

**REPORT ON THE ECONOMIC IMPACTS ON
WESTERN UTILITIES AND RATEPAYERS OF
PRICE CAPS ON SPOT MARKET SALES**

Note: This publicly released version of the report does not include a confidential Appendix A containing commercially sensitive information.

**Prepared by the Staff of the
Federal Energy Regulatory Commission**

January 31, 2002

REPORT

Submitted to the

United States Congress

Prepared by the Staff of the
Federal Energy Regulatory Commission

The Economic Impacts on Western Utilities
and Ratepayers of Price Caps on Spot Market Sales

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Table of Contents

Executive Summary 3

I. BACKGROUND 5

 A. The Purpose of This Report 5

 B. Description of Key Elements of the Commission's
 Prospective Mitigation and Monitoring Program 5

II. REQUESTS FOR INFORMATION 8

III. SUMMARY STATISTICS 10

IV. MARKET CONDITIONS IN THE WEST DURING 2001 14

V. ECONOMIC IMPACTS ON WESTERN UTILITIES AND RATEPAYERS 18

VI. ASSESSMENT OF WHOLESALE PRICE CURVES 20

VII. PRINCIPAL CONCLUSIONS 23

Appendices:

Appendix A – Confidential Key Identifying the Western Utilities 24

Appendix B – Copy of Staff Data Requests to the Western Utilities 25

Executive Summary

This Report was prepared by the Staff of the Federal Energy Regulatory Commission (Commission) pursuant to the conference report¹ accompanying the FY 2002 Energy and Water Development Appropriations Act (Act).² The conference report directs the Commission to submit to Congress, by January 31, 2002, a report on the economic impacts on Western utilities³ and ratepayers associated with price caps⁴ on daily spot market power sales.⁵ These daily spot market transactions involve the resale of energy purchased under long-term forward power contracts when such energy becomes surplus to system needs.

This Report focuses on the economic impact on eight Western load-serving utilities and their ratepayers of price caps on wholesale sales in the spot markets. To provide an appropriate perspective, the Report also includes corresponding data with respect to wholesales sales by those same companies in the non-spot markets, where price caps were *not* in effect. Actual sales data for the period of June 20, 2001 through November 30, 2001 are used. The Report discusses impacts on ratepayers, to the extent that such information was provided by the utilities. The Report reflects the views only of the Commission Staff; it has not been considered by the full Commission.

The Report makes three principal conclusions:

¹H. Rept. No. 107-258.

²Pub. L. No. 107-66, 115 Stat. 486 (2001).

³As used throughout this Report, "Western utilities" means the following companies (listed alphabetically): Avista Corporation, Idaho Power Company, Montana Power Company, Nevada Power Company, PacifiCorp, Portland General Electric Company, Puget Sound Energy, Inc., and Sierra Pacific Electric Company.

⁴The conference report uses the term "price cap," and this Report adopts the term as well. However, Staff notes that Commission orders on the price mitigation and monitoring plan did not use the term "price cap." Rather, the orders spoke of "mitigated price" based on a pricing methodology that was intended to replicate competitive market conditions.

⁵As used throughout this Report, the terms "spot market" or "spot market sales" means sales that are 24 hours or less and that are entered into the day of or the day prior to the delivery.

- (1) The prices at which the Western utilities resold power in the spot market were about \$35/MWh on average – well below the price cap of \$92/MWh;**
- (2) A soft spot market – adequate supply given the low demand during the time period – dictated the prices at which the Western utilities resold energy, not the \$92/MWh price cap; and**
- (3) Customers that the Western utilities had an obligation to serve benefitted from the resale of surplus energy from long-term contracts at the average \$35/MWh level because the revenues from the resales offset the sunk costs of the long-term contracts.**

The Report demonstrates that the average price (both simple and weighted) at which the Western utilities sold power in the daily spot market was significantly *below* the price cap of \$92/MWh. Moreover, while the softness of the spot market did not allow some companies to resell their surplus energy from forward purchases at the price they paid under the forward contracts, the companies were simultaneously reselling surplus energy from forward purchases in other short-term markets (longer than 24 hours) at more than what they paid under the forward contracts. The Report concludes that a wide variety of factors other than the price cap, such as conservation efforts, a downturn in the regional economy, and adequate supply given low demand, affected sales prices in both the spot and non-spot markets.

Traditionally, the Western utilities have acquired long-term resources by ownership or contract in order to reliably serve their native load at stable prices. To the extent that these resources are not fully needed to serve native load due to lower than expected demand, they are resold in short-term markets. Even if market conditions required these resales to be at prices below the full costs of the long-term resources, customers that the Western utilities had an obligation to serve benefitted because the revenues from the resales offset the sunk costs of the long-term resources.

Finally, the Report describes the current retail rate activity with respect to the recovery of the costs of wholesale purchases and sales.

I. BACKGROUND

A. The Purpose of This Report

The conference report (H. Rept. No. 107-258) that accompanies H.R. 2311, the FY 2002 Energy and Water Development Appropriations Act, directs the Commission to report to Congress on the economic impacts of price caps that the Commission included as part of a mitigation plan for the Western region of the United States. The conference report states:

The conferees direct the Commission to submit a report to Congress by January 31, 2002, on the economic impacts on western utilities and ratepayers associated with the Commission's emergency order imposing price caps on daily spot power sales resulting from the inability of western load serving utilities to recover costs from daily sales of excess power from long-term forward contracts.

This section of the Report discusses the context in which the Commission directed the use of price caps on spot market sales in California and, later, in the area within the Western Systems Coordinating Council (WSCC).⁶

B. Description of Key Elements of the Commission's Prospective Mitigation and Monitoring Program

Between August 2000 and July 2001, the Commission issued a series of orders (approximately 75) that, among other things, addressed the mitigation of prices for power sold at wholesale through centralized, single-price auction spot markets operated by the California Independent System Operator Corporation (ISO). Recognizing that the California market is integrated with markets in the other Western states, the Commission also implemented price mitigation in spot markets throughout the West. These orders were aimed at correcting the serious flaws in the dysfunctional market in California which contributed to the electricity crisis in California and at stabilizing prices in California and the West. In issuing the orders, the Commission adopted a measured approach to provide for market corrections and price mitigation, attempting to balance the need to protect customers from high prices in the short-term with the need to ensure that power continues to flow and that incentives are provided to bring much needed power supply on-line for the longer term.

⁶References throughout this Report to the WSCC are intended to refer only to the United States portion of the WSCC.

In general, the Commission's actions involved two general time frames. The first is a period from October 2, 2000 until June 20, 2001. This time period is not at issue in this Report and is not discussed further herein. The second time frame is from June 21, 2001 forward. For the latter time frame, principally through two orders,⁷ the Commission adopted a program to ensure that rates for spot market sales throughout the Western United States remain just and reasonable. It is the economic impact of price caps during this time frame that is the subject of this Report.

In the first order (the April 26 Order), the Commission established a prospective mitigation and monitoring plan for wholesale sales through the organized real-time markets operated by the ISO, and established an inquiry into whether a complementary price mitigation plan should be implemented throughout the WSCC.⁸ In the April 26 Order, the Commission established price mitigation for all sales in the ISO's real-time market during a reserve deficiency (that is, when reserves fall below seven percent). During those hours, the Commission required that the ISO's single price auction be subject to must-offer and certain other bidding requirements (based on gas-fired generation) which the ISO must use to establish the market clearing price (MCP) when mitigation applies (mitigated reserve deficiency MCP).⁹ Higher prices were permitted if they could be justified.

In the second order (the June 19 Order), the Commission modified and expanded the mitigation plan to include the entire WSCC during all hours of the day (using a modified version of the mechanism employed for reserve deficiency hours). The resulting price, which was in effect from June 20, 2001 through December 21, 2001, was \$92/MWh. In an effort to address the projected tight supply situation throughout the West, the Commission also required that all available generation not previously committed to serve load be offered in the spot market.

In the June 19 Order, the Commission noted that, in prescribing price mitigation for spot markets throughout the West, it was seeking to intervene in markets in as limited a

⁷San Diego Gas & Electric Co., et al., 95 FERC ¶ 61,115 (April 26 Order), order on reh'g, 95 FERC ¶ 61,418 (2001) (June 19 Order), order on clarification and reh'g, 97 FERC ¶ 61,275 (2001).

⁸The price mitigation established in the April 26 Order replaced a price mitigation plan previously in effect for such sales and was an outgrowth of a Commission investigation into the reasonableness of rates for public utility sales through the markets operated by the ISO and the California Power Exchange.

⁹The mitigated reserve deficiency MCP is the marginal cost of the last unit dispatched to serve the last increment of load during a period of reserve deficiency.

manner as possible consistent with the Commission's responsibilities and policies to ensure just and reasonable rates, to rely on market principles wherever possible, and to balance carefully the need for price relief against the need for price signals to attract critical supply entry.¹⁰

In an order issued on December 19, 2001,¹¹ the Commission made minor changes to this mitigation and monitoring plan. The Commission directed the ISO to recalculate the price cap for spot market sales when the average of certain gas indices increases ten percent from the level last used for calculating the mitigated price. As a starting point, the Commission set the West-wide winter price cap at \$108/MWh, effective as of December 21, 2001, which is above the previous West-wide price cap of \$92/MWh.

¹⁰June 19 Order, 96 FERC at 62,545.

¹¹Investigation of Wholesale Rates of Public Utility Sellers of Energy and Ancillary Services in the Western Systems Coordinating Council, 97 FERC ¶ 61,294 (2001).

II. REQUESTS FOR INFORMATION

In order to obtain the information necessary to complete its Report to Congress, on November 28, 2001, Commission Staff sent data requests to eight traditional investor-owned public utilities in the West outside of California.¹² Staff sought information from these utilities, but not others in the West, because it was only these utilities that raised the issue of the economic impact of the mitigation plan in proceedings before the Commission.

The data requests were not sent to the three California investor-owned public utilities.¹³ Through calendar year 2000, these three public utilities purchased power almost exclusively through the spot market pursuant to California state restructuring rules. As of 2001, due to the lowered credit ratings of two of the utilities, much of the California investor-owned public utilities' power needs were procured by a creditworthy third party. Because of these third party purchases, the California investor-owned public utilities do not currently resell surplus energy from long-term purchases in the spot markets studied in this Report.

Suppliers such as municipals, governmental agencies (*e.g.*, the California Department of Water Resources), cooperatives, and Federal Power Marketing Administrations serve about 50 percent of the load in the West. Staff did not request data from these entities because they are non-jurisdictional.

The data requests solicited the following information from the eight Western utilities: (1) cost and transaction data for both the original cost of the long-term purchases made by the public utilities and the revenues generated by reselling the surplus energy in the wholesale spot market and other wholesale markets; and (2) any effects on Western utilities and ratepayers due to this wholesale activity. Staff requested both actual transactions from June 21, 2001 (the effective date of the mitigation plan) and projected data through September 30, 2002 (the end of the mitigation plan). Not all Western utilities provided the projected data, and those that did cautioned that the data were speculative and unreliable. Therefore, this Report does not include the prospective data and its conclusions are not based on that information.

¹²Avista Corporation, Idaho Power Company, Montana Power Company, Nevada Power Company, PacifiCorp, Portland General Electric Company, Puget Sound Energy, Inc., and Sierra Pacific Electric Company.

¹³Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company.

A copy of the data request that was sent to each of the eight Western utilities is attached as Appendix B. Staff received responses to the data requests between December 21, 2001 and January 10, 2002. Because some of the responses to the data requests are commercially sensitive, several of the companies requested confidential treatment, in whole or in part. In order to accommodate these requests, the Report uses letter designations for all of the Western utilities. Appendix A contains a key that identifies each of the Western utilities with its letter designation. As noted in the cover letters transmitting this Report, in view of the confidential nature of this information, the Commission requests that the recipients of the Report withhold Appendix A from public disclosure.

One company, Utility E, did not meet the original deadline for providing the requested data. In its response to Staff's follow-up letter directing compliance, Utility E stated that it does not maintain the statistical data sought in the data requests in the format requested by Staff and claimed that it could not "spare the manpower" to provide the data in the format sought by Staff. Consequently, information for this company is not included in the tables and graphs contained in the Report.

III. SUMMARY STATISTICS

Staff requested information from the individual Western utilities on the cost of their respective long-term purchase power contracts and the amount of surplus energy (in MWh) available for resale. Because surplus energy from long-term contracts can be resold in a variety of ways, Staff requested actual revenue data for the period commencing June 21, 2001 to the present for surplus energy resold in the spot market, which is subject to price mitigation, as well as energy resold in other short-term markets (longer than 24 hours), which are not subject to mitigation. The following table contains a summary of this information, using the time period of June 21, 2001 through November 30, 2001:

Company	Spot Resales (Below) or Above Forward Contract Price	Non-Spot Resales (Below) or Above Forward Contract Price	Net Revenues
A	(\$316,976,099)	\$6,938,220	(\$310,037,879)
B	(\$152,072,399)	\$257,726,332	\$105,653,933
C	(\$155,276,866)	(\$19,654,273)	(\$174,931,139)
D	(\$44,941,168)	\$106,323,854	\$61,382,686
E	Not Provided	Not Provided	Not Provided
F	(\$55,908,419)	(\$11,124,672)	(\$67,033,091)
G	(\$54,652,418)	(\$23,255,003)	(\$77,907,421)
H	No Spot Resales	No Non-Spot Resales	N/A

Figures in parentheses signify that the short-term market was soft and did not allow the company to resell its long-term resources at the price paid for the resources. Conversely, prices without parentheses indicate that the short-term market supported resales above the price of the long-term resources.

The information provided by the Western utilities indicates that one utility (Utility H) had no transactions involving the resale of surplus power from long-term contracts. Utilities B and D were each able to resell surplus energy from their long-term resources at prices above those paid for the resources. Utilities A, C, F, and G recovered less due to the overall decline of prices as a result of a combination of factors that resulted in a soft spot market. As previously noted, Utility E did not provide this information, claiming that it did not maintain the data in the format requested and lacked the manpower needed to supply the requested data.

The data responses also indicate that the wholesale spot market price for the resale of surplus energy was generally considerably below the \$92/MWh price cap. In fact, most of the spot market transactions never approached the \$92/MWh price cap. The information reported indicates that the total average resale price is approximately \$35/MWh. The following table shows the simple and weighted average spot market prices for each Western utility.

Company	Daily Spot Resale Price (\$/MWh)	
	Simple Average	Weighted Average
A	\$33.96	\$36.47
B	\$35.45	\$38.39
C	\$29.41	\$29.42
D	\$36.93	\$35.63
E	Not Provided	Not Provided
F	\$32.01	\$34.47
G	\$30.27	\$27.26
H	No Spot Resales	No Spot Resales

The data also indicate that, after the Commission issued its June 19 Order, prices in the spot market steadily declined throughout the time period at issue and were well below the \$92/MWh price cap. The following graph illustrates the average price of the spot market sales and the decline in average prices.

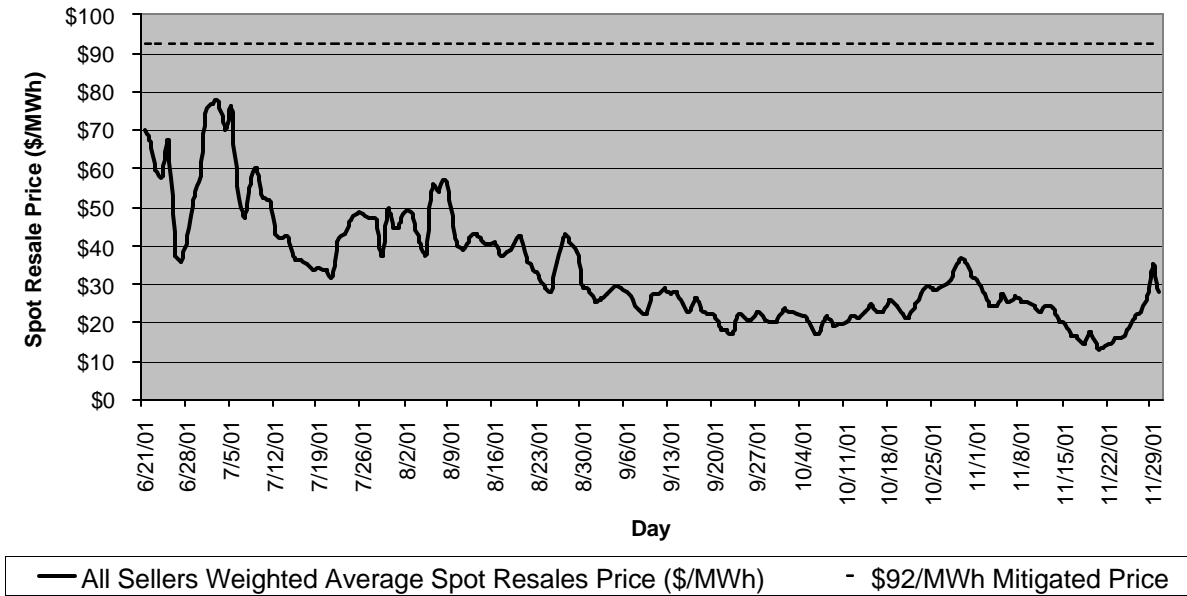


Figure 1: Northwest Spot Prices Decline over Time

The following bar graph illustrates the volumes and the resale prices in the spot market:

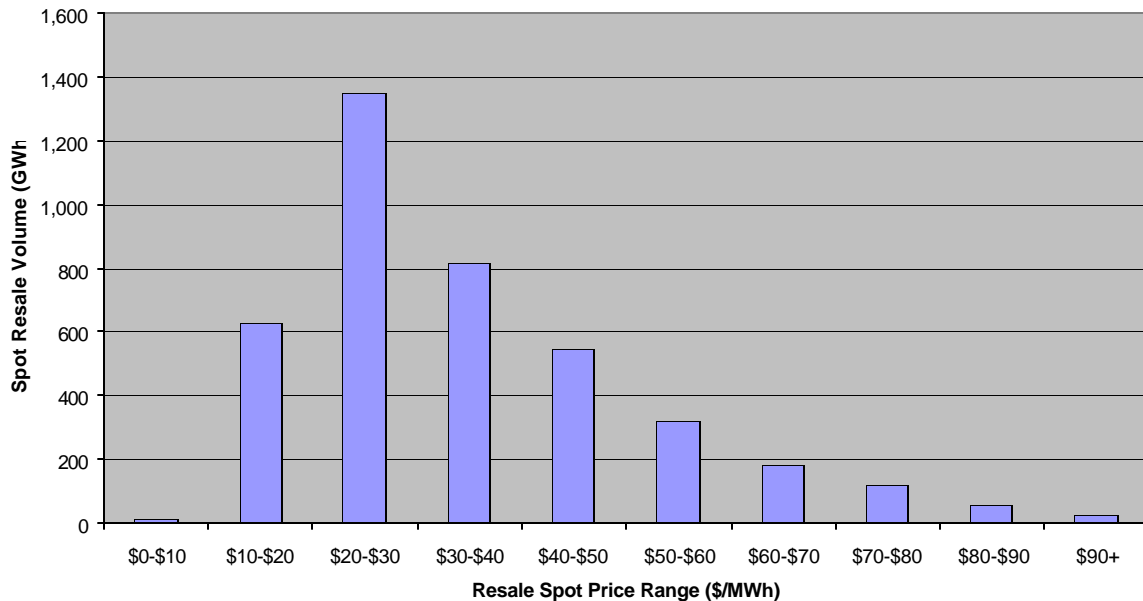


Figure 2: Northwest Spot Sales Volume By Spot Resale Price Range

Figure 2 indicates that, after the Commission issued its June 19 Order, a very small portion (less than one percent) of resales in the spot market occurred at prices approaching

the \$92/MWh price cap; in other words, a majority of resales in the spot market were at prices below the price cap.

IV. MARKET CONDITIONS IN THE WEST DURING 2001

In light of the supply problems that California had experienced during 2000, the regional supply outlook for 2001 in the West was projected to be very tight. For example, the North American Electric Reliability Council (NERC) released a report on expected summer 2001 supply conditions in California and the Pacific Northwest. In its report, NERC projected that the ISO would not have sufficient resources to meet expected demand during the summer of 2001, and that rotating blackouts (that is, localized curtailments of firm customer demand) should be expected. NERC's report stated that firm demand might be curtailed for approximately 260 hours over the course of the 2001 summer, with an average amount of firm demand curtailed of about 2,150 MW in each instance. NERC also predicted a reduction in the amount of energy traditionally available from Pacific Northwest utilities for export into California, due to limited energy output from hydroelectric facilities resulting from severe drought conditions.¹⁴ In addition, prices in the spot markets for the prior summer had been at historical highs.

In addition, on December 14, 2000, the Secretary of Energy declared an emergency in California due to a shortage of electric energy.¹⁵ The goal of the emergency declaration was to avoid blackouts in California by requiring generators and marketers to make electricity available for purchase. The emergency order affected approximately 75 entities, including investor-owned utilities, cooperatives, municipalities, and marketers located both within and outside California. The emergency order required these entities to sell energy to the ISO (to the extent each entity had energy available in excess of the amount needed to serve its firm customers) within 12 hours after the ISO had certified to the Department of Energy that it had been unable to acquire in the market adequate supplies of electricity to meet system demand and, as a consequence, either had or reasonably had anticipated an inadequate fuel or energy supply. The emergency order was ultimately extended to February 7, 2001.

As a result of the scarcity of supply as well as the serious flaws in the dysfunctional California market, energy prices in the long-term, short-term, and spot markets were high throughout the region.

¹⁴North American Electric Reliability Council, 2001 Summer Special Assessment, available at ftp://www.nerc.com/pub/sys/all_updl/docs/pubs/summer2001-special.pdf.

¹⁵Notice of Issuance of Emergency Orders Under Section 202(c) of the Federal Power Act, 65 Fed. Reg. 82,989 (December 29, 2000); see also U.S. Dept. of Energy, Amendment No. 2 to the Order Pursuant to Section 202(c) of the Federal Power Act, available to [http://www.energy.gov/HQPress/releases00/decpr/order202\(c\)amend2.pdf](http://www.energy.gov/HQPress/releases00/decpr/order202(c)amend2.pdf).

The following graph shows the spot market prices in the three Western hubs (Palo Verde, Mid-Columbia, and California-Oregon Border) beginning March 2001.

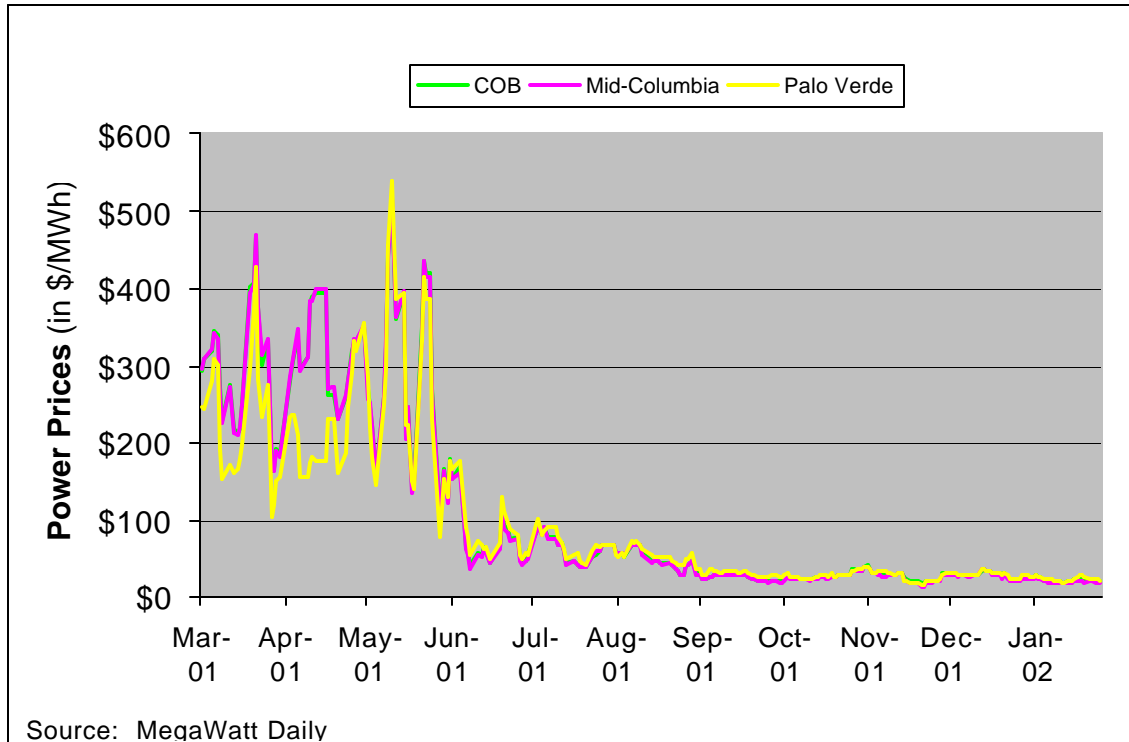


Figure 3 Western Hub Spot Market Prices

As shown, prices in the spring were in the range of \$400/MWh.

Based on the facts as known at the beginning of 2001, electric utilities in the West, including the utilities to whom Staff sent data requests, made purchasing decisions intended to ensure sufficient reliable resources to service their projected system loads. In an effort to avoid an over-exposure to the volatile spot market, the utilities locked in longer-term contracts. Once these contracts were executed, the costs became sunk costs for serving system loads.

System planners typically secure future resources sufficient to serve their system load forecast. This procurement strategy ensures system reliability, and is particularly important in a market with tight supplies, such as the Pacific Northwest, which is highly dependent on hydroelectric resources. At the time that the Western utilities made some of their long-term purchases (the beginning of 2001), the reservoirs in the region were at historic lows due to the extremely dry conditions throughout the West. Thus, other, non-hydroelectric resources were needed to make up the projected shortfall of hydroelectric generation.

While some of the Western utilities do not explain why, some of their long-term purchases were in excess of actual system loads (and therefore became available for resale in wholesale markets.) There are a number of possible explanations for this. For example, purchases may be in fixed amounts around the clock and thus become temporarily available for resale in shoulder or off-peak periods.¹⁶ Actual system loads may turn out to be lower than projected loads. Weather conditions can be more favorable than the recent or historical periods that were used to make projections. Greater than expected snow and rain can make more hydroelectric generation available than originally projected. Because a utility's own hydroelectric generation is cheaper than long-term purchased power, utilities can use such generation to displace their purchases for serving system loads. Successful conservation programs and general economic conditions may also explain differences between projected and actual system loads. Due to any of these factors, or any combination of these factors, the original long-term purchase can in some hours become surplus energy available for resale in short-term markets. Even if these resales are at prices below the cost of the long-term purchases, system customers benefit because the revenues from the short-term resales serve to offset the sunk costs of the long-term purchases.

The dire predictions as to the market conditions in the West did not generally come to pass due to better than expected supply conditions, lower than expected demand, and implementation of the Commission's price mitigation plan. The result was a decline in short-term and spot energy prices. In the week immediately following implementation of the April 26 Order (the week of June 9, 2001), Western spot market prices fell to below \$55/MWh compared to prices of about \$170/MWh the week before. As indicated by the responses to the data requests, the Western utilities' average prices for energy resold in the spot market all are about \$35/MWh, which is considerably below the \$92/MWh price cap established in the Commission's June 19 Order.

From the data the Western utilities provided, Staff concludes that the price cap had little, if any, influence on the price levels at which the Western utilities were able to resell surplus energy from their long-term contracts. These prices were a function of a soft spot market and fell well below the price cap. The spot market is the last opportunity to buy or sell energy before it is actually used. As a result, it is the most volatile market. This market will produce high prices in a tight supply situation because demand will be high relative to supply. Conversely, prices will be low when supply is abundant and there are many choices available to prospective buyers – the conditions present during the time period covered by this Report.

¹⁶One company, Utility A, states that this is the primary reason that it had surplus energy available for resale into the wholesale market.

V. ECONOMIC IMPACTS ON WESTERN UTILITIES AND RATEPAYERS

Among other things, Staff's data requests to the eight Western utilities requested that they each indicate what percentage of their total system supply is represented by the transactions in question. In response, Utility B states that the percentage of net system load represented by spot market transactions subject to the price cap is seven percent. Utility G reports that the resale of surplus energy in the spot and short-term markets represents approximately 7.5 percent of system sales. Utility A responds that, from June through December 2001, approximately 33 percent of its portfolio to serve wholesale and retail load was from both spot and longer term purchases.¹⁷ The remaining companies did not provide responses.

From the information provided by the Western utilities, only Utility A has a significant amount of wholesale purchases in its portfolio as compared to the other reporting companies. A review of recent historical data filed in Utility A's FERC Form No. 1 indicates that, during 1999 and 2000, this utility's wholesale sales volume was over one-third of its total sales. In other words, this company's purchases and sales volumes in the wholesale spot and short-term markets are a larger percent of its total sales than the other companies. As such, Utility A is more exposed to the risks and the benefits, as well as the volatility, of these markets than the other companies.

The data requests also asked the Western utilities to provide information indicating the impact on ratepayers due to the current price mitigation.

Utility E indicates that it filed a retail rate surcharge on December 3, 2001 to recover certain electric energy supply costs, including net purchase power costs. Utility E states that its net power costs include amounts paid for fuel for generation and for power purchased in wholesale markets and through long-term power purchase agreements, less amounts received from the sale of surplus power in off-system wholesale sales for the benefit of its customers. In recent years, it reports, these costs have steadily increased; however, a rate increase was not needed until the summer of 2001 because it was able to offset its increasing costs by selling surplus power into the spot market where prices have risen dramatically. Utility E states that, during the summer of 2001, market power prices fell dramatically and hydroelectric generating conditions in the region were the second worst on record. The company alleges that it could no longer market its surplus power at rates high enough to keep its net power costs down to the levels embedded in its existing rates. Utility E reports that the cumulative effect of these extraordinary circumstances and, more importantly, its increase in gas supply contracts for its generation resources, are the

¹⁷Utility A reported this information differently than other companies.

reasons for the proposed change in rates. The company states that it has not attempted to study the extent to which the Commission's June 19 Order has impacted its ratepayers.

Staff notes that, based on the responses, the primary retail rate cases of Utilities A, G and F involve the amount of the total cost of long-term purchases, which is not the subject of this Report.

Utility A states that it provides retail electric service in several Western states. To date, it has filed for recovery of its increased long-term purchased power costs in the majority of those states. It indicates that the percentage impact on its customers ranges from three percent to 8.6 percent. According to Utility A, the rate filings in these states are representative of the impact on the company's customers.

Utility G states that, due to the forecasts of tight supply conditions, it made both traditional long-term purchases and forward purchases in the form of load reduction or buy back programs that were approved by its state commissions. According to the company, at present, its retail customers will be responsible for approximately 81 percent of these costs. No additional information was provided.

Utility F states that it has experienced an increase in purchased power due primarily to record low hydroelectric generation conditions. The increase in purchased power, and the increased costs, led this company to file an expedited request for a surcharge on retail rates, which was partially granted in one state proceeding. In a related state proceeding, the utility filed for deferred accounting for power supply costs, which was also approved. The company also has filed for an additional (ten percent) interim rate increase which it proposes to take effect in 2002. Utility F serves retail customers in another state and has applied for a change in the power cost adjustment mechanism.

Utilities C and D did not provide any information on specific retail rate activity. They simply indicate that there may be impacts on the companies and their ratepayers.

VI. ASSESSMENT OF WHOLESALE PRICE CURVES

This section is intended to provide an overall assessment of the wholesale price curves during the last half of 2001 as reported by the Western utilities. The following graph shows the trend of the reported resale prices of surplus energy in the spot market:

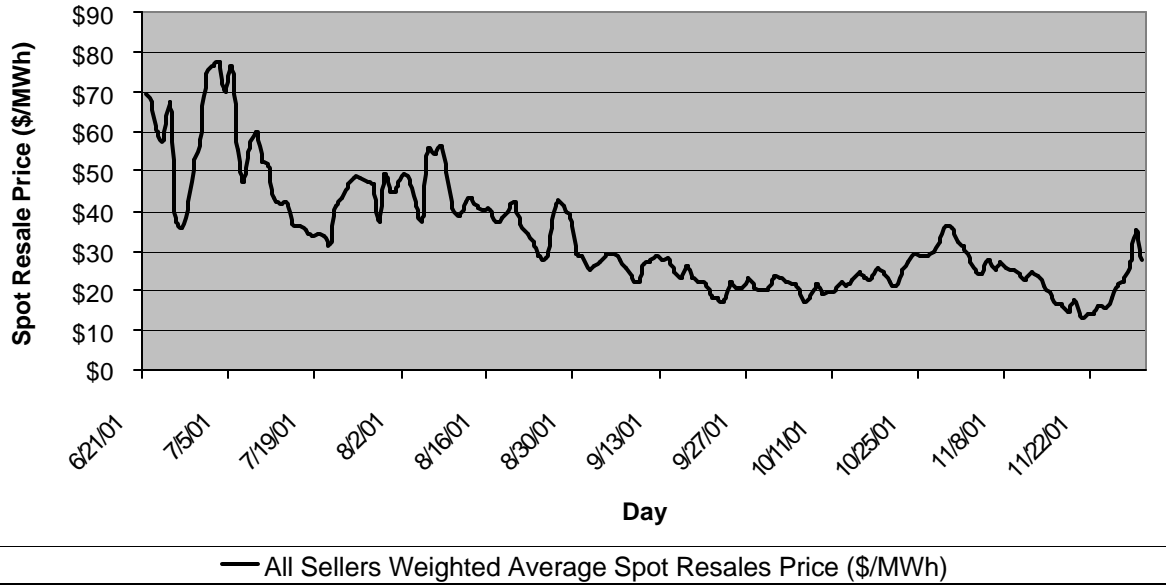


Figure 4: Trend of the reported resale prices of surplus energy in the spot market

The following graph shows the trend in the reported purchase price of the long-term contracts.

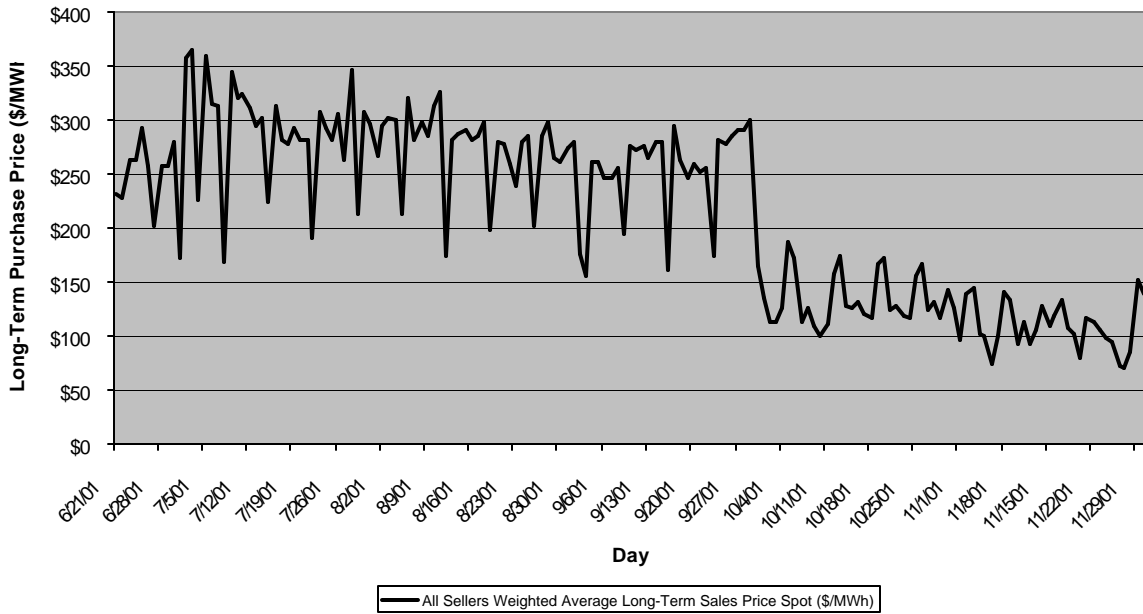


Figure 5: Trend in the reported purchase price of the long-term contracts

The following graph provides a comparison of the price data for both the long-term contracts and the resale of surplus energy in the spot market.

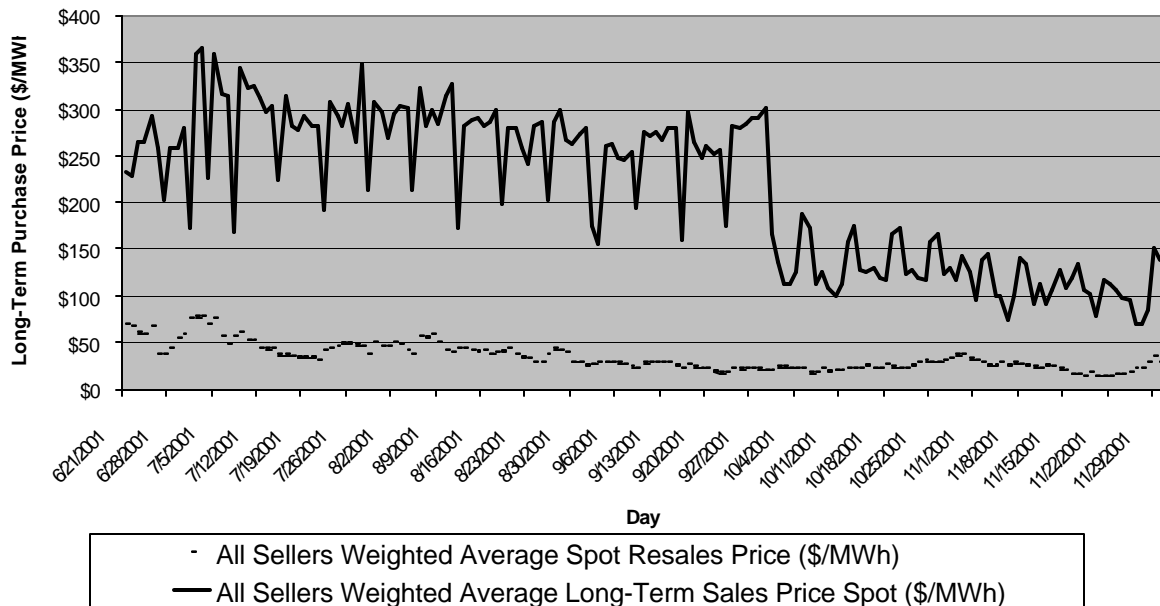


Figure 6: Spot Versus Long-term Price Comparison

As noted above, the average prices in the spot market are well below the \$92/MWh

price cap. The reported data indicate that the price of long-term contracts has declined dramatically throughout the period for which actual data were provided. Based on this data, Staff concludes that the time period that the public utilities were exposed to high priced, long-term purchases has passed. The improved market has also resulted in not only lower spot market prices, but also lower long-term prices.

VII. PRINCIPAL CONCLUSIONS

Based on the information provided in this Report, Staff makes the following three principal conclusions with respect to the economic impact on Western utilities and their ratepayers of the price caps on daily spot market sales:

- (1) The prices at which the Western utilities resold power in the spot market were about \$35/MWh on average – well below the price cap of \$92/MWh;
- (2) A soft spot market – adequate supply given the low demand during the time period – dictated the prices at which the Western utilities resold the energy, not the \$92/MWh price cap; and
- (3) Customers that the Western utilities had an obligation to serve benefitted from the resale of surplus energy from long-term contracts at the average \$35/MWh level because the revenues from the resales offset the sunk costs of the long-term contracts.

Appendix A

This publicly released version of the report does not include a confidential Appendix A containing commercially sensitive information.

Appendix B

Copy of Staff Data Requests to the Western Utilities