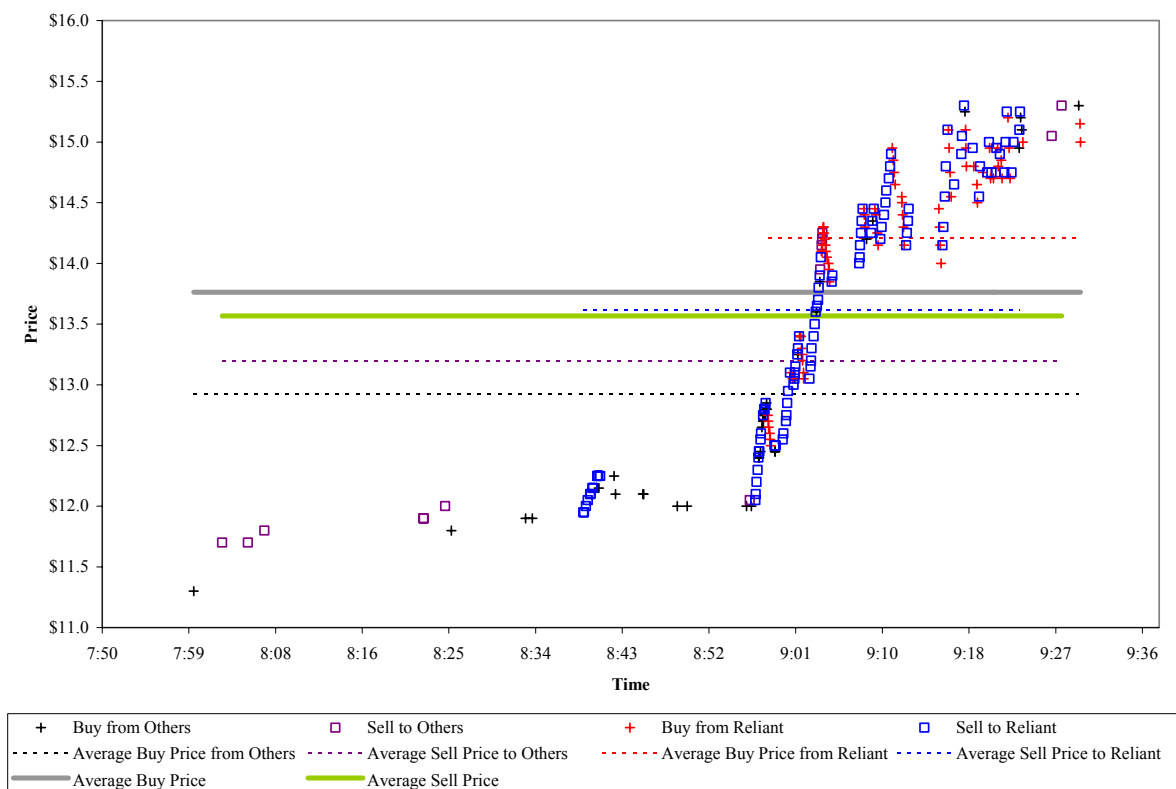
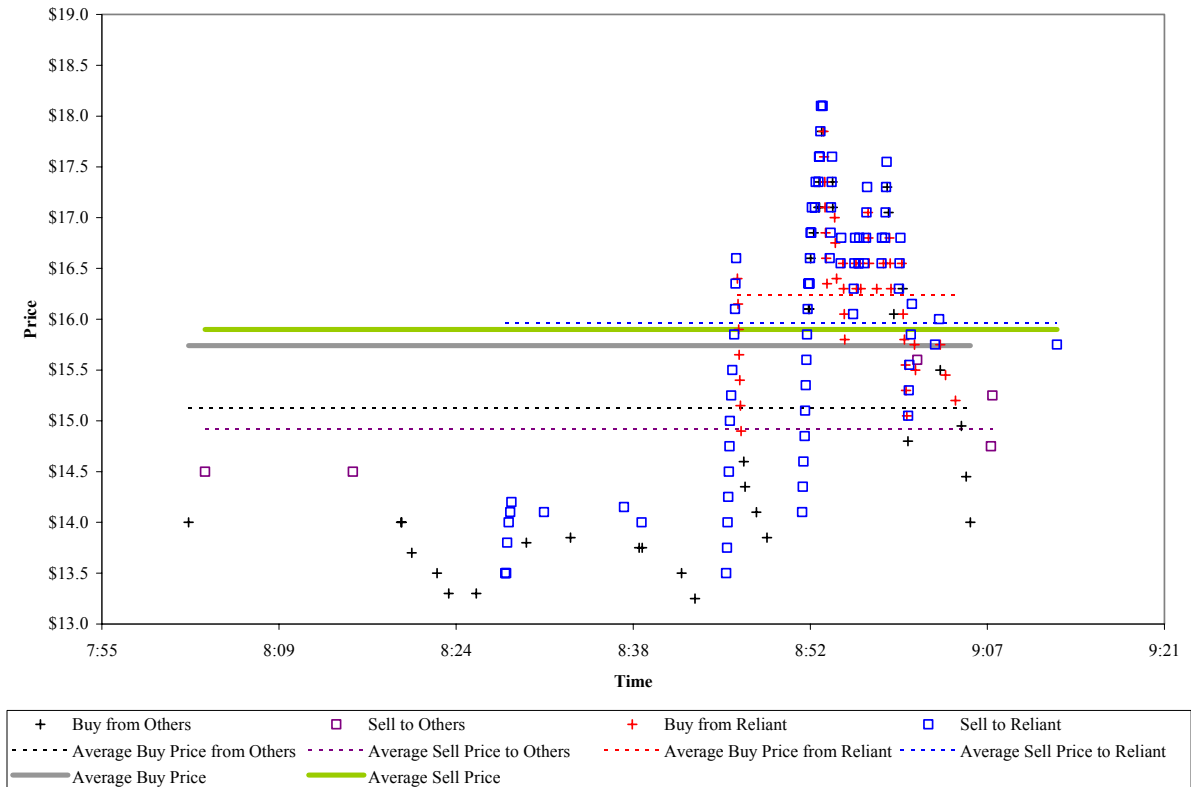


Figure II-5 depicts another Reliant churn day, February 2 for flow on February 3, 4, and 5. Again, we observe a pattern of Reliant buying and selling in extended bursts. In total, Reliant transacted 1,235,000 MMBtu of gas, for a net purchase of 355,000 MMBtu. Prices on this day began at \$14/MMBtu (Mirant selling to Enron) and reached a peak of \$18.10/MMBtu (Reliant buying from Enron) before closing at \$15.75/MMBtu (Reliant buying from Enron). Trading lasted 70 minutes. The *Gas Daily* price for the day was \$15.39/MMBtu. For the day, Enron's buy price was below its sell price, so in that sense Enron

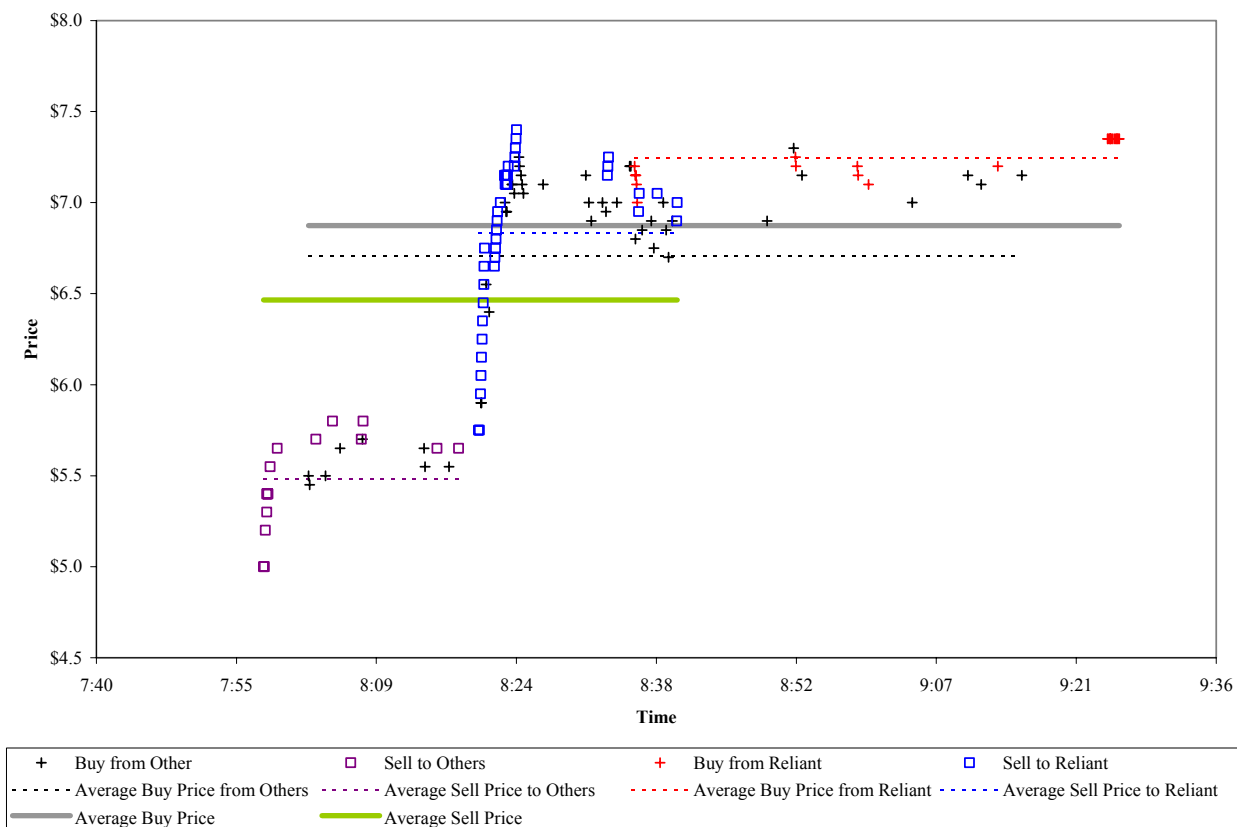
came out slightly ahead. Once again, Reliant's average sell price to Enron was above its buy price.

Figure II-5
Day-Ahead Trades at SoCal
February 2, 2001 for February 5, 2001 Gas



In Figure II-6, we see a somewhat different trading pattern. Here, Reliant does the bulk of its purchasing—400,000 MMBtu in 10,000-MMBtu increments—in a 5-minute time span and then sells off 224,000 MMBtu over the remainder of the trading interval, much of that in the last minute of trading. On this day, Enron's buy price is above its sell price. Reliant sells at a higher average price than it pays.

Figure II-6
Day-Ahead Trades at SoCal
June 11, 2001 for June 12, 2001 Gas



Reliant Trading and Market Volatility

Although Reliant was often a major factor in the SoCal points traded on EOL, there were days when Reliant's activity was fairly minimal. On those days, there were typically less pronounced price movements. Figures II-7 to II-9 depict three examples of days on which SoCal spot trading on EOL was fairly active but Reliant's churning did not play a part—November 28, 2000, January 29, 2001, and June 7, 2001.

What is most notable about these days is what is *not* observed—we do not see the rapid price swings up and down that are observed when Reliant churns. There are no bursts of trades at all, and prices remain flat for much of the day.

Figure II-7
Day-Ahead Trades at SoCal
November 28, 2000 for November 29, 2000 Gas

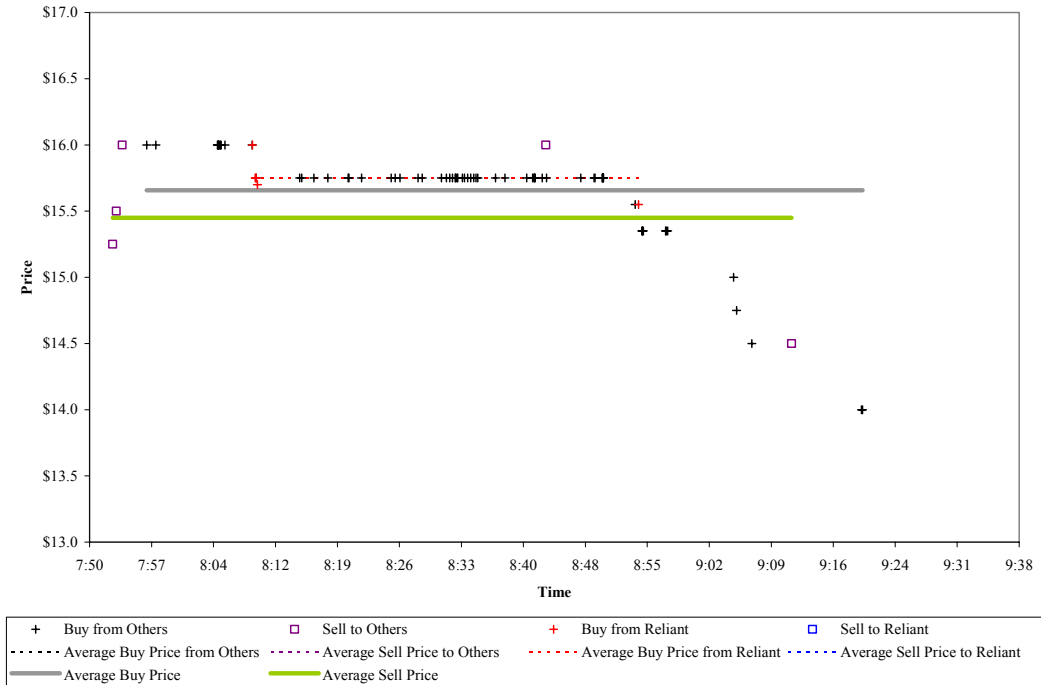


Figure II-8
Day-Ahead Trades at SoCal
January 29, 2001 for January 30, 2001 Gas

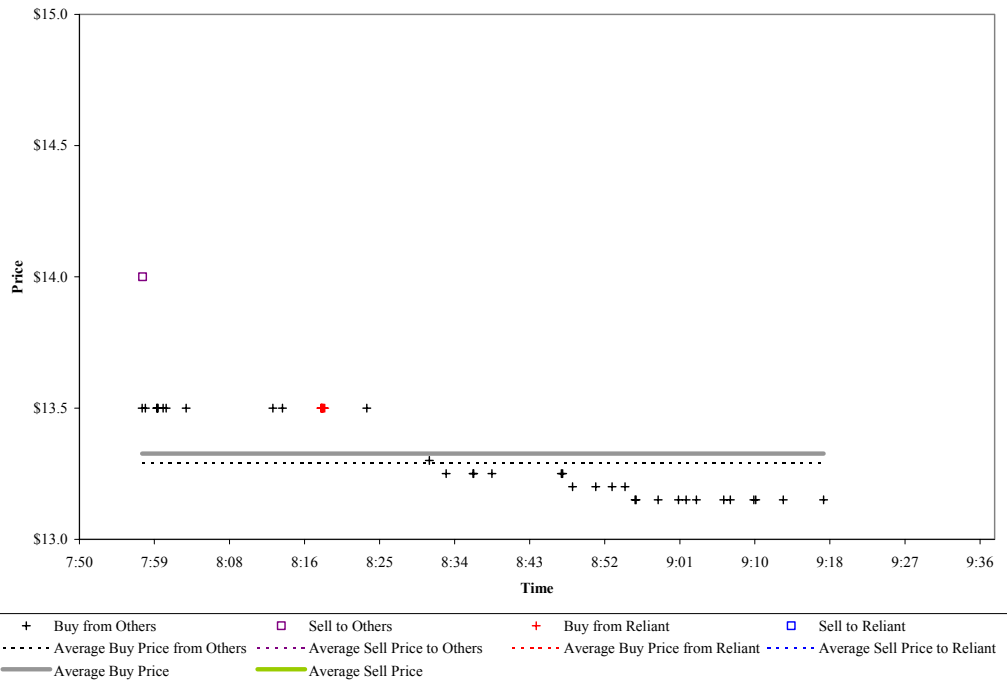
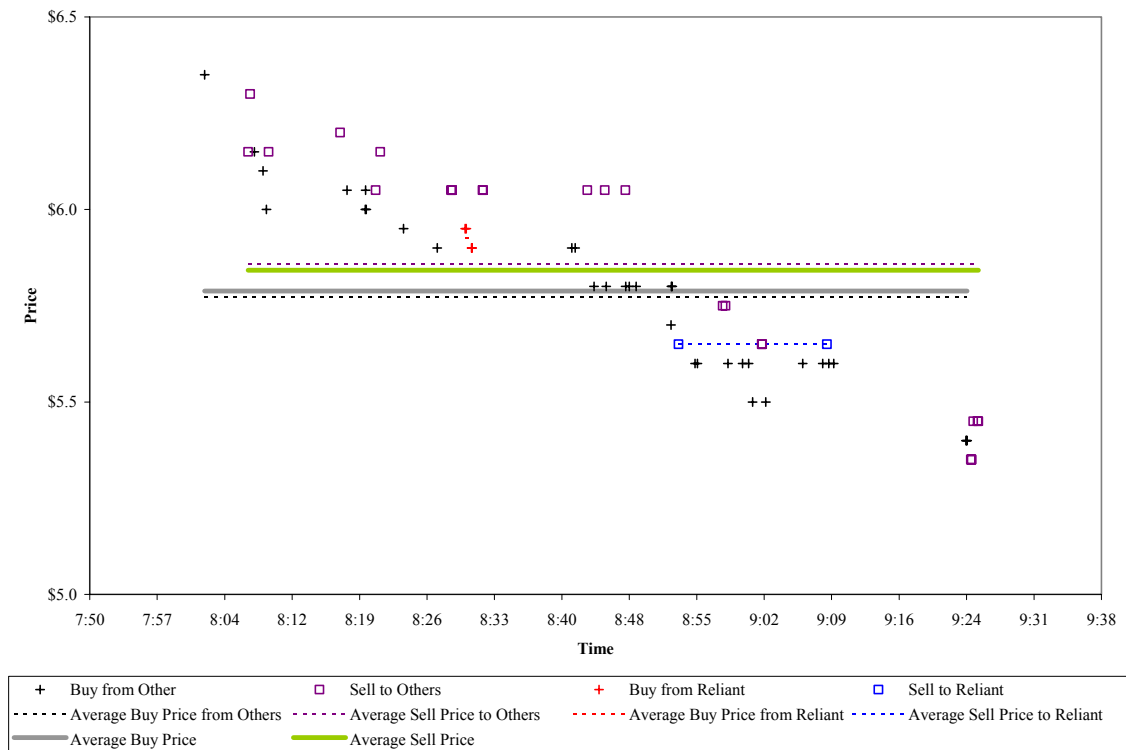


Figure II-9
Day-Ahead Trades at SoCal
June 7, 2001 for June 8, 2001 Gas



Figures II-7 to II-9 chart 3 relatively busy days at Topock on which Reliant was not a major force. The trading patterns observed on these days are visually quite different from those days on which Reliant was a major presence. No counterparty is seen to make bursts of purchases (or sales) in the way Reliant did. Trading activity is less frequent and price movements are less pronounced. Even when a number of trades in the same direction take place, such as on January 29, when counterparties sell to Enron repeatedly without an intervening purchase, we do not observe price movements of the sort that take place when Reliant rapidly enters into numerous transactions.

As a market point, the Topock point looks markedly different on the days of low Reliant activity. We also note that, rather than observing a balanced mix of both buyers and sellers transacting with Enron, what we see is tilted strongly toward counterparties selling gas to Enron. Enron was frequently a net buyer of spot gas at Topock.

Reliant Did Most of the Churning

After observing Reliant's churn trading, we performed an additional analysis to determine whether churn trading was found among counterparties other than Reliant or at other locations. As noted above, we defined churning as when a firm both bought and sold at least 100,000 MMBtu/d of spot gas on the same day for delivery at the same location. For the period from February 2000 through June 2001, we found 26 such instances. It was primarily Reliant that did this type of trading for all locations and counterparties; Reliant has 24 of the 26 churns (all at SoCal). (See Appendix II-A, Table II-A7.) While Reliant did not churn every day, it churned over the entire 8-month period and did so profitably, earning approximately \$9 million from this trading strategy (see Table II-7 below).

Reliant's Churning

In this section we focus on Reliant's churn trading. We examine the days on which churning took place and the *Gas Daily* index and EOL prices on those days. We look at when churning was most prevalent, who within Reliant carried out the trades, and what this trading behavior may have looked like to the rest of the market at the time.

Reliant's Churn Days

Although our data sample begins in February 2000, Reliant's churning takes place from November 1, 2000 through June 2001. In Table II-3 below, we list each of the 24 days of Reliant's churning on EOL. On many days, Reliant's trading volumes were much higher than our definition of at least 100,000 MMBtu/d bought and sold. For example, on December 5, 2000, Enron's total trading volume for Topock was 1,465,000 MMBtu. Of this, 62 percent (911,000 MMBtu) was transacted with Reliant and 554,000 MMBtu was transacted with all other counterparties combined. Reliant's net purchase from Enron for the day was 289,000 MMBtu. Other counterparties sold 474,000 MMBtu (net) to Enron. So for the day, Reliant traded 622,000 more MMBtu gross (311,000 MMBtu bought and 311,000 MMBtu sold) than it bought net. On the following day, Reliant's trading comprised 60 percent of the day's trading volume.

**Table II-3. Reliant Churn Days at SoCal (Topock and Ehrenberg),
Summary of Physical Daily Trades of Reliant and All Other Counterparties**

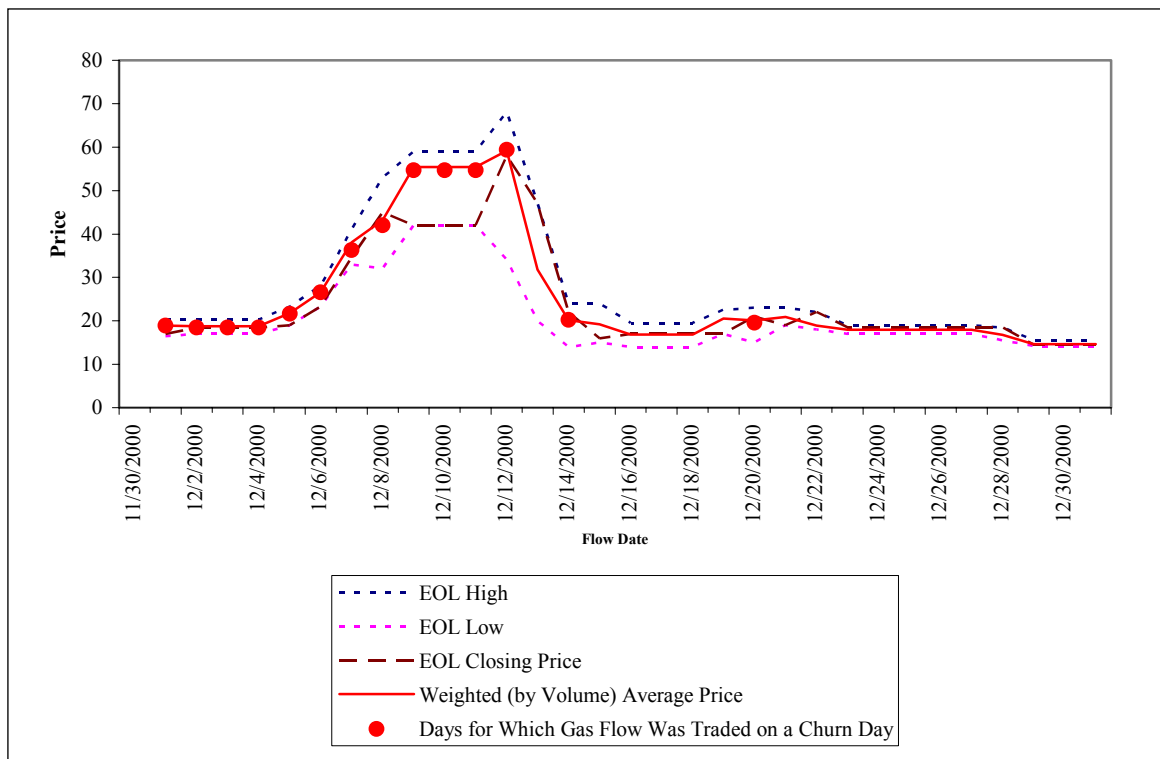
Transaction Date	Contracted Flow Date or Flow Period	EOL Gross Volume (MMBtu/d)	Reliant Gross Volume (MMBtu/d)	Reliant Net Volume (MMBtu/d)	Reliant Share of EOL Trading Volume	Reliant Churn Volume	Reliant Churn Volume Share of Trading
11/1/00	11/2/00	820,000	200,000	0	24.4%	200,000	100.0%
11/13/00	11/14/00	1,095,000	390,000	10,000	35.6%	380,000	97.4%
11/30/00	12/1/00	924,000	502,000	138,000	54.3%	364,000	72.5%
12/1/00	12/2 – 12/4/00	1,212,000	760,000	260,000	62.7%	500,000	65.8%
12/4/00	12/5/00	985,000	513,000	107,000	52.1%	406,000	79.1%
12/5/00	12/6/00	1,465,000	911,000	289,000	62.2%	622,000	68.3%
12/6/00	12/7/00	1,345,000	803,000	177,000	59.7%	626,000	78.0%
12/7/00	12/8/00	1,201,000	700,000	260,000	58.3%	440,000	62.9%
12/8/00	12/9 – 12/11/00	975,500	480,000	180,000	49.2%	300,000	62.5%
12/11/00	12/12/00	1,892,000	1,354,000	246,000	71.6%	1,108,000	81.8%
12/13/00	12/14/00	1,510,000	773,000	557,000	51.2%	216,000	27.9%
12/19/00	12/20/00	1,235,000	670,000	270,000	54.3%	400,000	59.7%
1/31/01	2/1/01	2,240,000	1,740,000	280,000	77.7%	1,460,000	83.9%
2/2/01	2/3 – 2/5/01	1,604,000	1,235,000	355,000	77.0%	880,000	71.3%
2/13/01	2/14/01	1,042,500	710,000	370,000	68.1%	340,000	47.9%
2/28/01	3/1/01	812,000	330,000	90,000	40.6%	240,000	72.7%
3/1/01	3/2/01	570,000	315,000	5,000	55.3%	310,000	98.4%
3/2/01	3/3 – 3/5/01	790,000	405,000	165,000	51.3%	240,000	59.3%
3/20/01	3/21/01	610,000	270,000	50,000	44.3%	220,000	81.5%
3/22/01	3/22/01	570,000	230,000	-30,000	40.4%	200,000	87.0%
3/23/01	3/24 – 3/26/01	1,105,000	670,000	30,000	60.6%	640,000	95.5%
4/3/01	4/4/01	538,012	220,000	-20,000	40.9%	200,000	90.9%
6/11/01	6/12/01	1,179,000	624,000	176,000	52.9%	448,000	71.8%
6/13/01	6/14/01	1,023,000	489,479	269,479	47.8%	220,000	44.9%

Reliant's Churning Peaked in December 2000

Of the 24 churn days shown in Table II-3, 8 are on consecutive trading days for delivery in December 2000. These particular days encompass the highest ever gas prices in California, reaching their peak on the eighth consecutive day of churning. The table shows that Reliant churning comprises more than 70 percent of its gross trading volume.

Figure II-10 charts price activity during December 2000, noting which days were churn days. The figure demonstrates that prices rose on most churn days. On the day after this string of churning ends, prices fall by more than \$25/MMBtu. The price data are provided in Appendix II-A, Table II-A8.

Figure II-10
December Price Chart



Reliant Bought and Sold in Bursts

All transactions on EOL are initiated by the counterparty, not by Enron. Enron would constantly offer two prices—one at which it was willing to buy and a higher one at which it was willing to sell. It was up to counterparties, such as Reliant, to make the decision to transact. Enron could change its posted prices to encourage trading (e.g., by lowering the price at which it was offering to sell, a counterparty would be more likely to buy), but it could not initiate transactions.

Reliant initiated transactions with Enron in bursts unmatched by other counterparties:

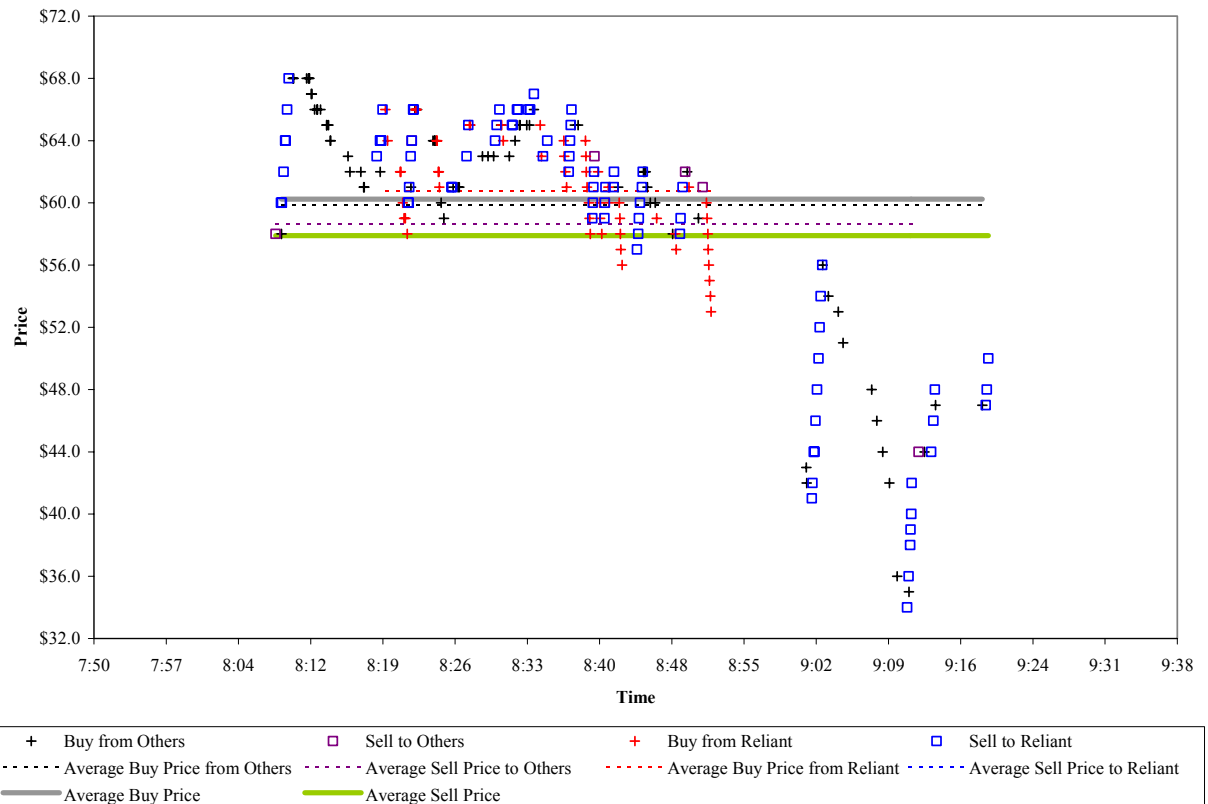
- ◆ From November 1, 2000 through June 2001, only once did another firm conduct as many as 10 trades at a single location within a clock minute (e.g., 8:51:00 a.m. to 8:51:59 a.m.); Reliant did this 14 times. Reliant was the trader for 38 of the 40 busiest minutes. (See Appendix II-A, Table II-A9.)
- ◆ When the time interval is increased from 1 clock minute to 5 clock minutes (e.g., 8:41:00 through 8:45:59), Reliant's trading pattern is even more unusual. No other firm ever made 15 or more trades in a single location within 5 minutes; Reliant did this 36 times. Reliant was the trading party for 39 of the 40 busiest 5-minute intervals. (See Appendix II-A, Table II-A10.)
- ◆ When observed somewhat differently, Reliant was by far the firm most likely to engage in consecutive trades for spot contracts on the EOL system. During one time span on January 31, 2001, Reliant made 43 consecutive trades before another firm conducted a trade. Reliant was the only firm to make more than 13 consecutive trades and was the counterparty for 34 of the 40 longest such streaks. (See Appendix II-A, Table II-A11.)
- ◆ In addition to being far more likely to engage in long stretches of consecutive trades, Reliant was also the most likely firm to transact a series of consecutive buys or sells without trading by any other firm. Reliant had the 4 longest streaks of consecutive purchases from Enron, as well as 8 of the 10 longest and 36 of the 40 longest streaks of consecutive purchases from Enron. (See Appendix II-A, Table II-A12.)

- ◆ In addition to long sequences of buy transactions and even though Reliant was usually a net buyer, Reliant also engaged in long sequences of sell transactions, although not generally as long as the buy sequences. Reliant transacted 6 of the 10 and 22 of the 40 longest streaks of consecutive sells to Enron (i.e., Enron buys). (See Appendix II-A, Table II-A13.)

Example of Effect of Burst Trading: December 11, 2000

Four of the forty longest uninterrupted sequences of trades (as shown in Appendix II-A, Tables II-A12 and II-A13), in which a single firm engages in consecutive trades, took place on December 11, 2000. On that day, Reliant bought contracts for 800,000 MMBtu and sold contracts for 554,000 MMBtu, resulting in a net purchase of 246,000 MMBtu for delivery the next day. (Figure II-11 shows the trading activity for this day, labeled in the same form as in Figures II-1 and II-4 to II-9.) This was a day on which the price varied particularly widely, ranging from \$34 to \$68; much of this variation took place during Reliant's stretches of consecutive transactions. Reliant opened its trading for the day at 8:09 a.m. with seven purchases (each for 10,000 MMBtu) within 45 seconds, during which the price rose from \$60 to \$68. At 8:51 a.m., Reliant sold eight contracts (each for 10,000 MMBtu) within 28 seconds, during which time the price dropped from \$60 to \$53; the next transaction took place at \$43. At 9:02 a.m., Reliant bought 10 contracts (each for 10,000 MMBtu) within 62 seconds, during which time the price rose from \$41 to \$56. Reliant then stayed inactive until 9:11 a.m., when it made another series of 12 purchases (each for 10,000 MMBtu) in three groups, during which time the price rose from \$34 to \$50.

Figure II-11
Day-Ahead Trades at SoCal
December 11, 2000 for December 12, 2000 Gas



Reliant's final position for the day was a net purchase of 246,000 MMBtu at a total (net) cost of \$12,606,000, for an effective net average price of \$51.24/MMBtu.¹⁷ This price is well below the price that the other two net purchasers paid on the same day, as well as below the day's weighted average price for sales to Enron, as shown in Table II-4. The *Gas Daily* index for the day reached its all-time high, \$59.42, and Enron still paid \$13 more than that—Enron paid, on average, \$72.15 for its net purchases of 172,000 MMBtu.

¹⁷This calculation assumes no netting arrangement of the sort described elsewhere in this chapter.

Table II-4. EOL Trading in Topock Spot Gas, December 11, 2000

Firm	Total Purchases (MMBtu)	Total Sales (MMBtu)	Net Purchases (MMBtu)	Effective Net Average Price (\$/MMBtu)
Net Purchasers				
Astra Power, LLC	10,000	0	10,000	64.00
Duke Energy Trading and Marketing, LLC	50,000	0	50,000	57.60
Reliant Energy Services, Inc.	800,000	554,000	246,000	51.24
Total	860,000	554,000	306,000	52.70 ¹⁸
Net Sellers				
AEP Energy Services, Inc.	0	5,000	-5,000	55.50
Aquila Dallas Marketing, LP	0	10,000	-10,000	60.50
Aquila Energy Marketing Corporation	0	90,000	-90,000	63.67
Coral Energy Resources, LP	0	25,000	-25,000	59.60
Dynegy Marketing and Trade	0	130,000	-130,000	57.46
Enserco Energy, Inc.	0	30,000	-30,000	62.13
Mirant Americas Energy Marketing, LP	0	48,000	-48,000	63.00
PG&E Energy Trading-Gas Corporation	0	10,000	-10,000	36.00
San Diego Gas & Electric Company	0	20,000	-20,000	43.00
Sempra Energy Trading Corp.	0	30,000	-30,000	62.33
Southern California Gas Company	0	60,000	-60,000	63.83
Texaco Natural Gas Inc.	0	15,000	-15,000	55.33
Tractebel Energy Marketing, Inc.	0	5,000	-5,000	65.00
Total	0	478,000	-478,000	59.70 ¹⁹
All External Firms (excluding Enron)	860,000	1,032,000	-172,000	
Enron	1,032,000	860,000	172,000	72.15 ²⁰

¹⁸Weighted average of effective net average price for net purchasers, using the net purchases as the weight.

¹⁹Weighted average of effective net average price for net sellers, using the net purchases as the weight.

²⁰Calculated as Enron's net payments of \$12,409,500, divided by net purchases, 172,000 MMBtu.

Reliant's Trading Had the Effect of Maximal Market Impact

In Figures II-4 to II-6 above, one of the most visually striking elements is the nearly vertical line formed by the consecutive strings of Reliant's purchases and sales. When Reliant churned, it apparently made no effort to mask its activity. If anything, the opposite was the case.

Reliant's purchases typically took place in bursts, with successive purchases made at increasingly higher prices, seemingly running through the EOL "stack."²¹ Given that there were sometimes more than a dozen purchases in a burst, it is quite possible that Reliant's bursts completely exhausted the stack. The same holds true for sales. Often when Reliant sold, it entered into several transactions in rapid succession, bringing prices down. In most cases, the net effect was an increase in prices (examined in more detail below).

Reliant's transaction pattern looks like the opposite of the usual expectation—buyers usually seek to minimize the extent to which they increase prices, and sellers usually seek to minimize the amount by which they bring prices down.

Reliant's Churning Raised the Index Prices

Because the published indexes report a midpoint (or an average) price for a day's trading, the churning activity inherently would bias the reported midpoint even if the churning had not affected closing prices.

When an index is based on an intraday average, the manner in which churning takes place is bound to affect the published index price. In the case at hand, churning raised prices, as Reliant typically began by buying and then later selling. In so doing, the initial buys raised prices. While the selling brought prices back down, the churning raised the day's median (and average) price.

For example, assume the day's prices open at \$5/MMBtu and a company needs to purchase 50,000 MMBtu and uses one of two buying strategies. In the first strategy, it simply buys 10,000 MMBtu five times in a row and acquires the 50,000 at a median (and average) price of \$5.20 (e.g., purchases of 10,000 MMBtu at prices of \$5, \$5.10, \$5.20, \$5.30, and \$5.40, respectively).

²¹Essentially, the stack is a queue of bids and asks that the Enron trader would maintain in order to quickly replace a bid or offer when it was accepted by a counterparty, so that the product would remain available on counterparty traders' screens at all times.

In the second strategy, the company chooses to buy 30,000 MMBtu more (for a total of 80,000 in purchases) and then sell that 30,000, resulting in the same net purchase amount of 50,000. Using the same price pattern as above, purchases 6, 7, and 8 are made at prices of \$5.50, \$5.60, and \$5.70, and the three sales are made at \$5.70, \$5.60, and \$5.50. Although the net amount purchased equals 50,000 MMBtu, the median transaction price for these 11 transactions is \$5.50, \$0.30 higher than under the first strategy. The company's own average purchase price, however, remains the same, at \$5.20.

Larger amounts of churning (where, as in Reliant's case, the sequence consisted of purchases followed by sales) would produce larger increases in the median and average prices.

Even if the day's closing prices for the two scenarios are the same, prices will have been higher throughout the trading day under the second strategy.²²

Churning on EOL Showed Price Gyration to the Whole Market

It is our understanding that virtually every gas trader had an EOL screen. EOL served as a common source for "price discovery"—traders looked to EOL for the current market price. One reason for this was that Enron always posted a "two-way"—a price at which it was willing to buy and a price at which it was willing to sell—and it is our understanding that Enron worked to keep its bid-ask spread as narrow as possible.

One implication of EOL's bid-ask prices, and changes in the bid-ask prices, being constantly observed by all gas traders is that as Reliant bought and sold in bursts, the whole market would see the resulting rapid, pronounced price movements. However, only Enron and Reliant would know *why* prices were moving when Reliant churned:

- ◆ Reliant always knew when its transactions were completed successfully, i.e., when its bids were accepted. So Reliant could see what happened to prices as it engaged in numerous successive transactions.
- ◆ Enron could see even more. Enron saw Reliant's activity along with every other trader's transactions and attempted transactions.

²²However, forming index prices by using only transactions near the end of the trading day would risk manipulation of the shorter price-setting interval. The risk of manipulating closing prices might be larger than that of manipulating a day's worth of prices.

Other traders could see only that the prices on their EOL screens were seesawing up and down—in a manner not observed at other trading locations. With all that was going on in the western energy markets at this time, particularly in December 2000, it would be difficult to surmise what these traders were thinking. However, they could not know what only Enron and Reliant knew.

EOL was the most public place possible for Reliant's trading activities. In interviews (described further below), Reliant's SoCal spot traders indicate that they did not view their spot market purchasing patterns as unusually affecting the market. They stated that purchasing a relatively large quantity of gas might or might not affect prices, but that the way they went about buying and selling did not. On its face, this seems implausible. Reliant is the only firm that consistently "hit the button" rapidly and repeatedly, and Reliant did so only at the SoCal border. The graphs of entire days of trading are perhaps most telling in that they display both the rapidity with which Reliant was trading and the price movements that came with those bursts of trading. Figure II-5 shows that prices rose straight up when Reliant made its numerous bursts of purchases and prices dropped precipitously (although not as far) when Reliant sold in bursts. Reliant would have Staff believe that it bought large amounts in quick bursts, saw prices rise immediately, and tried to sell back on EOL at the highest of these prices, but had no idea that it was affecting market prices.

Reliant's Western Market Gas Trading Operations

In our review of trading records, it became clear that a single Reliant trader was responsible for all of Reliant's churning and almost all of its SoCal trading.

On Enron's side, two Enron traders shared responsibility for trading SoCal spot gas. On any day, one of these two traders would transact all of Enron's trades. Over time, each of these two traded Topock roughly equally. Both of these Enron traders were counterparties in the anomalous trading patterns, in approximately equal proportions. They traded Topock almost exclusively—when they were not trading spot gas at Topock, they were not trading much of anything else. Given that it is the counterparty that initiates all transactions, we decided to focus on Reliant's side of these transactions.²³

²³From Enron's perspective, the churning may not have been looked upon as problematic because Enron knew when it was taking place and who was doing it.

Given that the transaction patterns appeared to place no emphasis on minimizing the market impact of engaging in successive bursts of transactions, we considered a number of alternative hypotheses that might explain the observed trading patterns. Some of the possibilities are more benign than others. Possible alternatives included:

5. Reliant's SoCal trader was given a set of instructions—e.g., to transact primarily on EOL or to buy a specified quantity and/or to “balance” Reliant's needs—but was not responsible for the price paid (perhaps since it considered EOL liquid and robust).
6. The Reliant trader simply did not care about prices paid, and was unsupervised.
7. The trader's compensation structure gave an incentive to churn—e.g., the trader was allowed to buy and sell on account while filling Reliant's physical needs, and was somehow rewarded for churning.
8. Something more deliberate—e.g., a strategy of trading on EOL to drive up prices and benefit a financial position as well as potentially profit from the physical trades. A key question to address in this regard is whether higher index prices benefited Reliant's financial positions (discussed below).

Each of these possibilities has implications for the motivations and oversight of Reliant's management. Reliant may have been unaware that its SoCal spot trader was moving prices. Or, Reliant may have been unconcerned—or pleased—by such trading. In our examination of Reliant's behavior during this time period, among the steps we took were to examine Reliant's physical and financial trading records for southern California. This included:

- ◆ All Reliant physical trading on EOL, since this is where the index prices would be affected most directly.
- ◆ Reliant's SoCal trading in swaps, basis swaps, and balance-of-month swing swaps.
- ◆ All Reliant physical and financial trading with all counterparties, not just Enron on EOL.
- ◆ Examination for linkages between Reliant's financial trading activity and Reliant's anomalous EOL trading days.

After the Initial Report was published, Staff held interviews with Reliant traders and reviewed several key documents. In these interviews, Reliant reported that approximately 70 percent of its

Additionally, it raised trading volumes and observed price movements, making the trading platform look both more vibrant and more liquid.

purchases in this time period were made on the spot market. In our discussions with Reliant traders and management, and from our review of Reliant's trading records, we gained an understanding of how Reliant carried out its trading activity, why this behavior took place at Reliant, and why Reliant stood out on EOL. A key factor in Reliant's gas operations was its contract with LADWP. During this time period, Reliant held a contract with LADWP to meet LADWP's gas needs for its power plants.

LADWP Contract

Reliant became LADWP's gas supplier in the summer of 1999, for a term of 1 year. This contract was renewed for an additional year; the second year includes the refund period.

Under the contract, LADWP was responsible for providing Reliant with estimates of its gas needs. LADWP was to make a monthly baseload nomination and subsequent daily swing nominations, and Reliant would then deliver gas to LADWP accordingly.

The pricing terms for this contract reflected the nominations arrangement. The price LADWP paid for its baseload nominations was based on the NGI monthly index. The price LADWP paid for its spot gas was based on the *Gas Daily* daily midpoint price. Three key implications of this contract structure are:

- ◆ Reliant would profit to the extent it could beat the published index prices.
- ◆ Reliant could minimize its price risk by matching its purchases for LADWP to LADWP's nominations, rather than (for example) holding a larger gas purchase portfolio and serving LADWP from it.
- ◆ LADWP did not benefit from Reliant's churning profits.

Southern California Gas Balancing Rules

Customers, such as Reliant, that used the SoCalGas intrastate system to serve customers had to contend with the SoCalGas balancing rules. In general, customers were expected to deliver gas in quantities that matched their usage. SoCalGas allowed its customers some tolerance from exactly matching nominations with usage. This tolerance was more stringent during the winter than the summer, and in the winter it was more stringent when physical system conditions—principally aggregate system storage levels—dictated it.

The SoCalGas balancing rules are regulated by the California Public Utilities Commission (CPUC). In all cases, balancing charges are invoked for a customer's failure to deliver sufficient quantities of gas. The level of the penalty is generally set at 150 percent of the highest reported spot price (over some relevant time period) multiplied by the amount the balance is below the tolerance. The balancing tolerance varies with SoCalGas's aggregate system storage balances.

Also, balancing rules are more stringent during the gas winter (November to March), including a set of triggers, based on the quantity of gas SoCalGas has in storage.²⁴ SoCalGas requires that customers deliver at least 50 percent of usage over a 5-day period from November through March. As SoCalGas's total (i.e., not customer-specific) storage inventory declines through the winter, the delivery requirement becomes daily and increases to 70 percent or 90 percent, depending on the level of inventory relative to peak-day minimums.²⁵

Monthly Tolerance is 10 Percent

SoCalGas's monthly balancing charges apply to imbalances beyond 10 percent of the customer's usage for the billing period. Imbalance quantities beyond the 10 percent are subject to separate charges for underdeliveries and overdeliveries. Underdeliveries beyond the 10-percent tolerance band incur a charge calculated at 150 percent of the highest daily border price index at the Southern California Border for the month that the imbalance is created. The highest daily border price index is an average of the highest prices from NGI's "Daily Gas Price Index—Southern California Border Average" and the *Gas Daily* "Daily Price Survey— SoCal Large Packages Midpoint Price."

November 1 to March 31

From November 1 through March 31, SoCalGas transportation customers (such as Reliant) are required to deliver a minimum of 50 percent of usage over a 5-day period. In other words, for each 5-day period, if the total delivery is less than 50 percent of the total gas usage, a daily balancing charge is set at 150 percent of the highest Southern California Border price during that 5-day period (as published in NGI's Daily Gas Price Index).

Therefore, a single high-priced transaction, as reported by NGI, can raise imbalance penalty amounts considerably. This can have its own "death spiral" effect—any customer thinking it will face the 150-

²⁴During the summer, SoCalGas applies a monthly charge only; the charge can be avoided by being no more than 10 percent out of balance for the month in total.

²⁵Customers, such as Reliant, can hold storage capacity on SoCalGas's system. Reliant held no storage.

percent penalty charge will be willing to pay more than the current market price for gas to restore balance and avoid the charge. The result of this is that it raises the level of the 150-percent charge for everyone facing it.

The 70-Percent Rule

At the beginning of the winter, SoCalGas is required to have a certain amount of gas in storage. Additionally, there is a peak-day minimum requirement that there be sufficient gas in storage to provide deliverability for the core 1-in-35-year peak-day event, firm withdrawal commitments, and noncore balancing requirement. When total SoCalGas storage inventory declines to a predefined (and CPUC-regulated) “peak-day minimum + 20,000,000 MMBtu trigger,” the minimum daily delivery requirement increases to 70 percent. Customers are then required to be balanced at a minimum of 70 percent of usage on a daily basis and the 5-day period no longer applies. The daily balancing standby rate is 150 percent of the highest Southern California Border price per NGI’s Daily Gas Price Index for the day and is applied to each day’s deliveries that are less than the 70-percent requirement.

For example, if on a given day when the 70-percent rule is in effect, total usage is 50,000 MMBtu and total deliveries are 30,000 MMBtu, then 5,000 MMBtu is subject to the daily balancing charge (70 percent times 50,000 minus 30,000 equals 5,000).

The 90-Percent Rule

When total SoCalGas storage inventories decline to the peak-day minimum + 5,000,000 MMBtu trigger, the minimum daily delivery requirement increases to 90 percent. Customers are required to be balanced at a minimum of 90 percent of usage on a daily basis. Similar to the 70-percent rule, the 5-day period no longer applies. The daily balancing charge is 150 percent of the highest Southern California Border price per NGI’s Daily Gas Price Index for the day.

Storage Balances Are Published

Information regarding the established peak-day minimums, daily balancing trigger levels, and total storage inventory levels is made available on a daily basis on SoCalGas’s Web site.

Having Gas in Storage Is Useful for Meeting the Balancing Requirements

There are a number of ways in which holding firm SoCalGas storage rights—and having gas in storage—can benefit a customer:

- ◆ Customers, such as Reliant, can nominate gas from storage to meet the 70-percent and 90-percent rules.
- ◆ At the customer's option, SoCalGas will use firm storage withdrawal volumes on behalf of the customer to match the customer's actual usage, as long as the customer has firm withdrawal rights and gas in storage.
- ◆ SoCalGas accepts intraday nominations to increase deliveries (including from storage).

What Happened in the winter of 2000–2001

During the winter of 2000–2001, SoCalGas gas storage balances dropped below the threshold level for switching from 5-day balancing to daily balancing on January 21, 2001, requiring customers to deliver 70 percent of their daily usage. As noted above, the penalty for being short was then set at 150 percent of the highest daily spot price.

The 70-percent requirement shifted to 90 percent on February 15, 2001 and lasted until March 17, 2001. During this period, each customer was required to deliver 90 percent of its daily usage or face the penalty set at 150 percent of the highest daily spot price.

From March 17, 2001 to March 31, 2001 (the end of the gas winter), SoCalGas operated on daily 70-percent balancing.

Because the imbalance penalties could be quite onerous, customers on SoCalGas's system needed to factor into their trading and nominating strategies the possibility of being assessed these penalties. To meet the balancing requirements, customers were willing to pay almost any price for gas because the alternative was to pay a penalty equal to 150 percent of the highest priced transaction reported by the index publishers. Reliant was one such customer.

Interview With Reliant's Southern California Spot Gas Traders

Staff interviewed Reliant's SoCal physical spot market traders²⁶ in September 2002. The intent of this interview was to learn more about how Reliant had carried out its trading operations during the time period of interest and about Reliant's primary SoCal physical spot market trader's role in particular.

From our review of Reliant's trading operations, we learned that these operations are divided between gas, power, and financial, and are split

²⁶On any given day, one Reliant trader would perform this role. For virtually all of the time period of interest, one particular Reliant trader performed this function.

geographically within each of those areas. Reliant's SoCal physical spot market trader worked in the physical gas trading area of Reliant, focusing on southern California spot market gas.

Reliant's primary SoCal physical spot market trader's background includes both trading experience as well as employment in the research department at NYMEX. Essentially, this person came to Reliant with the plants that Reliant bought from Southern California Edison, where this person had been working as a gas buyer. As a new Reliant employee, this person continued in the role of gas buyer and took on the added responsibility of servicing LADWP's spot gas needs, which approximately doubled this trader's responsibilities.

Unlike the rest of Reliant's gas traders, Reliant's primary SoCal physical spot market trader worked from home in the Los Angeles area and had limited interactions with the rest of Reliant's traders. Reliant's primary SoCal physical spot market trader reports that the main contact person was Reliant's head of gas trading.

Reliant's SoCal physical spot market trader's primary responsibilities were to determine and meet the gas needs of Reliant's power plants and to meet its commitments to LADWP. The trader did this by communicating with personnel at the various plants and incorporating their estimates. Reliant would purchase all of the swing gas needed, which kept them quite busy during this period. A key responsibility was trying to avoid incurring the penalties from SoCalGas described above (and to which we return below).

Reliant's primary SoCal physical spot market trader states that trading typically lasted from 6:45 to 8 a.m. California time, a 75-minute interval. EOL trading records confirm that trading lasted about 75 (or as long as 90) minutes (although the exact time interval reported by Reliant's primary SoCal physical spot market trader varies from what we see on EOL). LADWP's nominations were due to Reliant at 7 a.m. California time. Trading on EOL for spot gas at the Arizona border typically stopped at about 7:30 a.m. California time (EOL used the Central time zone for time reporting purposes.)

It is clear that the time available was quite limited. On many days, as noted above, Reliant's primary SoCal physical spot market trader purchased (net) more than 300,000 MMBtu of gas from EOL alone (see Appendix II-A, Table II-A2).

Reliant's primary SoCal physical spot market trader's volume of gross transactions was often much larger, on one day reaching as high as 1,740,000 MMBtu, all of which was purchased in the typical EOL

maximum increment of 10,000 MMBtu. On that day, this trader's transactions were carried out in approximately 51 minutes, and 90 percent were carried out within a 30-minute interval, *an average of one trade every 10 seconds*.

Reliant's primary SoCal physical spot market trader offered several reasons for trading so extensively on EOL:

1. Availability/liquidity—Enron was always willing to transact, and the trader believed Enron's EOL prices were as good as any others and better than any other trading platform.
2. The view that one was not trading with Enron *per se*, but with a seller matched to one's purchases.
3. The netting arrangement this trader had with Enron (described below).
4. This trader's view that cuts at Topock were more predictable than those at Ehrenberg—that the benefit of any higher average flow at Ehrenberg would be more than offset by a perceived greater variance in cuts.

Netting Arrangements for El Paso Cuts

Reliant's netting arrangement with Enron had two important characteristics. The first was that purchases were treated at the average cost. A concern at this time for all buyers was the way in which a counterparty handled the cuts from El Paso. During this period, it was not unusual to expect a 40-percent cut in purchases at Topock. An entity selling gas might invoke price majeure—upon receiving its cuts from El Paso, the seller would then cut its counterparties in order of price. Accordingly, getting a lower price on a transaction might bring with it a lower probability of flow. This concern was especially important to Reliant, as it was such a large buyer in the spot market. The netting arrangement used average prices so that lower cost purchases could no longer be targeted for cuts. This gave Reliant an incentive to trade on EOL as a general matter.

The second important feature of the arrangement was that purchases were sheltered from cuts altogether up to the amount of sales made to Enron and any net profits from the sales were retained by Reliant. All of Reliant's purchases from Enron would be taken together to form a volume-weighted average price. All Reliant sales to Enron would be combined in the same way. When there are both sales and purchases, there are two separate calculations. The matching amounts (sales and purchases) would first be netted out against each other and the balance would then be settled at the respective average price. This is the

critical netting feature of the arrangement that gave Reliant an incentive to churn on EOL.

To see the effects of the netting feature, consider an example in which Reliant bought 200,000 MMBtu from Enron at an average price of \$10 and sold 100,000 MMBtu at an average price of \$15 on a particular day.

In one approach to handling this day's trades, shown in Table II-5, a 40-percent cut is applied to net purchases of 100,000 MMBtu and Reliant would purchase 60,000 MMBtu from Enron at an average price of \$5/MMBtu, or \$300,000.²⁷

Table II-5. Netting Example—Settlement Without Netting

	Quantity Transacted (MMBtu)	Average Transaction Price (\$/MMBtu)	Transaction Amount (\$)
Total buys	200,000	\$10.00	-2,000,000
Total sells	100,000	\$15.00	1,500,000
Net purchase	100,000		-500,000
Average purchase price		\$5.00	
Actual flow	60%		
Reliant's purchase price	60,000	\$5.00	-\$300,000

The actual netting agreement between Reliant and Enron worked as described in Table II-6. All of Reliant's purchases from Enron would be taken together to form a volume-weighted average price. All Reliant sales to Enron would be combined in the same way. When there are both sales and purchases, the matching amounts would first be netted out against each other and the balance would then be settled at the respective average prices.

²⁷We use a 40-percent cut level as this is consistent with what has been represented to us by numerous sources as a typical cut level.

Table II-6. Netting Example—Settlement With Netting

	Quantity Transacted (MMBtu)	Average Transaction Price (\$/MMBtu)	Transaction Amount (\$)
Offsetting buys	100,000	\$10.00	-1,000,000
Offsetting sells	100,000	\$15.00	1,500,000
Netted amount	100,000	\$5.00	\$500,000
Additional purchase	100,000	\$10.00	
Actual flow	60%		
Flowed quantity	60,000	\$10.00	-\$600,000
Reliant's purchase price	60,000	\$1.67	-\$100,000

If, on a given day, Reliant bought 200,000 MMBtu from Enron at an average price of \$10 and sold back 100,000 MMBtu at an average price of \$15, then 100,000 MMBtu would be netted out, with Reliant profiting \$500,000 from the price spread. According to Reliant, this calculation is done first and, regardless of the cuts, the \$500,000 profit to Reliant would not be affected. If the remaining amount purchased from Enron were cut by 40 percent, Reliant would be billed for 60,000 MMBtu at the average purchase price of \$10, or \$600,000. This would result in a net cost to Reliant of \$100,000, with the full profit from its sales netted against its net purchase amount. This results in a purchase price for the 60,000 MMBtu of only \$1.67/MMBtu. In fact, if the entire net purchase of 100,000 were cut, Reliant would still retain its \$500,000 profit. Thus, purchases are sheltered from cuts up to the amount of sales and any net profit on the sales is retained.

Thus, there was a financial incentive to churn. Traders who think they can do better than average (presumably most traders) can lock in gains by churning, in a way that could not have been done without the netting arrangement (and that would have existed had there not been cuts on El Paso). Reliant's primary SoCal physical spot market trader reports that the netting arrangement was verbal, i.e., there was no paperwork.

It can be shown mathematically that whenever Reliant was a net buyer, there was a benefit to the netting arrangement that equaled the product of the price difference, the percentage cut (1 – the percentage delivered), and the quantity sold.²⁸

²⁸Assume that Reliant buys X (MMBtu) gas from EOL at price A (\$/MMBtu), and sells Y (MMBtu) gas to EOL at price b (\$/MMBtu). Suppose for this day's trades, the actual delivery rate is k percent. Without the netting agreement, Reliant pays aX dollars for the gas they bought and gets bY dollars for the gas they sold. In total,

Reliant's total profits from the netting agreement are shown in Table II-7. The table shows that profits from the netting arrangement were \$8.9 million and that the majority of the profits came on days when Reliant churned.

Table II-7. Reliant's Profit From EOL-Reliant Netting Agreement, November 2000 – June 2001

	24 Churn Days	All Other Days	Total
Profit from the Netting Agreement	\$7,267,962	\$1,541,962	\$8,809,924
Percentage	82.50%	17.50%	100%

Table II-8 shows the average purchase price that Reliant paid for gas under the netting agreement compared with what it would have paid if there were no netting agreement in place. It shows that the effective price differential (with and without the netting agreement) is substantial for churn days (\$0.76/MMBtu) and negligible on other days (\$0.03/MMBtu).

Reliant pays $(aX - bY)$ dollars if all net purchases were delivered. When some gas gets cut, that is, when k percent is less than 100 percent, the total amount of money Reliant needs to pay to EOL is $(aX - bY) * k$. With the netting agreement, the churn portion of the buy and sell will cancel each other out first and a cash credit is given for every MMBtu if the sell price is higher than the buy price. The net purchase is then settled at the buy price. If Reliant acts as a net buyer ($X > Y$), the total amount of money it needs to pay to EOL is $(X - Y) * a * k - (b - a) * Y$. The possible advantage of the netting agreement to Reliant can be measured as:

$$\begin{aligned}
 & [(aX - bY) * k] - [(X - Y) * a * k - (b - a) * Y] \\
 & = akX - bkY - [akX - akY - (b - a)Y] \\
 & = akY - bkY + (b - a)Y \\
 & = (b - a)Y - (b - a)kY \\
 & = (b - a)(1 - k)Y
 \end{aligned}$$

That is, the advantage is the product of the price difference (sell-buy), the percentage cut, and the quantity sold. If Reliant acts as a net seller rather than a net buyer, the advantage of the netting agreement is the product of the price difference (sell-buy), the percentage cut, and the quantity bought. For a net buyer, the sell quantity Y is the churn quantity (the quantity that gets netted out). For a net seller, the buy quantity X is the churn quantity. Therefore, as buyer or as seller, Reliant's profit would increase proportionally to the churn quantity, independent of its actual net purchase or sales quantity.

Table II-8. EOL-Reliant Netting Agreement's Impact on Physical Spot Trading Outcomes, November 2000 – June 2001

		24 Churn Days	All Other Days	Total
Average Buy Price	Without the Netting Agreement	\$24.36	\$15.35	\$17.08
	Applying Profit from the Netting Agreement, Assuming 60% Flow	\$23.60	\$15.32	\$16.91
Note: Reliant was a net seller for three of the 24 Churn Days. The average buy price does not factor in those.				

Tables II-A14 and II-A15 in Appendix II-A provide details of the impact of the netting agreement (assuming 60 percent flow) on a daily basis for high-profit days (Reliant profit > \$100,000). These tables show that the highest priced day in market history was also the day of the highest profits from netting—December 11. Tables II-A16 and II-A17 provide details of the impact of the netting agreement on a daily basis for all churn days. These tables show that Reliant lost money from netting on only 3 of 24 days, and that the total amount of losses was less than \$30,000. In contrast, the netting arrangement resulted in a number of days of significant upside for Reliant. Tables II-A18 and II-A19 provide details of the impact of the netting agreement on a daily basis for all days in December 2000. These tables show that Reliant's profits from netting were approximately \$5 million for December; virtually all of the profits occurred in the first 8 days of trading, when market prices rose to all-time highs.

Econometric Analysis of Reliant Trading Impact on Gas Prices

The previous sections of this chapter (along with Appendix II-A) document in detail that Reliant's SoCal trading on EOL stands out. No other firm traded in the manner in which Reliant traded, and Reliant's churn trading took place only during a highly unusual period for energy markets and only at one particular, key location—the California-Arizona border—where prices reached record highs.

However, this does not tell us whether or to what extent Reliant's trading impacted the market as a whole, which we discuss in this section. We performed the impact analysis in two steps:

1. We determined whether prices rose during the trading interval on the days Reliant churned.
2. We calculated the impact of churn on prices.

The first step in this impact analysis focused on the trading interval itself, as this is when Reliant could have affected the market most directly. During the November to June time period, prices generally rose sharply when Reliant made an uninterrupted series of purchases in a short amount of time. Similarly, we also observe that prices fell when Reliant made a burst of sales. The second step examines the effect of churn across days.

As the EOL prices rose and fell, they were seen by virtually all gas traders. In fact, as discussed in Chapter III, many traders used EOL as their main tool for price discovery and many reported the prices they saw on EOL to the Trade Press, who published the gas price indices.

Intraday EOL Price Analysis

This section examines whether SoCal prices rose during the 90-minute trading interval on the days Reliant churned. For purposes of this analysis, we define churn in two ways:

1. Days on which Reliant both bought and sold at least 100,000 MMBtu/d. Under this definition, Reliant either churned or it did not.²⁹
2. The lesser of Reliant's daily total purchases and total sales. For example, if Reliant bought 50,000 MMBtu and sold 30,000 MMBtu (for a net purchase of 20,000 MMBtu), the churn variable takes on a value of 30,000 MMBtu.

The following descriptive statistics compare gas prices on churn vs. nonchurn days according to the first definition:

- ◆ The change in intraday price levels is significantly larger on churn days (+9 percent). The average intraday price change is 9 percent larger on churn days.
- ◆ The average price is more than \$9/MMBtu higher on churn days (\$22.02 on churn days vs. \$12.79 on other days).
- ◆ The minimum price is \$17.32 on churn days vs. \$11.67 on other days.
- ◆ The maximum price is \$24.56 on churn days vs. \$13.85 on other days.

²⁹We identified 24 such days for Reliant in the period, while there are only 2 churn days for all other counterparties combined across all EOL trading locations in the West.

- ◆ The spread between the maximum and minimum prices is greater on churn days, with a \$7.24 spread on churn days and a \$2.18 spread on nonchurn days.
- ◆ Measured from the start of trading to the close of trading, prices rose on average by \$1.28/MMBtu on churn days and fell on average by \$0.30/MMBtu on nonchurn days.

This suggests that the market behaved differently on churn days. Since Reliant churned on some days and not on others, we can examine the price impact with some relatively straightforward econometrics. In the econometric analysis, we include variables to control for other factors in order to determine, all else being equal, if prices rose more (or fell less) on days when Reliant churned. The econometric analysis uses EOL trading data for November 1, 2000 through June 2001, the period when the churning took place. Four variables are used to capture factors other than churning: one captures the effect of a transaction having taken place in December 2000, a second captures differences between Friday trading intervals for Saturday to Monday flow and other trading intervals for normal weekday flow, and the remaining two variables reflect basin price changes for western Canada (measured at Sumas, Washington) and San Juan.

For both regression specifications, churning is found to be positively correlated with intraday gas price changes and is statistically significant. Stated differently, when Reliant churned, prices rose on EOL and on the indices. The regression results are summarized in Appendix II-B.

We examined whether the results of our econometric analysis were robust. For example, changing the threshold for churn from 100,000 MMBtu/d to a different level (higher or lower) does not change results materially. Similarly, the results are also robust to changes in the time period considered (i.e., including earlier months along with November to June). Similarly, the results are unaffected by: (1) using other basin prices, (2) *not* controlling for the weekend effect or for the December effect, and (3) calculating the intraday price change using an average of the first few and last few sales rather than the first and last sales. With any of these changes to the model, the core result is unaffected—there is a statistically significant relationship between churning and increasing prices.

The clear statistically significant relationship between the churn variable and higher prices in the regression models suggests Reliant's churning artificially raised gas prices. In the next section, we estimate the net impact of churning on prices.

Interday EOL Price Analysis and Counterfactual Gas Prices

The second step in the impact analysis is to determine the extent to which the within-day price increase observed in the first step persists across days (i.e., whether the price increase caused by churning carried from one day to the next) and to estimate what the prices would have been in the absence of churning—i.e., to calculate counterfactual SoCal gas prices. By comparing the observed prices with the calculated counterfactual prices, we can determine the economic impact of churning.

The calculation of counterfactual gas prices is based on an econometric analysis similar to that described in the previous section, with some minor differences. First, the analysis examines interday rather than intraday price changes. Interday price changes reflect both intraday and overnight price changes. Second, the model captures the effect of churn on price changes on days after the day on which churn takes place, i.e., the model allows us to measure the persistence of the effect of churn. We model persistence by including lags of the churn variable.³⁰ Third, the model includes variables designed to capture the general tendency of prices to revert toward “equilibrium” values. We model mean-reversion—the general tendency of prices to revert toward “equilibrium” values—by including the lagged level of the EOL price and, in some specifications, additional variables.

Mean-reversion is an important component of energy price movements in both the long term and short term. In the long term, high prices induce further exploration and production, leading to increased supply. To the extent that demand is price sensitive, high prices may also reduce demand in both the long term and short term. By inducing additional supply and reducing demand, high current prices tend to lead to lower prices in the future. Conversely, low prices today tend to lead to higher prices in the future. The details of the model specifications and counterfactual calculations are provided in Appendix II-B.

We specify mean-reversion in two ways:

³⁰We include three lags of churn in the model, i.e., we measure for churn’s effect on price changes up to 3 days in the future. We have obtained qualitatively similar results by including different numbers of lags. We also include three lags of the relevant control variables.

1. *Equilibrium gas price varies as a function of the data.* We assume that levels of the control variables, such as basin gas prices, determine an equilibrium price. Price movements are a function of the difference between the lagged EOL Topock price and the equilibrium price. To the extent that the lagged price is above the equilibrium level, prices tend to fall (i.e., price changes are more negative). To the extent that the lagged price is below this equilibrium level, prices tend to rise (i.e., price changes are more positive).
2. *Equilibrium gas price is assumed to be constant.* This is a simplification of the first approach. Rather than modeling an equilibrium price that can change in response to changes in certain variables, we assume that the equilibrium price is fixed.

Which of these specifications is “better” is ultimately an empirical question.

Regression models are estimated over the entire period for which we have EOL data, i.e., February 7, 2000 to June 29, 2001. We focus on counterfactual prices from November 1, 2000 forward. This is also the period under consideration in the refund case and the period during which many long-term power contracts currently subject to litigation and renegotiation were signed.

The regression results are summarized in Appendix II-B. We report results for four different specifications based on two methods for measuring churn and two methods for modeling mean-reversion. The results of all specifications are similar and show that:

- ◆ Churn tends to elevate prices close to when it occurs, but the effect dissipates after several days.
- ◆ In every specification, when prices are high they tend to fall and when prices are low they tend to rise.
- ◆ Models in which the equilibrium price is allowed to vary fit the data better.

For a single instance of churning (where none takes place in the 3 trading days prior to or subsequent to the churn day), the counterfactual gas price calculation has several steps.³¹ When churn days occur within 3 days of one another, the counterfactual gas price calculation is somewhat more complex. The following example assumes an isolated day of churn trading:

³¹The econometric specification uses logarithms. Accordingly, an additional step is exponentiation of the logarithmic results.

1. Using the EOL trading data, calculate the observed interday price change.
2. Using the results from the econometric analysis, determine the price increase from churn (the model specifies that the percentage increase is the same for every day on which churning takes place).
3. Subtract the churn-related price increase from the actual day-to-day price change.
4. Add the difference in step 3 to the previous day's closing price to form the counterfactual gas price.
5. The difference between the counterfactual gas price and the actual price is the amount attributable to churn.

Using the calculated counterfactual gas price, repeat this calculation iteratively for the next 3 trading days, after which we assume that actual and counterfactual prices are equal.

Rather than posit that there is one “true” econometric model that can produce counterfactual gas prices, we have performed the analysis in four ways that are largely similar to each other but differ in key ways. Using this approach, we observe that no matter the model specification, the results are essentially the same. Prices would have been lower in the absence of churning. The more churning that occurred, the higher the market prices.

One key difference between the models is that two specifications use the either-or specification of churn. Any day with more than 100,000 MMBtu/d of buys and 100,000 MMBtu/d of sells is a churn day. Any day with less buying or selling (such as a day with 300,000 MMBtu of buys and only 90,000 MMBtu of sells) is not a churn day. This specification of churn ignores what might be called “minor” churn days.

The other two specifications use a definition of churn that captures all days on which Reliant both buys and sells gas at SoCal on EOL. In so doing, these specifications give greater weight to the days with the most churning activity, unlike the either-or specifications, but also count the minor days of churning on which the behavior is far less pronounced. There are many instances of relatively small amounts of churning, especially in January, February, and April 2001.

The second difference between the model specifications is the treatment of mean-reversion. Two specifications assume a fixed

equilibrium price and two allow the equilibrium price to vary across time.

Table II-9 shows counterfactual prices computed from the four regressions presented in Appendix II-B. These are estimates of what spot prices for natural gas would have been at Topock if Reliant had not churned on EOL. We focus on December 2000, the period with the highest observed prices, a time span during the period under consideration in the refund hearings, and one of the months in which refunds potentially are largest.³² The churn effect on gas prices is biggest in December because that is when the most churning takes place. For December 2000, a simple average of the four specifications' monthly average counterfactual gas prices is \$8.54/MMBtu less than the average EOL prices. This is not to say that gas prices would have been precisely \$8.54/MMBtu less in the absence of churning. It is simply the average from our four estimates.

Significant differences between actual and counterfactual gas prices also occur in February 2001 (when estimates vary from \$1.30 less to \$2.52 less per MMBtu) and March 2001 (when estimates vary from \$1.94 less to \$3.29 less per MMBtu).

For other months, the difference between the calculated counterfactual gas prices and the EOL and published index prices is lower. In May 2001, when there were no instances of buys and sells of at least 100,000 MMBtu/d, the counterfactual prices based on the either-or measure of churn are the same as the EOL prices, and the prices based on the alternative measure of churn are only 5 to 7 cents lower.

³²Because FERC has limited refunds to "spot" transactions, potential refunds are larger for months during which significant volumes were transacted through the California Power Exchange (PX). The PX ceased trading in January 2001.

Table II-9. Counterfactual Price Summary

		Churn = Buys of at least 100,000 MMBtu/d and Sells of at least 100,000 MMBtu/d		Churn = Minimum of Buy Quantity and Sell Quantity		
Month	EOL Mean	Model 1	Model 2	Model 1	Model 2	EOL Mean – Average of All 4 Models
November	\$9.86	\$9.65	\$9.64	\$9.43	\$9.26	\$0.36
December	\$25.26	\$17.39	\$16.69	\$18.09	\$14.70	\$8.54
January	\$12.82	\$12.82	\$12.82	\$12.03	\$11.09	\$0.63
February	\$18.57	\$17.27	\$17.19	\$16.68	\$16.05	\$1.77
March	\$14.76	\$12.46	\$12.34	\$12.82	\$11.47	\$2.49
April	\$13.72	\$13.45	\$13.44	\$12.60	\$11.09	\$1.08
May	\$11.77	\$11.77	\$11.77	\$11.71	\$11.68	\$0.04
June	\$6.06	\$5.82	\$5.80	\$5.90	\$5.84	\$0.22
						Weighted Average: \$1.91
Model 1 Time-varying equilibrium price assumed to be a function of independent variables.						
Model 2 Constant equilibrium price is estimated.						

Physical/Financial Linkages in Reliant's Trading

If the relationship that has been identified between interday and intraday price changes and Reliant's churning behavior is suggestive of Reliant's influence on spot prices on these days, a reasonable line of inquiry is whether Reliant's financial trading activity also benefited from its physical churn trading activity. The trades discussed in this section, like the physical trades already discussed, are bilateral in nature rather than exchange-traded or exchange-settled.

In this section, we present an analysis of Reliant's financial trading activity, focusing on how this activity aligns with physical trading activity and spot gas prices. We focus on Reliant's financial trading for trading activity just prior to periods of churning.³³

³³In the discussion below, we distinguish between the date that a trade is executed (i.e., the "transaction" date on which the trade occurs) and the date for which the trade applies (i.e., the "flow" date on which the trade is evaluated relative to a price index to ascertain the financial outcome).

How Gas Swaps Work

Reliant's financial trading consists primarily of various forms of financially settled swaps. In a swap, two counterparties execute a trade in which the buyer pays a fixed, known price for some notional quantity of gas and the seller pays a price that will vary with the market price (generally based on some agreed-upon price index), which will only be known later. Thus, the buyer in a swap transaction is going long—making a bet that the market price will rise—and the seller is betting that prices will fall. The two types of swaps that we examined are explained below:

- ◆ “Balance-of-month” (swing) swaps are intramonth swaps that applied for the remainder of the month, with settlement based on daily spot market prices throughout the duration of the contract. Similar to ordinary swaps, the buyer profits if gas prices rise.
- ◆ “Basis” swaps are trades in which the buyer pays, for some notional quantity of gas, a fixed, known price and receives the “to be determined” market price differential between two different locations—e.g., SoCal minus Henry Hub. Thus, the buyer in a swap transaction is betting that the price difference (the basis differential) between SoCal and Henry Hub will rise and the seller is betting that the basis differential will fall.

An example of how a trader can profit from a swing swap is provided in Tables II-10 and II-11. Table II-10 shows one of Reliant's swing swap transactions as an example. In the example, Reliant purchases a 10,000 MMBtu SoCal swap, which begins February 14, 2001 and lasts through February 28, 2001. If prices turn out to be higher than \$17.50/MMBtu, Reliant profits.

Table II-10. A Swing Swap Trade With Reliant as Buyer

Buy/ Sell	Volume (MMBtu)	Price	Trade Date	Contract Begin Date	Contract End Date
Buy	10,000	\$17.50	02/12/01	02/14/01	02/28/01

Table II-11 shows the outcome of the swap. On the first day of notional “flow,” gas prices were \$17.03 higher than the swap price, resulting in a \$170,250 profit to Reliant. The next day, prices rose a little higher (to \$19.29), resulting in additional profits of \$192,900 to

Reliant. Over the next week or so, prices fell back to \$17.50 and then lower. On February 28, prices were \$5.05 below the \$17.50 swap price, resulting in a loss to Reliant of \$50,500 for the day. Cumulatively, the swap purchase resulted in a profit of \$702,550 to Reliant.

Table II-11. Profitability of Swing Swap

Flow Date	SoCal Index Price (\$/MMBtu)	Difference From \$17.50 Swap Price (\$/MMBtu)	Realized Profit for Day	Cumulative Profit From Trade
02/14/01	34.53	17.03	\$170,250	\$170,250
02/15/01	36.79	19.29	\$192,900	\$363,150
02/16/01	33.25	15.75	\$157,500	\$520,650
02/17/01	25.25	7.75	\$77,450	\$598,100
02/18/01	25.25	7.75	\$77,450	\$675,550
02/19/01	25.25	7.75	\$77,450	\$753,000
02/20/01	25.25	7.75	\$77,450	\$830,450
02/21/01	24.43	6.93	\$69,300	\$899,750
02/22/01	21.69	4.19	\$41,900	\$941,650
02/23/01	17.48	-0.02	-\$200	\$941,450
02/24/01	12.68	-4.82	-\$48,200	\$893,250
02/25/01	12.68	-4.82	-\$48,200	\$845,050
02/26/01	12.68	-4.82	-\$48,200	\$796,850
02/27/01	13.12	-4.38	-\$43,800	\$753,050
02/28/01	12.45	-5.05	-\$50,500	\$702,550

Reliant's Financial Trading Activity—Basis Trading and Swaps

Staff analyzed Reliant's financial gas trades, including basis trades and swaps having different effective start dates and durations, to establish Reliant's net financial position at each point in time (i.e., each day) over the period of interest. The net financial position takes into account any prior trade (possibly occurring as early as several months earlier or as late as the previous day) that affects the Reliant financial position at the start of the day. The trades that affect the net financial position on any day comprise both basis trades (generally monthly) and swaps (generally rest-of-month).

Reliant's Southern California Basis Trades

Our analysis of Reliant basis trades used the net financial position resulting from trading activity that occurred prior to the start of the month. We compiled, on a cumulative basis over time, the net financial position for basis trades that apply to a given month for November 2000, December 2000, January 2001, and February 2001. Our calculations do not appear to suggest any type of systematic positions or trading activity on the part of Reliant that would indicate it attempted to structure its financial basis trading behavior so as to benefit from its physical trading activities.

Reliant's Southern California Swaps

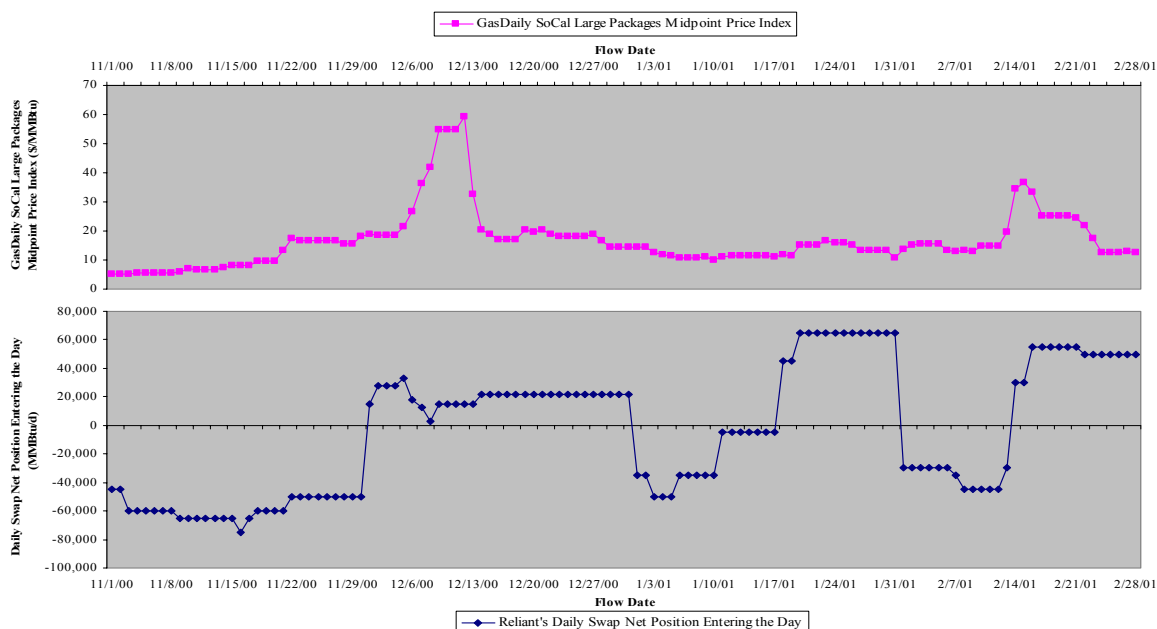
Figure II-12 shows the daily net financial position for Reliant for the period November 1, 2000 through February 2001 as a result of financial swaps. The figure shows that Reliant's daily net financial position ranged from a short position of 75,000 MMBtu/d on November 16, 2000 to a long position of 65,000 MMBtu/d between January 20, 2001 and January 31, 2001.³⁴ From November 2000 through February 2001, there are three subperiods during which Reliant changed its net financial swap position markedly from a short position to a long position, and maintained the long position for a number of days. These three subperiods began on or about December 1, 2000; January 18, 2001; and February 12, 2001.

In addition to Reliant's net financial position, Figure II-12 also shows the *Gas Daily* spot price for SoCal.³⁵ The *Gas Daily* SoCal spot price is relevant because it is the reference price for settlement of Reliant's swaps that apply to a particular day. To the extent that Reliant has a net long financial position on a given day, the difference between the *Gas Daily* spot price and Reliant's weighted average swap buy price (i.e., across all trades affecting the net position for the day) will determine the profit that Reliant will realize on its net financial position for the day.

³⁴The daily swap net position is calculated using the trading records provided by Reliant.

³⁵*Gas Daily* SoCal Large Packages Midpoint Price.

Figure II-12
Reliant's Daily Swap Net Position and Gas *Daily SoCal Large Packages* Midpoint Price Index
November 2000 – February 2001



Note: This graph does not show the individual trades. Rather, it shows the cumulative outcome of the trades - the net position. For example, the net position of 9/1/2000 may be the outcome of trades made several months prior.

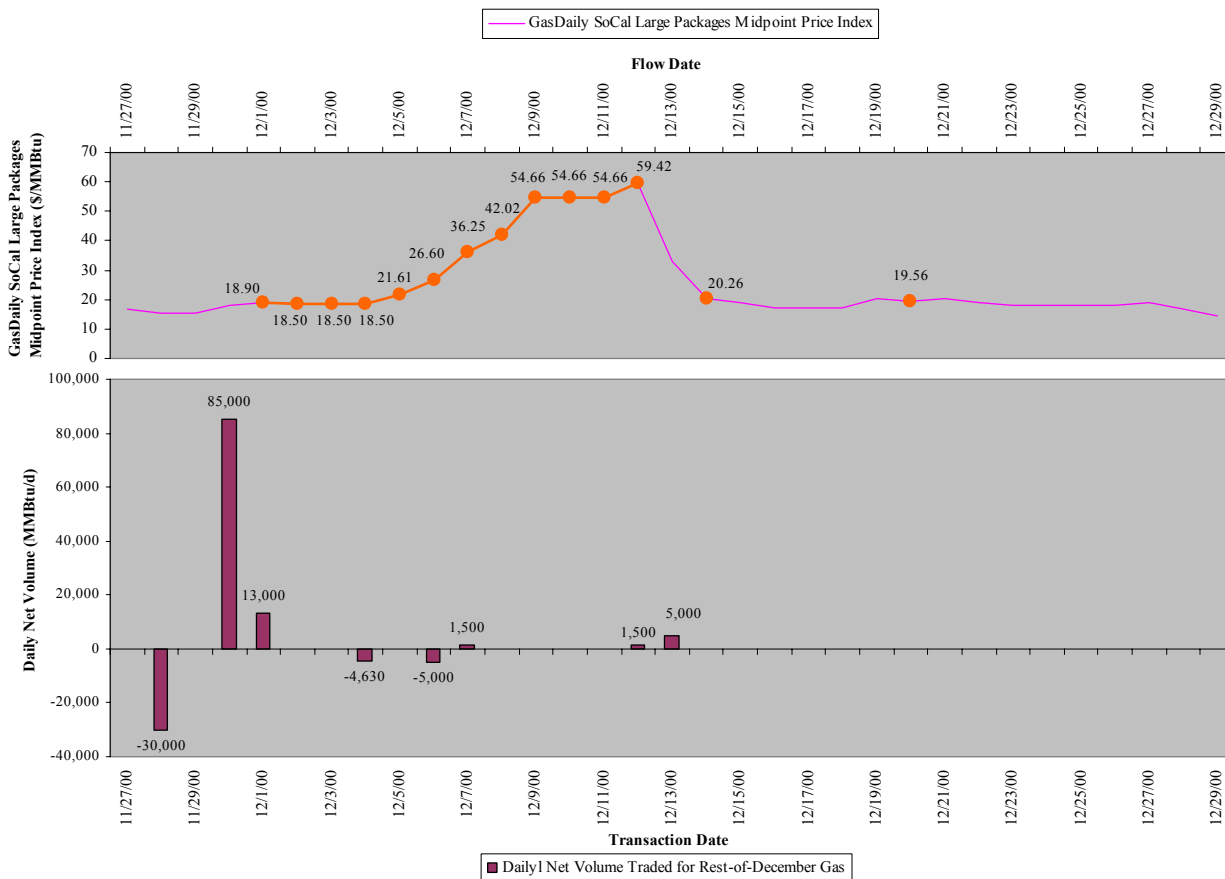
Figure II-12 shows that of the three times when Reliant shifted noticeably to a net long position (i.e., Reliant would benefit from price increases), for two of these periods it did so just prior to a sharp increase in the *Gas Daily SoCal* spot price. If this net financial position were taken in anticipation of the spot price increase, Reliant would benefit. One hypothesis suggested by the analysis of physical trading activity is that Reliant may have influenced prices on certain days; one motive would be to reap the benefits of its financial trading positions on those days. Collaboration between physical and financial trading could explain the timing of the price increase coinciding with moving to long net financial positions.

Subperiod 1: November 27 Through December 31, 2000

Figure II-13 provides a closer look at the trading activity of a particular Reliant trader, “financial trader A,” for one period of interest, November 27, 2000 through December 31, 2000. It shows the average net position in swaps (for rest-of-December gas) and the SoCal spot price for each day. This trader purchased a large number of swaps on November 30, 2000.³⁶ As shown in Figure II-13, on November 30, 2000 financial trader A made trades that resulted in a long position of 85,000 MMBtu/d just prior to a series of 8 consecutive days of churn trading. The profits associated with financial trader A’s financial trading for November 30 to December 1, 2000, just prior to this period of consecutive churn days, were more than \$23.4 million (shown in more detail in Table II-A20 in Appendix II-A). Essentially, this \$23.4 million profit results from the purchase of 85,000 MMBtu/d of SoCal swing swaps for December, just prior to an unprecedented increase in SoCal gas prices and at the beginning of 8 consecutive days of Reliant churn trading.

³⁶Note that financial trader A accounted for 78 percent of the gross volume of Reliant financial swaps for this period.

Figure II-13
Financial Trader A's Daily Net Volume Traded for Rest-of-December Gas,
Compared With Gas Daily SoCal Large Packages Midpoint Price Index
November 27, 2000 – December 29, 2000

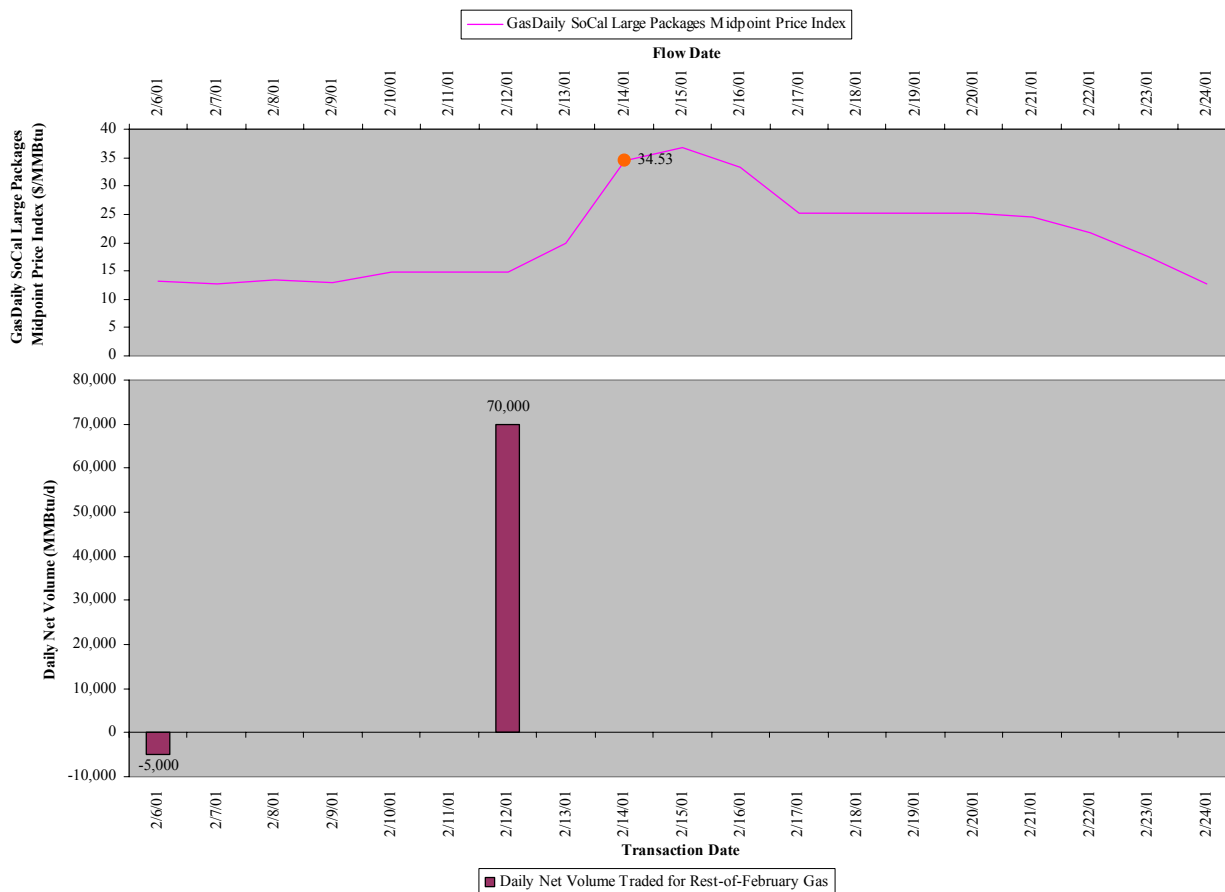


Note: The orange dots on the index price line show days for which the gas flow was traded on a Churn day.
The Daily Net Volume Traded accounts for contracts starting the next day or the day after and last through the end of the month.

Subperiod 2: February 6 Through February 24, 2001

Figure II-14 provides a closer look at financial trader A's trading for the second subperiod of interest, February 6, 2001 through February 24, 2001. During this period, February 13 trading (for flow on February 14) was the only churn day. From February 14 through February 24, 2001, gas prices were substantially higher than they had been for the first part of February. On February 12, 2001, financial trader A bought 13 swaps that resulted in a long position of 70,000 MMBtu/d. February 12, 2001 was the day prior to the only churn trading day in the period, and the SoCal spot gas price of the gas flow traded on this day rose sharply to \$34.53/MMBtu. The profits associated with financial trader A's financial trading for February 12, 2001, were \$4.4 million. (See Appendix II-A, Table II-A21.)

Figure II-14
Financial Trader A's Daily Net Volume Traded for Rest-of-February Gas,
Compared With Gas Daily SoCal Large Packages Midpoint Price Index
February 6, 2001 – February 24, 2001



Note: The orange dot on the index price line shows the day for which the gas flow was traded on a Churn day.
The Daily Net Volume Traded accounts for contracts starting the next day or the day after and last through the end of the month.

Of the approximately \$23 million that Reliant derived from financial transactions in December 2000 that were pegged to natural gas spot prices at the Southern California Border, approximately \$17 million was attributable to the increase in physical gas prices caused by its churning. Of the approximately \$3.8 million that Reliant derived from financial transactions in February 2001 that were pegged to natural gas spot prices at the Southern California Border, approximately \$1 million was attributable to the increase in physical gas prices caused by its churning. In sum, Reliant derived profits from financial transactions of approximately \$18 million due to churning during the relevant 8-month period.

Conclusion Concerning Reliant Trading

At certain times, Reliant employed a churning strategy for buying physical spot gas at Topock on EOL. Reliant needed this gas to generate and sell power into the spot market and to fulfill its contract for supplying gas to LADWP. Reliant's churning strategy involved the repeated buying and selling of substantial quantities of spot gas in a very short period of time in amounts far in excess of its actual needs. When churning, Reliant often traded in bursts unlike any other trader by executing a large number of purchases and sales in a short period of time—sometimes entering into transactions at the rate of one every 10 seconds. No other firm ever made 15 or more trades in a single location within 5 minutes; Reliant did this 36 times. Reliant dominated the churn trading, accounting for 24 of the 26 instances we found; this includes 8 consecutive trading days for December 2000, which encompass the highest-ever gas prices in California. Over this critical 8-day churn period, Reliant's churn volume comprised more than 70 percent of its gross trading volume. On the day after this string of churning ends, prices drop by more than \$25/MMBtu.

For trading volume, Reliant had the 19 busiest and 24 of the 25 busiest trading days on EOL. At Topock and Ehrenberg in particular, Reliant had all 30 of the busiest trading days, measured by number of trades executed. As such, the assumption of liquidity at Topock was often invalid—on a number of days most of the EOL trades took place between Enron and Reliant, rather than there being a more diverse mix of active traders. For the 3-month period from December 2000 to February 2001, nearly 50 percent of the spot gas trades on EOL were with Reliant. For the other 5 months of the refund period, Reliant's share varied between 20 and 30 percent. On the day of the highest Topock prices (flow date of December 12), Reliant accounted for more than 70 percent of the trading volume.

In addition, Reliant often swamped the Topock delivery point with its net gas purchases. On 30 separate occasions, Reliant's net purchases of gas were in amounts greater than half of Topock's 540,000 MMBtu/d capacity. In fact, on two occasions, Reliant's net purchases exceeded the total capacity at Topock. On these days, Reliant's net purchases alone ensured that there would be cuts at Topock.

Reliant's rapid-fire sale and purchase of gas in amounts far in excess of its needs raised the price of gas on EOL significantly. On average, the price is \$9/MMBtu higher on churn days than on other days.

Reliant's churning also resulted in significant price volatility. The within-day price spread is \$5/MMBtu greater on churn days than on other days.

Reliant was able to benefit from churning even though this raised prices and Reliant was a net buyer of gas for its needs. This is because Reliant was often able to profit from the price run-up it caused by unloading its unneeded gas at the higher prices. In spot market trades, Reliant earned more than \$8.8 million from its churning and had a netting arrangement with Enron that sheltered its sales from cuts on the El Paso pipeline. Trading under this arrangement allowed Reliant to reduce its average cost of purchasing gas by more than \$0.75/MMBtu on churn days.³⁷

Reliant deliberately bought and sold gas in a manner that had the effect of raising prices and used its netting agreement with Enron to capture the related profits. It used these profits to reduce the total cost it paid for the gas it needed. Reliant traded Topock gas almost exclusively on EOL, and virtually every trader had an EOL screen. As a result, the price gyrations caused by Reliant were seen by the whole market; however, only Reliant and Enron knew what was causing the price movements. Since EOL served as the primary source for price discovery, its prices virtually mirrored those of *Gas Daily*. Reliant's churning had the effect of moving the entire market price by an average of some \$8.54/MMBtu for December 2000 and by an average of \$1.91/MMBtu over the 8-month period that it churned. These figures represent the average of analyses we have performed in four different ways. All of the analyses are fundamentally alike, but deal in slightly different ways with certain input variables. Notably, the results of all four analyses are the same—Reliant's churning raised prices, and the more Reliant churned, the higher the prices rose.

Deliveries into SoCalGas at the California-Arizona border are considered as one pricing point in *Gas Daily*. If we assume that Reliant's trading affected the entire gas volume of 2,500,000 MMBtu/d delivered into SoCalGas at the California-Arizona border,³⁸ customers paid excessive gas costs in the neighborhood of \$650 million for December 2000 and about \$1.15 billion for the 8-month period.³⁹ More significantly, if we assume an average load in the

³⁷Assuming 60 percent flow.

³⁸El Paso into SoCalGas at Topock of 540,000 MMBtu/d and at Ehrenberg of 1,210,000 MMBtu/d, and Transwestern into SoCalGas at Needles of 750,000 MMBtu/d.

³⁹Not all of the gas entering SoCalGas's system transacts, at least initially, at daily index prices. In particular, some gas flows under prices tied to a monthly index. However, monthly gas may be resold at index prices and intrastate California production may also transact at a price tied to a daily index.

California spot market of 20,000 MW for November through the end of the PX in January 2001 and 5,000 MW thereafter through June 2001, an excessive gas price of \$8.54/MMBtu (about \$85/MWh) would inflate electric clearing prices by some \$1.2 billion for December 2000. Overall, an excessive gas price of \$1.91/MMBtu⁴⁰ (about \$19/MWh) would inflate electric clearing prices by about \$1.6 billion.

Reliant priced all the spot gas it sold to LADWP at index prices. Reliant used the spot gas it purchased for itself to generate and sell power at spot market prices, which reflected the indices. Therefore, Reliant was largely insulated from the increase it caused in the market price of spot gas and effectively bought cheaper gas for itself at everyone else's expense.

We know Reliant had the ability to unilaterally move the market price through churning, and that it did so. Our econometric evidence is clear on this point. Second, we know that Reliant had a financial incentive to influence prices by churning, and that it profited by doing so. Our analysis of the netting arrangement makes this clear. Third, we know that churning pushed up the price paid by all participants whose costs were tied in one way or another to spot market index prices.

**Recommendation: Remedial
Action To Address Reliant's
Churning**

Reliant profited from churning in both the physical and financial markets. In so doing, Reliant adversely impacted prices to such a significant degree that remedial action is justified.

The Commission has authority to regulate commodity sales that do not constitute "first sales."⁴¹ Sales that are not first sales are sales of gas by an interstate or intrastate pipeline, a local distribution company (LDC), or an affiliate thereof. During 2000 and 2001, Reliant was an affiliate of an interstate pipeline and thus its sales were not first sales, i.e., its sales were subject to Commission jurisdiction. In late 2002, Reliant was spun off and is no longer affiliated with a pipeline. Therefore, its sales are now first sales.

⁴⁰To form an average for the 9-month refund period, we assume zero churning effect for October 2000, for an average price effect of \$1.69/MMBtu.

⁴¹First sales are defined in Section 2(21) of the Natural Gas Policy Act of 1978 (NGPA), 15 U.S.C. § 3301(21) (1994). The Commission does not have jurisdiction to regulate first sales pursuant to Section 601(a)(1)(C) of the NGPA, as amended by the Natural Gas Wellhead Decontrol Act of 1989, Pub. L. No. 101-60.

Section 284.402 of the Commission's regulations⁴² authorizes any person who is not an interstate pipeline to sell gas for resale in interstate commerce at negotiated rates. The gas cannot involve first sales but must be within the Commission's jurisdiction.⁴³ Gas sold by Reliant is subject to the Commission's jurisdiction, i.e., it does not constitute a first sale because it was sold by an affiliate of an interstate pipeline. Reliant's churning did not violate Section 284.402 of the Commission's regulations because those regulations contain no explicit guidelines or prohibitions for trading gas.

Staff recommends that Sections 284.284 and 284.402 of the regulations be amended to provide explicit guidelines or prohibitions for trading natural gas under Commission blanket certificates. Staff also suggests a generic proceeding to develop appropriate reporting and monitoring requirements for sellers of gas under Commission certificates.

⁴²18 C.F.R. § 284.402 (2002).

⁴³For example, Order No. 637-A, FERC Stats. & Regs, Regulations Preambles ¶ 31,099 at 31,603 (1999). ("To the extent that the gas sale is a first sale, it would not be jurisdictional, and for jurisdictional gas sales, the Commission has already granted a blanket certificate to make sales for resale at negotiated rates.")

III. Manipulations of Published Natural Gas Price Indices

On August 13, 2002, the Commission made publicly available Staff's Initial Report of its investigation in Docket No. PA02-2-000. Staff inquired into the characteristics of publicly reported price data, including natural gas spot prices at California delivery points that are used in the California refund proceeding. Staff found significant problems with published price indices and specific issues with respect to California delivery point spot prices, as described below:¹

- ◆ The Commission cannot independently verify the published price data (primarily because the source of the publications' raw data has not been disclosed due to publishers' confidentiality concerns about revealing source data).
- ◆ Undetected errors may exist because trade publications reporting spot and forward prices do not employ statistically valid sampling procedures or a systematic, formal verification procedure.
- ◆ Market participants have significant incentives to manipulate spot market prices reported to the reporting firms because natural gas is the fuel input for the electricity generators that set the market price in California.
- ◆ Wash trades may have an adverse effect on reported price data.
- ◆ EnronOnline (EOL), Enron's former electronic trading platform, was a significant source of price discovery and formation and was potentially susceptible to manipulation by market participants, which could affect the published price indices.

Based on these findings, Staff concluded that published California delivery point natural gas spot prices are not sufficiently reliable to be used in the California refund proceeding for purposes of calculating the MMCP and resultant refunds. A detailed discussion of the alternative proposal is in Chapter IV.

¹These findings are summarized in the Initial Report on pp. 3-5 and 34; a detailed discussion is provided on pp. 35-57.

**Developments in the
Investigation Since
August 13, 2002**

Since the Initial Report was issued, five companies (Dynergy, AEP, Williams, CMS, and El Paso) have admitted that their employees provided false data to the Trade Press.² On December 2, 2002, the Office of the United States Attorney in Houston indicted a former vice president of El Paso Energy on charges of false reporting and wire fraud in connection with his reporting of false trades to *Inside FERC* on November 30, 2001. These false trades were to be part of the calculation for the December 2001 monthly price index for the Sumas trading point at the U.S.-Canada border.

On December 18, 2002, the CFTC announced that it had reached a \$5 million settlement with Dynergy and West Coast Power LLC. The settlement stated that Dynergy had “knowingly submitted false information to the reporting firms in an attempt to skew those indexes to Dynergy Marketing & Trades’ financial benefit.”

On January 26, 2003, Michelle Valencia, a former senior trader at Dynergy, was indicted on federal charges of giving false data to *Inside FERC* by the Office of the United States Attorney in Houston. She was charged with three counts of false reporting under the Commodity Exchange Act as well as four counts of wire fraud. She pleaded not guilty.

On October 22, 2002, Staff sent a data request to the 10 largest natural gas marketers and asked a series of questions regarding their past reporting practices, any internal procedures or controls they had in place, any changes they made in those procedures, and any investigations they had in progress. Staff required those companies to investigate whether they had misreported data to the Trade Press and to provide data on actual trades and reported data so that Staff could check the accuracy of those reports. Staff also investigated reporting practices of the five companies that admitted that some of their employees provided false data to the Trade Press.

²The El Paso admission came in response to Staff’s October 22, 2002 Data Request in Docket No. PA02-2 regarding the price reporting practices of the largest natural gas marketers in the United States.

In short, the investigations and responses to the data requests indicate that the companies had little, if any, formal procedures in place to ensure the accuracy of the data reported to the Trade Press. In fact, in some cases there were systematic efforts to bias the data reported to the Trade Press for the purpose of trying to offset the perceived dominance of Enron's input to the process, trying to benefit traders' own positions or that of their trading desk, and trying to offset the inaccuracies that other companies were reporting. In addition, even when these companies claim they were not trying to influence the published indices, Staff uncovered cases in which the data were inaccurate due to unstructured or nonexistent processes for reporting, such as calculating a "volume-weighted average" by taking the simple arithmetic average of the high and low trades, making up trades in order to come up with an average that was the midpoint of the traders' perceived range, and entering fictitious trades (both prices and volumes) in order to replicate what they had seen on EOL or other platforms.

Platts *Gas Daily* and Platts *Inside FERC* were the trade publications publishing the indices that were most widely used in the industry. *Gas Daily* published a daily price index and *Inside FERC* published a monthly index. *Gas Daily* published three daily natural gas prices for more than 100 pricing points: the absolute range, the common range, and the midpoint of the common range. Through interviews (primarily via telephone or fax) with natural gas market participants such as traders, end users, and producers, Platts reporters collect prices, dates, volumes, and sometimes counter parties for individual deals. According to Platts, it then sorts prices from low to high, looks for "outliers" (those prices that are greater than two standard deviations from the mean), cross-checks with counterparties, and calculates descriptive statistics (e.g., mean, median, variance, and range). The index price is based on this analysis.

Inside FERC published monthly price indices based on bid-week fixed-price transactions for gas flowing the entire next month.³ Rather than calling traders on the phone as was the case with *Gas Daily*, *Inside FERC* had a standardized spreadsheet on which traders were to enter prices, volumes, and locations for all fixed-price deals during bid-week. The traders e-mailed the spreadsheet to *Inside FERC*, whose editors performed an analysis similar to the one performed by editors of *Gas Daily* to arrive at the published index.

³A fixed-price transaction is a bilateral deal based on an agreed upon price rather than a price based on an index or a basis differential off an index. Generally, a bid week begins 5 working days prior to the last trading day of the month, but it can vary across regions of the country. A bid-week price is the volume-weighted measure of gas prices for the following month done during the pipeline nomination period.

The investigation and responses to Staff requests for information on the data gathering process of the Trade Press were also documented in the Initial Report. However, the Trade Press asserted First Amendment protection from revealing data, so Staff was unable to get a complete picture of the process. After the Initial Report was completed, Staff collected pertinent information from the companies that provide data to the Trade Press. Having seen the process from the other side, it is clear that the information being sent to the Trade Press was subject to manipulation and the companies claim there was confusion among the traders regarding what the Trade Press was looking for (i.e., all trades, only fixed-price trades, observed trades, “feel for the market”), particularly in the case of daily indices. However, even when it was clear as to what the Trade Press was looking for (i.e., the *Inside FERC* spreadsheet), the traders often sent false data.

Staff also found that traders routinely complained to the Trade Press about the accuracy of the indices and that certain large players were, in fact, manipulating the indices. Traders report that large players leaned on the Trade Press to change indices after they were calculated. Further, some companies wrote letters to the Trade Press complaining about the methodology (e.g., not requiring counterparties from everyone), noting problems, and identifying irregularities. The editors of the Trade Press, therefore, were on notice that some of the data they were receiving could have been false. As such, sometimes they would have had to rely on their judgment and feel for the market rather than using a strict calculation.

Company-Specific Reporting Practices

As stated above, five companies (Dynergy, AEP, Williams, CMS, and El Paso) have admitted that their employees provided false data to the Trade Press, including *Gas Daily* and *Inside FERC*. Some of the companies state that they have taken disciplinary actions against those employees involved in false reporting, including termination of employment and forced resignation.

This section describes the price reporting practices for each of the five companies that have admitted to providing false data to the Trade Press. Although the details vary somewhat for each company, there are common themes throughout. The reporting was done by the trading desks and the traders themselves. There was little, if any, internal oversight by management or desk heads. In fact, in some cases, the desk heads and management were orchestrating the price

manipulation. The traders provided false data in order to (1) offset the perceived dominance of Enron's input to the process, (2) benefit traders' own positions or that of their trading desk, and (3) offset the inaccuracies that other companies were reporting.

Moreover, it is clear that the traders understood the process the Trade Press used to try to filter out false data and drew on that understanding to manipulate prices by constructing phony counterparties and by keeping their false data within the range of trading, only reporting numbers that favored their position (i.e., traders that wanted to see a high price only reported high-priced trades or inflated volumes on those trades).

Dynegy

On September 25, 2002, Dynegy announced it had discovered that 15 of its employees had engaged in reporting false data to the Trade Press. Of those, seven were fired, four were given the opportunity to resign, and four were otherwise disciplined by the company. Dynegy interviewed all of its employees who were involved in reporting trade data to the Trade Press. The results of the interviews indicated that for a number of years the Dynegy trading desks systematically reported false data to the Trade Press. Dynegy states that there is no evidence of a conspiracy among the trading desks or between natural gas and power traders, that it had no systematic method in place for reporting trading information to the Trade Press, and that it has moved the reporting function to its risk management group.

The employees who provided false or inaccurate data to the Trade Press reported both monthly (*Inside FERC* and *NGI*) and daily indices (*Gas Daily*). In their reports to the monthly indices, they fabricated trades to come to a predetermined average. For the daily indices, the main method of manipulation was inflating volumes of trades.

Many of the traders stated that they felt pressure from the heads of the trading desks to report inflated volumes or prices that benefited the desk's position. One trader reported that the heads of the trading desks would instruct traders to report transactions that had not actually taken place. Another trader said the desk head told him he had to inflate volumes and report false prices. The trader stated that sometime in 2000 he was told by his boss that "this is how the game is played and you need to play it too." The trader went on to say that on one occasion, he took his trading report to his boss, who "told him to go back and do the report again, make the volume 2 or 3 times greater and make the price range higher or lower" (he could not remember which).

The trader claimed that he reported inaccurate numbers for 2 months and then stopped doing so, and left the company shortly thereafter.

In addition, some of the fired and disciplined Dynegy traders stated that the way in which they reported price data was similar to the way in which it was done at their previous companies and they considered it to be “common practice in the industry.”

Many traders reported that they provided a “survey” to *Inside FERC* and *Gas Daily*, whereby they found the “average” of the range of trades they observed and/or participated in and then constructed false trades to come up with the average. One trader stated that this was the same way in which he had reported prices when he was employed by another large energy trading company. Many of the Dynegy traders stated that they submitted bogus data (particularly to *Inside FERC*) because there were very few fixed-price trades, which is what *Inside FERC* used for its monthly index. In particular, one trader stated that it was “widely known” that “there were no fixed-price physical deals at some locations.” In addition, traders claim that the heads of the trading desks were aware of this and pressured traders to report bogus fixed-price trades in order for Dynegy’s numbers to be reflected in the indices. Many of the traders indicated that *Inside FERC* had to know what it was getting from the traders—that is, data on trades that never occurred. Specifically, one trader claimed that he provided his trades along with what he saw in the market to *Inside FERC* and that, despite the fact that the *Inside FERC* spreadsheet specifically asked for actual fixed-price trades made by the companies, “*Inside FERC* knew what they were getting.”

Another Dynegy trader stated that he reported trades he saw on EOL or the IntercontinentalExchange (ICE) to both *Gas Daily* and *Inside FERC* because they “wanted to report more than a deal or two,” and to show the marketplace that they were a player in it. Another trader stated that he felt implicit pressure to inflate volumes because of the “fear of bad ranking.”⁴

Another Dynegy employee admitted to overreporting volumes because of expectations to do so or in response to prices that did not seem fair (e.g., those seen on EOL). This employee claimed to “make false reports in order to counteract false reports made by others” and said the reason for this practice was that this was “as much as a general attitude that we needed to fight back” because “the market got ridiculous with Enron.” The investigation uncovered evidence of one

⁴Staff has not determined whether the ranking refers to the ranking of trading companies by volume of trading or the ranking of individual traders or desks within the company.

employee instructing other employees to submit false trades in order to serve as counterparty so the manipulation could not be detected by the Trade Press.

Staff also found evidence that a Dynegy trader and a trader at another company coordinated their numbers in order to report offsetting trades. In one case, for example, the Dynegy trader indicates an attempt to move the price at one trading point (Malin) down, and therefore only reported the low trades to *Inside FERC* (in the range of \$12 to \$12.50/MMBtu) that occurred during bid week. The other trader indicated that its actual trades were around \$14/MMBtu.

In another example, the Dynegy trader and the other trader are coordinating their data reporting to *Inside FERC* for bid week at Malin and PG&E citygate—two significant natural gas trading points in the western United States. In both cases, the traders are discussing coordinating their reporting to ensure that their false numbers are included in the index calculation.

On December 18, 2002, the CFTC issued an Order saying that it had reached a \$5 million settlement with Dynegy and West Coast Power LLC. The Order found that Dynegy had “knowingly submitted false information to the reporting firms in an attempt to skew those indexes to Dynegy Marketing & Trades’ financial benefit.”

On January 26, 2003, Michelle Valencia, a former senior trader at Dynegy, was indicted on federal charges of giving false data to *Inside FERC* by the Office of the United States Attorney in Houston. She was charged with three counts of false reporting under the Commodity Exchange Act as well as four counts of wire fraud. She pleaded not guilty.

On January 27, 2003, Dynegy issued the following statement:

The former employee was one of seven dismissed by the company since Oct. 18, 2002, after an ongoing internal investigation, conducted by the Dynegy Board of Directors’ Audit and Compliance committee in collaboration with independent counsel, discovered circumstances indicating that inaccurate information regarding natural gas trades was reported to various energy industry publications. In addition, Dynegy has disciplined seven other employees for their involvement in this activity.⁵

⁵Dynegy press release, January 27, 2003. www.dynegy.com.

Dynegy further stated that “[t]he past actions by these employees were in violation of the company’s policies as outlined in its Code of Business Conduct” and that it was “committed to fully cooperating with all ongoing investigations into these matters.”

AEP

On October 9, 2002, AEP announced that it had “dismissed five employees involved in natural gas trading and marketing after the company determined that they provided inaccurate price information for use in indexes compiled and published by the trade publications.”⁶ The inaccurate price information referred to in the October 9, 2002 announcement was for the Gulf Coast region. In response to the Staff investigation, AEP officials explained that the traders claimed to have been providing false information in order to counteract the false information being provided by marketers and traders at other companies.

On October 4, 2002, AEP began an internal investigation of its trade data reporting to the Trade Press. AEP states that it initiated the investigation in response to the September 25 revelation by Dynegy that some of its employees had reported false data to the Trade Press. AEP found evidence indicating that some of its employees had submitted false data to the Trade Press during the period from 1998 to 2002.

The traders claimed to have been instructed by their boss (the head of the trading desk) to adjust the prices and volumes of trades they had made and, in some cases, to report trades that never occurred. AEP claims that the traders indicated that they were doing this because they believed it was common practice in the industry, so their false reports were only intended to counteract false information reported by counterparties.

The traders were asked how they would know how much to manipulate the numbers they reported so as to offset what they perceived the other companies were reporting, if these companies were presumably reporting simultaneously. The traders responded that they had a feel (based on buys and sells) for the way in which the market was headed. AEP did not ask the traders whether they tried to influence the index in order to benefit their own positions. However, they did ask the traders if they ever provided information that they

⁶AEP press release, October 9, 2002.

knew in advance would be detrimental to their trading positions, and each indicated they had not.

AEP states that prior to October 2002, there was no process in place for gathering or reporting data to the Trade Press. Since its internal investigation, AEP has instructed all traders not to provide any data to the Trade Press. All trade data will go directly to the head of the Market Risk Oversight Group, who will verify that the data are accurate and then submit the data to the appropriate publications as necessary.

AEP states that it is continuing its internal investigation and cooperating with all relevant regulatory agencies (including FERC, the CFTC, and the SEC) as well as the U.S. Department of Justice. AEP further states that it has moved the market data reporting function from the trading desks to the risk management office.

Williams

On October 25, 2002, Williams announced it had learned that a few traders in its natural gas trading business provided inaccurate information regarding natural gas trades to an energy industry publication that compiles and reports index prices. Williams stated that the inaccuracies were discovered during an independent, internal review of its trading activities.

Williams hired an outside company to conduct an internal investigation of its price reporting. Williams' investigation of the West found no evidence that the daily data provided to *Gas Daily* over the phone were inaccurate. However, the investigation did find that the monthly data reported to *Inside FERC* were inaccurate. Specifically, it found that in a number of instances the volume of trades reported to *Inside FERC* exceeded the actual volume of Williams' trading activity.

In response to the Staff data request, Williams offers the following explanations for the discrepancies: (1) the belief that *Inside FERC* expected Williams to report not only transactions to which Williams was a party, but other transactions occurring during bid week; (2) the reported transaction dates do not necessarily correlate with dates in Williams' database; (3) the reported delivery points do not necessarily correlate with delivery points in Williams' database; (4) ambiguities caused by *Inside FERC*'s requirement that numbers be rounded; (5) the evolving nature of the *Inside FERC* form, which purported to narrow the categories of transactions about which information was

sought over time; and (6) *Williams' traders' reporting of inaccurate information* (emphasis added).⁷

The review found that some Williams traders manipulated the data they provided to the *Inside FERC* spreadsheet. They stated that they were doing this because significant market players (Enron and El Paso) were submitting a great deal of false trade data that were outside the range of prices that were actually trading, and they were trying to offset this false reporting. In addition, they wanted to show the Trade Press that they were players in the market. The traders also claimed that everyone in the industry, as well as *Inside FERC*, knew that this activity was taking place. They further stated that they believed the Trade Press was able to ferret out the most egregious misreporting and arrive at generally accurate priced indices. Williams has stopped reporting market price data to the Trade Press.

Williams did, however, find evidence of deliberate attempts to manipulate the published price indices in the Northeast. In each case, Williams found recorded telephone conversations indicating that editors of the Trade Press were questioning the accuracy of the trades reported by Williams' traders.

In one case, a reporter from *Gas Daily* indicates that there were very few reported trades for that trading point, so the trades reported by Williams changed the index by up to 10 cents per MMBtu. The reporter from *Gas Daily* indicates that he was getting numerous complaints about the published index price and requests counterparty information so he can cross-check Williams' reported numbers, but the Williams trader refuses to provide counterparties due to confidentiality concerns.

In another case, a trader is asked by an editor from *Inside FERC* to provide counterparties for the reported transactions that are on the high end of the reported range and appear to be questionable. The trader makes up counterparties, but when the editor cross-checks with the reported counterparties, they deny being involved in the transactions.

In addition, an analysis of the financial positions of the Williams trading desks indicates that the trading desk profited from the movement of the prices.

⁷December 13 Response at 5.

CMS

On November 4, 2002, CMS announced that it was conducting an internal review of the natural gas trade information provided to the Trade Press by two subsidiaries, CMS Marketing Services and Trading and CMS Field Services. CMS stated that a preliminary analysis indicated some employees provided inaccurate data to the Trade Press. CMS further stated that it would take appropriate disciplinary action and it would stop providing information to the Trade Press.

In its responses to Staff data requests, CMS stated that it had taken disciplinary action regarding seven employees (including firing four employees, three of whom were regional directors) following its inquiry into price reporting practices.

CMS hired an outside counsel who analyzed the accuracy of the trades submitted to *Inside FERC* from December 2000 to June 2002 for its monthly index. Of the 472 trades reported to *Inside FERC* for that period, there were 116 exact matches. The reasons for the 356 reported trades that did not have an exact match were: (1) reporting the sense of the market, (2) rounding off, (3) aggregation of small deals, and (4) reporting what they saw in the market.

The outside counsel interviewed gas traders and desk heads who reported CMS's trading information to the Trade Press. One trader stated that he perceived pressure from his desk head to report inaccurate prices (high or low) in order to affect the index price. The trader said he resisted the pressure, but on one occasion he did report false data in order to manipulate an index to favor the desk's position. According to the trader, during the winter of 2000–2001 the difference between the natural gas prices (basis differential) at two significant Midwestern trading points was unusually large. The trader's boss (the desk head) wanted him to narrow the basis differential between the two prices. The trader then reported high prices for the lower one in order to narrow the spread between the two.

Another trader said that the same desk head asked him to create a spreadsheet with fictitious trades designed to narrow another basis differential. The trader claims that he did create such a spreadsheet to send to *Inside FERC* and e-mailed it to the desk head.

There are many financial products traded by energy companies that are based on the basis differential between two natural gas delivery points. Companies use financial swaps and other instruments to mitigate risks

they face due to the differences in prices at various delivery locations. They also trade basis differentials in order to speculate on those differences. Because companies are taking positions based on the difference between two points, they can profit if they can affect the basis differential by moving one of the prices up and/or moving the other price down. Staff has seen examples of both. One method of manipulating indices in order to affect basis differentials is to simply make up prices, as was the case with CMS. Another way would be to only report those trades that favor their positions or inflate the volumes of those trades that favor their positions.

CMS has shut down its energy trading operation, thus it no longer reports market data to the Trade Press.

El Paso Merchant Energy

On November 8, 2002, El Paso Merchant Energy (El Paso) announced it found evidence that one of its employees had misreported trade data to the Trade Press. El Paso informed Staff that the employee refused to talk about the incident to company attorneys and resigned from the company on November 12. El Paso states that on November 30, 2001, an employee of *Inside FERC* questioned the accuracy of certain trade information submitted by that same El Paso employee.

On December 2, 2002, the Office of the United States Attorney in Houston indicted Todd Geiger, a former vice president of El Paso Energy, on charges of false reporting and wire fraud in connection with his reporting of false trades to *Inside FERC* on November 30, 2001 to be part of the calculation for the December 2001 monthly price index for the Sumas trading point at the U.S.-Canada border. On December 9, 2002, Mr. Geiger pleaded not guilty to the charges.

El Paso provided FERC Staff with recordings of telephone conversations between El Paso employees and an editor of *Inside FERC*. The tapes are telling in that the *Inside FERC* editor was trying to convince the El Paso traders to provide counterparties for all the trades they report in order to “true-up” the index. He explained that unless everyone provides counterparties, traders can submit false data with no way of being detected as long as the trades are not too far out of line with the market. He also explained that once everyone knows that the other traders are reporting counterparties, everyone will know they must provide accurate data reflecting only fixed-price deals made during bid week.

El Paso analyzed the accuracy of its reported data for its Western trading desk by comparing what was reported to the Trade Press with the actual deals captured in its information system for 728 fixed-price trades that took place between October 2000 and December 2001. El Paso found that approximately 80 percent of the transactions they analyzed were perfectly matched, meaning the price and volume reported were exactly the same as the actual price and volume. Of the 20 percent (145 trades) that were not perfect matches, 23 reported transactions had the same price but a volume different from the actual transaction. El Paso explains that 115 of the remaining 122 trades were within 5 percent of the high and low trading range of the NYMEX during the 3-day period comprising 2 business days prior to, and the day of, the NYMEX settlement for each particular month, plus the published basis index for that month at a particular pricing location.

An analysis of El Paso's reporting for the rest of the country (the Northeast, Mid-Continent, and Gulf trading desks) shows far less accuracy in the reporting than in the West. As shown in Table III-1, the percentage of exact matches between actual trades and reported trades was 1.2 percent, 1.0 percent, and 0.5 percent for the Northeast, Mid-Continent, and Gulf trading desks, respectively. That is, for these regions, approximately 99 percent of the reported trades did not represent actual trades conducted by El Paso.

The volumes of the trades are also shown in Table III-1. For these three trading desks for the period July 2000 through December 2001, El Paso traded 640,568,790 MMBtu of fixed-price physical gas. For illustration, if the average price of the gas were \$4/MMBtu for the period, then the value of the gas would be approximately \$2.5 billion. So, El Paso misreported 99 percent of the prices on trades worth over \$2 billion. In addition, as discussed earlier, the published indices are the basis for billions of dollars of financial derivative contracts as well as physical and financial electricity contracts.

On January 13, 2003, El Paso updated its disclosures regarding price reporting to the Office of the United States Attorney in Houston. El Paso disclosed that it had found further instances of inaccurate reporting to the trade publications. On January 16, 2003, representatives from El Paso and the outside counsel performing the investigation briefed Commission Staff on its findings.

The investigation uncovered evidence that indicated there was systematic price manipulation occurring at El Paso. Specifically, prior to October 2000, El Paso reported data according to its "book bias." Staff understands that "book bias" refers to El Paso's trading position. In other words, in reporting according to the book bias, if El Paso had a long position it would report high prices and if El Paso had a short

position it would report low prices. That is, it was trying to manipulate the published price index in order to favor the company's financial position.

Table III-1. Price Reporting Summary, July 2000 – December 2001

	No. of Deals	Percent	Absolute Volume	Percent
Northeast				
Price in range but no deal match	368	84.8%	154,197,500	82.1%
Price equal to or less than 1%	40	9.2%	20,900,000	11.1%
Deal found but price and/or volume do not match	0	0.0%	0	0.0%
Deal price and volume match	5	1.2%	3,487,500	1.9%
	413	95.2%	178,585,000	95.1%
Price greater than 1% and equal to or less than 5%	15	3.5%	7,440,000	4.0%
Price greater than 5% and equal to or less than 10%	5	1.2%	1,550,000	0.8%
Price greater than 10%	1	0.2%	310,000	0.2%
	21	4.8%	9,300,000	4.9%
	434	100.0%	187,885,000	100.0%
Mid-Continent/Midwest				
Price in range but no deal match	388	74.3%	211,827,000	77.9%
Price equal to or less than 1%	65	12.5%	31,407,000	11.6%
Deal found but price and/or volume do not match	7	1.3%	2,765,000	1.0%
Deal price and volume match	5	1.0%	1,540,000	0.6%
	465	89.1%	247,539,000	91.1%
Price greater than 1% and equal to or less than 5%	54	10.3%	23,382,000	8.6%
Price greater than 5% and equal to or less than 10%	3	0.6%	930,000	0.3%
Price greater than 10%	0	0.0%	0	0.0%
	57	10.9%	24,312,000	8.9%
	522	100.0%	271,851,000	100.0%
Texas/Gulf Coast/Southeast				
Price in range but no deal match	1,065	81.5%	546,347,090	85.3%
Price equal to or less than 1%	94	7.2%	35,728,000	5.6%
Deal found but price and/or volume do not match	8	0.6%	2,140,700	0.3%
Deal price and volume match	6	0.5%	1,590,000	0.2%
	1,173	89.8%	585,805,790	91.5%
Price greater than 1% and equal to or less than 5%	114	8.7%	46,565,000	7.3%
Price greater than 5% and equal to or less than 10%	19	1.5%	8,198,000	1.3%
Price greater than 10%	0	0.0%	0	0.0%
	133	10.2%	54,763,000	8.5%
	1,306	100.0%	640,568,790	100.0%

Based on information available as of January 9, 2003.

In October 2000, El Paso reported accurate numbers but the evidence indicates that El Paso desk heads, traders, and management considered whether to continue reporting accurate numbers or go back to reporting the book bias. The evidence shows that many of the traders, desk heads, and managers recommended going back to reporting the book bias. The data in Table III-1 strongly suggest that for those regions, El Paso did indeed go back to reporting its book bias for the period from November 2000 to December 2001.

El Paso states that it has stopped reporting trading information to the Trade Press.

Staff Reaction to the Admissions of False Reporting

Staff expressed concerns about the accuracy of the published price indices in its Initial Report. At that time we had no conclusive evidence that anyone had actually manipulated the published price indices. We argued that, due to the generic problems with the price reporting process and problems specific to the California Border gas indices, many companies had the incentive and ability to manipulate the indices. The admissions (described above) by five significant energy trading companies (Dynergy, AEP, Williams, CMS, and El Paso) confirm our concerns. Particularly troubling is the common theme that because everyone knew that everyone else was manipulating the indices by reporting false prices and volumes, it was somehow acceptable and even necessary for this to take place. Whether the intent was to influence an index in order to favor its positions or to somehow offset the false information being provided by others, the traders of these companies were deliberately manipulating the published price indices by providing false data to the Trade Press. In addition, in many cases the heads of the trading desks were aware of the manipulations; in some cases, they were orchestrating the manipulations.

Many traders said they were attempting to manipulate the index prices in order to offset the attempts at manipulation by others. The AEP traders were asked if they ever provided information that they knew in advance would be detrimental to their trading position, and each indicated they had not. The obvious followup question, which was not asked by AEP (or at least not reported by AEP), is whether they ever provided information that they knew in advance would be good for their trading position. In general, the traders from the companies that

admitted to providing inaccurate data said they were doing so in order to ensure that their positions were reflected in the indices and that they were seen as a major player in the markets. In particular, the CFTC has concluded that Dynegy was knowingly submitting false information to the reporting firms in an attempt to skew the indices to favor its own position. Staff concludes that the most likely scenario is that traders were manipulating price indices not to help create accurate indices by offsetting the inaccuracies of others, but, to the extent possible, to move the indices in a direction that favored their positions and create the illusion that they were key players at particular locations.

The responses also indicate that price index manipulation was part of the price formation process. The indices are supposed to be based on fixed-price trades. Traders manipulated the indices by reporting false and inaccurate data on their fixed-price trading activity. Any resulting inaccuracy in the published price index fed back into the markets. Staff interviews with traders indicate that traders looked at prices in *Gas Daily* every day, just as they watched the activity on EOL. The previous day's index price served as an indicator of the opening trading price. In addition, manipulation of the daily indices would feed back into the monthly indices because monthly and daily gas are, to some extent, substitutes for each other. Moreover, trends in daily prices (especially late in the month) provide price information for next month's gas.

One of the arguments made in defense of the price index reporting process and the accuracy of the indices is that, because there are entities with the ability and incentive to manipulate the indices in both directions, the manipulation is offsetting and therefore the indices are accurate. Staff does not find this argument to be persuasive.

First, there is no reason to conclude that all of the manipulation is exactly offset. For example, many of the entities with the most influence on the indices are on the same side of the market (that is, they want to see the price move in the same direction). Specifically, some of the large purchasers of natural gas at the southern California border bought gas at fixed prices but sold it at an index price. The entities that bought gas at an index price would not be able to influence the price, but those that bought at a fixed price would have the incentive and ability to increase the index price.

In fact, six large natural gas buyers (Coral, Duke, Dynegy, Mirant, Reliant, and Williams) provided data from 18,320 natural gas transactions in California during the period from October 2, 2000 to June 22, 2001.⁸ During that time the generators' fixed-price purchases

⁸Reishus and Wang Data filed under EL00-95.

were, on average, \$0.30/MMBtu less than the published price indices for southern California.⁹ During the period they paid \$46.8 million less for their fixed-price purchase than they would have paid if they had purchased the gas at the index price.

Table III-2 shows that in December 2000, a month with extremely high and volatile natural gas prices in California, fixed-price purchases were, on average, \$0.78/MMBtu lower than the published index, which is supposed to be based on fixed-price trades.

**Table III-2. December Southern California
Average of (Spot Price – Published Index)**

	Fixed Price Transactions	Indexed Price Transactions
Buys	-0.78	-0.11
Sells	0.30	-0.22

Second, it is unrealistic that the traders could use their feel for the market (as described by the AEP traders) to predict the direction and magnitude of the other traders' manipulations and calculate a perfectly offsetting manipulation of their own. Staff finds that argument to be preposterous. As stated by the Trade Press on numerous occasions, the only way to ensure accurate index prices is to provide counterparties to all trades so they can be cross-checked, thus forcing the trading companies to provide accurate data (unless they are colluding) or have it thrown out by the Trade Press.

Third, Staff cannot recommend relying on such a haphazard method—hoping that the editors of the trade publications can perform some kind of alchemy and arrive at accurate prices despite deliberate manipulation and no systematic method of reporting the data to the Trade Press. Since the Commission has jurisdiction over most of the transactions that form the basis for the indices and many Commission-jurisdictional transactions (both gas and electric) are based on the indices, it needs to be sure that the published indices are accurate, not subject to manipulation, and not serving as a means for price manipulation. As the agency of the U.S. Government with the statutory obligation to ensure just and reasonable electricity rates, the Commission cannot rely on a recipe of offsetting false reports, traders' feel for the market, and editorial judgment (subject to claims of First Amendment protection) for accurate price indices.

The conversations between the editor of *Inside FERC* and the El Paso traders show the inherent flaws in the system. In those conversations

⁹In addition, their index-priced transactions were, on average, \$0.10/MMBtu lower than the published index prices.

(which took place in late 2001, after the California energy crisis), the *Inside FERC* editor is clearly trying to obtain the most accurate data possible. This is consistent with Platts' assertion that it tried to publish the most accurate indices possible. However, the fact that the industry was not providing counterparties by late 2001 shows that the indices were still subject to manipulation. Without counterparty information, there was no way for the Trade Press to cross-check for accuracy of the reported trades. Platts and other companies that publish indices have made improvements in their data-gathering process in the last few months. In addition, energy trading companies have expressed a willingness to provide complete and accurate data, including counterparty information. It is clear to Staff that without counterparty information from all parties providing trade data, the published indices cannot be counted on to be accurate and free from price manipulation.

Even with counterparty information, price indices could be manipulated through collusion by (1) engaging in wash trading, which, as described in Chapter VII, occurred on numerous occasions during 2000 and 2001; or (2) arranging with another company to submit false information in order to provide phony counterparties. Therefore, providing counterparty information is a necessary, but not sufficient, condition for price indices that are accurate and free from manipulation.

The Commission's vision is to ensure dependable, affordable energy through sustained competitive markets. The basis for using markets to set energy prices rather than cost-of-service regulation is the belief that competitive markets can more efficiently allocate scarce resources. In a properly functioning competitive market, the market price serves to allocate resources. The price represents the value of the resource to society, reflecting demand and supply conditions. The price sends a signal to potential suppliers considering expanding production or entering the market; to the financial industry considering whether to finance such expansion, and, if so, at what interest rate; to consumers making short-term decisions regarding how much energy to consume at a given time and long-term decisions such as whether to buy an energy-efficient furnace or a gas or electric appliance; and to energy-intensive businesses regarding where to locate and which energy source to use. The price also signals where infrastructure improvements are most critical. A manipulated price sends a false price signal and misallocates resources.

The accuracy and integrity of the market price are especially critical in capital-intensive industries such as natural gas and electricity. Moreover, as the predominant input choice for new electricity generation, the accuracy and integrity of natural gas prices are

particularly critical. The decision of whether and where to build a natural gas-fired generation facility is distorted if the natural gas price has been manipulated, which leads to long-term misallocation of critical resources and ultimately hurts consumers. Accurate natural gas prices that are free from manipulation are the cornerstone of competitive natural gas and electricity markets.

In addition, the published price indices serve as the basis for a huge volume of financial derivative trading. Energy companies that serve customers use financial markets to hedge the risk in the energy industry, which is significant due to inherent price volatility and the need to make long-term decisions with little certainty regarding future prices. When index prices are manipulated (up or down), financial derivative products are not priced properly, market participants lose faith in financial markets, and the cost of risk management is increased. Ultimately, energy consumers are hurt by the increased costs and inability of energy companies to properly manage risk.

Responses to the October 22, 2002 Data Request

On October 22, 2002, Staff sent a data request to the largest natural gas marketers and asked a series of questions regarding past reporting practices, any internal procedures or controls they may have had in place; any changes they have made to those procedures; and any investigations they have in progress.¹⁰ Staff required those companies to investigate whether, in fact, they had misreported data to the Trade Press and to provide information on actual trades and reported data so that Staff could check the accuracy of those reports.

This section describes the price reporting practices of seven of the largest natural gas marketing companies in the United States. The practices for reporting information to the Trade Press varied across companies, but there are common themes across companies. In most cases, the reporting was done by the trading desks and the traders themselves; there was little, if any, internal oversight by management or desk heads. In fact, in some cases, the desk heads and management were orchestrating the price manipulation. The traders claim they provided false data in order to (1) offset the perceived dominance of Enron's input to the process, (2) prove that they could affect the published price indices, (3) offset the inaccuracies that other

¹⁰Of these ten, three (Dynergy, Williams, and AEP) had already received data requests and/or subpoenas from Staff under Docket No. PA02-2 regarding their price reporting practices.

companies were reporting, and (4) replicate the prices they perceived to be the true range and average of the market. Staff concludes that, at least in some cases, the false reporting was done to favor the traders', desks', or companies' financial position. In fact, the CFTC has concluded that Dynegy "knowingly submitted false information to reporting firms in order to skew those indices to Dynegy Marketing."

In some cases, the traders understood the process the Trade Press used to try to filter out false data and drew on that understanding to manipulate the prices by constructing phony counterparties and keeping the false data within the range of trading, but only reporting numbers that favored their position (i.e., traders that wanted to see a low price only reported low trades or inflated volumes on those trades). In some cases the traders claim they were unsure of what the Trade Press was looking for, so they would report a mix of real trades, observed trades, and fabricated trades that reflected their sense of market conditions.

Duke Energy Trading and Marketing

Duke Energy Trading and Marketing (Duke) performed an analysis of the correlation between the data reported by its Salt Lake City office (West trading desk) to the Trade Press and the actual trade data recorded in Duke's database for its western United States transactions. The analysis found that for monthly transactions, 95 percent of the reported trades matched the recorded trade on price, 93 percent matched on volume, and 92 percent matched on both price and volume. For daily transactions reported to the Trade Press, 88 percent of the reported trades matched the recorded trade on price, 82 percent matched on volume, and 78 percent matched on both price and volume. Stated another way, 8 percent of the reported monthly trades were inaccurate in terms of price, volume, or both, and 22 percent of reported daily trades were inaccurate in terms of price, volume, or both.

Duke interviewed its Salt Lake City traders to try to understand why there would be occasions when the recorded trade and the reported trade did not match completely. The reasons offered by the traders included (1) some small-volume trades were excluded from the reporting, (2) some trades occurred after the office's reporting deadline of 1:00 p.m. (Mountain Time), (3) the inadvertent failure to attach a list of online trades to the form that was faxed to the Trade Press of daily gas indices, (4) a trader's use of "an eyeball estimate" of a weighted average price for transactions that were reported on an

aggregated basis, and (5) a trader's reporting of an intracompany trade that was normally excluded. Duke concludes that for the vast majority of its trades, the Salt Lake City office reported its actual transactions to the Trade Press and there was no trader intent to manipulate the indices.

Duke did not perform a similar analysis for its eastern United States transactions because "DETM's Houston office reported to the Trade Press data for indicative transactions on broader market information than just its transactions."¹¹ That is, because Duke reported trades that it observed in the marketplace, it would not be expected that the reported data would correlate highly with recorded transaction data.

In addition, Duke provided Staff with electronic records of the spreadsheets it used to record the range of trades and volume-weighted average that it sent to *Gas Daily*. Examination of these spreadsheets shows that Duke calculated its volume-weighted average by taking the simple arithmetic average of its high and low trades for the day. Therefore, even if the Duke traders were trying to report accurately, they were not. Calculating a volume in this manner would not create a systematic bias in either direction (that is, tending to systematically overstate or understate the volume-weighted average); it provides another source of inaccurate price data that is reflected in the published price indices.¹²

Duke did find significant inaccuracies in its reporting by the Mid-Continent, Gulf, and East trading desks, all located in Houston. Unlike traders in Salt Lake City, who reported on actual trades, the Houston traders reported their "sense of the market." The reporting was done by the physical gas traders, who generally received the data from management and the financial traders. The investigation has found that the management and financial traders sometimes biased the reported numbers to favor the trading desk's financial position.

Duke contends that by providing a "sense of the market," the traders thought they were providing what the Trade Press was looking for. Staff finds this argument unpersuasive because, for monthly prices, *Inside FERC* was explicit in its description of what it needed for its monthly index—actual fixed-price physical natural gas trades, not a "sense of the market" or basis or financial trades.

¹¹Duke response to October 22 Staff Data Request, November 8, 2002.

¹²If the distribution of prices was perfectly symmetric about the mean price, then the volume-weighted average would be equal to the simple average of the high and low trade. There is no reason to believe that would be the case with any regularity.

Duke states that most of the senior management in the Houston office, including all who participated in the inaccurate reporting, are no longer with the company.

Duke states that its internal review indicates that the process of reporting natural gas market data to the Trade Press was informal. Duke claims that much of the informality was due to a general lack of understanding by Duke regarding what the various publications were seeking. Duke states that it has implemented new compliance procedures, under the direction of its chief risk officer, to ensure the accuracy of the data reported to the Trade Press.

Coral Energy

Coral Energy (Coral) interviewed all employees who provided data to the Trade Press. Coral has concluded that “the information it provided to the Trade Press accurately reflected then current market information.” Coral described the type of information each trader (or other employee that provided trade data) gave the Trade Press. For both daily and monthly data, many Coral traders provided prices and volumes of (1) actual trades they had entered into, (2) trades they heard had taken place in the market, and (3) trades they had seen on trading platforms, including EOL.¹³

Coral does not address the seemingly obvious problem with reporting prices and volumes of trades that traders had “heard about” or “seen on electronic trading platforms.” If a trade on EOL was witnessed by 100 traders, that does not mean the trade happened 100 times. However, if the industry practice was to report prices and volumes of trades that had been observed or heard about, then trading volumes were overstated and those trades made on EOL (the most widely observed trading platform) carried undue influence on the published price indices. Staff described the influence of EOL in the gas market price formation process, especially the Southern California Border daily market, in the Initial Report. The fact that traders were reporting trades they saw on EOL, sometimes misrepresenting them as their own trades, is another way EOL influenced the published indices. As stated throughout this chapter, many large traders used the same sort of “survey” reporting described by Coral.

¹³Some Coral traders only provided data on trades they had actually made.

Mirant

Mirant was the largest natural gas marketer in 2001, as measured by total value of trades. Mirant states that prior to September 2002, it had no formal or consistent process in place for communicating wholesale natural gas transaction data to the Trade Press. Mirant did not have any internal policies, spreadsheets, or directives with respect to the form or type of information that was being communicated to the Trade Press. Natural gas traders provided natural gas transaction information, generally over the telephone and through e-mail and facsimile, based on questions asked by various Trade Press representatives.

Mirant's Office of General Counsel and Office of Internal Audit investigated Mirant's practice of reporting information to the Trade Press for the period January 1, 2000 to October 15, 2002. Mirant's investigation team concluded that Mirant traders did not provide data that were nonrepresentative of either transactions undertaken by Mirant or actual market conditions.

Mirant did find that traders often reported transactions they had seen in the marketplace rather than only reporting its own fixed-price trades, but they believed they were reporting in good faith what was transpiring in the marketplace. Mirant's investigation indicates that the Trade Publications relied on traders that were active in the market and had access to information about the transactions of other players to provide prices from observed transactions. Mirant explains that the "observed transactions" came from computer screens provided by certain brokers and online trading platforms such as EOL and Alltrade.

Mirant found that one trader deliberately took note of "observed transactions" and reported observed prices to *Gas Daily*. That trader, who bought natural gas to serve Mirant's electric generation plants in California, had strong suspicions that the price index was being skewed upward by other trading companies that were net sellers of natural gas in California. He stated that he reported actual "observed transactions" at prices lower than he was transacting to counter the artificially high prices he perceived were being reported to push up the index price. The trader stated that he told *Gas Daily* and NGI that their published indices appeared to be nonrepresentative of the California gas market and that there were several occasions when the Trade Press did find reported trades that were not representative of the market and excluded those trades from the index calculation.

Since October 2002, Mirant has implemented a formal process for reporting information on natural gas transactions to the Trade Press. Mirant now directs all calls or contacts from the Trade Press to a designated employee in the Risk Control department who is responsible for collecting responsive data from Mirant's actual trading records for submission to the publications. Moreover, since October 2002, records are being kept as to data requested and data submitted.

BP Energy Company

BP Energy Company (BP) provided records for trading data reported to the Trade Press by fax or e-mail. BP states that during the period in question, it provided natural gas prices and transaction data to the Trade Press on spreadsheets containing information drawn or downloaded directly from the transaction support system. BP had a formal system in place for reporting transaction data to the Trade Press that included assigning the responsibility for reporting to a single trader with oversight and accountability from the trading managers.

BP could not provide records of the data reported to the daily publications over the phone. BP states that any information reported over the phone came directly from daily deal sheets. BP's internal price index reporting policy requires all discussions with third-party publications to be limited to the designated representative, with the trading managers serving as backups.

Reliant

For daily price reporting (*Gas Daily* and NGI), Reliant reported daily trading by fax to the Trade Press. Each day, traders would pass a daily worksheet around the trading floor and one or more traders would handwrite information on trading points with which they were knowledgeable. Some traders reported pricing for Reliant trades; others also reported other trades observed in the markets. At 2:30 p.m. each day, a Reliant analyst would fax the worksheet to the Trade Press. Reliant states, "[t]he worksheet was not reviewed by a supervisor or another employee before it was transmitted."¹⁴

Reliant used different monthly price reporting procedures at its various trading desks. It has almost no record of the West desk's reporting (it found a single spreadsheet from the Denver office). However, Reliant

¹⁴Reliant response to October 22 Staff Data Request at 4.

was able to locate many of the spreadsheets sent from the East trading desks (Southeast and Northeast).

Reliant's process for reporting to *Inside FERC* is particularly noteworthy. As described in this Report, Platts' *Inside FERC* had a standard spreadsheet that it required companies submitting trade data to use for reporting bid-week trades for its monthly index. The spreadsheet required price, volume, date, and company name to be entered for each reported trade. Reliant did not use actual trades to fill in the bid-week survey; rather, it used a three-part process to generate a set of fictitious trades to enter into the spreadsheet: First, the traders agreed to a "consensus" range of trades. Next, an analyst determined the midpoint of the consensus range. Finally, "the analyst would generate a list of prices—all falling within the consensus range—and volumes that arithmetically led to a weighted average at the consensus midpoint."¹⁵

Reliant states that it believes the method described above was not meant to influence prices; rather, it was intended to provide accurate information about market prices. In support of this conclusion, Reliant notes that the volumes reported to *Inside FERC* were often substantially lower than Reliant's actual trade volumes at the reported locations. Reliant argues that someone trying to influence the index price would tend to overstate volume rather than understate it.

Reliant compared the reported data to the actual trade data captured in its internal computer system. It found that approximately 65 percent of the reported midpoints were within 1 percent of the actual midpoint, approximately 97 percent were within 5 percent of the actual midpoint, and approximately 99 percent were within 10 percent of the midpoint. Moreover, the data support Reliant's claim that it consistently underreported the volume of its trades. Of 514 price reports for which comparisons could be made, the reported volume was less than the actual trade volume in 432 cases (84 percent). In the cases where Reliant underreported its volume, the volume reported was approximately 15 percent of the actual volume. In 84 cases (approximately 16 percent), the reported volume was greater than the actual volume—on average, approximately 100 percent above the actual volume. Reliant states that the discrepancy in volume was not surprising because traders focused on accurate prices rather than volumes.

Staff notes that accurate volumes are a critical part of calculating an accurate price index because the indices are volume-weighted averages. It is clear from the investigation that one of the ways in

¹⁵Reliant response to October 22 Staff Data Request at 8.

which companies tried to manipulate the published price indices was by reporting inaccurate volumes—both by overstating volumes of trades that favored their position and by understating volumes of trades that hurt their position.

Sempra

Sempra Energy has three affiliates—Sempra Energy Trading (SET), Southern California Gas Company (SoCalGas), and San Diego Gas & Electric (SDG&E)—that reported prices to the Trade Press. Each entity had different degrees of interaction with the Trade Press and had its own reporting procedures.

SET states that it sent e-mails to *Inside FERC* and NGI and received phone calls from *Gas Daily* and Btu.¹⁶ SET states that no record exists of any of the telephone conversations with *Gas Daily* and Btu. SET found only five e-mails of data submitted to *Inside FERC* and NGI for all of 2000 and 2001. SET compared actual trade data with data reported to the Trade Press for the small subset of reported trades for which it had records, and found no discrepancies. SET states that it has learned of some minor discrepancies (\$0.01 to \$0.02/MMBtu) in the data reported to *Gas Daily* on a few occasions involving an area in the Rocky Mountain region.¹⁷ SET explains that both *Inside FERC* and NGI requested written transaction information via fax or e-mail for their monthly indices. With respect to *Gas Daily*, there was no formal reporting practice. As was the case with other energy trading companies, SET employees were sometimes asked by *Gas Daily* to report or comment on general market conditions and/or other trades they may have been aware of. SET states that “Responses to such requests varied. Some employees refused to comment on trades not executed by SET. Others reported their knowledge of various trades in the market based on data available on electronic trading platforms (such as ICE).”¹⁸

SoCalGas unequivocally states that no employee provided inaccurate data to the Trade Press. They provided written records of the trades but state that there is no way to check on them because they were reported over unrecorded phone lines. SoCalGas also states that it is required by the California Public Utilities Commission (CPUC) to submit all of its trade data to the CPUC and that it provides the same data to the Trade Press that it provides to the CPUC. In addition, SoCalGas provided

¹⁶Btu Publishing Inc. publishes energy market information and price indices in its publications: Btu Weekly, Btu’s Daily Gas Wire, and Btu’s Midday Report.

¹⁷SET response to October 22 Staff Data Request at 2.

¹⁸SET response to October 22 Staff Data Request at 3.

Staff with spreadsheets identifying all spot market transactions for 2000 and 2001; the spreadsheets indicated if the transaction was a purchase or sale, price, volume, and counterparty. These data were the same as the data submitted to the CPUC.

SDG&E states that it was not a significant natural gas trader and, as such, its employees provided prices and volumes to the Trade Press on a limited number of occasions. SDG&E states that no employee provided any inaccurate information to any entity publishing price indices. SDG&E further states that as a regulated California public utility, it provides monthly reports to the CPUC's Energy Division and to the CPUC's Office of Ratepayer Advocates, providing details of all its physical and financial natural gas transactions.

Aquila Merchant Services

Aquila Merchant Services (AMS) states that it had three trading desks: West, East, and Mid-Continent. It reported daily trading data to *Gas Daily* and monthly data to *Inside FERC* and NGI; daily trading data were reported by fax. Each day traders would pass a form (the Aquila Energy Marketing *Gas Daily* Pricing Log) around the trading floor and one or more traders would handwrite information on trading points with which they were knowledgeable. AMS would report the range of trades, midpoint, and volume. AMS states that although the desk head was ultimately responsible for the information sent to *Gas Daily*, it appears that any trader could enter data onto the form. Interviews with traders indicate that some traders provided only actual AMS trades while others reported a combination of trades they saw on electronic platforms (such as EOL) and actual AMS trades. Traders indicate that there was some uncertainty over the specific data *Gas Daily* wanted, that is, whether *Gas Daily* wanted only actual trades or more of a market survey.

For monthly reporting, AMS employees reported trade data by e-mail on a spreadsheet that was stored on a shared drive. As with daily reporting, although the desk head was ultimately responsible for the information sent to *Inside FERC* and NGI, it appears that any trader could enter data onto the form. In compliance with Staff's data request, AMS analyzed the accuracy of the reported monthly prices by comparing the actual trade data with the reported trade data. AMS found that the data reported by the West desk were accurate, but the data reported by the East and Mid-Continent desks showed discrepancies for January, February, March, April, and June 2000. In one case, a trader stated that the desk head provided a range of prices that he knew were not based on real prices and a volume-weighted

average price that he knew was not accurate, and gave instructions to fill in fictitious numbers within the false range on the spreadsheet to arrive at the false weighted average. The trader stated that this practice stopped after October 2000, when AMS instituted a practice of reporting counterparties for every trade and only reporting fixed-price trades.

The evidence suggests that the attempt at price manipulation was not done specifically to offset the misreporting of other companies, but there was a general sense among the traders and desk heads that other companies (including Enron) were attempting to manipulate the published indices to their financial advantage and hurting AMS. One trader described it as a Prisoners' Dilemma,¹⁹ that is, given what the other large trading companies were doing (reporting false data to favor their positions), his best response was to report false prices even though everyone would be better off with accurate price indices.

AMS states it had concerns with the price reporting methodology and it perceived that others were manipulating the indices. Through interviews with traders, desk heads, and former AMS managers, it found specific accounts of AMS employees contacting the Trade Press to question the accuracy of the published indices when AMS employees did not believe the indices were representative of market conditions. AMS provided copies of letters sent by its General Manager to Financial Times Energy and *Inside FERC* regarding the methodology used to compile its indices and advocated accepting only trade data from companies that have agreed to be audited.

In August 2002, AMS announced that it was shutting down its wholesale marketing and trading operations. By the end of the third quarter of 2002, AMS had eliminated most of its wholesale marketing and trading business, including market making activity and speculative trading. By the end of the fourth quarter of 2002, AMS had unwound almost all of its energy trading positions. AMS states that it has eliminated most of its positions in merchant operations and most of its employees, and no longer reports trade information to energy industry publications such as *Gas Daily*, *Inside FERC*, or NGI.

¹⁹In the Prisoners' Dilemma, two prisoners must decide separately whether to confess to a crime; if only one prisoner confesses, he will receive a lighter sentence and his accomplice will receive a heavier one, but if neither confesses, sentences will be lighter than if both confess. The individual incentives faced by both prisoners force them to confess, even though they would both be better off if they did not. The outcome (mutual defection) is an example of a Nash Equilibrium in game theory. See, for example, Robert S. Pindyck and Daniel Rubinfeld, *Microeconomics*, 5th edition, pp. 442-444.

**Staff Reaction to Responses
to the October 22, 2002 Data
Request**

The answers to the questions in the October 22, 2002 Data Request show that the industry lacked systematic reporting procedures and internal verification processes.²⁰ The responses also show that the price manipulation goes beyond the five companies that have admitted to such behavior.

As noted above, most of the largest natural gas marketing companies in the country had no formal process for reporting trade data to the publishers of the price indices; the process was left to the trading desks and the traders themselves. Traders from all companies describe a typical trading day as hectic, pressure packed, and frenetic. One of their many tasks was to report trading data to the Trade Press; this was viewed as bothersome but necessary. Often it was a job given to the newest employee. Many companies report passing around a form or using a spreadsheet on a shared drive. The last person who filled out the form or spreadsheet may have been required to total the numbers and send them to the Trade Press. There was nothing to stop a trader from changing the numbers someone else had entered. In other cases, traders took an oral “survey” to get a sense of where the market was trading. Sometimes they represented it to the Trade Press as an actual survey, but in other cases they made up trades to average out to a number that was consistent with this “survey.”

Although *Inside FERC* did have a spreadsheet and requested data on fixed-price deals transacted during bid week only, it is clear that the companies were reporting a combination of fixed-price deals during bid week, trades observed on EOL, and trades they made up to reach a predetermined average.

The process for reporting daily prices was more chaotic than the process for the monthly indices. Again, the responses show that traders reported some combination of actual trades, trades they observed, and trades they made up. Some traders reported a range of prices and some reported an average. Sometimes the average was volume weighted; at

²⁰BP Energy is a notable exception. It is clear from BP’s response to the Staff data request that it recognized the influence a significant trader such as itself could have on the published indices. BP put internal controls in place to ensure the accuracy of the reported data and employed a system of accountability for the trading desk heads.

other times it was the simple average of the high and low trades. Some traders received phone calls, some called the Trade Press, and some faxed prices and volumes. Staff inspection of the faxes shows that there was no standardization of the data reported to the Trade Press. In some cases volumes and average prices were reported, some had individual trades, some showed basis differentials, and some were financial rather than physical deals. Because most of the reporting was done by phone, there are significant barriers to finding out what the traders actually reported to the Trade Press. As with *Inside FERC*, the editors of *Gas Daily* assert First Amendment protection, so there is no way to ascertain what they were told and their awareness of the extent of the manipulation. Moreover, the companies themselves were unable to re-create their daily reporting because (1) it was done by phone and the phone calls were not always recorded (even if they were recorded, it would take thousands of hours to listen to the recorded calls) and (2) the Trade Press denied companies' requests for their own data, citing confidentiality and First Amendment protection.

In short, the responses indicate that the reported price indices were based on data that were confusing, inaccurate, misleading, and often false. Staff concludes that an accurate index could not have resulted from the data that were reported. In addition, because the Trade Press has not revealed their data, there is no way to verify the accuracy of the reported indices by comparing them with the data reported to the Trade Press.

Staff Attempts To Verify the Accuracy of the Reported Indices

As part of the investigation, Staff attempted to verify the accuracy of the reported price indices; however, there have been significant barriers to this process. First, in many cases the companies cannot reproduce the data they reported to the Trade Press for the reasons described above: daily reporting was done by phone, often on unrecorded lines; many traders reported their own trades along with those they observed in the market; and records of the reported data were not maintained because there was no formal process for reporting the data. In addition, the Trade Press has not revealed the data used to calculate the indices.

One of the issues that became apparent to Staff while investigating Enron and other energy traders is that they lack many business records that are essential when investigating allegations regarding trading activities. Because the companies have argued that their trading

activities are not jurisdictional to FERC, CFTC, or SEC, many fail to keep records that would be required of a regulated company. For example, maintenance of phone tape recordings can be haphazard at these companies. Staff found evidence indicating that Enron had received a legal opinion finding that their 4-month tape retention policy was not in compliance with FERC regulations. During the same time that Enron received this finding, they were reducing their retention to 30 days. Although the retention of phone tapes in the power industry is an accepted practice, the length of retention varies. Specifically, the lack of record keeping, especially recorded telephone conversations, made it difficult and, in some cases, impossible to verify the data provided by the companies to the Trade Press.

As described earlier in this chapter, Staff analyzed the trading data of six major gas purchasers in California and compared them to the published price indices. The analysis uses data submitted under Docket No. EL00-95 by David Reishus and Patrick Wang of Lexecon Inc. on behalf of five companies involved in that proceeding (Duke, Dynegy, Mirant, Reliant, and Williams). The database they used included spot transactions from six companies: Coral, Duke, Dynegy, Mirant, Reliant, and Williams. Staff found that for those six companies during that period, their fixed-price purchases were systematically lower than the published index prices (which are supposed to be based on that type of transaction only).²¹

Industrywide Reporting Issues

As described in the Initial Report, the industry relies on both daily and monthly natural gas price indices. The monthly price indices are based on fixed-price transactions occurring during bid week. During the course of the investigation, it became clear to Staff that transactions occurring during bid week do not give an accurate picture of the monthly natural gas trading activity. A number of large traders (e.g., Dynegy, AEP, and Williams) stated that they did very little fixed-price trading during bid week. They stated that they mainly traded indexed contracts or small fixed-price deals designed to fine tune their physical and/or financial positions for the month. Data provided from the large natural gas traders and marketers confirm this position. In fact, traders said that one of the reasons they fabricated the prices and volumes they provided to the Trade Press was that they had very few trades during bid week and they wanted to reflect their actual trading activity for the month. Another problem with reporting bid-week trades only is that

²¹See Table III-2 on page III-17.

the market is quite thin during this period; that is, there are fewer buyers and sellers (at least for fixed-price deals). Therefore, even if prices for trades made during bid week were reported accurately, those prices do not necessarily reflect competitive market prices.

The Testimony of Michele Markey

On November 18, 2002, Michele Markey testified before the State of California Senate Select Committee to Investigate Price Manipulation of the Wholesale Energy Market. According to her testimony, from May 1998 to September 2001 Ms. Markey was in charge of the gas price and electric price teams that gathered information from the industry for publishing the price indices in *Gas Daily* and *Megawatt Daily*. From her experience as a trader and her work at Financial Times Energy and Platts,²² Ms. Markey described the energy trading process, the data gathering process at the daily and monthly publications, and the perception in the marketplace of the published price indices; she also gave examples of how an index could be manipulated. When asked by Senator Dunn if, in her opinion, it was common practice in the industry to exaggerate the prices reported to the indices, she replied: “It was common industry knowledge that exaggeration was part of the process.”²³

One of the subjects Ms. Markey addressed was that traders understood that if the prices they reported were too far out of line with real prices, they would be thrown out by the editors of the price indices. Therefore, traders would report trades that favored their positions but were within the range of actual trading. She explained that because the indices were weighted averages, traders could manipulate the index by reporting inflated volumes at prices that favored their positions:

Common practice was to exaggerate your transactions to the price reporters, report more volume, report a higher price than that was actually transacted. You stretched your price in favor of what the company’s position was, or don’t report at all, because you would know whether or not your indices—your volume and price could in fact affect the index.²⁴

Ms. Markey also discussed a proposal by Enron for *Gas Daily* to create an electronic platform price index. The index was designed to

²²Ms. Markey also worked as a West desk trader for Reliant prior to her employment with Financial Times and Platts. At the time it was called Noram Energy Services.

²³Markey testimony at 13.

²⁴Markey testimony at 15.

capture all trading on electronic platforms, but ultimately captured only Enron. She testified that:

In effect, Enron gave us the methodology and dictated to us how that price index was going to be calculated. And we set it up basically at their request.²⁵

In the summer of 2001, Ms. Markey proposed that *Gas Daily* (owned by Financial Times Energy at that time) audit the data from EOL in order to ensure its accuracy. She stated that a number of energy traders complained that Enron was manipulating prices through EOL. She arranged for Price-Waterhouse-Cooper to audit the data and the contract was ready to be signed; however, in August 2001, the plan was abandoned when Platts purchased *Gas Daily*. Therefore, there was no audit of the Enron data.

On November 19, 2002, the president of Platts, Harry Sachinis, issued a statement in response to Ms. Markey's claims. Mr. Sachinis explained why Platts had rejected her proposal to publish an EOL price index and to audit the data from EOL:

Michele Markey, who worked for Platts for only six months, implied that we quashed a suggestion to audit questionable trading data supplied by Enron because Enron was a Platts customer. This is completely false. In fact, Platts chose not to pursue Ms. Markey's auditing proposal because publishing an index based on Enron Online trading data would have little if any value to subscribers. Platts had previously declined requests by Enron to publish such an index. Platts believes that an index based on a single company's trades would be unreliable and subject to manipulation, whether audited or not.²⁶

The Effect of Enron and EOL on the Published Price Indices

The issues discussed by Ms. Markey are related to some of the concerns raised by Staff in the Initial Report regarding the influence of EOL on the published price indices. As stated in the Initial Report, EOL was a significant source of price discovery in the natural gas markets. The responses to the data request confirm that many traders looked at EOL to observe market conditions. In fact, many traders

²⁵Markey testimony at 39.

²⁶Platts response to Markey, November 19, 2002.

actually reported trades they observed on EOL to the Trade Press; some of those traders misrepresented those trades as transactions they had made themselves. As described in this Report, EOL was a one-to-many trading platform, i.e., the Enron market maker was on one side of every trade done on EOL. The market maker established the bid and ask prices and profited from the spread between the two. In addition, the market maker had information superior to the rest of the market and had the ability to influence the price. By posting the bid and ask prices for a particular location at a given price, an Enron trader would have a greater likelihood of affecting the index price at any point traded on EOL than any other single trader. Thus, trades made on EOL could be fed into a particular index over and over, as other traders were reporting what they observed on EOL to the Trade Press. Some of the traders that attempted to manipulate the indices said that they were doing so in order to offset Enron's perceived dominance at particular trading points, particularly at Topock on the California border.

Ms. Markey proposed publishing an EOL price index and auditing Enron's reporting practices. As argued by Platts' president Harry Sachinis:

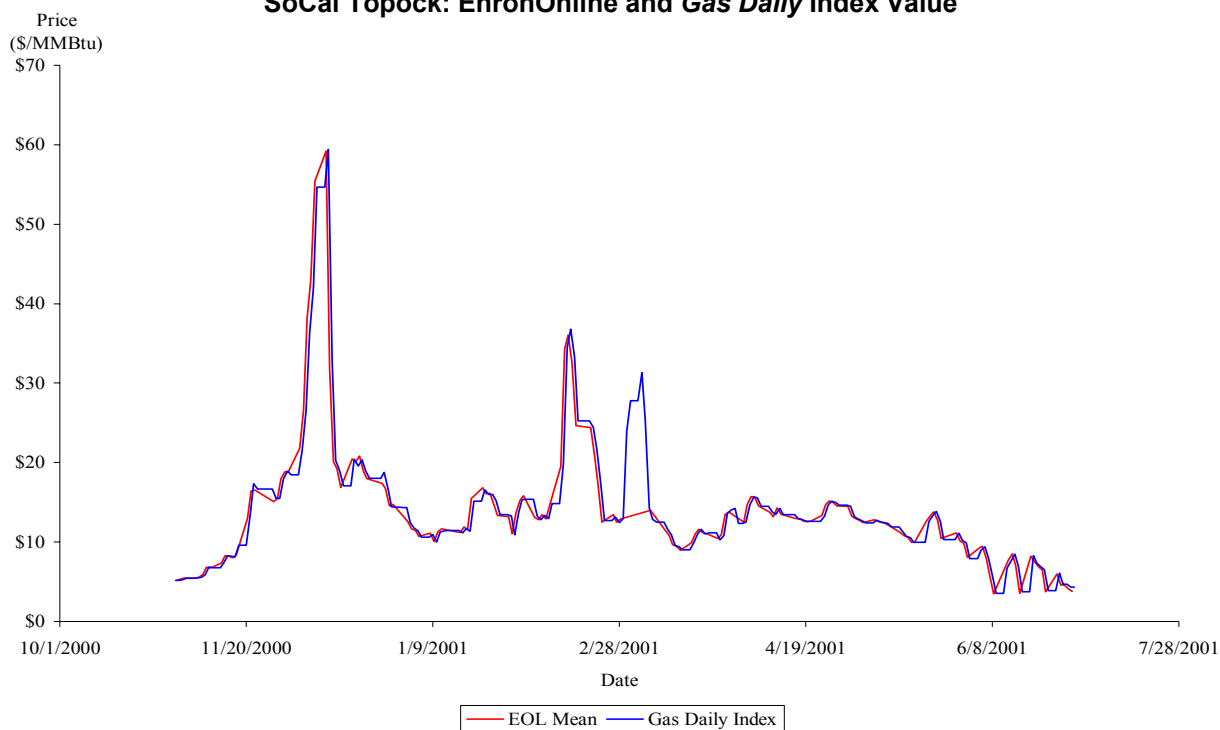
Platts chose not to pursue Ms. Markey's auditing proposal because publishing an index based on EnronOnline trading data would have little if any value to subscribers. Platts had previously declined requests by Enron to publish such an index. Platts believes that an index based on a single company's trades would be unreliable and subject to manipulation, whether audited or not.

Staff agrees with Mr. Sachinis's conclusion that an index based on a single company's trades would be unreliable and subject to manipulation. The facts uncovered in this investigation indicate that EOL had an undue influence on the published indices, especially the SoCal Topock *Gas Daily* Index. Those facts are as follows:

1. A large percentage of the legitimate trading for SoCal Topock took place on EOL.
2. Much of the trading for SoCal Topock on EOL was between Enron and one counterparty, Reliant, which had a "netting arrangement" with Enron; this arrangement created the incentive to "churn" (see Chapter II) natural gas on EOL. Only Enron and the Reliant trader knew of the netting arrangement.
3. Many traders reported trades they observed on EOL. Some traders misrepresented those trades as their own transactions.

4. Traders used EOL for price discovery, so the price of off-EOL trades was influenced by EOL.

Figure III-1
SoCal Topock: EnronOnline and Gas Daily Index Value



As shown in Figure III-1, the *Gas Daily* price almost perfectly tracks the EOL price. In the Initial Report, Staff focused on one trading day, January 31, 2001. On that day, total trading volume at southern California Topock reported to *Gas Daily* was 6,766,000 MMBtu, which was the busiest trading point for that day. The total volume on EOL for next-day Topock gas for the day was 2,240,000 MMBtu. At the time of the Initial Report, Staff did not know the extent to which the reporting of trading volume was manipulated by the traders. The total volume of trading on EOL for the day (2,240,000 MMBtu) is actual trading verified by Staff. The total volume reported by *Gas Daily* (6,766,000 MMBtu) cannot be verified because *Gas Daily* has not revealed its data. Moreover, as described above, most companies spoke to *Gas Daily*'s editors over the phone and did not keep records of what they reported. Staff suspects that of the 6,766,000 MMBtu reported by *Gas Daily*, much of it was based on trades observed on EOL in addition to the actual trades made on EOL. Finally, as noted in the Initial Report and discussed in Chapter II, more than 75 percent of the trading on EOL that day was with one trader from Reliant. Thus, the volume reported and the observed activity on EOL give the illusion of a much more liquid market than was actually present.

As described in detail in Chapter II, the anomalous trading behavior on EOL would influence the index price because the index price was a volume-weighted average.²⁷ That is, even if the price returned to where it was before a flurry of buying and selling (churning), the volume-weighted average would increase because all of the buys and sells occurring during the churning were taking place at a higher price. The fact that numerous market participants were reporting what they saw on EOL only intensifies this effect.

In addition, as described in detail in Chapter IX, Staff has identified a case in which Enron traders used EOL to manipulate the Henry Hub market price. In the July 19, 2001 manipulation, the Enron market maker aggressively bought natural gas at Henry Hub to drive up the price, then aggressively sold the gas, driving the price back down, while his partners in the scheme made huge profits in financial derivative products by selling short when the price was rising, knowing that it would soon fall. Even though the price returned to its premanipulation level once the scheme was complete, the manipulation affected the index price because it is a volume-weighted average. The manipulation induced a price run-up and an ensuing fall. The trades that took place during the manipulation were all above the pre- and postmanipulation price level, thus bringing up the average. Again, the fact that numerous market participants were reporting what they saw on EOL intensified this effect.

The index prices also fed back into southern California natural gas market performance through the gas imbalance penalties on the SoCalGas system. As described in Chapter II, the penalties for imbalances on the SoCalGas system were 150 percent of the highest daily border price index at the Southern California Border for the month the imbalance is created. The highest daily border price index is an average of the prices from NGI's "Daily Gas Price Index—Southern California Average" and the *Gas Daily* "Daily Price Survey—SoCal Large Packages Midpoint Price." Therefore, a higher index price would increase the imbalance penalty, which would in turn increase the price buyers were willing to pay for gas in order to avoid the penalty.

Staff concludes that all of the concerns expressed in the Initial Report have been confirmed. These concerns include the following:

²⁷See Chapter II, Reliant's Churning Raised the Index Prices, page II-30.

- ◆ The Commission cannot independently verify the published price data.
- ◆ Undetected errors may exist because trade publications reporting spot and forward prices do not employ statistically valid sampling procedures or a systematic, formal verification procedure.
- ◆ Market participants have significant incentives to manipulate spot market prices reported to the reporting firms because natural gas is the fuel input for the electricity generators that set the market price in California.
- ◆ Wash trades may have an adverse effect on reported price data.
- ◆ EOL was a significant source of price discovery and formation and was potentially susceptible to manipulation by market participants, which could affect the published price indices.

Moreover, systematic attempts to manipulate the published price indices by various significant market participants occurred for at least 4 years. Because of these events, some companies have stopped reporting trading data to the Trade Press;²⁸ many companies have left the trading business;²⁹ Dynegy settled with the CFTC for attempted price manipulation and other violations of the Commodity Futures Trading Act; some traders have been indicted on Federal criminal charges;³⁰ and AEP has been the subject of a class-action lawsuit.

On the positive side, there has been a movement within the industry to fundamentally reform the price reporting process. Suggestions for reform and tangible reforms have come from market participants, risk officers, the trade publications themselves, new entrants into the price reporting business, government agencies, consumer groups, and others.

On January 15, 2003, Commission Staff from the Office of Market Oversight and Investigation (OMOI) reported concerns regarding price index formation to the Commission at its public meeting. Staff explained the Commission's interest in price index formation, reviewed the public evidence that raised questions about it, defined the high-level criteria that are important to developing trustworthy price information in the future, and proposed some next steps.

OMOI Staff proposed that in the future, the Commission should require that natural gas price indices meet certain minimum requirements before natural gas pipelines are permitted to use the

²⁸For example, BP Energy, El Paso, Reliant, Williams, Constellation, and PP&L.

²⁹For example, Aquila Marketing Services and CMS.

³⁰See El Paso and Dynegy.

indices in new tariffs or for other new regulatory purposes. Staff proposed that evidence for these new filings would need to be presented and reviewed to ensure that any referenced price index meets minimum index formation standards. In particular, the index would need to accurately reflect the market. For approval, a new tariff containing a reference to an index would need to demonstrate:

1. Confidence in the accuracy of price reporting—that is, the ability to verify that reporting is for deals actually done, not simply aggregate options.
2. Adequacy of coverage—that is, the ability to ensure the collection of adequate information to represent prices across the relevant marketplace.
3. Information about market liquidity or some insight into how much trading is going on a particular point in order to generate warnings when markets are thin and confidence when they are liquid.
4. Verifiability—that is, the ability to ensure integrity of the process through independent review by a trustworthy third party (preferably not a government entity).³¹

Reform of the Price Reporting Process

Company Changes

Most of the companies involved in natural gas trading and marketing have implemented or are in the process of implementing new procedures for reporting trading information to the Trade Press. Specifically, many companies are moving the data reporting process away from the trading desks to the risk management office. In addition, companies are using their IT systems to capture the relevant data and send it directly to the risk management office. For example, Duke's new policy is as follows:

Transactions are captured in DETM's trading systems. System queries have been developed to extract the relevant third-party physical transactions from the source systems and generate a report. The report contains the location, price, and volume for each transaction. The mid-office receives the electronic report and reviews the data. The transactions that are submitted to the publications are validated through a combination of confirmation and trade validation control

³¹FERC OMOI Staff Report. 2003 Natural Gas Market Assessment.

procedures. These procedures will ensure that only information about actual transactions entered into with third parties will be provided to the Trade Press publications.³²

As noted above, many other trading companies (including Mirant, AEP, and Dynegy) are adopting similar procedures. Staff finds that the revised process for reporting the relevant trade data to the Trade Press is a significant improvement that gives credibility to the data and that it is in stark contrast to the nearly universally haphazard reporting that took place in the past.

In addition, many companies (including PP&L, BP Energy, El Paso, Reliant, Williams, CMS, and Constellation) have stopped reporting trading data to the Trade Press. This is an understandable reaction given the chaos in the industry and the legal issues facing firms that have already admitted to providing false information and those that are still investigating or are the subject of investigations as to whether they provided false information. Because the indices for commercial transactions are very important, procedures must be put in place to ensure the accuracy of the indices and to encourage (or require) all market participants to provide complete and accurate data. Staff recommends that a process for establishing standards for price reporting be established by the Commission, with input and cooperation from the energy industry and the price reporting firms. In addition, other government agencies (such as the CFTC and the Energy Information Administration) should be involved in the process. Significant progress has been made in this area since the issue regarding the accuracy of the reported indices became a subject of this investigation.

Proposal of the Committee of Chief Risk Officers

As described above, in many cases the reporting function is being moved to the companies' risk management offices. On November 19, 2002, the Committee of Chief Risk Officers (CCRO) (representing 31 energy companies) announced that it is examining how companies submit price data and what type of data are submitted and that it hopes to develop a "transparent and robust methodology" that will maintain confidentiality.

On December 4, 2002, the CCRO met with the publishers of energy price indices to discuss the attributes of credible market price indices

³²Letter to Donald Gelinas, Associate Director, Office of Markets, Tariffs, and Rates, from Mark Perlis, Counsel to Duke Energy Trading and Marketing L.L.C., under Docket No. PA02-2, November 8, 2002.

for energy transactions. The forum was open to all companies currently publishing indices for the North American energy market. The CCRO stated that “[l]eaders of the Committee’s Market Price Indices Working Group embarked on this task amid questions about how price indices for natural gas and electricity transactions have been, and are being, tabulated.” The CCRO further stated that it “intends to consider information and points of view provided by the publishers’ representatives to help produce draft recommendations that will lead to credible, sustainable price indices in the coming weeks.”³³

On February 27, 2003, the CCRO released its Best Practices for Energy Price Indices white paper. The CCRO white paper includes recommendations for data gathering and submission procedures, index construction processes and methodology, and necessary contractual arrangements to facilitate the recommended changes on the part of both the companies supplying market information and any entity publishing energy price indices. The white paper also recommends a formal auditing process for both the energy companies providing data and the companies publishing price indices.

Data Gathering and Submission

The CCRO recommends that data providers supply index developers with these and other data points about each trade, every day they trade:

- ◆ Buy or sell indicator.
- ◆ Volume of energy involved.
- ◆ Flow date(s) of the energy transaction.
- ◆ Location of delivery points.
- ◆ Price.
- ◆ Any exchange or clearinghouse involved.
- ◆ Date the transaction was executed.
- ◆ Counterparty.

Index Construction Process and Methodology

The CCRO has the following recommendations for index publications:

- ◆ Index developers should implement robust IT and data security protections against data misuse by employees.
- ◆ Index developers should publish the index methodology, including defining (1) a sufficient sample size for normal creation of an

³³December 2, 2002 press release: Committee of Chief Risk Officers Plans Forum to Discuss Energy Price Indices.

index and (2) the process for determining an index value where there are insufficient data.

- ◆ Index developers should ensure that the “strictest standards of care” will be maintained over commercially sensitive data. The paper also recommends that index developers audit their processes annually.

Contractual Arrangements

The CCRO recommends that before the information described above is provided, contracts should be drawn up and amended between counterparties to protect the confidentiality of the data. The CCRO encouraged data providers and index developers to sign an agreement that, among other things:

- ◆ Commits each party to a specific data-reporting protocol.
- ◆ Protects the confidentiality of the data.
- ◆ Prohibits the use of data beyond constructing an index.

The CCRO recommended that counterparty information should be submitted only after:

- ◆ Each individual with access to the data at the index developer signs a clear-cut, enforceable confidentiality agreement.
- ◆ Any index produced by a publishing organization is separated from any news-gathering operations by a verifiable and auditable “Chinese wall.”

Auditing Process

The white paper recommends a formal auditing process for both the energy companies providing data and the companies publishing price indices.

The CCRO recommends that independent audits be conducted by each company publishing indices at its expense at least annually to determine the following:

- ◆ The data are properly collected and stored in compliance with all contractual arrangements with data providers, including confidentiality arrangements. Specifically, the data are properly protected from release and misuse at all levels.
- ◆ The methodology established and published by the index developer is the same as that used to calculate and publish the actual index.

- ◆ The methodology established and published by the index developer satisfies the attribute of robustness as defined by the index developer in accordance with the principles in this white paper.
- ◆ Periodic tests are conducted to verify that the process used to derive published indices is accurate, objective, and reliable.

The CCRO also recommends a formal auditing procedure for the companies submitting data for index publication:

An independent (internal or external) audit group should review the data gathering and submission process at least annually, verifying the proper implementation of and adherence to the data gathering and submission process that the company has established. This audit should be conducted at the expense of the data provider by a qualified individual, i.e., Certified Public Accountant or Certified Internal Auditor. The pass/fail results of the audit should be made available to the index developers upon request. In the event of a failed audit, the data provider should be able to reaudit once appropriate process changes are made.

Staff commends the CCRO on its efforts to reform the index price reporting process. Although the CCRO white paper is a recommendation for best practices and not a binding commitment by its member companies, it addresses the fundamental problems in the process and provides feasible solutions. The necessary data to compile an accurate and reliable index identified by the CCRO are nearly identical to those proposed by Staff later in this chapter.³⁴

The CCRO paper has directly addressed the critical pieces of information for ensuring an accurate index: providing the counterparty and buy/sell information for every trade. The paper recognizes the commercial sensitivity of such information, but proposes amending existing energy contracts to allow for its provision, provided the confidentiality is preserved by the index publishers through explicit contracts. As discussed throughout this chapter, without the ability to cross-check reported prices and volumes, the published indices will not be reliable. As noted by Platts in its February 10, 2003 call to action:

³⁴It is Staff's position that one critical piece of information missing from the CCRO proposal is the time stamp of when the transaction was made. Staff understands this to be an IT issue that could be worked out. The time stamp would further aid in cross-checking transactions and assessing whether an outlier should be rejected (since prices may move significantly within a day of trading) when calculating a price index.

Information on counterparties, buy/sell indicators and time stamps is critical to the process of verifying data. This information will help Platts in its efforts to confirm such data characteristics as completeness (by enabling publishers to detect a provider's omission of certain deals) and accuracy, and it will serve as a check against double counting. In fact, counterparty information is one of the best means for publishers to identify inaccurate or, indeed, fictional transactions. The industry should make the provision of counterparty names a top priority and resolve confidentiality or other issues that some companies say prevent them from providing that information.

It is Staff's position that if both the index publisher and all of the energy companies providing data followed the best practices described in the CCRO paper, the resulting index would meet the standards proposed by Staff for an index that can be used for Commission-jurisdictional transactions. Staff recognizes that the CCRO cannot, nor does it attempt to, make its recommendations mandatory. Staff commends the CCRO on putting forth a serious proposal that is already part of the discussion on fixing the energy indices and will continue to be part of the solution. As discussed in the "Staff Recommendation to the Commission," many of the best practices described by the CCRO are the same as those Staff recommends be made mandatory for Commission-jurisdictional companies.

Changes by the Trade Press in the Price Index Methodologies

In the Initial Report, Staff noted that the Trade Press announced changes to its data gathering procedures in order to improve the accuracy of the reported indices. In addition, the Trade Press has continued with those efforts since the Initial Report was issued.

Platts

In the Initial Report, Staff noted that Platts had proposed refinements to its power market methodology.³⁵ On September 2, 2002, Platts proposed refinements to its natural gas price index methodology. Those changes included the following:

To improve the quality of information it receives for each transaction, Platts will be asking market participants to provide quantity and price, the name of the counterparty, whether the reporting company was the

³⁵Initial Report at p. 37 (fn 44).

buyer or seller, and the time at which the transaction was completed. Currently, Platts obtains these data from some (but not all) market participants. Platts also is considering other refinements to increase the quality of its gas pricing data and welcomes industry input before any changes are made. Changes under consideration include the following:

- ◆ Using physical basis transactions in its monthly surveys. Basis deals transacted during the last 3 days of trading of the near-month NYMEX gas futures contract would be included with fixed-price physical deals. Among other things, Platts solicits input on whether physical basis transactions generally are compatible with fixed-price deals in some regional markets but not others.
- ◆ Requiring the signature of a senior company official to verify the accuracy of price data submitted to Platts.
- ◆ Obtaining data from back offices rather than trading desks.³⁶

On October 28, 2002, Platts announced that it was adopting steps to strengthen the price survey of the U.S. electricity markets and that it was making similar changes to its methodology for natural gas indexes and assessments.³⁷

On February 10, 2003, Platts published a statement on its views of the necessary reforms in the price index reporting process, *Market Reporting in North American Natural Gas and Electricity—Recommendations for Restoring Trust and Transparency: A Call To Action*. Platts made the following recommendations:

- ◆ Market participants should provide data from a central source in a mid- or back-office operation that would have the responsibility for confirming the accuracy and completeness of the data provided to price-reporting organizations such as Platts.
- ◆ Market participants should submit detailed transactional level data—not aggregated data.
- ◆ Market participants should provide counterparty information for each transaction reported. The naming of counterparties offers an important check for verifying the completeness and accuracy of trade data.
- ◆ Market participants should provide written certification from a senior level official, such as a chief risk officer, attesting to the accuracy and completeness of the information reported to publishers. This certification would be renewed periodically.

³⁶*Gas Daily*, Proposed Refinements To US Gas Price Methodology (September 2, 2002).

³⁷*Megawatt Daily*, October 28, 2002.

- ◆ Market participants should understand that these measures and others noted below can only serve to re-establish confidence and credibility in price reporting on the North American gas and electricity markets.

Platts described the high-quality data that it is seeking from market participants in order to ensure accurate price indices:

In North America, Platts is asking electricity market participants to provide for each transaction the delivery location, trade date, start flow date, end flow date, peak or off-peak, physical or financial, price (\$/MWh), volume (MW), transaction time, buy or sell indicator, and counterparty. In the gas market, Platts asks market participants to provide for each transaction the delivery location, the trade date, flow date, price (\$/MMBtu), volume (Mcf), and counterparty, and to state whether the deal is fixed-price physical or basis and whether it is a buy or sell transaction.³⁸

Platts further described the need for critical pieces of information such as counterparties to each trade:

Information on counterparties, buy/sell indicators and time stamps is critical to the process of verifying data. This information will help Platts in its efforts to confirm such data characteristics as completeness (by enabling publishers to detect a provider's omission of certain deals) and accuracy, and it will serve as a check against double counting. In fact, counterparty information is one of the best means for publishers to identify inaccurate or, indeed, fictional transactions. The industry should make the provision of counterparty names a top priority and resolve confidentiality or other issues that some companies say prevent them from providing that information.

Moreover, additional information such as counterparty names, buy/sell indicators and time stamps may well be useful to determine a market price and to produce better benchmarks in relatively illiquid markets or during unusual trading conditions when markets are under stress.³⁹

³⁸*Market Reporting in North American Natural Gas and Electricity—Recommendations for Restoring Trust and Transparency: A Call To Action.*

³⁹Id.

Platts acknowledged that, due to the decline in energy trading and the fact that some companies have ceased reporting trade data to the Trade Press, at some trading points there is very little data from which to construct an index:

Some US gas and electricity pricing points currently are showing little or even no trading. Platts editors can use their experience to assess the representative prices at which limited trading did occur or, in the absence of trades, would have occurred.

Platts is committed to providing as much transparency as possible on how such assessments are made and what method is used to produce a given price. In US gas markets in recent months, Platts has used its traditional index methods for trading points that are sufficiently liquid and a broader assessment process when we have concluded that transactional data alone provides an insufficient base for analysis. Once the market shows signs of stabilizing, Platts will provide a clear statement on how it intends to assess US gas markets in the longer term.⁴⁰

Platts recognizes the value of showing the degree of liquidity in the markets for which it publishes price indices and states that it is currently publishing the total trading volume for some of its indices and is moving toward publishing volumes for more of its price indices:

Platts agrees with those who assert that the degree of liquidity of a given market should be disclosed by publishers in some fashion. It already provides information on liquidity for many of its US gas and electric benchmarks, and is moving toward expanding the provision of that type of information. While volumetric information may be subject to misinterpretation or may even encourage attempts to manipulate markets, Platts is committed to providing a window on the depth of the trading points it covers.⁴¹

NGI

On September 16, 2002, NGI announced that it was proposing modifications to its index price methodology for both its daily and weekly indices. The proposed modifications were designed to increase

⁴⁰Id.

⁴¹Id.

the accuracy of the reported indices and more accurately reflect the way market participants are doing business. Specifically, NGI recognized the move away from negotiated fixed-price deals during bid week toward basis trading for the monthly market. NGI also stated that for several years they have been aware that some portion of the deals reported to them as fixed price have, in fact, been physical basis transactions that it has struggled to identify and remove from its calculations.

NGI proposed including the basis deals in the index and offered two suggestions for doing so: (1) the basis trades would include physical basis deals done during the last 3 days of the NYMEX trading before the near-month contract expires or (2) the basis trades would only include quotes from the last day of trading or the settlement day.

In addition, NGI asked its survey participants to report, wherever possible, counterparty information on baseload transactions and the date and/or time of the transaction (in addition to price and quantity). NGI states that the counterparty and time/date information helps them verify that reported transactions meet their survey criteria and helps to resolve questions regarding the veracity of certain data when outliers in the data are encountered. Moreover, NGI stated that a large portion of reporting companies were currently including counterparty and or date/time information.

IntercontinentalExchange

ICE is now computing indices, especially for next-day products, based on a volume-weighted average of the complete set of trades on its platform. This provides a way to avoid the sampling bias, manipulation, and verification problems associated with conventional energy indices constructed by the Trade Press and suggests that it is feasible to impose standards on indices to ensure their objectivity. In fact, ICE is encouraging the creation of swap contracts based on its next-day gas and power indices (“ICE swaps”). ICE has retained Ernst and Young, LLP to audit its procedures and verify to the marketplace the integrity of its process.

In October 2002, ICE announced the formation of the 10x Group, which publishes electricity and natural gas price indices directly from trades on the ICE platform. In addition, ICE has added a trade confirmation process, eConfirm, which has the ability to confirm trades conducted at over 100 over-the-counter brokerages and trading arenas. ICE describes the system as follows:

The eConfirm system matches a participant's trade data to its counter party's data to execute confirmations and identify discrepancies in real time, contrasting to the manual method of confirming trades and reconciling voice broker invoices which may typically take days or weeks. eConfirm matched trades are considered to be legally binding under identical Intercontinental participant agreements that counter parties must execute in order to be active on the system.⁴²

ICE states that as of February 19, 2003, there were 28 energy companies using eConfirm and those companies had used eConfirm to confirm more than 75,000 trades occurring at 49 different brokers and execution venues. Along with the trades made over the ICE platform, those trades confirmed by the eConfirm system are used in the calculation of the 10x published price indices. In addition, ICE announced an agreement with Prebon (a large energy product voice broker) in which Prebon will use the eConfirm system for all of its energy trades, and those trades will be included in the database used in calculating ICE's price indices.

In short, ICE (through its 10x subsidiary) is in the process of constructing price indices that are based solely on actual, verifiable trades from its platform or through its confirmation process. Moreover, with the agreement of a major voice broker to use ICE's confirmation system, the volume of trades reflected in its published indices is increasing. Staff is encouraged by this development and sees it as an important part of the necessary reforms to the price index reporting process.

Staff Reaction to the Proposed Changes

Staff commended the Trade Press's efforts to increase the accuracy of the indices included in the Initial Report. The further revisions to the process for reporting trade data are also positive developments. Combined with the establishment of internal controls on the part of the companies providing data to the Trade Press, the entire process has improved significantly. It is Staff's position, however, that the process is fundamentally flawed because the Trade Press data are still not subject to independent verification. In order for the published indices to be reliable, there must be a way to audit the entire information chain. The chain consists of (1) the actual trades, (2) the data provided by the companies to the reporting firms, (3) the data used by the

⁴²IntercontinentalExchange press release, February 19, 2003.

reporting firms to calculate the indices, and (4) the method for calculating the indices.

As discussed in the Initial Report, the Trade Press has been willing to describe its methodology for calculating the prices despite its unwillingness to make the data available to Staff or anyone else for auditing. Combined with the industry changes in the data reporting process and the Commission's data filing requirements, three of the four components of the information chain (the actual trades, the data provided by the companies to the reporting firms, and the method for calculating the indices) could be audited. However, as long as the companies publishing the indices continue to refuse to disclose the actual calculations of the published price indices, the information chain cannot be audited and the Commission cannot verify the accuracy of the published indices. Therefore, Staff recommends that only price indices calculated from actual trades that can be verified by the Commission should be used as the basis for any Commission-approved sales of natural gas or electricity.

Future Index Reporting

As noted throughout this chapter, there have been significant improvements in the price-reporting process on both sides. Companies have moved the trade data reporting function to the risk management offices. The trading data flow directly from the companies' deal-capture system to the risk management office, and the accuracy of the data submitted to the Trade Press is verified and certified by the chief risk officer. The Trade Press is now requiring counterparty information for all data they receive to ensure the validity of the data and the accuracy of the published price indices. The Trade Press has long held the position that this is necessary, and Staff strongly agrees. Electronic platforms such as ICE have begun publishing indices based on trades coming directly from the platform.

It is important for index construction to be objective and address the fundamental problems that have been identified. The problems of sampling bias, manipulation, and verification are not inherently difficult and can be overcome with a fresh perspective and at a relatively modest cost.

A variety of trading systems exist, including electronic platforms, voice brokers, hybrid markets, and trading floors. However, in all of these designs it is feasible to compute the average price over a specified period of time. There is no reason for prices to reflect the impression of individual traders. Instead, they should reflect the reality

of the actual trades. The approach taken by ICE to compute its indices by providing the volume-weighted average execution price for the specified period applies not only to ICE and other electronic platforms, but also to individual voice brokers, hybrid markets (a combination of a voice broker and an electronic platform), and even trading floors. This raises the question of how to enforce these standards.

Any marketer or broker could be required by “anti-fraud” regulations or legislation to provide accurate index information (such as average prices and volume). This should be a basic requirement for a market center such as a trading platform, broker, or trading floor. Although not all market contexts have such reporting requirements (e.g., foreign exchange trading does not have these restrictions), they are important for domestic energy markets in light of the extent of reliance on index prices for pricing physical flows and the small number of market participants for many products (which leads to the potential for market manipulation). Similarly, our discussion of (ex post) transparency in Chapter IX emphasized the value of requiring timely trade reports; this could be enforced by requiring that these reports be subject to appropriate anti-fraud standards. The data and informational requirements for trade reporting are much stronger than those for index reporting, which is actually an aggregate form of trade reporting.

Services that purport to measure index prices across platforms or voice brokers should be governed by the same anti-fraud rules. Acceptable indices in this context should also provide appropriate volume-weighted averages to aggregate across portions of the marketplace. The computation of such measures would require average prices and volumes from those markets and/or brokers, whose prices are included in the benchmark.

This raises the question about whether reasonable indices could be computed solely from a single online platform or two (such as ICE and TradeSpark) with an automated computational process. Because such an index would only reflect online transactions, it would not reflect all of the buying and selling of a particular product. Staff recognizes that in a perfectly functioning market, arbitrage would drive the prices between on- and off-line exchanges together. However, Staff has learned from this investigation that energy markets are not always perfectly functioning. As such, the ideal index should capture as much of the entire universe of trades as possible. Along that line, as discussed earlier in this chapter, at least one online exchange has entered into an agreement with a major voice broker that would include the broker’s transactions in its price index.

**Staff Recommendations to
the Commission**

Staff makes the following recommendations for the Commission to consider regarding the characteristics of any future published price indices and Commission action to ensure the accuracy and integrity of price indices:

1. Any company publishing price indices to be used as a basis for Commission-jurisdictional transactions, e.g., natural gas pipeline balancing or market-based electricity pricing, should be subject to audit by the Commission to ensure the accuracy of the data going in and the calculations themselves. That is, an index that meets the requirements established by the Commission for use in Commission-jurisdictional transactions would have the Commission's seal of approval. All data used in the index calculation, including data that are thrown out (e.g., outliers, questionable reported trades, trades reported without counterparty verification), should be available to the Commission. In the Initial Report, Staff described the verification, auditing, and oversight procedures associated with NYMEX energy trading. Staff suggests that these procedures should serve as a model for price index reporting in the future. The characteristics of NYMEX and its price index calculations are as follows:

- ◆ NYMEX is an organized exchange subject to CFTC regulation.
- ◆ NYMEX is required by the CFTC to maintain and enforce an internal auditing mechanism and to maintain records of trading activity so a clear audit trail is possible.
- ◆ NYMEX is required to conduct, with CFTC oversight, market surveillance and trade surveillance designed to prevent market manipulation and other anti-competitive activity.
- ◆ The Futures Trading Practices Act requires that trade information be submitted to NYMEX and time-stamped within 1 minute of a trade. NYMEX requires its traders to use a special trading pad that provides NYMEX with an unalterable audit trail through the use of individually numbered, time-stamped computer scans of trader records.

2. The Commission should condition all market-based rate and blanket natural gas sales certificate authority on companies providing complete, accurate, and honest information to any entity that publishes price indices. The information must be detailed transactional data that includes:

- ◆ Price.
- ◆ Volume.
- ◆ Delivery point.
- ◆ Duration (i.e., hourly, daily, monthly).
- ◆ Date and time (to the minute) of the transaction.
- ◆ Whether the transaction is a purchase or a sale.
- ◆ Counterparty.

It must be clear that manipulating index prices is a violation of the tariff and grounds for revoking market-based pricing or blanket natural gas sales authority and for requiring disgorgement of any profits resulting from the manipulation.

3. The Commission should require that jurisdictional entities retain all information concerning their transactions and any and all information submitted to any entity publishing natural gas or electricity price indices and provide it to the Commission upon demand. Such information would promote more transparent markets and reduce incentives to manipulate or attempt to manipulate energy markets. For example, the CFTC requires that “[a]ll books and records required to be kept by the Act or by these regulations shall be kept for a period of 5 years from the date thereof and shall be readily accessible during the first 2 years of the 5-year period. All such books and records shall be open to inspection by any representative of the [CFTC] or the United States Department of Justice.”⁴³

4. The Commission should approve standard product definitions for published natural gas and electricity price indices used in jurisdictional transactions and standard methodologies for calculating the price indices.

Staff has a specific recommendation for an alternative to the published price indices that meets the criteria specified above. That is, the Commission should require any jurisdictional transaction that is based on a published price index to be taken from an index that is calculated directly from the trade data from one or more many-to-many electronic exchanges and voice brokers that meet all of the criteria specified above. The exchange or voice broker must be audited by an outside entity, and the audit must be subject to Commission review. An index calculated as such would be free from the ability and incentive of

⁴³Commodity Futures Trading Commission Commodities Exchange Act Regulation 1.31.

traders to manipulate the prices and would be feasible in terms of implementation cost, time, and verification.

Staff further recommends that the process for establishing standards for price reporting be established by the Commission, with input and cooperation from the energy industry and the price reporting firms. In addition, other government agencies, such as the CFTC and the Energy Information Administration, should be involved in the process. The process should begin with a technical conference at FERC.⁴⁴

As described throughout this chapter, there are a significant number of companies whose employees manipulated or attempted to manipulate the published price indices by reporting inaccurate or misleading data to the Trade Press. Those manipulations and attempts to manipulate the published price indices may involve criminal violations. In fact, as of February 28, 2003, United States Attorneys have filed criminal charges against two former traders (one from Dynegy and one from El Paso Merchant Energy). Staff has provided the United States Attorneys' Offices any relevant information regarding these cases and will continue to do so. In addition, Staff has provided other government agencies (including the CFTC and the SEC) with any relevant information regarding their investigations of index price reporting and will continue to do so.

Also, as described in this chapter, many of those companies have taken internal measures to correct the problem, such as firing or disciplining employees who manipulated or attempted to manipulate the indices; moving the reporting process away from the trading desk and toward the risk management office; and having a company officer attest to the accuracy of data reported to a trade publication.

Staff recognizes the importance of accurate price indices to the overall health of competitive energy markets. The companies discussed at length in this chapter are significant participants in U.S. electricity and natural gas markets. In order for the published price indices to be accurate and credible, they must receive complete and accurate information from these companies. As such, Staff recommends that the following companies be required to show the Commission that they have fixed their internal processes for reporting trading data to the Trade Press:

- ◆ Dynegy
- ◆ Aquila
- ◆ AEP

⁴⁴Commission Staff has scheduled a technical conference relating to the issue for April 24, 2003.

- ◆ El Paso Merchant Energy
- ◆ Williams
- ◆ Reliant
- ◆ Duke
- ◆ CMS
- ◆ Mirant
- ◆ Coral
- ◆ Sempra Energy Trading

At a minimum, these companies need to show the following:

- ◆ Those employees, including trading desk heads and managers, who participated in manipulations or attempted manipulations of the published price indices have been disciplined.
- ◆ The company has a clear code of conduct in place for reporting price information.
- ◆ All trade data reporting is done by an entity within the company that does not have a financial interest in the published index (preferably the chief risk officer).
- ◆ The company is fully cooperating with any government agency investigating its past price reporting.

Conclusion

The process for reporting natural gas price indices was fundamentally flawed and must be fixed. Traders had the ability and incentive to manipulate the published indices and they did so. Given the degree of systematic manipulation described in this chapter, the published indices could not possibly be accurate based solely on the publishers' editorial judgement, the traders' feel for the market, or the hope that competing traders could offset each other's false reporting.

Staff began the investigation looking for evidence of energy price manipulation in the West. Staff found evidence of manipulation (direct and indirect) of the published natural gas price indices at significant trading points all over the United States—the U.S.-Canada border in Washington (El Paso), Oregon and San Francisco (Dynergy), the Gulf Coast (AEP), the Great Lakes (CMS), the Northeast (Williams), the Henry Hub in Louisiana (Enron), and the Southern California-Arizona Border (Enron and Reliant).

In many cases, electricity prices are directly (through explicit contracts) or indirectly (through the generation costs of electricity suppliers) determined by natural gas prices. Therefore, the manipulation of natural gas prices also affected electricity prices. As the agency of the U.S. Government with the statutory obligation to ensure just and reasonable electricity rates, the Commission cannot rely on a recipe of offsetting false reports, traders' feel for the market, and editorial judgement for accurate price indices.

As noted in this chapter, there has been a movement within the industry to fundamentally reform the price reporting process. Suggestions for reform and tangible reforms have come from market participants, risk officers, the trade publications themselves, new entrants into the price reporting business, government agencies, consumer groups, and others. Moreover, Commission Staff will convene a technical conference on April 24, 2003 on the issue of price reporting, bringing together these parties and working toward a solution. It is clear that the parties involved recognize the problem, agree that a competitive energy market must have accurate price indices to function properly, and are willing to make changes to the process in order to ensure that the indices are accurate and reliable.

IV. Staff Alternative Mitigation Proposal

Summary and Conclusions

In this and previous chapters of this Report, Staff concludes that California spot gas prices were artificially high due to market dysfunctions, illiquidity, misreporting, and a rupture causing an abnormal pipeline capacity shortage. The spot gas prices reflected extraordinary basis differentials that far exceeded the cost of transportation and reached levels that would never have been sustained in a competitive market. The effects of these inflated gas prices were greatly magnified because they were used in the California Refund Proceeding to compute clearing prices for the entire electric spot power market. While there is no way to precisely replicate the level that spot gas prices would have reached in a competitive market, Staff recommends the use of producing-area prices plus transportation as a proxy for competitively derived gas prices in computing the market-clearing prices in the California Refund Proceeding. Over the 9-month refund period, Staff's proposal would reduce gas costs used in the refund formula by \$7.03 in southern California and \$4.18 in northern California, or about \$5.60 on average.

That said, many generators paid these distorted gas prices and fundamental fairness dictates that they be able to recover their costs. Accordingly, Staff also recommends that generators be made whole for the gas prices they paid, but that this recovery be on a dollar-for-dollar basis and not be part of the market-clearing price.

Introduction

In its July 25, 2001 Order, the Commission established the scope and methodology for calculating refunds for bulk power sales in the California spot power markets made between October 2, 2000 and June 20, 2001. The prescribed methodology would determine the mitigated market-clearing price (MMCP) based on the heat rate of the least efficient generator dispatched in the ISO's real-time energy market multiplied by the spot price of gas. The purpose of this methodology was to "provide prices that emulate closely those that would result in a competitive market and that provide generators with a reasonable opportunity to recover their costs."¹

In its August 13, 2002 Initial Report on this investigation, Staff concluded that the California spot price gas indices may have been

¹95 FERC ¶ 61,418, mimeo, p. 38.

manipulated and were not appropriate for price mitigation. Staff recommended that mitigated market-clearing prices be based on producing-area spot index prices plus a transportation allowance. To the extent that generators paid higher prices for gas to nonaffiliated suppliers, these costs would be recoverable through a fuel uplift offset to refund obligations. Comments filed in response to the Initial Report assert that despite Staff's concerns regarding index manipulation, generators did in fact pay the California spot price for gas, and the spot gas price was driven by fundamental supply and demand forces.

In concluding this investigation, Staff has determined that the California spot gas prices were affected by the same factors that rendered the electric power market dysfunctional, were closely linked to the price levels prevailing for electric power, and reached extraordinary levels in part due to pipeline capacity shortages, speculative trading, and attempted market manipulation, including index price misreporting. Staff concludes that the Commission's objective of creating mitigated prices that would emulate the result of a competitive market cannot be achieved by using California gas spot prices.

Staff reaffirms its recommendation that the Commission modify the market-clearing price formula in the California Refund Proceeding to use producing-area prices plus a tariff rate transportation allowance instead of California spot gas prices. Staff believes that the California spot gas prices would have closely tracked producing-area prices plus transportation had the gas market been free from the distorting influence of electric market dysfunction and attempted price manipulation and only influenced by the interaction of high demand and limited supply. Some portion of the premium over producing-area prices also reflected, to some degree, pipeline capacity shortages including the El Paso Carlsbad rupture. Ideally, the portion of the increased border prices attributable to legitimate scarcity should be reflected in the market-clearing price. However, Staff does not believe the effects of scarcity can be separated from those of market dysfunction and price manipulation. Therefore, Staff recommends that fuel input costs above the producing-area cost allowance should be recoverable as a refund offset depending on each generator's heat rate, but would not become an input to the market-clearing price.

In the Initial Report, Staff acknowledged that its proposed method for calculating the MMCP and refunds for California was a regulatory response to a breakdown of the California electricity market:

Staff's proposed substitute is a regulatory solution to a market failure. Staff recognizes that the basis differential between

trading points (in this case, between the western production basins and the California delivery points) represents differences in fundamental supply and demand conditions between points, particularly the scarcity of natural gas due to limited gas transportation to California, and is an important signal for both buyers and sellers. Under normal circumstances, that basis differential should be preserved so the MMCP is the true marginal cost of the last plant producing electricity in California. However, during the period in question, circumstances were not normal. California's electricity market was in crisis, and the combination of the inelastic demand for electricity and the fact that natural gas was the fuel used by the marginal electricity generators was transmitting the problems in the electricity market back to the gas market. That is, electricity generators in California would be willing to pay almost any price for natural gas because they would be able to pass any gas costs through the wholesale electricity market. Given these conditions and the problems with the published California natural gas price indices described above, Staff finds that the proposed substitute, along with the opportunity to recover verifiable gas costs that reflect the scarcity premium, as specified above, is the best way for the Commission to establish just and reasonable rates for the refund period.

The facts uncovered in the investigation since the August 2002 Initial Report confirm Staff's position that the California electricity market was fundamentally flawed and that the dysfunction in the electricity market fed back into the natural gas market. In fact, due to the influence of EnronOnline (EOL) and the other problems described in this Report, the natural gas market at the California border was itself one of the forces driving the meltdown of the California electricity market.

The proposed solution in this chapter refines Staff's August 2002 proposal by allowing generators to recover costs and earn a fair return on their investment while protecting California consumers from unjust and unreasonable electricity prices. It allows the companies that made investments in efficient generators to keep the profits derived from generating electricity at a lower cost than less efficient generators (by setting the MMCP as the marginal heat rate times the basin-plus-transportation natural gas price) without giving them an "efficiency bonus" by leveraging the portion of the natural gas price that is largely attributed to the market dysfunctions described throughout the Report,

which would come at the expense of the California utilities and ultimately of California consumers.

The proposed methodology does, however, recognize the need for generators to recover the cost of producing electricity in California during the refund period. Many generators actually paid index prices and will receive a one-for-one payment to recoup their costs. As described in this chapter, the California index price reflects the scarcity of the natural gas delivered to the California border along with the dysfunctions and manipulations of the market. Ideally, Staff would separate the scarcity from the manipulation and dysfunction and calculate a price that reflected only the true scarcity. In Staff's view that process, if possible, would take years. Staff cannot recommend that this uncertainty and imprecision be introduced into a clearing price and used to value all the power in an entire market. Staff's proposal strikes a balance by using the basin-plus-transportation price, which reflects no scarcity for the clearing price, and using the California index price, which reflects scarcity as well as market dysfunction and manipulation for the cost recovery. It protects California consumers from the multiplier effect of running the California index price through the MMCP without unduly penalizing generators who paid inflated prices for gas in the spot market.

Throughout this Report, Staff has proposed penalties to those who did manipulate the natural gas market and remedies so that it does not happen again. Generators who purchased gas at artificially high prices due to market dysfunction and manipulation do not deserve to be penalized any more than the California electricity consumers who clearly paid excessive electricity prices due to the gas and electricity market manipulation and dysfunction.

Why California Gas Spot Prices Should Not Be Used for Price Mitigation

In specifying that California spot gas prices be used to emulate the outcome of a competitive market, the Commission assumed that the gas spot market was truly competitive and could provide a reliable foundation for emulating the outcome of a competitive power market. Staff believes, based on information developed in this investigation, that the prices established in the gas spot market were not the outcome of fundamental supply and demand forces, but were affected by dysfunctional spot electricity markets, an illiquid spot gas market, speculative trading, and, in some instances, market manipulation. All

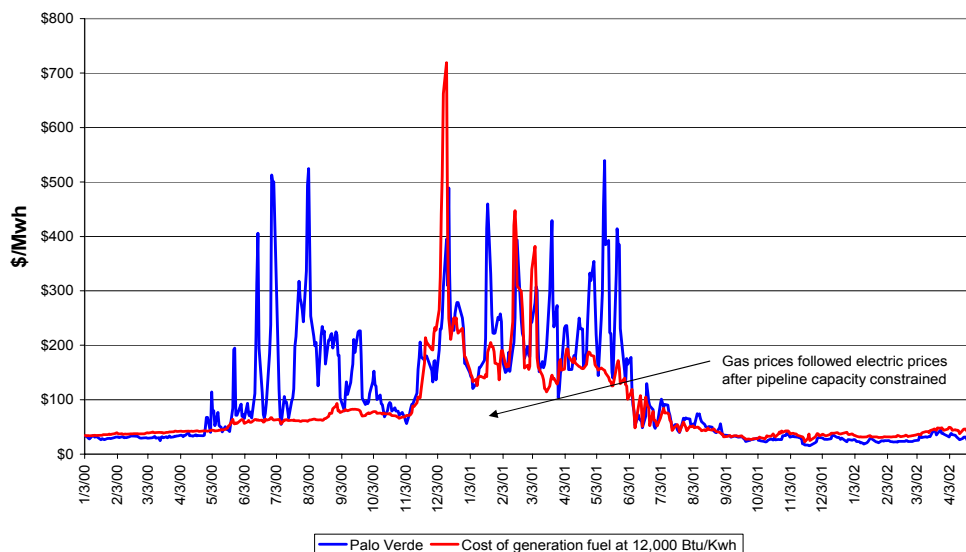
of these factors influenced the California spot prices. While the analysis in Chapter II of this Report attempts to quantify the impact of speculative trading and churning on EOL, simply removing that portion from the California spot price would not remove all vestiges of market dysfunction from the gas prices used for power market price mitigation.

Gas Prices Were Driven by Power Prices Once Pipeline Capacity Became Constrained

As Figure IV-1 indicates, the relationship between gas and electric power prices changed over time. In the summer and fall of 2000, electric power prices rose to very high levels while gas prices stayed relatively low. Once colder weather arrived in November and December 2000, and the combined heating and power load fully used available pipeline capacity, gas prices started to generally follow electric prices.

Figure IV-1

Palo Verde Power Price vs. California Gas Price High Power Prices Preceded Gas Price Rise



This trend illustrates a fundamental dynamic in natural gas pricing: in a nonconstrained market, gas prices are driven by seller competition and the seller's marginal cost; in a constrained market, prices are driven by buyer competition for scarce resources, and prices reach the buyer's value for gas—in this case, the value of gas for power generation. In other words, in the capacity-constrained California market, gas prices were driven in substantial part by power prices. In this regard, Staff agrees with the observation of Henning and Sloan of EEA in comments filed by Duke Energy:²

Indeed, in California, when power prices exploded to record heights, power generation customers were willing to pay astronomically high gas prices since electricity prices made it economically feasible to do so.

**Pipeline Capacity
Constraints Were Not
Entirely Market Related**

During the refund period, the El Paso pipeline was operating at reduced capacity due to the Carlsbad pipeline explosion. This reduced El Paso's capacity to California by 270 MMcf/d, more than 10 percent of its average actual deliveries. The loss of this capacity was clearly not anticipated, but it had a large impact on price. Had that capacity been available, the spot market price would in all likelihood have been substantially lower than the price that was paid. When warmer weather returned during the first 10 days of January 2001, market demand dropped by 240 MMcf/d compared with the last 10 days of December 2000. The corresponding price differential between California and Southwest price points dropped from \$7.25 to \$2.20/MMBtu.³ While this remains some four times higher than transportation costs to the border, the difference strongly implies that the Carlsbad rupture contributed significantly to the extraordinarily high California spot gas prices. Although a pipeline outage has an element of legitimate scarcity, there is no way to isolate these scarcity costs. In addition, Staff does not believe that there is any compelling reason to include

²Comments of Duke Energy filed October 15, 2002 in Docket No. EL00-95-045, Exhibit B, p. 11.

³For the period from December 21-31, 2000, average El Paso deliveries to California were 2,788,244 Mcf/d, the average California spot price was \$16.73, and the average Southwest spot price was \$9.48. For the period from January 1-11, 2002, average El Paso deliveries to California were 2,547,007 Mcf/d, California spot prices averaged \$11.40, and Southwest prices averaged \$9.20.

costs related to such an abnormal event in the clearing prices for an entire electric spot market.

California Gas Prices Were Artificially High

As discussed elsewhere in this Report, the investigation has identified evidence of gas market dysfunction, speculative trading, and index misreporting. These factors, in addition to the linkage between gas and electric markets, resulted in artificially high gas prices. Staff recommends that the Commission reconsider whether high gas prices should automatically mean that generators are entitled to higher operating profit, especially if gas prices are found to be artificial.

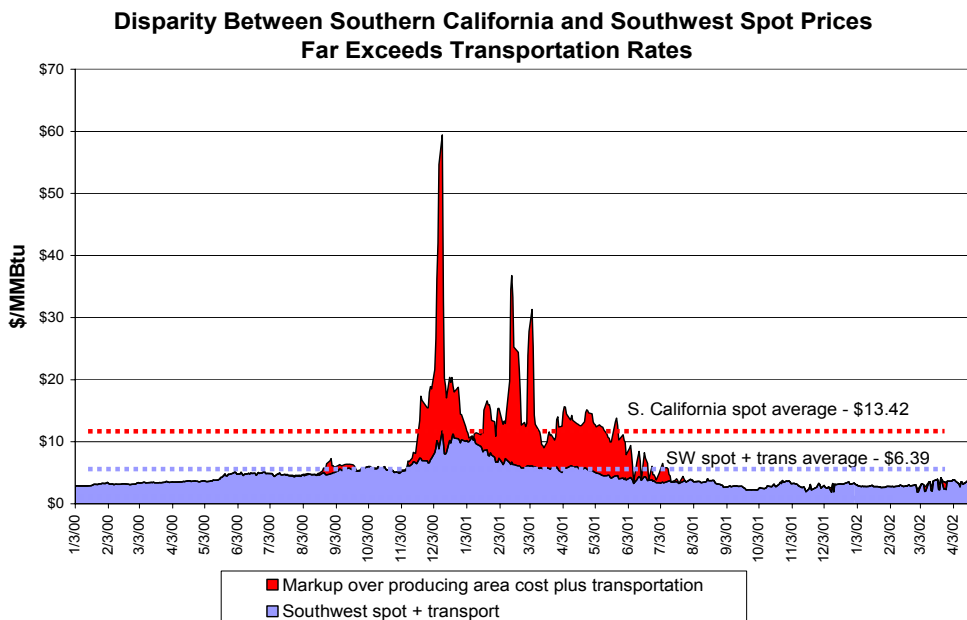
Spot Gas Prices Contained a Transportation Premium Far in Excess of Pipeline Transportation Rates

During the refund period, California spot gas prices reached heights never before seen in the California market, rising to \$59.42/MMBtu on December 11, 2000. On average, southern California spot prices were \$13.42/MMBtu compared with \$5.53 for the Southwest spot supply for the refund period.⁴ The markup over Southwest spot prices averaged \$7.89 compared with a maximum transportation rate of \$0.86, including fuel. The markup in excess of transportation costs, averaging \$7.03, represented 52.4 percent of the reported spot price.⁵ Figure IV-2 shows the disparity between Southwest spot gas costs and southern California spot prices.

⁴Southern California spot prices were based on *Gas Daily* price for SoCal large packages. Southwest price was based on the average between *Gas Daily* Waha and El Paso – Bondad pricing points. All *Gas Daily* prices were the midpoint of the common range.

⁵Transport cost: El Paso IT—\$0.3968, 3.74 percent fuel at \$5.53 average price; SoCal GT F5—\$0.2542 including fuel.

Figure IV-2

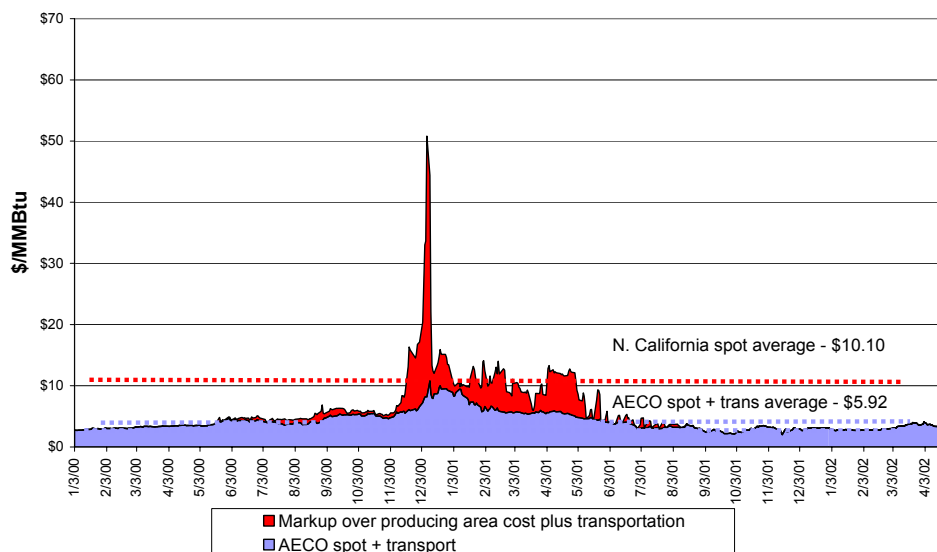


During the refund period, the Southwest gas price also reached record heights, reflecting commodity value in the producing area. The average Southwest price of \$5.53 during the refund period was 40 percent higher than prices in the preceding summer, and more than twice the price during the preceding and succeeding winter periods.

Similar prices existed in northern California. Figure IV-3 shows the disparity between the PG&E citygate price and upstream Canadian supplies during the refund period. The peak PG&E citygate price reached \$50.79/MMBtu on December 8, 2000, averaging \$10.10/MMBtu, compared with \$4.79/MMBtu for the AECO Canadian producing-area point over the refund period.⁶

⁶Northern California spot prices were based on the *Gas Daily* PG&E citygate pricing point; AECO prices from *Gas Daily*. All *Gas Daily* prices were the midpoint of the common range.

Figure IV-3
Disparity Between Northern California and Canadian Spot Prices
Far Exceeds Transportation Rates



The markup over Canadian spot prices averaged \$5.31 compared with a maximum transportation rate of \$1.13, including fuel. The markup in excess of transportation costs, averaging \$4.18, represented 41.4 percent of the reported spot price.⁷

Under the Market-Clearing Price Mechanism, Generator Operating Profit Increases With the Gas Price

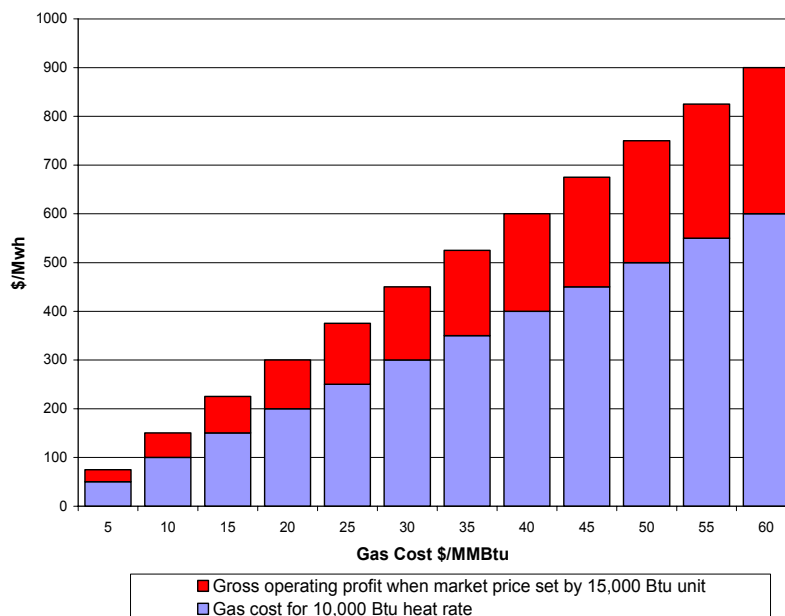
Artificially High Gas Prices Equal Artificially High Profits

Under the July 25 Order's mitigation methodology, the gas component of the market-clearing price is determined by multiplying the spot gas price by the heat rate of the least efficient generator dispatched by the ISO. All other generators receive this same price. Generators with heat rates more efficient than the market-clearing unit retain the difference between the market-clearing price and their actual fuel costs, referred to here as gross operating profit. The gross operating profit is a function of the gas input price, as shown in Figure IV-4. For example, if the least efficient marginal unit has a heat rate of 15,000 Btu/kWh

⁷Transport cost: TransCanada—\$0.1820 including fuel; PGT IT—\$0.2722, 3.06 percent fuel; PG&E G-AFT—\$0.2687; PG&E G-EG—\$0.1995, 1.37 percent fuel at \$4.18 average price.

and the spot gas cost is \$5/MMBtu, the gas cost component of the mitigated market-clearing price would be \$75/MWh. A 10,000 Btu/kWh unit would incur only \$50/MWh in gas costs due to higher efficiency, yielding a \$25/MWh gross operating profit. At a \$20/MMBtu gas price, however, the gross operating profit of the 10,000 Btu unit rises to \$100/MWh. At \$60/MMBtu, the gross profit rises to \$300/MWh.

Figure IV-4
Generator Profitability Rises With Gas Cost



Thus, under the July 25 Order, the profitability for generators more efficient than the market-clearing unit is directly related to gas input prices. The higher the gas price, the higher the average generator's allowed gross operating profit. The single clearing price auction, where all sellers receive the price at which the last unit of supply clears the market, was an integral part of the California restructuring framework. The choice of a single clearing price, as opposed to a market design where each seller receives the particular price it demands, was the result of an extensive stakeholder process with the support of many economists.

**Modification of the Mitigated
Market-Clearing Price
Methodology Is Needed**

As shown above, the July 25 methodology rewards generators who paid high gas prices with mitigated power prices that, for most generators, produce higher gross operating profit than under normal market conditions. Staff believes that California spot gas prices reached levels that would not have existed in a competitive gas market. The shortage conditions that existed were not wholly market related, but rather were in part the result of an abnormality—the El Paso Carlsbad rupture. Further, various attempts to manipulate prices, as described within this Report, cast doubt on whether the California spot prices were legitimate.

Staff believes that the problems identified with California spot gas prices warrant a revision in the Commission’s price mitigation methodology. The challenge is to design price mitigation that compensates the marginal generator for gas costs incurred in good faith to provide needed power supply, while recognizing that unusually high gas costs overcompensate other, more efficient generators. While efficiency should be rewarded, Staff believes this reward should have limits, particularly at the extraordinary and questionable gas price levels that prevailed during the refund period.

**Options for Establishing
Natural Gas Prices for Power
Price Mitigation**

In Staff’s view there are various approaches the Commission should consider to determine the appropriate natural gas price level for establishing mitigated power prices. As discussed above, Staff does not support using the California spot index price.

The central problem is to determine what level California spot market-clearing power prices would have reached in a hypothetically competitive market, free of the distorting influences of power market dysfunction, gas market manipulation, and lack of liquidity. Staff submits that there is no clean way of separating the components of the artificially high California spot gas prices to determine such a hypothetical price level. In Staff’s view, the best way to ensure that the mitigated market-clearing price is completely independent of

distortion and manipulation is to substitute producing-area prices plus a tariff transportation allowance for California spot prices. This approach would approximate gas market conditions had there been no electric market dysfunction, no pipeline constraints, and no gas price manipulation. As explained in the Initial Report, Staff believes the index price for Southwest and Canadian producing areas is reliable and was not subject to manipulation because these prices correlate well with the larger and more liquid Henry Hub market.⁸

Unfortunately, many generators did in fact pay prices that included the effect of these factors. Fairness dictates that generators be permitted to recover these costs. However, since these costs reflect (at least in part) some degree of artificiality, they need not be reflected in the mitigated market-clearing price for power. Treating these costs on a dollar-for-dollar basis allows the recovery of legitimate scarcity costs and is consistent with the approach the Commission adopted in the July 25 Order for nitrogen oxide credits.

The remaining issue is the level of costs above the producing-area allowance that should be recoverable. Staff proposes that the Commission consider three options for determining the level of the additional fuel cost pass-through allowance.

The first option would be to adopt the approach recommended in the Staff's August 13 Initial Report. At that time Staff proposed to limit the level of additional fuel cost recovery to the average price of each generator's portfolio of gas supplies from nonaffiliated suppliers. In response to that proposal, several commenters pointed out that the portfolio approach would penalize generators who managed to keep their gas costs below the California spot index price. Determining actual costs could involve substantial effort and subjective cost allocations. Further, comments indicated that in most cases generators did in fact pay the California spot gas index price.⁹

The second option would be to determine the additional fuel cost allowance based on the California spot gas index rather than on the gas portfolio cost. Under this method the cost of fuel over and above the production area allowance would be determined by each generator's heat rate multiplied by the amount the California spot index exceeded the producing-area index plus fuel and transportation. This approach would simplify the additional fuel cost determination and avoid an indepth analysis of gas portfolios and costs. Since many generators paid the index price for their spot gas, a detailed analysis of their

⁸Initial Report at p. 71.

⁹See study by Drs. Wang and Reishus filed by the comment of the Generator Group (Mirant, Dynegy, Williams, Duke Energy, and Reliant Energy).

actual portfolios should not produce substantially different results. Further, the gas portfolio approach could deprive generators of the benefits of responsible fuel cost management. Those generators who took the risk of acquiring firm service and supported pipeline capacity expansions, for example, would be entitled to keep the difference between their fuel costs and the California border price. The market-clearing price for electricity, however, would be based on the production area price allowance.

A third option would base the additional fuel cost allowance on the price of actual California daily spot market gas purchases rather than rely on the reported indices. This option would still rely on daily spot market prices to determine the additional fuel cost allowance, but would establish those prices based on a review of actual spot market purchases by generators serving the California market. This approach would test the claim by the generators that the reported California spot market index corresponded closely with actual spot market gas costs. This approach would require generators to file actual spot market purchase costs, which would be more data intensive than relying on the reported gas indices, but would reduce uncertainties as to whether the reported index was in fact what generators paid for spot market gas.

How the Alternate Market-Clearing Price Mechanism Would Work

The Staff's proposal for mitigated power price has two components—an alternate market-clearing price and an additional fuel cost allowance. The alternate market-clearing price would be based on the fuel cost of the least efficient unit dispatched priced at the producing-area price index plus transportation and fuel. The additional fuel cost allowance would be passed through on a dollar-for-dollar basis as an offset against refund exposure.

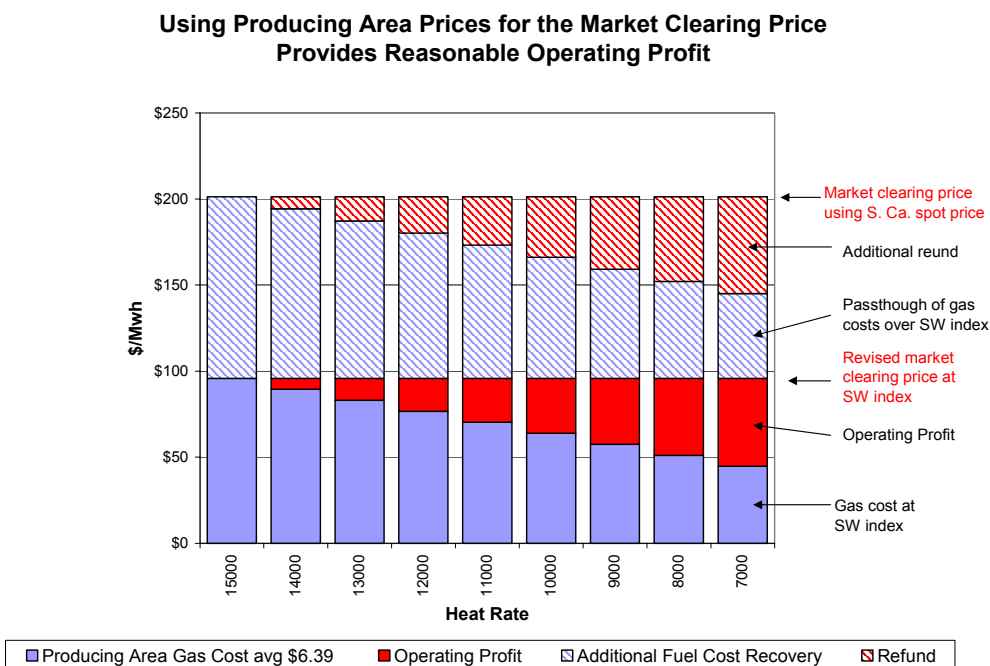
Figure IV-5 illustrates the separate determination of the market-clearing price and the additional fuel cost allowance at various generator heat rates. The figure assumes for illustration that the market-clearing unit had a heat rate of 15,000 Btu/kWh and the average heat rate for California generators is 10,000 Btu/kWh.¹⁰ During the refund period, the average southern California gas spot index price was \$13.42/MMBtu, and the average Southwest spot price

¹⁰The average heat rate at full capacity for generators reported by the California ISO in Docket No. EL00-95 was 10,189 Btu/kWh (derived from Exhibit ISO-8).

plus transportation was \$6.39/MMBtu. Operation and maintenance costs were excluded for the sake of simplicity.

As illustrated in the figure, the alternate market-clearing price for a marginal unit (15,000 Btu heat rate) would be \$95.84/MWh and the additional fuel cost allowance would be \$105.48/MWh,¹¹ for a total of \$201.32/MWh. While this is the same total price as that produced using the California spot price, the market-clearing price would be reduced to \$95.84/MWh. For a 10,000 Btu heat rate unit, however, the additional fuel cost allowance would be \$70.32/MWh¹² (because the more efficient unit uses less fuel), for a total of \$166.16/MWh, or \$35.16/MWh less than the July 25 Order methodology. Again, the \$70.32/MWh would not be part of the market-clearing price.

Figure IV-5



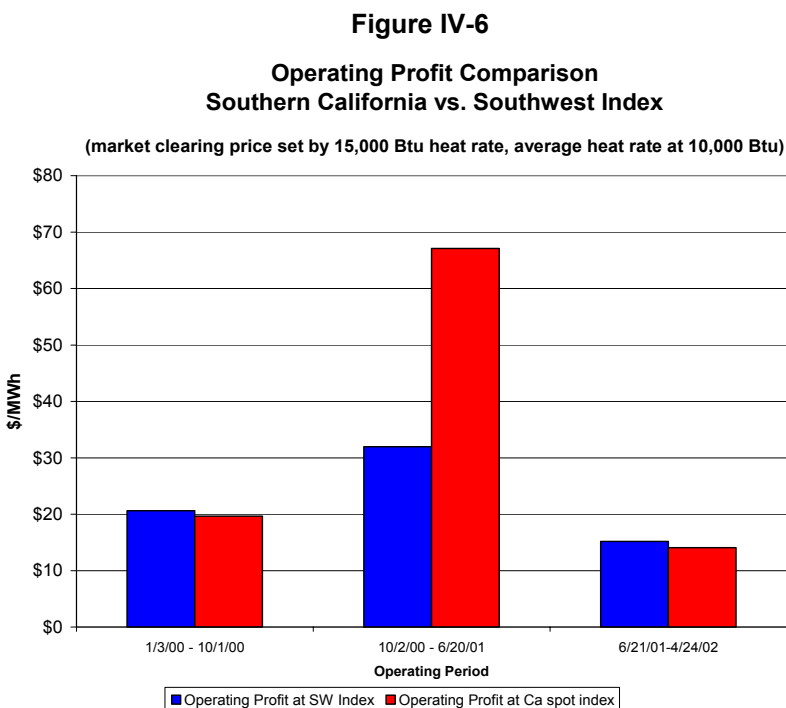
Under the alternate market-clearing methodology, units more efficient than the marginal unit would receive an efficiency profit, but that profit would be based on the producing-area index price. The additional fuel allowance would be based on each individual generator's heat rate and would be passed through as a refund offset, but would not be included in the market-clearing price.

¹¹Alternate market-clearing price: \$95.84/MWh = 15,000 Btu/kWh × \$6.39/MMBtu. Additional fuel cost allowance for a 15,000 Btu heat rate: \$105.48/MWh = 15,000 Btu/kWh × (\$13.42 - \$6.39)/MMBtu.

¹²Additional fuel cost allowance for a 10,000 Btu heat rate: \$70.32/MWh = 10,000 Btu/kWh × (\$13.42 - \$6.39)/MMBtu.

Impact of the Proposed Alternate Mitigation Methodology

Figure IV-6 compares, for various periods, the estimated generator gross operating profit under the July 25 Order and Staff's proposed alternate mitigation methodology. During the refund period, an average generator with a 10,000 Btu heat rate would have earned an average gross operating profit of \$67/MWh based on California spot prices, and \$32/MWh under the alternate methodology.



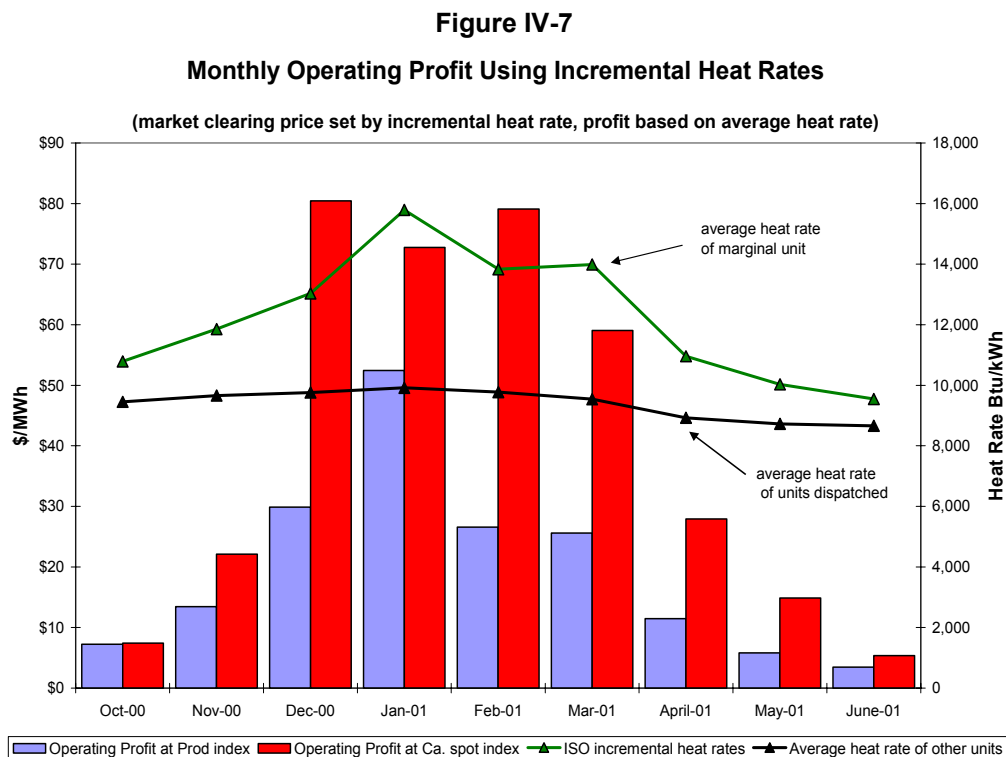
Comparing the calculated \$32/MWh operating profit for the refund period with levels in periods before and after shows that the alternate methodology satisfies the Commission's goal of providing generators with a reasonable opportunity to recover their fixed costs. During the refund period, the average computed operating profit was \$32/MWh, or 55 percent higher than that of the preceding 10-month period and twice the operating profit level experienced in the succeeding 10-month period.

The \$32/MWh operating profit substantially exceeded the capital recovery requirement of a hypothetical new power project. The California Energy Commission (CEC) estimates that a new combined cycle gas turbine would require capital recovery of between \$85 and

\$100/kW per year, or \$16.17 to \$19.03/MWh at a 60-percent plant factor.¹³ As such, gross operating profits were in line with capital costs before and after the refund period. This indicates that the single clearing price auction produced reasonable results except when the gas input prices were artificially inflated.

Use of Incremental Versus Average Heat Rates

On December 12, 2002, Administrative Law Judge (ALJ) Birchman issued his Certification of Proposed Findings on California Refund Liability. The ALJ found that marginal heat rates for refund determination purposes should be based on the change in heat rate over a given load interval rather than the average heat rate for generating power at a given load level. The incremental heat rates used by the ALJ averaged 12,268 Btu/kWh on a load-averaged basis for the refund period, versus the 15,000 Btu/kWh used for illustrative purposes in the preceding examples.¹⁴ Figure IV-7 shows how generator operating profit would be affected by the Staff refund methodology if the Commission adopted the ALJ's heat rate finding.



¹³California Energy Commission, *2002–2012 Electricity Outlook Report*, pp. 32-33.

¹⁴Heat rates from Exhibit ISO-3, in Docket No. EL00-95-045. Load averaging based on daily system load as reported on the California ISO Oasis Web site.

The figure shows that the combination of the incremental heat rates used by the ALJ and the Staff's recommended producing-area index for price mitigation would reduce operating profit levels considerably. Using the ALJ heat rates and the California spot gas price, the average operating profit would be \$41.80/MWh for the average generator operating at a 9,400 Btu heat rate. Using Staff's recommended producing-area gas price methodology and the ALJ's heat rates would reduce average operating profit to \$20.04/MWh. This level of operating profit is within the range needed to support new generation investment.

Response to Comments on Initial Report

Did the index reflect what generators actually paid for gas?

Drs. Wang and Reishus looked at natural gas transaction data for Mirant, Dynegy, Williams, Duke Energy, and Reliant Energy (Generator Group) for the refund period. They found that the price the Generator Group actually paid for gas was nearly perfectly correlated with the index price. They conclude that the index price was an accurate measure of the market price, contrary to Staff's conclusions.

Dr. Van Vactor testified on behalf of Coral Energy. He analyzed the reported price data from all of the major natural gas price reporting publications and compared the reported natural gas prices with the prices posted on another trading platform, IntercontinentalExchange (ICE), for the period beginning April 2001. He found that the prices were nearly identical during the refund period and concluded that the price data from McGraw Hill (Platts), Intelligence Press, and the Energy Intelligence Group were accurate. He also cited the similarity of the reported prices to those reported on ICE after April 2001 and argued that this similarity provides further evidence that the reported prices were accurate.

Staff response:

Staff believes that the price generators paid correlates closely with the index because the purchase agreements were for index-priced gas. Since index-based pricing is prevalent in spot market sales and in intracompany price determination, it is not surprising that generators, at least on paper, paid the index price for gas. The commenters misconstrue the premise for Staff's alternate index proposal. The issue is not whether generators paid the index price, but rather (1) whether the index price was the result of manipulation, and (2) whether basing

mitigated market-clearing prices on the index emulates the result of a competitive market while providing generators with a reasonable opportunity to recover their costs. Staff finds that the index price was the outcome of market dysfunction and manipulation enabled by pipeline capacity shortages and, given the mechanics of the market-clearing price mechanism at high gas prices, over-recovers generator costs.

Staff ignored the fundamental reasons for high natural gas prices at the California border during the refund period.

Many commenters (NGSA, EPSA, Williams, TransAlta, Powerex, Anaheim, Burbank, SoCal, LADWP) argue that there are many well-documented reasons for the high natural gas prices in southern California during the refund period. Those reasons include the scarcity due to inadequate natural gas infrastructure (as noted by the CEC in its study of natural gas infrastructure issues); increased demand for gas due to low hydro reserves leading to more gas-fired generation; imbalance penalties on the SoCal system; and flaws in the wholesale and retail electricity market design, which spilled over into the gas market. They argue that Staff ignored those reasons and made a leap to gas market manipulation and manipulation of the reported indices.

Staff response:

Staff accepts that market manipulation was not the sole cause of high California spot gas prices. A portion of the increase in California border prices reflected legitimate scarcity. Nevertheless, Staff believes that unusually high demand and a shortage of pipeline capacity created the opportunity for manipulation, which did occur and did influence prices. The various forces and behaviors described in this Report cast a cloud over the gas market and taint the reported indices. The Commission need not find that *all* of the price differential between producing-area and California pricing points was due to manipulation to accept Staff's recommended alternate mitigation proposal. There is no fundamental policy reason that generators are entitled to higher gross operating profits simply because gas prices skyrocketed. By treating the transportation premium embedded in the gas price as a pass-through cost, generators are assured of a reasonable opportunity to recover their costs while at the same time assuring that a potential taint on gas prices is eliminated from the market-clearing price and generator profitability.

How should the MMCP account for scarcity?

In its Initial Report, Staff argued that the opportunity to recover gas costs over and above the production area price will allow parties to recover any costs reasonably associated with scarcity. In its August 13 request for comments on the Staff's Initial Report, the Commission asked the question: "What is an appropriate way to account for scarcity?"

Many commenters stress the point that Staff did not account for scarcity in its proposed methodology. SoCalGas and San Diego Gas & Electric Company argue that the only way to account for scarcity is to use the market prices relied on by market participants trading at arm's length. They state that no formula intended to recreate gas prices retrospectively can appropriately account for scarcity. As noted above, Dr. Roach suggests that the Commission use the actual prices that gas-fired generators paid for spot gas to construct a price, which would account for scarcity.

Staff response:

Most of the commenters implicitly assume that mitigated power prices should be based on spot gas prices regardless of the level of gas prices, or whether the gas price levels were artificially high. Staff disputes this notion. There is no fundamental principle that requires the Commission to allow artificially high gas input costs to produce proportionately higher generator gross operating profits. This is especially true when a significant portion of the higher gas costs was driven by market dysfunction and manipulation in addition to a scarcity of pipeline capacity.

Staff maintains that legitimate scarcity costs cannot be separated from the influence of market distortions affecting the California gas market. Further, it is not clear whether an effort to emulate the outcome of a competitive market should include the influence of abnormalities such as the Carlsbad rupture. In Staff's view, the use of the producing-area cost allowance provides generators with a reasonable opportunity to recover their costs. As shown above, basing the MMCP on the producing-area index plus transportation yields reasonable operating profit levels, more than sufficient to support investment in new generation.

Staff recognizes that the proposed methodology, which allows less efficient units to charge a higher price, could be construed as penalizing more efficient generating units, thus stifling investment in

more efficient generation. The long-term benefit of competitive electricity markets comes from the suppliers' incentive to invest in more efficient, cleaner generation in order to maximize its profits. More efficient units will earn greater profits by producing at a lower cost. However, given Staff's conclusion that the high natural gas prices reflected (in part) market dysfunction and manipulation, part of any profit earned by the more efficient units would be due to the higher prices resulting from dysfunction and manipulation, the cost of which would ultimately be borne by consumers. A price based on market dysfunction and manipulation does not send an accurate signal regarding the profitability of investment. Staff's proposed methodology strikes a balance between protecting customers from prices based on market manipulation and dysfunction and protecting suppliers' ability to earn a fair profit in a competitive market.

California Parties' concerns about fuel cost recovery

The California Parties argue that the Commission should not allow a cost-based recovery mechanism for fuel costs above the producing area allowance because this would mix market-based rate and cost-based recovery mechanisms. The California Parties assert that the Commission has already provided a cost-of-service alternative mechanism for those parties who find that the July 25 MMCP methodology provides insufficient revenue to cover their costs. The California Parties argue that the fuel recovery mechanism proposed in the August 13 Initial Report is flawed because (1) it would depend on unit heat rates, which vary with load, and some portion of that load is serving bilateral contracts rather than Cal ISO and Cal PX spot markets; (2) bids to the Cal ISO and Cal PX were not unit specific, thus making heat rate determinations problematic; and (3) more efficient generators may not need a fuel recovery allowance to remain profitable.

Staff response:

Staff submits that the proposed additional fuel cost recovery mechanism is a pragmatic adjustment to the market-based methodology prescribed by the July 25 Order. The cost-of-service alternative would still be available to generators or marketers who are not satisfied with the revised MMCP methodology. Since the proposed modification to the July 25 methodology would substantially reduce the MMCP below the cost of generating power using California spot market gas, the additional fuel cost recovery mechanism is needed for the market-based option to be fair and realistic.

With regard to heat rate determination, Staff does not agree that a generator should allocate its fuel consumption to different services at different loading levels. Staff proposes that a single heat rate for each 10-minute interval should apply to all services the generator provides. With regard to the concern that the Cal ISO and Cal PX bids were not unit specific, Staff asserts that the generators must make a showing of which units served the Cal ISO and Cal PX market in the Compliance filing phase of the refund proceeding. The California Parties will have an opportunity to review this submission and advise the Commission on their concerns at that time. With regard to the level of profitability of specific generators, Staff's analysis in this Report addresses generator operating profitability in detail. The proposed methodology reduces generator profitability but provides a reasonable opportunity to recover costs consistent with the goal of the price mitigation as discussed in the July 25 Order.