California Independent
System Operator

CALIFORNIA ISO

Memorandum

To: ISO Board of Governors

From: Anjali Sheffrin, Ph.D., Director of Market Analysis

cc: ISO Officers, ISO Board Assistants

Date: January 16, 2004

Re: **Market Analysis Report for November and December 2003**

This is a status report only. No Board Action is required.

Executive Summary

- ***Real-time balancing markets were largely decremental in most hours.***
- ***ISO often relied heavily on the real-time incremental balancing market to meet the steep early-evening load ramp.***
- ***Ancillary Services' bid insufficiency often resulted in higher real-time prices during those ramp periods.***
- ***Higher balancing prices were consistent with higher natural gas prices.***
- ***Intrazonal congestion cost $15.7 million in December, due to substation derates and lack of transmission for new Mexican generation.***

For the first time in several months, average loads in November were lower than last year's levels due to mild weather. However, as more normal weather returned in December, loads again were nearly 3 percent higher than in December last year. In most other hours, schedules were more than sufficient to meet load, and balancing activity continued to be overwhelmingly in the decremental direction. Decremental energy prices averaged $18.88 and $15.69/MWh in November and December, respectively. The daily load shape has changed to the winter seasonal pattern, characterized by sharp evening peaks, driven by residential use of heating and electrical appliances in the early evening. During this sharp change in load, the ISO must often rely heavily on the real-time market to balance system generation and load. The heavy reliance on the real-time market during these periods contributed to several systemwide price spikes. Additionally, insufficient bids of capacity in the ancillary services (A/S) markets have had an impact on real-time energy prices. Deficiencies in A/S procurement markets have necessitated that the ISO not utilize real-time energy bids from A/S resources in order to conserve operating reserves, and instead use higher cost supplemental bids. The real-time incremental energy price averaged a moderate $54.58 per megawatt-hour (MWh) in November, increasing to $69.35/MWh in December. These price increases were aligned with those for natural gas. Natural gas prices reached their highest levels since the gas price spike in February and March 2003.

Intrazonal congestion continues to be a significant problem in the ISO real-time market. While out-of-sequence redispatch costs were down to $3.8 million in November as a result of lower loads, these costs increased to $15.7 million in December, the highest levels of 2003, due primarily to large substation derates in Southern California. Of the $15.7 million costs in December, $6 million was attributed to the ongoing problem surrounding decremental OOS dispatches to the generation units in Northern Mexico, while $9.7 million was the result of incremental OOS dispatches resulting largely from the derate of the Sylmar substation.

The conditions causing ancillary service bid insufficiency in October have continued through November and December. Conditions causing insufficiency have also spread to the regulation up (RU) and non-spinning reserve (NS) markets. During October, bid insufficiency was primarily limited to spinning reserves (SP).

I. Fundamental Market Trends

- ***November and December had the typical evening-peak load pattern.***
- ***Operational balancing challenges during the early-evening ramp required significant incremental energy dispatches in real time.***
- ***Unusually high gas prices.***
- ***Units out for seasonal maintenance.***

Loads. For the first time in several months, average loads were lower than during the same period last year. Mild weather in November 2003 resulted in loads averaging 24,565 MW, a 0.2 percent decrease from November 2002. However, December's colder weather resulted in average loads higher than last December. Loads averaged 25,583 in December 2003, a 2.8 percent increase over December 2002. The following charts compare November and December loads for the two years.

Figure 1a. November Loads: 0.2% decrease in 2003 v. 2002

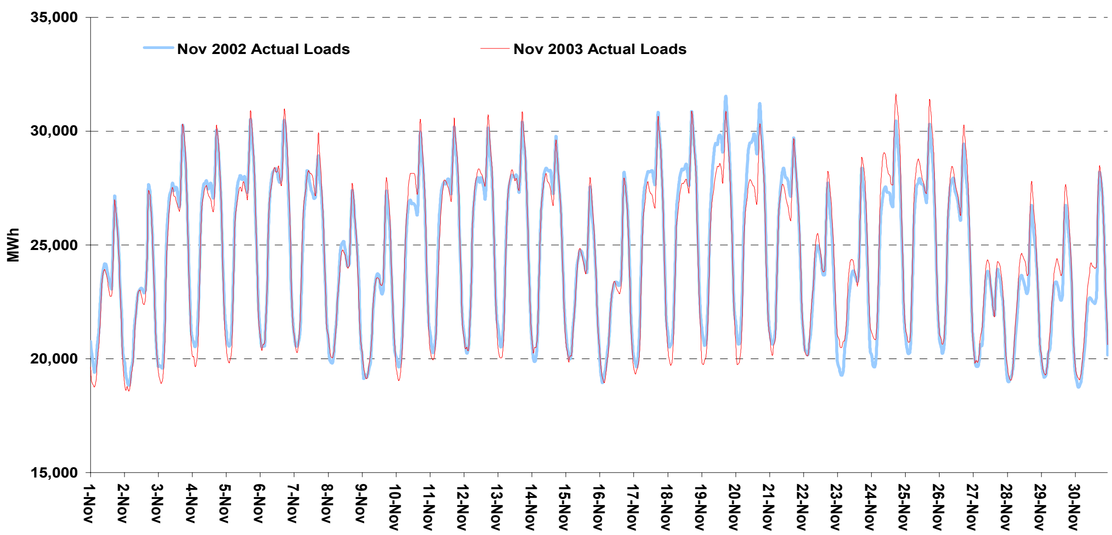
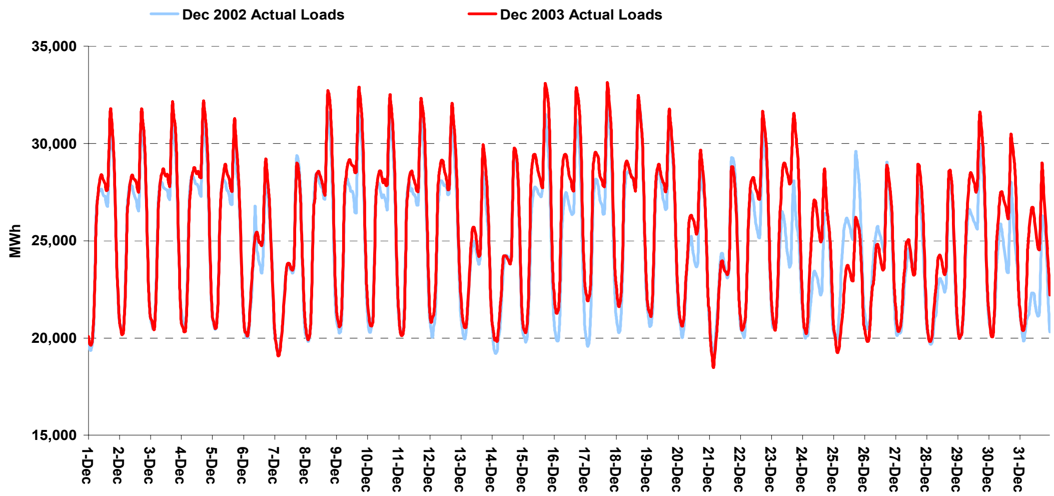
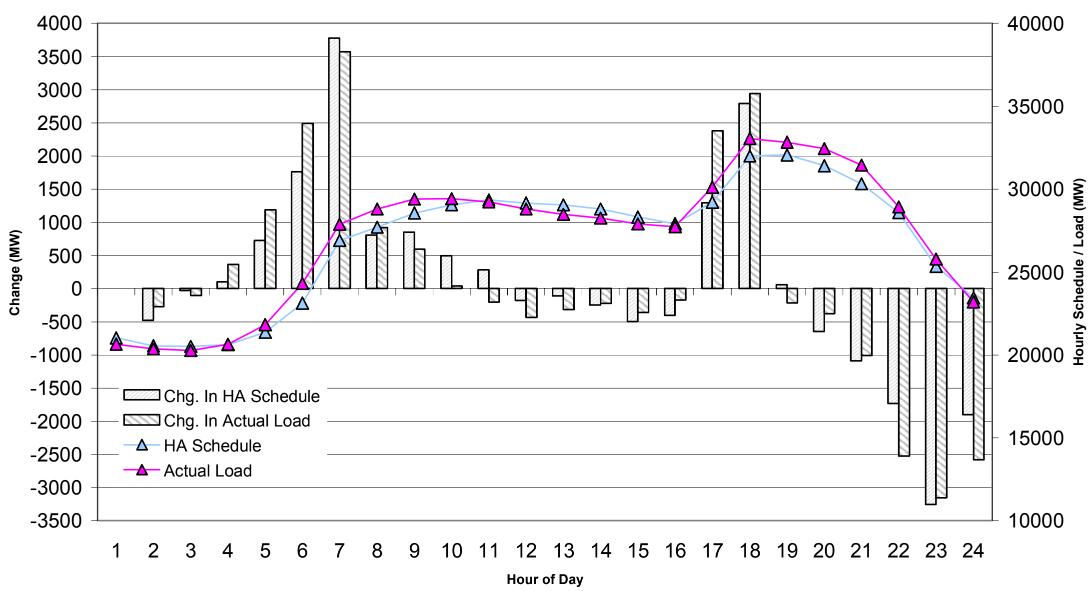


Figure 1b. December Loads: 2.8% increase in 2003 v. 2002



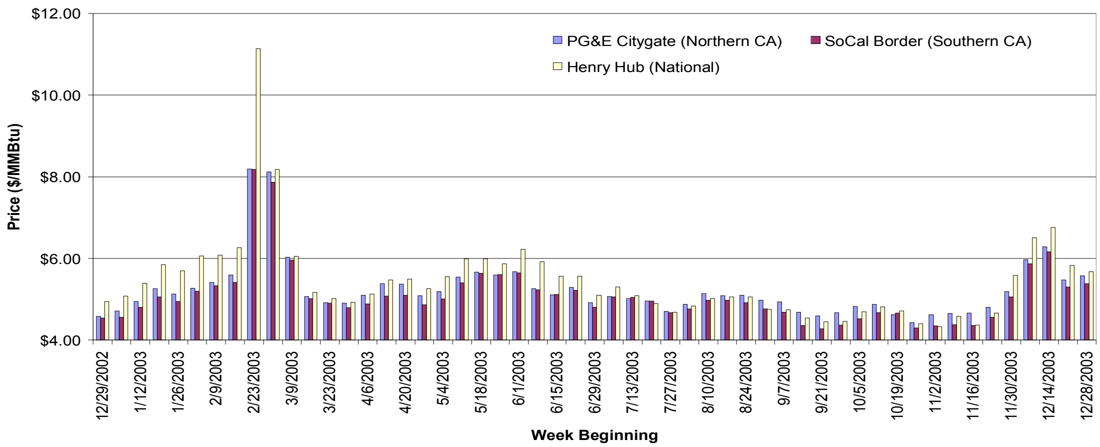
With the shift to the winter load pattern, system balancing has been increasingly challenging during the early-evening ramp. Between 4:00 and 7:00 p.m., the load rapidly approaches its daily winter peak, driven primarily by residential heating, lighting, and appliance use. Meanwhile, the amount of forward-scheduled energy available in each time period has not perfectly coincided with the load change in these hours. The difference between the forward-scheduled energy available and the corresponding load must be recovered in the real-time balancing market. This can also be a problem during 5:00 to 7:00 a.m., and 9:00 to 11:00 p.m. Monday through Saturday, when energy scheduled through the State of California's long-term energy contracts differ from rapid changes in load. The following chart shows the hourly load profile for December 15, a day in which a steep load ramp and an insufficient match between load and forward schedules contributed in part to a price spike.

Figure 2. Hourly Loads and Schedules: Totals and Hourly Changes, December 15, 2003
Unmatched in hour ending 17:00 (4:00-5:00 p.m.)



Gas Prices. In early December, unseasonably cold weather in many regions of the United States caused the price of natural gas, the primary fuel for electricity generation in California, to reach its highest level since an extraordinary spike in March 2003. For more information, please see the section below on natural gas markets.

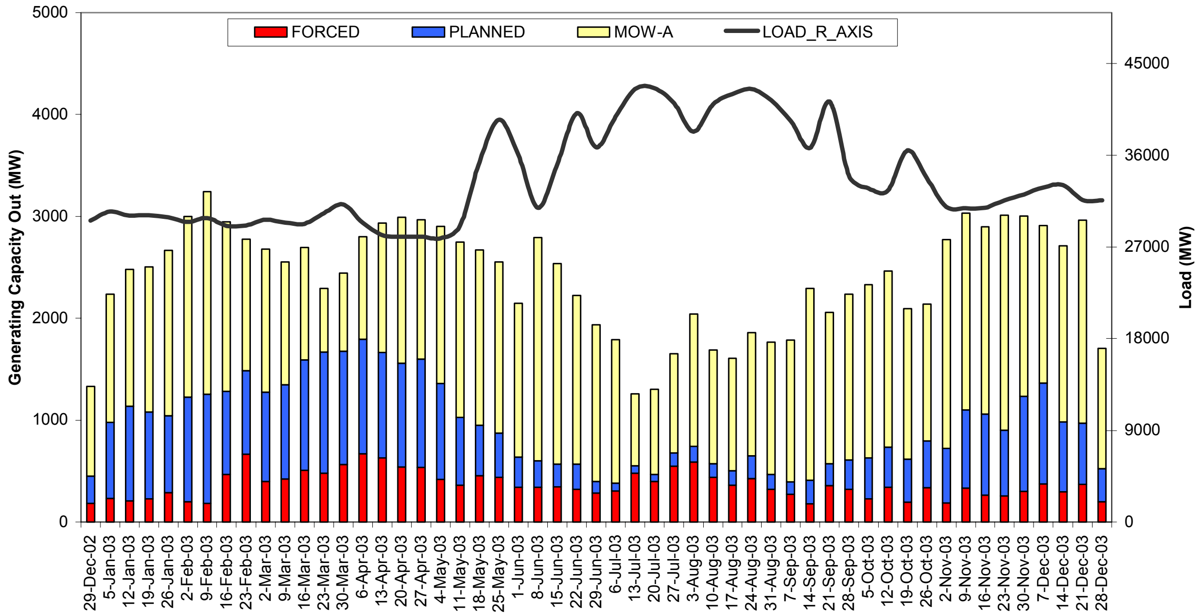
Figure 3. 2003 Weekly Average Natural Gas Prices: Above $6/MMBtu[1] in December



Outages. November and December typically have low-load shoulder periods during which units are often scheduled to be off-line for maintenance. In early December, scheduled outages averaged over 5,000 MW. The ISO retained some units online by denying waiver applications to the Must-Offer Requirement in order to meet balancing requirements during sharp load swings in the early evenings. (Please see the description of Minimum Load Cost Compensation below for more information.) The following chart shows weekly average outages for 2003.

[1] MMBtu: Millions of British thermal units, a unit of natural gas

Figure 4. Weekly Average Outages by Outage Type:[2]
Significant Seasonal Scheduled Outages in November and December



II. Real-Time Balancing Energy Markets

- ***Out-of-Sequence Procurement in Southern California continues to be costly***
- ***Significant incremental energy dispatches during evening ramp period results in system-wide price spikes***
- ***Imports bids have returned to the real-time market***

The ISO pays the incremental price to generators to increase output above schedules whenever actual load exceeds scheduled generation; generators pay the decremental price to the ISO to decrease output whenever actual load falls short of scheduled generation.

Activity in the ISO's real-time balancing market continues to be largely in the decremental direction. Long-term and other forward-contracted products have been more than sufficient to meet the November and December loads in most hours. Incremental and decremental awards respectively have averaged 76 and 432 MW in November and 110 and 494 MW in December. The average incremental ("INC") price in November was $54.58/MWh, the lowest seen in 2003. December's price was $69.35/MWh, compared to October's price of $74.59/MWh. Decremental ("DEC") prices have declined slightly since their July peak. November and December averages were $18.88 and $15.69/MWh, respectively, compared to $18.09 in October. The following tables show monthly volume-weighted average prices, total awarded energy, average load, and average deviations of schedules from actual load in peak and off-peak periods in November and December The chart following shows monthly price and volume trends in 2003.

2 "MOW-A" denotes units off-line by application for Must-Offer waiver.

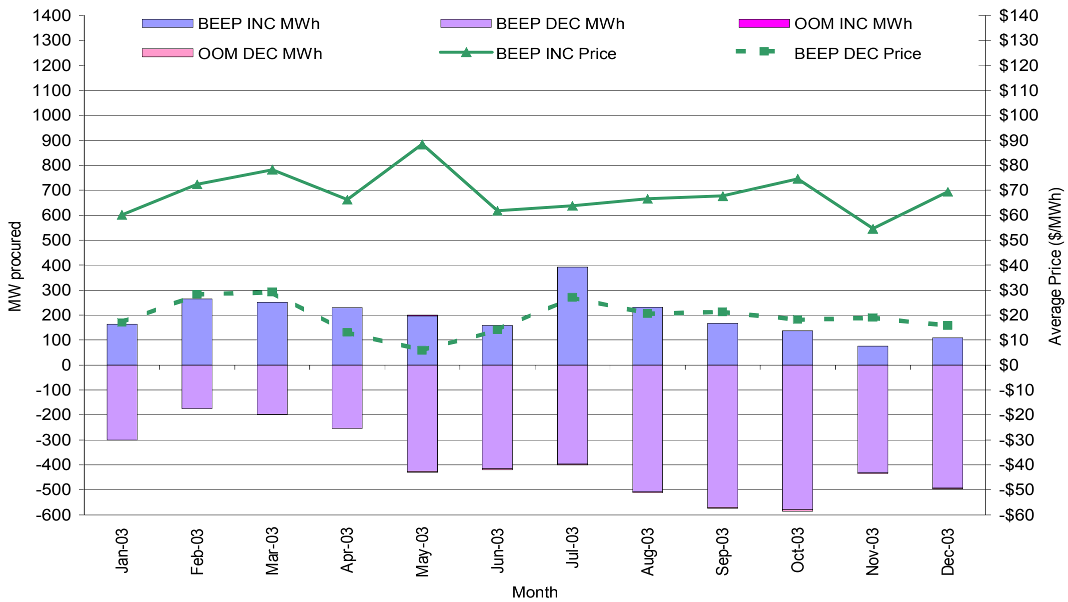
Table 1a. Average Real-Time Balancing Energy Prices and Total Awarded, Average System Loads, and Average Deviation from Schedules, in November

	Overall Avg. Real-Time Price and Total Awarded Energy		Avg. System Loads (MW) and Pct. Underscheduling
	Inc	Dec	
Peak	$56.15	$20.80	26,419 MW
	37 GWh	211 GWh	-0.3%
Off-Peak	$51.23	$14.90	20,858 MW
	17 GWh	101 GWh	-1.5%
All Hours	$54.58	$18.88	24,565 MW
	54 GWh	312 GWh	-0.6%

Table 1b. Average Real-Time Balancing Energy Prices and Total Awarded, Average System Loads, and Average Deviation from Schedules, in December

	Overall Avg. Real-Time Price and Total Awarded Energy		Avg. System Loads (MW) and Pct. Underscheduling
	Inc	Dec	
Peak	$ 68.67	$ 18.69	27,541 MW
	61 GWh	245 GWh	-0.2%
Off-Peak	$ 71.32	$ 9.75	21,668 MW
	21 GWh	123 GWh	-0.8%
All Hours	$ 69.35	$ 15.69	25,583 MW
	82 GWh	369 GWh	-0.4%

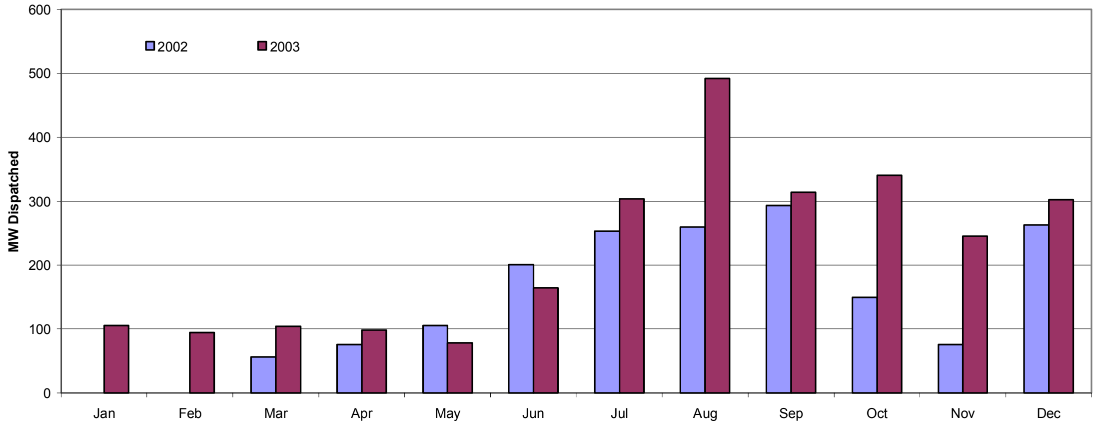
Figure 5. Monthly Average Prices and Volumes in the Real-Time Balancing Market: Volume Continues to be largely Decremental



Minimum Load Cost Compensation. To ensure reliability, the Federal Energy Regulatory Commission directed in its June 19, 2001 Order, upheld in later Orders, that all participating generation in the ISO Control Area must offer all available capacity into an ISO market (the "Must-Offer Obligation"). The Commission then approved a process by which units may apply to the ISO for waivers from the Must-Offer Obligation when not needed for reliability. In the event such a waiver is denied, the ISO will compensate the denied units their minimum-load operating costs, based upon a current gas price index.

An average of 245 and 302 MW of capacity in November and December, respectively, were denied applications for waiver to the Must-Offer Obligation and held on minimum load. The average was 340 MW in October. The capacity held on minimum load in November represents a 227 percent increase from November 2002, due largely to reliability concerns resulting from intrazonal congestion within Southern California. The following chart shows capacity held on-line by denial of waiver applications to the Must-Offer Obligation, and thus entitled to minimum-load cost compensation, since March 2002.

Figure 6. Average Dispatched Capacity Entitled to Minimum-Load Cost Compensation: Higher due to Reliability Concerns surrounding Intrazonal Congestion Issues



Intrazonal (within-zone) Congestion. Lower loads in November resulted in a decrease in the number of incremental out-of-sequence (OOS) dispatches. However, increased loads and a derating of the Sylmar substation resulted in a significant increase in OOS dispatches in December. The ongoing new generation problem in northern Mexico caused the level of decremental OOS dispatches to remain at the high levels seen in recent months.

Incremental OOS Dispatches. A total of 48,103 MWh and 249,011 MWh of incremental energy was called out-of-sequence (OOS) by ISO operators to address intrazonal congestion in November and December respectively. In November the average price paid was $54.30/MWh. The re-dispatch premium in excess of the Market Clearing Price (MCP) was approximately $1.2 million, or $25.47/MWh. In December the average price paid was $67.89/MWh and the re-dispatch premium in excess of the Market Clearing Price (MCP) was approximately $9.7 million, or $39.11/MWh.

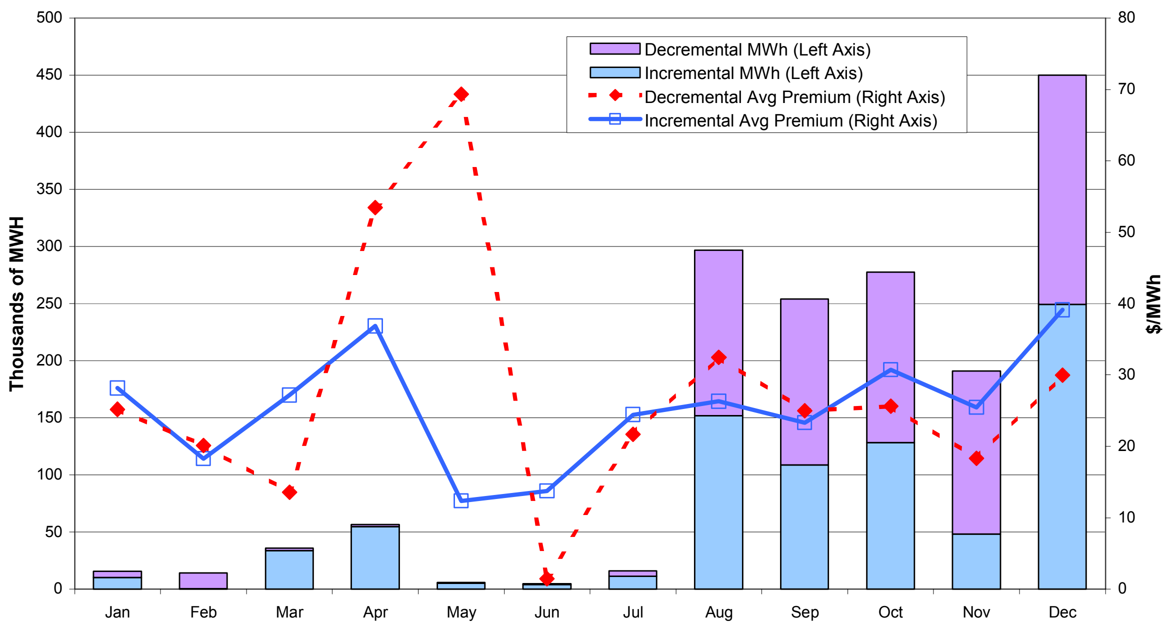
There were a number of reasons for these incremental dispatches.

1. At the Sylmar substation, Bank E was out for maintenance for three weeks in December. This had cumulative effects on the rest of the grid, especially in the Victorville-Lugo area. The vast majority of the incremental OOS calls were due to this maintenance work and resulting mitigation measures.
2. Due to the fire in late March only two of the three Vincent 500/230 kV transformers have been in reliable service. At the end of November, the third bank finally became fully operational. There were intermittent incremental dispatches to generators south of Vincent until that date.
3. There were incidental OOS calls due to transmission line and substation maintenance.

All incremental OOS dispatches are subject to mitigation. For the year 2003, there has been a total of approximately $50 million of gross OOS incremental costs. The current mitigation structure has resulted in approximately $2.3 million in cost reductions year-to-date (4.7% of gross costs, or 9.3% of the re-dispatch premium), due to incremental OOS bid mitigation.

Decremental OOS Dispatches. The ISO dispatched a total of 142,883 MWh and 200,717 MWh of decremental energy out of sequence in November and December respectively. All of this energy was settled according to the provisions of the Amendment 50 mitigation measures approved by FERC. The approximate re-dispatch premium in excess of the market clearing price was $2.6 million in November and $6 million in December. As in previous months, almost all of the decremental activity was due to intrazonal congestion in the San Diego region caused by the new generation units located in northern Mexico. The following chart shows the OOS volumes and redispatch premiums.

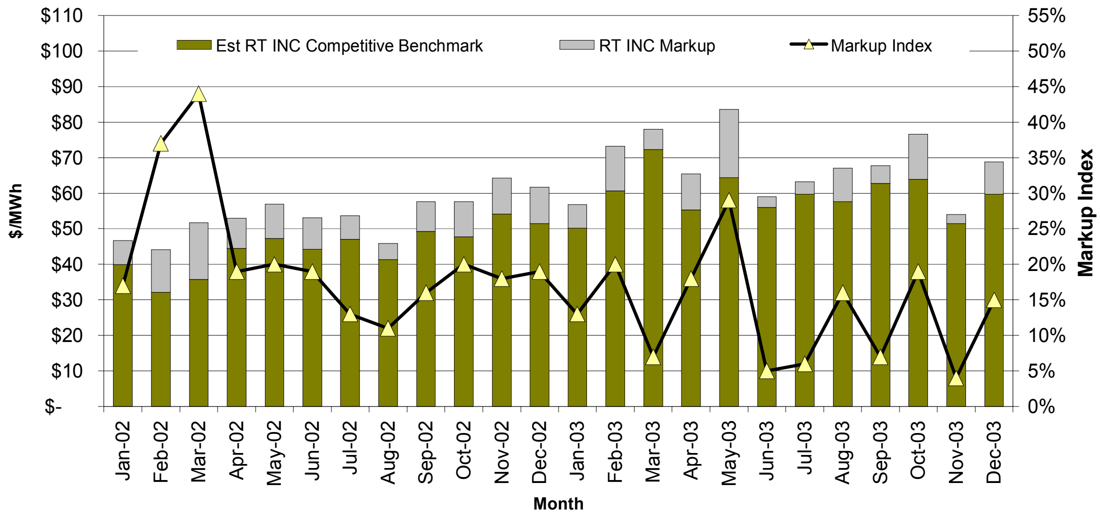
Figure 7. Out-of-Sequence Volume and Average Redispatch Premium: Incremental due to Substation and Transmission Outages; Decremental due to Transmission Bottlenecks between Mexican Generation and San Diego



Market Power. One measure of market power, or the ability of one or more sellers to force prices above those that would exist in a competitive market, is price-to-cost markup. The Department of Market Analysis is temporarily using a conservative estimate of market power based upon real-time incremental balancing energy only, until short-term bilateral forward contract information once again becomes available. Please see the Market Analysis Report for September 2003 for more information.

Low prices and a soft market in November resulted in a record low 4 percent monthly average price-to-cost markup. The markup rose to 15 percent in December, approximately 37 percent of which was accrued during price spikes on December 15 and 26. The discussion on price spikes below notes extraordinary levels of markup in individual hours. The following chart shows monthly real-time price-to-cost markup, a measure of market power, through December 2003.

Figure 8. Temporary Competitiveness Index
Real-time Price-to-Cost Markup through December:
37% of the December Markup Due to Spikes on December 15 and 26



Systemwide Incremental AMP Performance and Price Spikes. For actual bid mitigation to occur under the AMP, three screening conditions must be met: 1) the predicted imbalance energy price must be greater than $91.87/MWh; 2) one or more bids must violate the conduct test; and 3; the resulting change in the market clearing price must pass the market impact test.[3] Since its implementation on October 30, 2002, no bids have been mitigated under AMP. In November, no bids failed the AMP conduct test in any hour. In December, bids failed the test in 13 hours by an average of 9 units in each hour, with actual incremental dispatches of six of them. No unit whose bid failed the conduct test in a specific hour was awarded a dispatch in that same hour.

The Department of Market Analysis tracks "potential" conduct test failures, or bids – particularly awarded bids – that would have failed the conduct test in an hour that the conduct test was not actually applied due a bid being above the price screen limit.[4] There were approximately eight individual situations in November and seven in December in which an awarded bid would have failed the conduct test if the bid price had exceeded the price screen of $91.87/MWh. All such bids were from hydroelectric resources and all were below $91.87/MWh. A number of gas-fired thermal units that were awarded dispatches that would have failed the conduct test multiple times if it had been applied, some in as many as 17 distinct hours over the course of the two months. However, the actual bid steps that were awarded were not in violation of conduct test thresholds. Only other out-of-merit portions of the units' bids would have caused the thermal units' bids to fail the conduct test. Thus, we conclude that nonapplication of the conduct test did not cause price spikes in either November or December.

There were multiple costly price spikes in both November and December. The following charts show hourly average incremental and decremental prices for these months.

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[3] The Conduct Test is violated if a bid is either $100/MWh or 200 percent greater than the units reference level bid. The Impact Test is passed if the mitigated MCP is $50 less or 200 percent less than the unmitigated MCP.
[4] In these instances, the forecasted imbalance energy price was less than the $91.87/MWh price screen so AMP was not applied.

Figure 9a. Hourly Average Real-Time Balancing Energy Prices for November

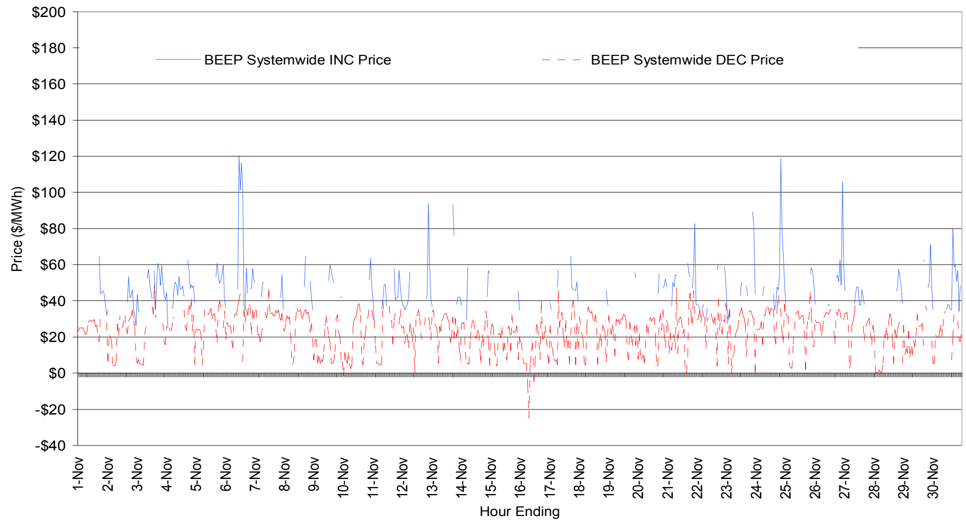
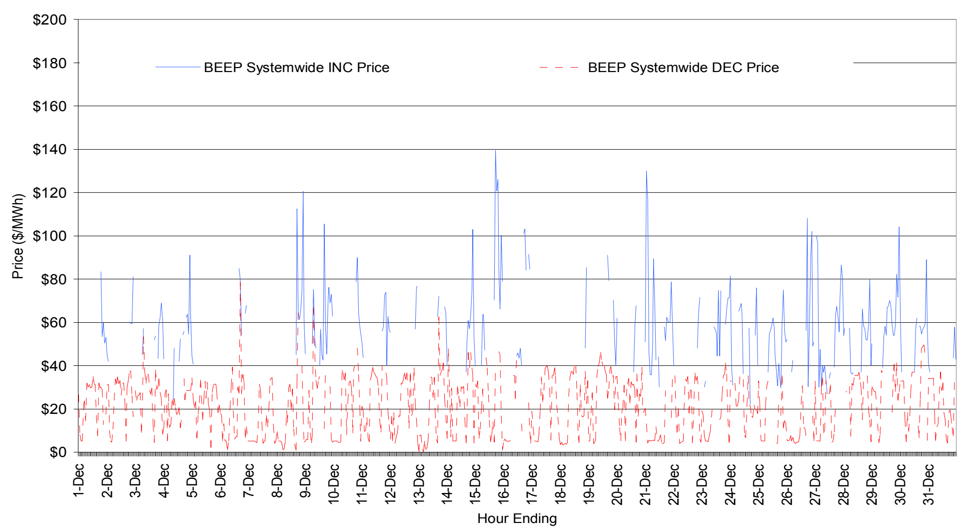


Figure 9b. Hourly Average Real-Time Balancing Energy Prices for December



On November 6, the ISO curtailed flows into Southern California pursuant to the Southern California Import Transmission Nomogram (SCIT) causing the incremental balancing energy price to spike to $125.86/MWh within SP15. The market impact[5] of this spike was nearly $100,000.The same unit setting the November 6 price set the price again on November 13 at $125.86/MWh following a contingency due to resource loss. This spike had a market impact of approximately $21,000.

[5] Market impact is defined as the increase in price of the spike over the monthly average for an equal volume of energy.

On November 16, forward-scheduled energy that exceeded the morning load ramp caused generation to exceed load. The ISO awarded decremental bids and depleted the bid stack. The lowest-priced bid of -$25/MWh set the DEC price.[6] Over 2,500 MWh were procured with an approximate market impact of $135,000.

On December 8, schedule cuts due to a curtailment and generation short of load required a rapid incremental dispatch. This caused the price to fluctuate between $117 and $137/MWh for one hour around the end of the peak-hour period (21:50 through 22:40). The price was alternately set by a municipal hydroelectric unit, which would have failed the AMP conduct test had the predicted MCP been above $91.87/MWh, and a large thermal unit. Market impact was approximately $50,000.

On December 15, a spike lasted from 5:10 p.m. to 8:00 p.m. system-wide in the market, as an operating reserves deficiency necessitated that the ISO skip energy bids from ancillary services.[7] Meanwhile, as shown in Figure 2 above, changes in scheduled energy varied from load by over 1,000 MW. At this time, the ISO was also making OOS calls to manage intrazonal congestion. The price ranged between $100 and $141/MWh, with a market impact of approximately $142,000. We estimate price-to-cost markup in these hours to have reached a maximum of 90.5 percent. This day accounted for approximately 27 percent of the monthly total markup.

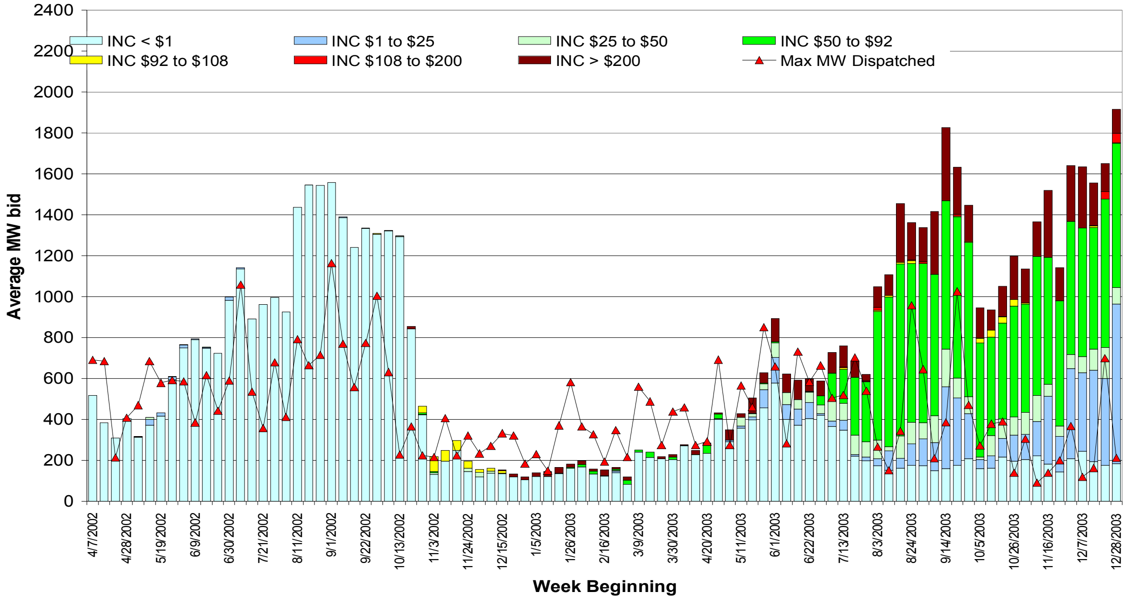
On December 21, a forced derate of Path 26 caused the price to rise to $130/MWh from 1:40 to 2:50 a.m. This spike had a market impact of approximately $56,000. We believe that no part of that impact was due to markup.

On December 26, a series of spikes due to ISO software issues and a ramp planning miscalculation caused the price to vary from $100 to $110.86/MWh intermittently for a total of 110 minutes between 5:20 p.m. and 9:40 p.m. The market impact of these combined spikes was approximately $120,000. This day accounted for approximately 10 percent of the monthly total markup.

Import bids into the Real-Time Market. The restriction that real-time balancing energy bids imported from resources outside the ISO Control Area (also known as System Resources) bid incremental energy at a price of $0/MWh was lifted by the Commission on June 25, 2003. Since that time, import bids have made a robust return to the real-time market, varying throughout the fall, but exceeding 1,600 MW on average in December. In comparison, the import bid volume in December 2002 was less than 200 MW on average. Additionally, volume growth has been primarily among bids priced below $25/MWh. The following chart shows weekly average import bid volume in the real-time balancing energy market through December 2003.

[6] Suppliers pay the DEC price to the ISO in order to generate at levels below their forward-contracted schedules. When the DEC price is negative, the ISO effectively pays sellers to generate less energy.
[7] ISO Operating Procedure M-430

Figure 10. History of Import Bid Volume in Real-Time Market: Weekly Averages through December 2003



III. Ancillary Services Markets

- ***Average prices for all services were moderate compared to prices during the summer of 2003.***
- ***Frequent bid insufficiency in the spin market caused deficiencies in the amount of operating reserves acquired through the market.***
- ***RMR contracts were called to supply reserves that could not be procured through the A/S markets.***
- ***In many hours, A/S markets accepted the highest-priced bid offered, as all bids were exhausted.***

Market Prices. Market prices for spinning (SP) and non-spinning (NS) reserve were lower on average in November and December than in October. However, these prices increased from November to December. Market prices for regulation up (RU) decreased from October to November then increased substantially in December. In the regulation down (RD) market, prices increased through all three months. A major factor driving these price fluctuations was bid insufficiency prevalent during November and December 2003.

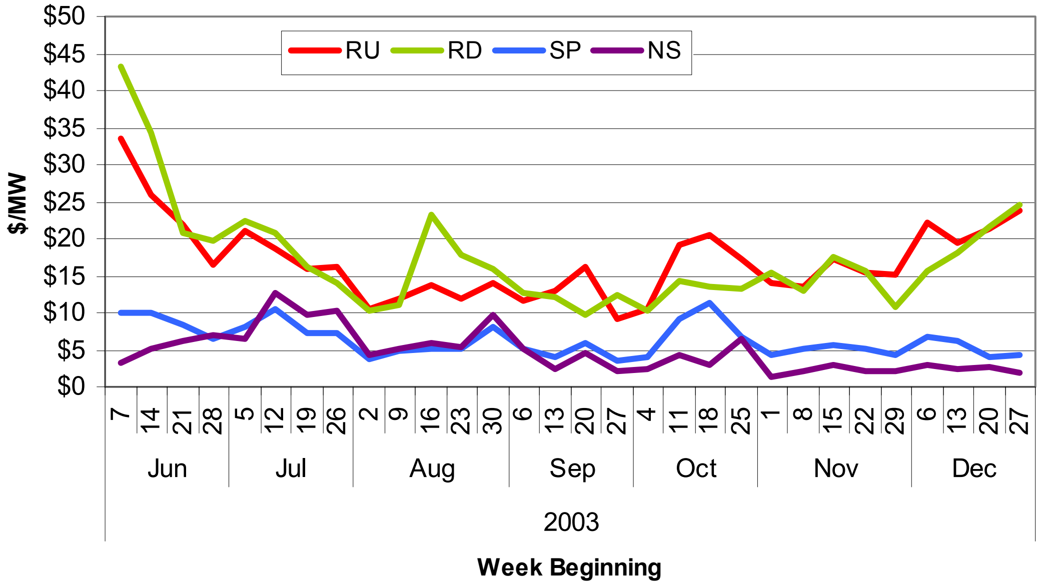
Demand for all ancillary services was lower on average in November and December than in October. This accounts for the decrease in the prices of operating reserves (SP, NS). It does not account for the increases in the prices of the regulation products (RU, RD). These increases correspond to increases in the frequency and intensity of bid insufficiency in the related markets.

Table 2. A/S Average Requirement and Price

	Average Required (MW)				Weighted Average Price ($/MW)			
	RU	RD	SP	NS	RU	RD	SP	NS
Oct 03	382	404	796	731	$ 16.23	$ 12.73	$ 7.24	$ 3.85
Nov 03	360	385	688	656	$ 15.20	$ 15.22	$ 4.76	$ 2.14
Dec 03	370	388	714	653	$ 20.35	$ 18.19	$ 5.42	$ 2.54

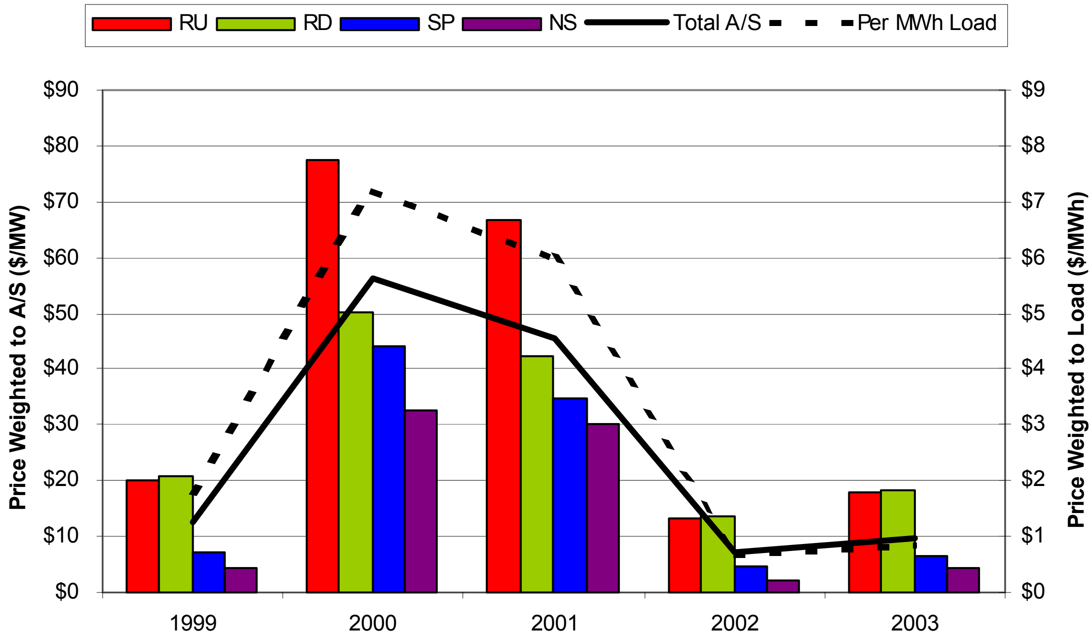
Prices in the RU and RD markets increased throughout December. Prices in the NS markets remained steady throughout the two-month period. Prices in the SP markets peaked higher than in weeks in early December during a period of severe, *day-ahead* bid insufficiency.

Figure 11. A/S Weekly Weighted-Average Prices
October – December 2003: Increase in Regulation Prices



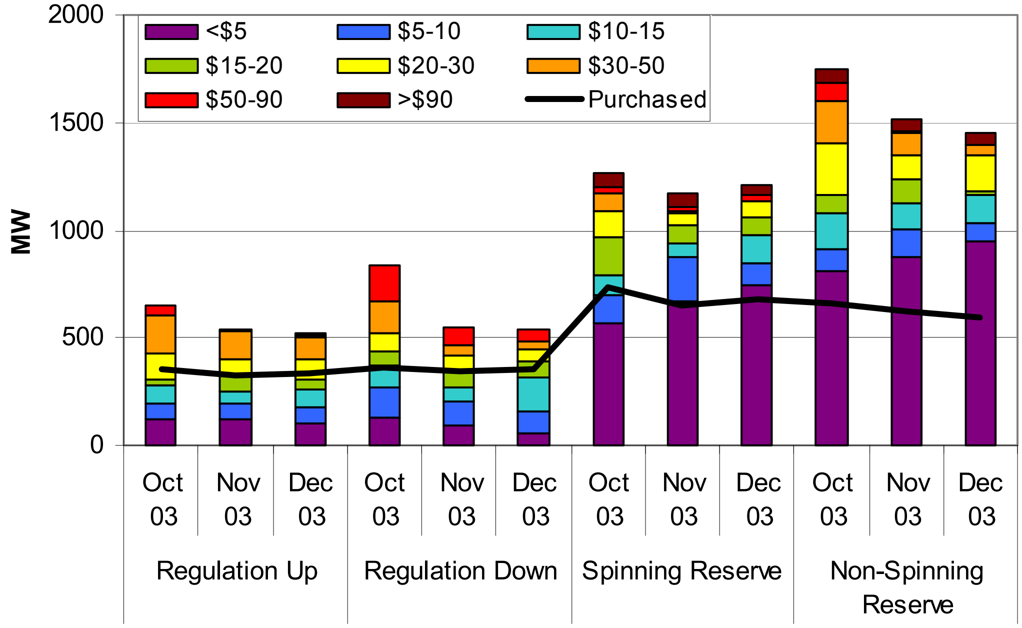
The following chart shows annual weighted-average prices for the four ancillary service products that are actively procured. Ancillary service prices in 2003 were greater than in 2002 by an average of 39% (from an average of $7.11/MW in 2002 to $9.85/MW in 2003). Ancillary services prices in 2003 were lower than prices in any complete year other than 2002 which had the lowest prices in the history of the markets.

Figure 12. A/S Annual Weighted-Average Prices, 1999 – 2003
2003 average prices 39% above 2002 averages, but below all other years' averages



Market Bids. Overall supply decreased for all ancillary service products from October to November/December. Bid composition trends in the operating reserve markets (SP, NS) favored decreasing prices. Bid composition in the regulation (RU, RD) markets combined with a decline in bid volume favored increasing prices.

Figure 13. Ancillary Service Bid Composition, October - December 2003: Declined



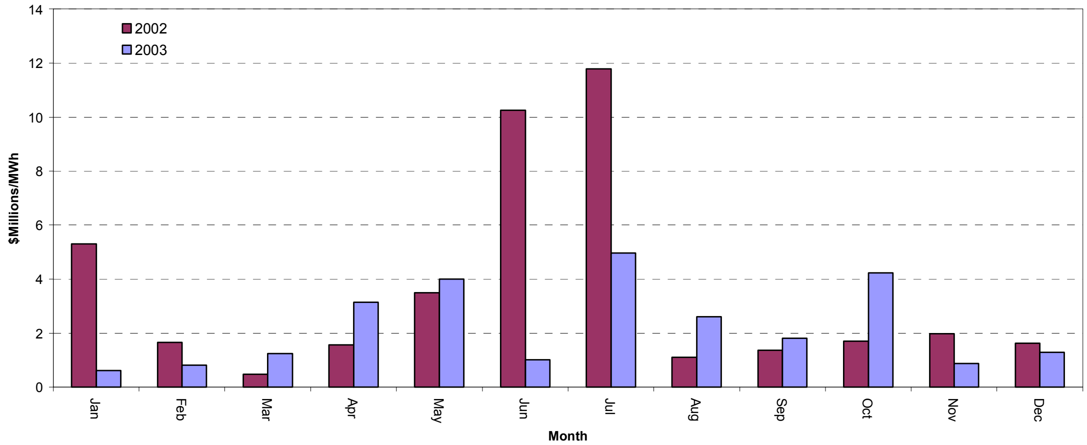
Please see the section on Issues under Review for discussion of continuing bid insufficiency in the A/S markets.

IV. Interzonal Congestion Markets

- ***Interzonal Congestion Costs Decrease in November and December 2003***

Interzonal Congestion costs were $870,000 and $1.28 million in November and December respectively, a significant decrease from the $4.2 million reported in October. Most noticeably, Path 26 has been less congested in these two months, both in the number of congested hours and total congestion costs. Congestion costs on Path 26 totaled approximately $2,000 and $98,000 respectively in November and December, substantially less than the $3 million in October. The other major congested paths are COI, El Dorado, and Palo Verde branch groups. All report a monthly congestion cost greater than $100,000. The following chart shows monthly total congestion costs in 2002 and 2003.

Figure 14. Interzonal Congestion Costs in 2002 and 2003



Most congestion on the California-Oregon Intertie (COI), one of two major branch groups that import power from the Pacific Northwest to the CAISO control area, was due to line de-rates. The import capacity of COI was derated from about 4,800 MW to as low as 3,000 MW for some days in these two months due to scheduled maintenance. Congestion prices were modest, peaking at approximately $7/MWh. The import capacity on the Pacific DC Intertie (also known as the North-of-Oregon Border Intertie, or NOB) remained at 725 MW, significantly lower than its normal import capacity of about 2,000 MW.

Congestion on El Dorado occurred during a few days. In a few hours on November 24, the import capacity of this line decreased from approximately 1,200 MW to 800 MW. Congestion prices at this time exceeded $30/MWh and peaked at $60/MWh in the day-ahead market. In December, congestion occurred only during a few hours on December 1, 10, and 11, with the highest congestion price being approximately $45/MWh.

Congestion on Palo Verde occurred more frequently throughout November and December. For a significant number of hours, the scheduled flow on the line had exceeded or had been near the import capacity of the line. Day-ahead schedule curtailment was frequent in December because submitted preferred schedules exceeded the line capacity. The highest congestion price was $10/MWh. Total congestion costs were $525,000 and $282,000 in November and December, respectively. The following tables show Interzonal congestion frequencies and prices in November and December.

Table 3a. Interzonal Congestion Frequencies and Prices, November 2003

	Day-Ahead Market				Hour-ahead Market			
	Percentage of Hours Being Congested (%)		Average Congestion Price ($/MWh)		Percentage of Hours Being Congested (%)		Average Congestion Price ($/MWh)	
	Import	Export	Import	Export	Import	Export	Import	Export
COI	18	0	$1		4	0	$4	
ELDORADO	1	0	$35		1	0	$16	
LUGOIPPDC	0	0			1	0	$30	
LUGOTMONA	0	0			0	0	$30	
MEAD	0	0			0	0	$35	
NOB	6	0	$0		3	0	$0	
PALOVRDE	13	0	$3		3	0	$13	
PATH 15	16	0	$0		2	0	$9	
PATH 26	0	1		$0	0	0		$0
SUMMIT	1	0	$0		0	0		

Table 3b. Interzonal Congestion Frequencies and Prices, December 2003

	Day-Ahead Market				Hour-ahead Market			
	Percentage of Hours Being Congested (%)		Average Congestion Price ($/MWh)		Percentage of Hours Being Congested (%)		Average Congestion Price ($/MWh)	
	Import	Export	Import	Export	Import	Export	Import	Export
CASCADE	9	0	$0		3	0	$0	
COI	34	0	$1		18	0	$10	
ELDORADO	6	0	$14		2	0	$17	
LUGOIPPDC	0	0			2	0	$30	
LUGOTMONA	2	0	$0		1	0	$30	
LUGOWSTWG	1	0	$30		0	0		
MEAD	1	0	$1		0	0		
NOB	31	0	$0		15	0	$6	$7
PALOVRDE	22	0	$1		4	0	$19	
PATH 15	17	0	$0		8	0	$16	
PATH 26	0	6		$1	0	0	$0	$8
SUMMIT	4	0	$0		1	0	$0	

Table 4. Interzonal Congestion Costs, November 2003

Branch Group	Day-ahead		Hour-ahead		Total Congestion Cost		Total Congestion Cost		Total Congestion Cost
	Import	Export	Import	Export	Export	Import	Day-ahead	Hour-ahead	
COI	$97,104	$0	$7,665	$0	$104,769	$0	$97,104	$7,665	$104,769
ELDORADO	$203,119	$0	$302	$0	$203,421	$0	$203,119	$302	$203,421
LUGOIPPDC	$0	$0	$781	$0	$781	$0	$0	$781	$781
LUGOTMONA	$0	$0	$4,053	$0	$4,053	$0	$0	$4,053	$4,053
MEAD	$0	$0	$2,937	$0	$2,937	$0	$0	$2,937	$2,937
NOB	$3,200	$5	$1,201	$0	$4,400	$5	$3,205	$1,201	$4,406
PALOVRDE	$512,511	$0	$2,692	$0	$515,203	$0	$512,511	$2,692	$515,203
PATH 15	$33,231	$0	$0	$0	$33,232	$0	$33,231	$0	$33,232
PATH 26	$0	$1,898	$0	$0	$0	$1,898	$1,898	$0	$1,898
Grand Total	$849,166	$1,903	$19,630	$0	$868,796	$1,903	$851,069	$19,630	$870,700

Table 5. Interzonal Congestion Costs, December 2003

Branch Group	Day-ahead		Hour-ahead		Total Congestion Cost		Total Congestion Cost		Total Congestion Cost
	Import	Export	Import	Export	Export	Import	Day-ahead	Hour-ahead	
CASCADE	$780	$0	$0	$0	$781	$0	$780	$0	$781
COI	$310,893	$0	$17,098	$0	$327,991	$0	$310,893	$17,098	$327,991
ELDORADO	$452,882	$0	-$2,033	$0	$450,849	$0	$452,882	-$2,033	$450,849
LUGOMKTPC	$0	$2	$0	$0	$0	$2	$2	$0	$2
LUGOTMONA	$640	$0	$0	$0	$640	$0	$640	$0	$640
LUGOWSTWG	$24,316	$0	$0	$0	$24,316	$0	$24,316	$0	$24,316
MEAD	$2,873	$0	$0	$0	$2,873	$0	$2,873	$0	$2,873
NOB	$52,115	$0	$10,124	$15,353	$62,239	$15,353	$52,115	$25,477	$77,592
PALOVRDE	$281,581	$0	$23	$0	$281,604	$0	$281,581	$23	$281,604
PATH 15	$0	$0	$13,114	$0	$13,114	$0	$0	$13,114	$13,114
PATH 26	$0	$97,588	$2	$0	$2	$97,589	$97,588	$2	$97,590
Grand Total	$1,126,081	$97,590	$38,329	$15,353	$1,164,410	$112,943	$1,223,671	$53,682	$1,277,353

V. Firm Congestion Rights Market

FTR scheduling. FTRs can be used to hedge against high congestion prices and establish scheduling priority in the day-ahead market. As shown in the following tables, a high percentage of FTRs was scheduled on some paths (November: 74% on Eldorado, 86% on LOGOIPPDC, 67% on Palo Verde, 99% on Silver Peak in the import direction, and 41% on Path 26; December: 79% on Eldorado, 93% on LOGOIPPDC, 65% on Palo Verde, 100% on Silver Peak in the import direction, and 46% on Path 26). FTRs on those paths are mainly owned by Southern California Edison Company (SCE1) and municipal utilities.

Table 6. FTR Scheduling Statistics for November, 2003*

Direction	Branch Group	MW FTR Auctioned	Avg MW FTR Sch	Max MW FTR Sch	Max Single SC FTR Scheduled	% FTR Schedule – Dir
IMP	COI	745	176	500	500	24%
IMP	ELDORADO	510	377	410	410	74%
IMP	IID-SCE	600	410	432	412	68%
IMP	LUGOIPPDC	370	318	362	230	86%
IMP	LUGOMKTPC	247	1	8	8	0%
IMP	LUGOTMONA	167	86	92	52	51%
IMP	LUGOWSTWG	93	27	41	28	29%
IMP	MEAD	516	22	83	28	4%
IMP	NOB	686	29	147	100	4%
IMP	PALOVRDE	627	419	425	400	67%
IMP	SILVERPK	10	10	10	10	99%
EXP	LUGOMKTPC	247	3	6	6	1%
EXP	LUGOTMONA	543	2	132	132	0%
EXP	NOB	664	34	83	83	5%
EXP	PATH 26	1425	578	1282	560	41%

Table 7. FTR Scheduling Statistics for December, 2003*

Direction	Branch Group	MW FTR Auctioned	Avg MW FTR Sch	Max MW FTR Sch	Max Single SC FTR Scheduled	% FTR Schedule - Dir
IMP	BLYTHE	167	9	167	167	5%
IMP	COI	745	186	500	500	25%
IMP	ELDORADO	510	403	410	410	79%
IMP	IID-SCE	600	436	480	460	73%
IMP	LUGOIPPDC	370	346	362	230	93%
IMP	LUGOTMONA	167	80	92	52	48%
IMP	LUGOWSTWG	93	32	41	28	34%
IMP	MEAD	516	26	93	26	5%
IMP	NOB	686	60	161	100	9%
IMP	PALOVRDE	627	408	622	602	65%
IMP	SILVERPK	10	10	10	10	100%
EXP	LUGOMKTPC	247	3	4	4	1%
EXP	LUGOTMONA	543	0	10	10	0%
EXP	NOB	664	31	83	83	5%
EXP	PATH 26	1425	653	1291	560	46%

*only those paths on which 1% or more of FTRs were attached are listed.
** The FTRs on these paths were awarded to municipal utilities that converted their lines under the ISO operation and there were not released in the primary auction.

FTR Revenue per Megawatt. The following table summarizes the FTR revenue collected through December 2003. Positive FTR revenue appears only in a few branch groups, namely COI, El Dorado, and Palo Verde. The FTR revenues on COI (import), El Dorado (import), and Path 26 (north to south) were $100/MW, $248/MWh, and $249/MW respectively in November and $284/MW, $576/MWh, and $139/MW respectively in December.

Table 8. FTR Revenue Per MW ($/MW), December 2003

Direction	Branch Group	Net $/MW FTR Rev									Cumm Net $/MW FTRREV – Imp	Pro Rated NET $/MW FTRREV - Imp	FTR Auction Price
		Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec			
IMPORT	BLYTHE	69	0	231	1,422	376	0	0	0	0	2,097	2,797	5,460
IMPORT	COI	723	536	299	138	440	192	352	100	284	3,065	4,087	59,484
IMPORT	ELDORADO	0	0	1	0	0	268	516	248	576	1,609	2,146	33,888
IMPORT	LUGOIPPDC**	272	0	0	5,151	8	0	30	2	0	5,463	7,284	N/A
IMPORT	LUGOTMONA**	0	715	7	0	15	310	461	24	4	1,537	2,049	N/A
IMPORT	LUGOWSTWG**	3	0	0	0	0	9	0	0	261	273	365	N/A
IMPORT	MEAD	166	0	14	150	85	137	158	4	3	716	955	46,920
IMPORT	NOB	249	203	68	96	118	42	68	5	86	935	1,246	73,470
IMPORT	PALOVRDE	233	15	5	251	355	413	49	249	139	1,710	2,280	88,167
IMPORT	PATH 26	0	0	5	0	0	0	0	0	0	5	6	1,470
IMPORT	SUMMIT	108	0	0	0	0	0	0	0	0	108	145	2,600
EXPORT	IID-SDGE	0	480	0	0	5,651	0	0	0	0	6,131	8,175	364
EXPORT	NOB	0	0	0	0	0	0	3	0	21	24	32	5,085
EXPORT	PATH 15	0	5	0	0	0	0	0	0	0	5	7	N/A
EXPORT	PATH 26	1,147	1,500	224	780	572	113	1,433	1	41	5,812	7,749	34,408
EXPORT	SILVERPK	0	0	720	0	0	0	0	0	0	720	960	100

*Pro-rate Annual FTR revenue is estimated based on the actual FTR revenue collected in this FTR cycle and assuming that FTRs would collect same rate of revenue in the remaining months of this FTR cycle.
** FTRs on these paths were awarded to municipal utilities that converted their lines to the ISO, and there were not released in the primary auction.

FTR Concentration There was no trade in the secondary FTR market in the month. Therefore, the FTR owner concentration table reported in April remains valid.

VI. Natural Gas Markets

- ***Natural gas prices increased by 28% from November to December due to cold Northeastern weather.***

Natural gas prices were essentially flat throughout November, with average West Coast prices lower than October averages. Henry Hub prices were slightly higher, although still fairly constant. Daily natural gas prices averaged $4.48/MMBtu at Henry Hub, $4.33/MMBtu at Malin, $4.67/MMBtu at PG&E Citygate, and $4.40/MMBtu at Southern California Border Average during

November 2003. Average bid week prices for December were $4.55, $4.52, and $4.86 for SoCal Gas, Malin, and PG&E Citygate, respectively, up 6%, 6%, and 7%, from November bid week prices.

Prices rose sharply during the first week of December, particularly at Henry Hub due to the severe blizzards in the Northeast and rising NYMEX futures prices on expectations of further cold weather. At Henry Hub, prices increased from $4.86/MMBtu on November 30 to $6.29/MMBtu on December 7. During this time there was also a substantial spread between California prices and Henry Hub owing to cold weather in the east, with Henry Hub prices averaging $0.60/MMBtu higher than California prices. During later weeks, prices continued their ascent until monthly highs were reached during the third week, when Henry Hub prices peaked on December 18 at $6.98/MMBtu. As the Christmas holiday approached, demand for natural gas fell, causing Henry Hub prices to decrease from $6.93/MMBtu on December 19 to $5.50/MMBtu on December 24. Average daily gas prices for December were $6.15/MMBtu at Henry Hub, $5.40/MMBtu at Malin, $5.74/MMBtu at PG&E Citygate, and $5.60/MMBtu at Southern California Border Average. Average bid week prices for January were $5.45, $5.29, and $5.59 for SoCal Gas, Malin, and PG&E Citygate, respectively, up 20%, 17%, and 15%, from December bid week prices. Figure 1, in the previous section on fundamental market trends, shows weekly average gas prices at regional delivery points through December.

Dow Jones Newswires reports that the Commodities and Futures Trading Commission has initiated an investigation into possible manipulation of the NYMEX natural gas futures market following the recent increase in daily natural gas prices and NYMEX Henry Hub natural gas futures prices.

VII. Bilateral Forward Electric Spot Markets

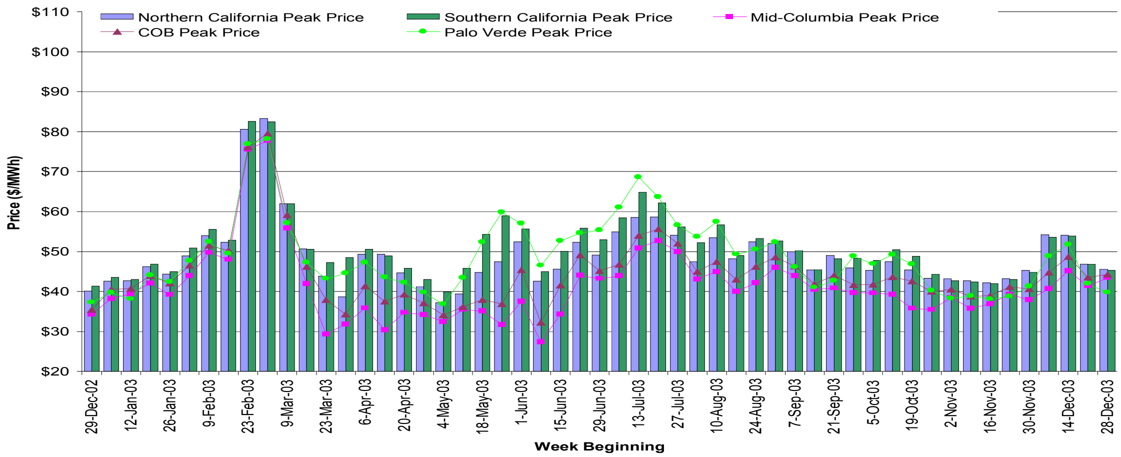
- ***Electricity prices increased by 18% from November to December on sharp rise in natural gas prices.***

Regional day-ahead electricity prices averaged $40.42/MWh at the California-Oregon Border, $37.94/MWh at Mid-Columbia, $39.41/MWh at Palo Verde, $43.79/MWh in Northern California, and $43.55/MWh in Southern California on the weekdays in November. Flat natural gas prices during the month helped to keep electricity prices near their monthly averages throughout November.

The sharp increase in natural gas prices in December drove electricity prices higher as well, with peak weekday regional day-ahead electricity prices averaging $45.46/MWh at the California-Oregon Border, $42.32/MWh at Mid-Columbia, $47.06/MWh at Palo Verde, $51.59/MWh in Northern California, and $51.17/MWh in Southern California. Prices did not change substantially during the first week of December. However, California prices increased from $44.65/MWh to $53.00/MWh between December 6 and December 8, coinciding with the increase in natural gas prices. Two days later, the monthly price peaked at $63.00/MWh in Northern California and $62.00/MWh in Southern California. For the remainder of the second and the third week, prices stayed in the range of $56/MWh. Reduced industrial load from the Christmas holiday dropped prices to about $50/MWh on December 23, and $45/MWh after December 26. Prices ended

December in the $50/MWh range. The following chart shows weekly average day-ahead bilateral electricity contract prices through December.

Figure 15. Weekly Average Day-Ahead Bilateral Electric Contract Prices



VIII. Issues under Review

- ***Bid insufficiency in the Ancillary Services Markets is ongoing.***
- ***AMP Quarterly Report to be released shortly.***

Ancillary Service Bid Insufficiency Status Update. The conditions causing ancillary service bid insufficiency in October have continued through November and December. Conditions causing insufficiency have also spread to the regulation up (RU) and non-spinning reserve (NS) markets. During October, bid insufficiency was primarily limited to spinning reserves (SP).

The following charts show the trends in bid insufficiency during the fourth quarter of 2003. Although the frequency (number of service-hours) of bid insufficiency peaked in October, the intensity (total peak MW deficient) peaked in December. During this period, market notices were issued several times encouraging participants to submit ancillary service bids based on severe, day-ahead bid insufficiency.

Figure 16. Daily Intensity of A/S Deficiency, Oct - Dec 2003

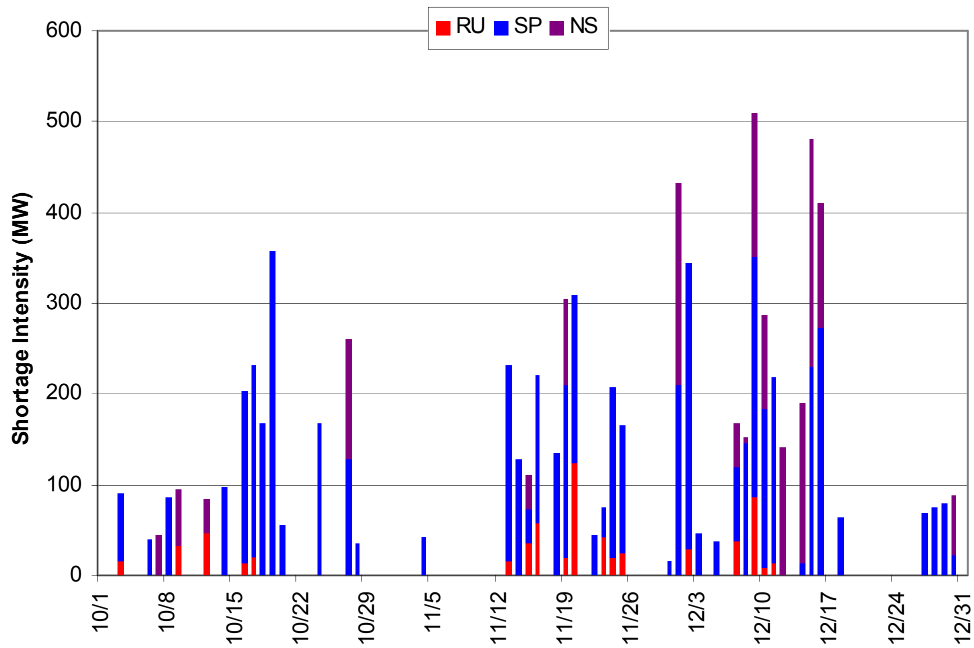
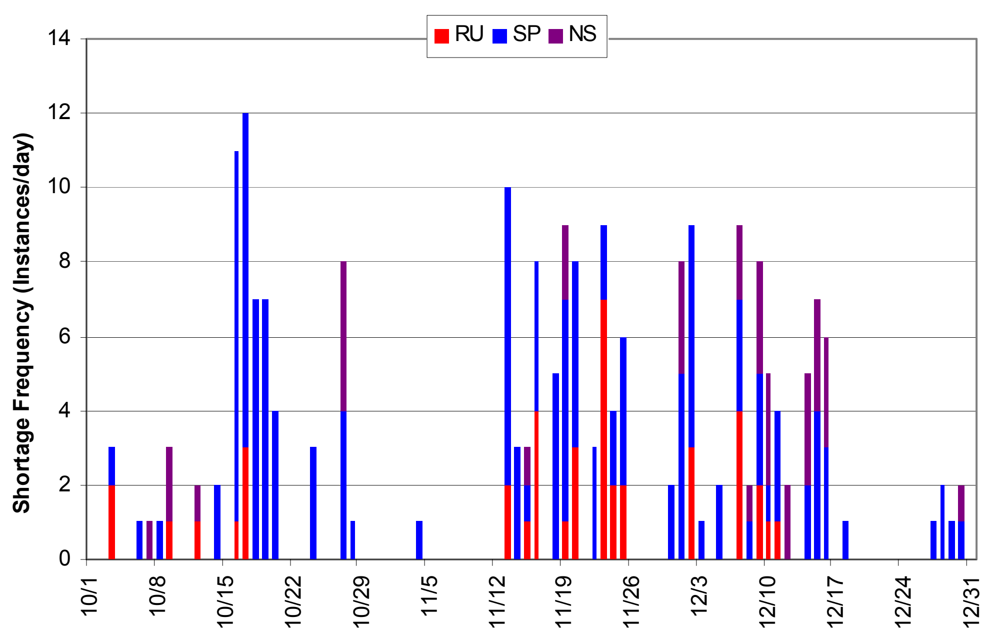


Figure 17. Daily Frequency of A/S Bid Deficiency



A discussion of the causes of this situation is available in the October 2003 monthly report.

AMP Report. The Department of Market Analysis has reviewed the performance of system-wide incremental AMP through September 2003 and completed a public report that will be filed with FERC shortly. This report evaluates the effectiveness of AMP in its ability to mitigate extraordinary instances of bidding behavior consistent with the exercise of market power. In particular, it considered the effects of the AMP conduct test and the "price screen," which dictates that the conduct test be applied only if a predicted price exceeds $91.87/MWh.

Our report concludes that most bids consistent with the exercise of market power are still within the thresholds permitted by AMP. Thus, they would not have failed the conduct test even if their price screen had exceeded $91.87 and AMP had been applied. It also finds that several key units' reference levels have moved upward, even when controlling for natural gas price adjustments.