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 Assistant

Date: February 18, 2005

Re: ***Market Analysis Report for January 2005***

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

Executive Summary

Load growth was moderate in January with loads averaging 25,211 MW. This was approximately 1.6 percent higher than January 2004 loads and approximately 1,000 MW lower than in December. The drop in average loads since December was due largely to milder weather and the end of the holiday lighting season.

Two nuclear units returned to service in the ISO control area in late December, significantly increasing the supply of power within California. The return of these key base load nuclear units and the return of the Pacific DC intertie reduced the need for the ISO to commit generation units within SP15 pursuant to the Must-Offer Obligation. This resulted in lower overall supply costs in January.

Average natural gas prices in January decreased from December levels, particularly in southern California and at the Malin hub. Gas prices remained flat around the $6/MMBtu range through much of January, responding to reports of above-average storage levels and despite cold temperatures throughout much of the east coast. Regional day-ahead power prices responded similarly decreasing by nearly $10/MWh between the start and end of January.

Increased supply coupled with lower demand in January resulted in significantly lower real-time imbalance energy costs to load per megawatt-hour for in-sequence energy in January. The average price paid to suppliers to increment generation above schedules was at its lowest point in over two years, averaging $54.23/MWh. Real-time energy price spikes continued to occur frequently, most often occurring when the real-time market application (RTMA) exhausts the incremental bid stack as it balances generation with actual load during ramping periods.

Intra-zonal (within zone) congestion costs remained high in January although lower than that measured in recent months as both incremental and decremental congestion volumes decreased. January out-of-sequence dispatches to mitigate intra-zonal congestion resulted in a net cost (re-dispatch premium) of approximately $5.6 million, down from $8.7 million in December. Inter-zonal (between zone) congestion costs totaled $4.2 million in January, due largely to transmission constraints on the Palo Verde and California-Oregon Interties.

The January ancillary services market was characterized by greater bid insufficiency than in December. The average prices for all services spiked upward before moderating later in the month. The tight supply in the ancillary service markets resulted in average ancillary service prices that were 48 percent higher than December levels.

I. Conditions Affecting Electricity Demand and Supply

- *Loads up slightly, but not at the rate seen in recent months*
- *Supply has been robust since the return of key nuclear units*
- *Due to strong supply, energy prices softened*

Loads. Loads averaged 25,211 MW in January 2005, approximately 1.6 percent higher than those in January 2004. For purposes of this calculation, the ISO (DMA) adjusted its load base since it no longer includes load served by the Western Area Power Administration (WAPA). Western load became part of the Sacramento Municipal Utility District (SMUD) control area on January 1. The WAPA areas averaged approximately 287 megawatts (MW) of load in January 2004 and had a 2004 summer peak of approximately 612 MW.[1] Using a 2004 baseline that excludes load from departed areas, load continues to grow, albeit more slowly than the trend of approximately 4 percent annually that the ISO has observed since the summer of 2003. The slowdown in growth may actually be more significant than the raw numbers suggest. Load increased despite two factors in January 2005 that normally would have an increasing effect on load: the lack of a mid-week New Year holiday (it fell on Friday, December 31, 2004), and colder temperatures in January 2005 compared to 2004. The chart immediately below compares hourly loads in January 2005 with January 2004 loads, excluding WAPA load. The table that follows shows indices of growth that compare similar months year-to-year.

[1] Occurred July 21, 2004, hour ending 16:00. At this hour the Western load represented 1.4 percent of the ISO's 44,267 MW load.

Figure 1. ISO Actual Load: January 2005 v. January 2004[2]

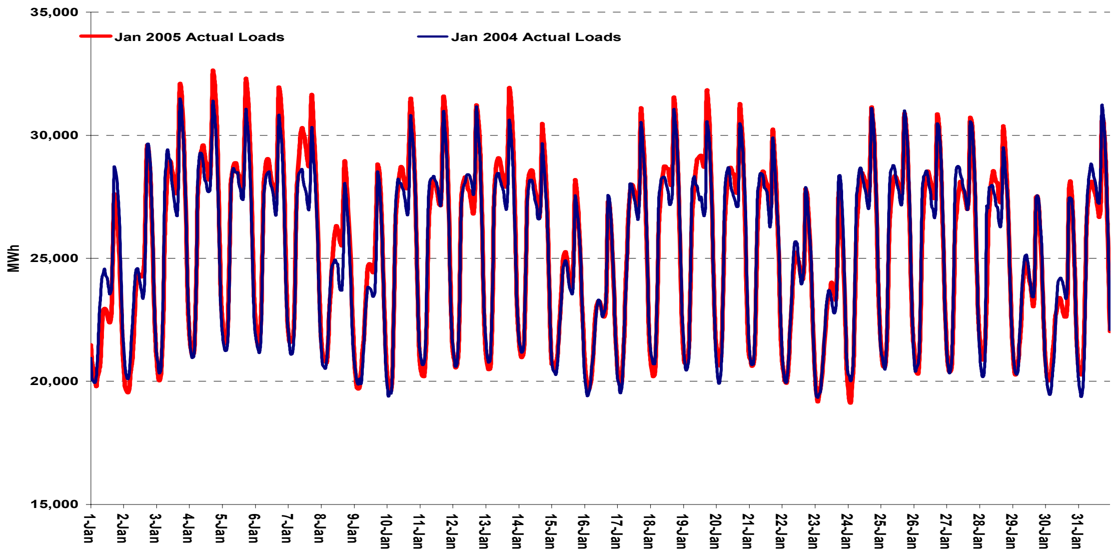


Table 1. Load Growth Indices through January 2005[3]

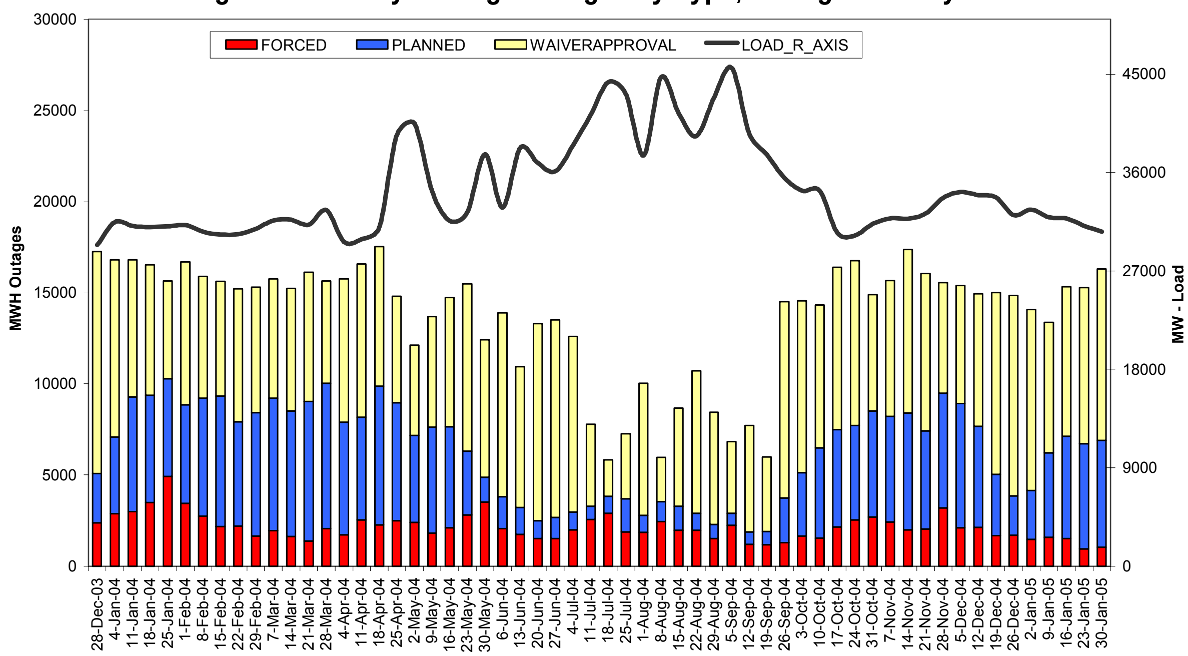
	Avg. Hrly. Load	Avg. Daily Peak	Avg. Daily Trough	Monthly Peak
February-04	4.5%	3.9%	5.4%	4.5%
March-04	4.4%	5.1%	2.5%	4.5%
April-04	7.1%	8.3%	4.8%	31.1%
May-04	7.3%	7.7%	5.5%	2.5%
June-04	6.6%	6.9%	6.1%	-4.7%
July-04	0.7%	0.3%	1.9%	4.0%
August-04	1.0%	0.6%	0.6%	5.2%
September-04	3.4%	3.5%	3.4%	10.1%
October-04	-1.4%	-2.8%	1.5%	-5.9%
November-04	4.2%	3.9%	3.9%	6.6%
December-04	4.4%	4.1%	6.5%	3.4%
January-05	1.6%	2.7%	1.4%	5.0%

Generation Supply. With three nuclear units returning to service in late December, the supply of power within the Western Interconnection, and within California in particular, increased substantially. While this was partially offset by a large gas-fired combined cycle plant outage within

[2] January 2004 adjusted for day of the week. Dates actually shown are 1/3/04 to 2/2/04.
[3] Uses top-of-hour loads through 7/10/03, and hourly average loads since 7/11/03.

SP15, the overall effect on supply was positive and significant. The following chart shows generation outages on a weekly average basis through January.

Figure 2. Weekly Average Outages by Type, through January[4]



Generation versus Load. The return of key base load nuclear units and the completion of the Pacific DC Intertie in December reduced the need for procurement within SP15 pursuant to the Must-Offer Obligation.[5] This resulted in lower overall supply costs in January. Meanwhile, loads were approximately 1,000 MW lower on average, thanks to milder weather and the end of the holiday lighting season. The following charts compare actual load to energy supply within SP15 (excluding in-sequence balancing energy) for Mondays through Saturdays in each of December and January.

[4] Data are subject to review and/or change.
[5] FERC, 6/19/2001 Order and subsequent Orders.

Figure 3. Actual Load v. Forward Schedules, Must-Offer Committed Generation, and Net OOS/OOM Generation within SP15: Mondays-Saturdays in December 2004

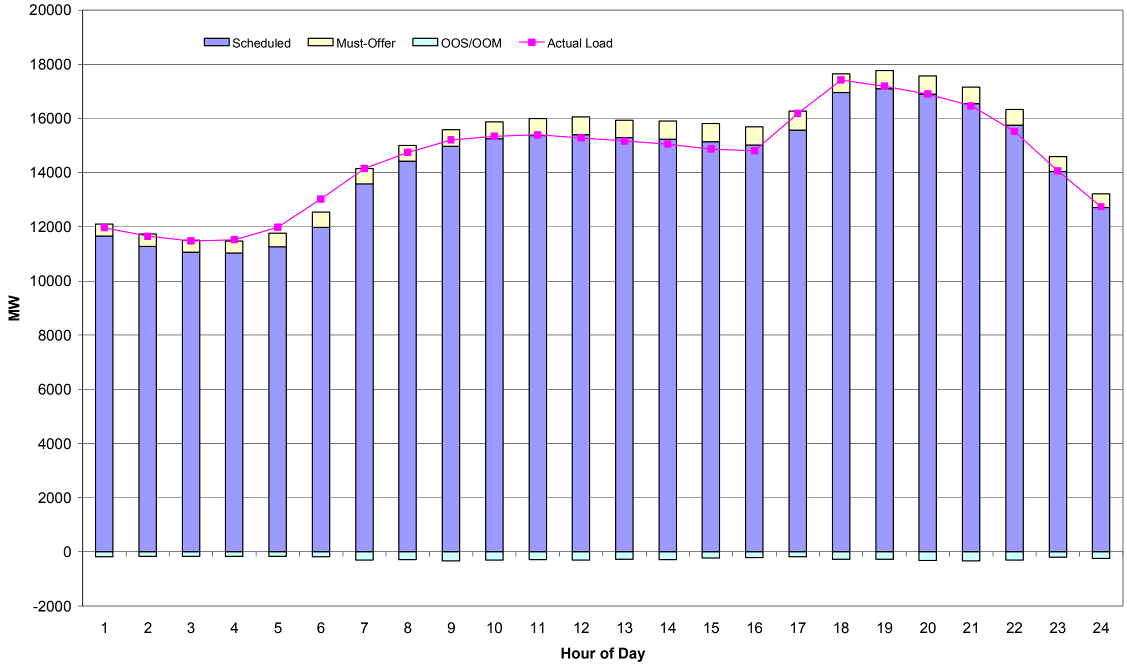
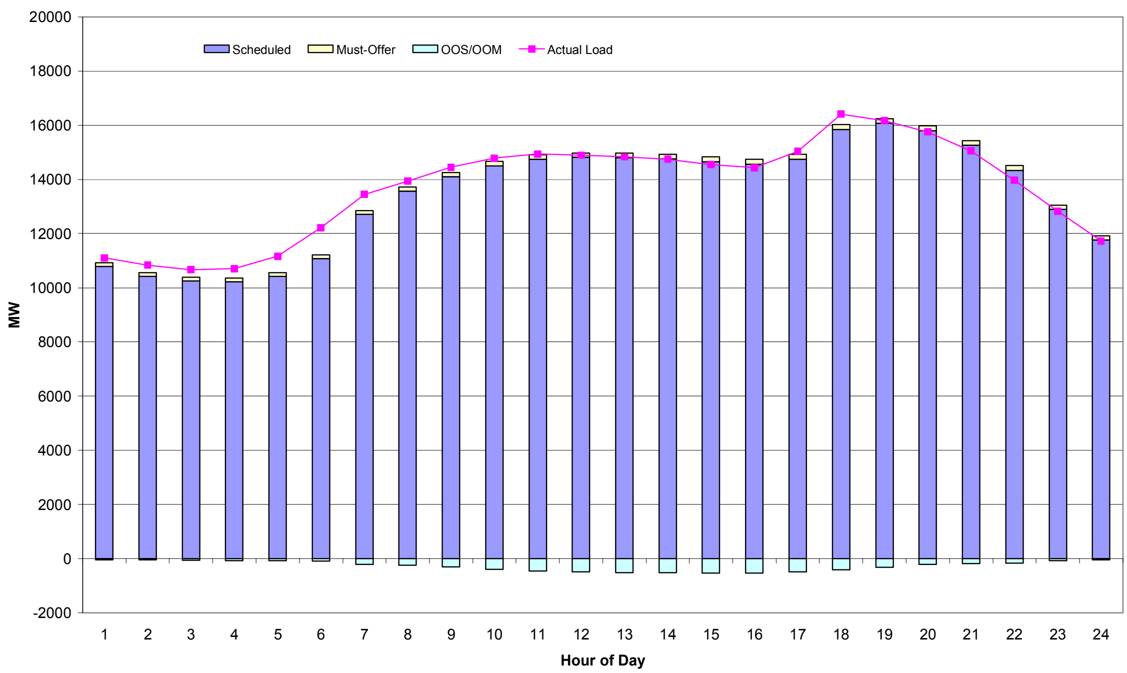


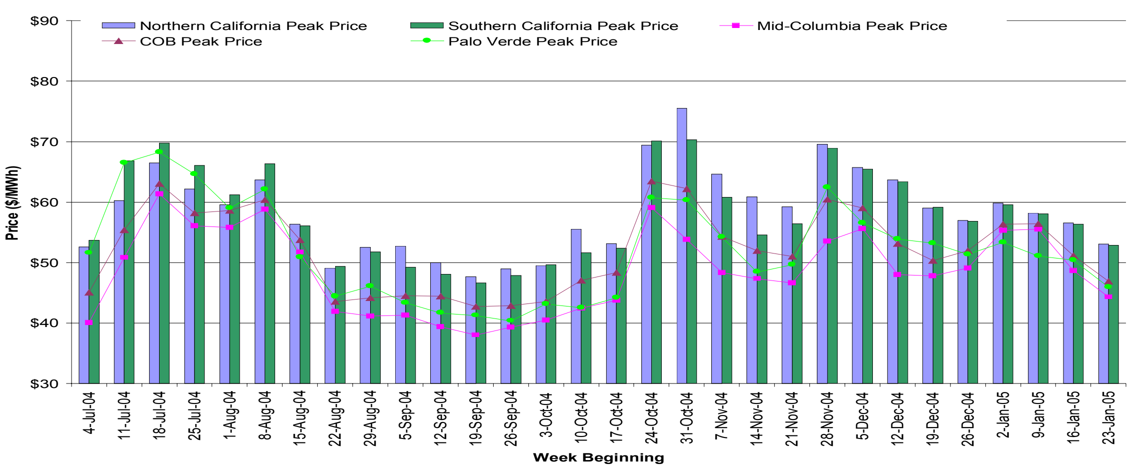
Figure 4. Actual Load v. Forward Schedules, Must-Offer Committed Generation, and Net OOS/OOM Generation within SP15: Mondays-Saturdays, January 2005



Bilateral Markets. The increases in supply have had a softening effect on prices in both forward and real-time markets. Regional day-ahead bilateral prices for power deliveries within the ISO control area have fallen approximately 23 percent since late November to the low $50/MWh range in late January, despite stable natural gas prices. Other regional hub prices, which generally trend several dollars below California prices, due in part to congestion costs, also fell. Finally, price discrepancies between NP15 and SP15 have been less frequent, thanks in part to the upgrade of Path 15 and the resultant reduction in congestion.

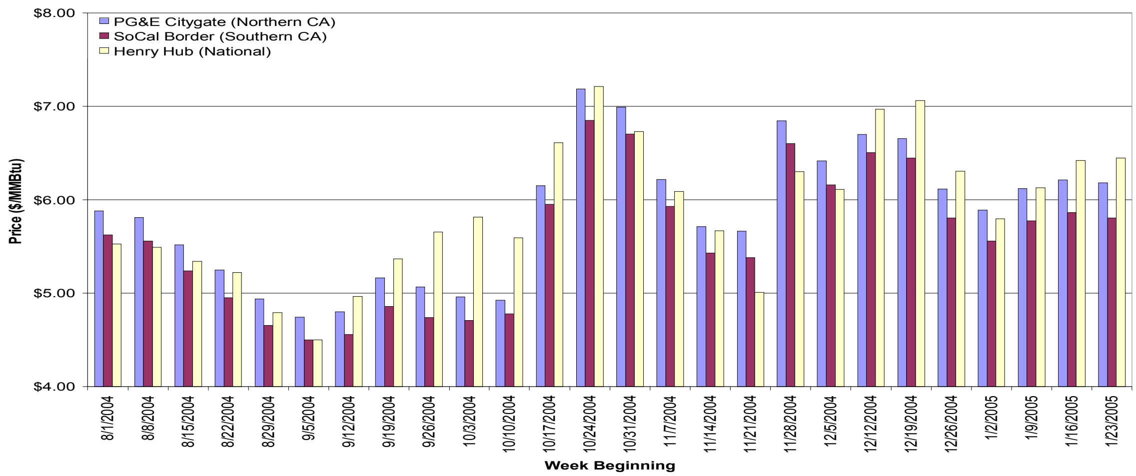
January average peak regional day-ahead electricity prices were lower than those in December, except for Mid-Columbia prices, which were essentially unchanged from December. Milder temperatures in California resulted in lower electricity prices through the last two weeks of January. The monthly peak was on trade date January 6, and was attributable to colder weather and outages at Four Corners 4 and 5. Average January peak weekday regional day-ahead electricity prices were $53.70 at the California-Oregon Border, $51.79/MWh at Mid-Columbia, $51.57/MWh at Palo Verde, $58.71/MWh in northern California, and $58.47/MWh in southern California. The following chart shows weekly average forward prices for day-ahead bilateral contracted energy through January.

Figure 5. Day-Ahead Bilateral Forward Energy Prices: Weekly Averages through January



Natural Gas Prices. Average natural gas prices in January decreased compared to December prices, particularly in southern California and at Malin. Gas prices remained around the $6/MMBtu range through much of January due to above average storage levels and despite cold temperatures throughout much of the East Coast. Price changes were flatter than NYMEX Henry Hub February 2005 contract prices, although prices increased in line with NYMEX prices after the second week of January. Average daily gas prices for January were $6.17/MMBtu at Henry Hub, $5.70/MMBtu at Malin, $6.09/MMBtu at PG&E Citygate, and $5.74/MMBtu at Southern California Border Average. The following chart shows weekly average prices for natural gas at regional delivery points through January.

Figure 6. Natural Gas Prices: Weekly Averages through January

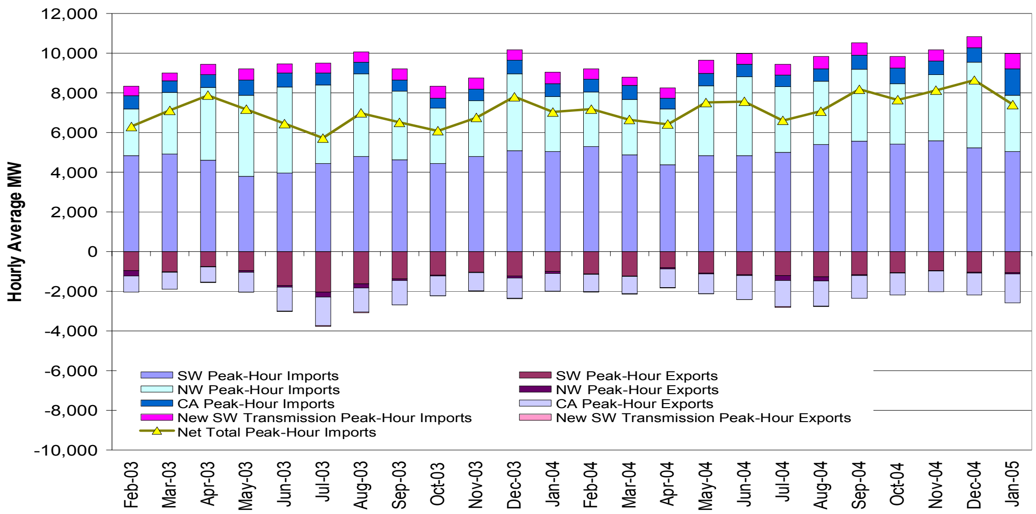


Upcoming Hydro Conditions. According to the United States Department of Agriculture's Natural Resources Conservation Service, as of January 1, 2005, winter storms have left a snowpack in excess of 150 percent of average in mountain ranges in California, Nevada, Utah, and in the southwest. However, the snowpack was reported to be below 50 percent of average in Oregon and Washington, due to low precipitation in those regions. The NRCS predicts springtime runoff performance will correspond to snowpack in those regions.[6]

Imports and Exports. Net imports decreased in January, due primarily to the exodus of WAPA load to the SMUD Control Area. The ISO now counts these as exports to the California region. In addition, energy on transmission owned by new southern California municipal Participating Transmission Owners is now included in imports on new Southwest transmission. The following chart shows monthly average scheduled imports and exports by region, and total net imports, through January.

[6] Natural Resources Conservation Service, "January 1, 2005 Western Snowpack Conditions and Water Supply Forecasts," www.wcc.nrcs.usda.gov.

Figure 7. Peak-Hour Scheduled Imports and Exports by Region: Monthly Averages through January



I. Real-Time Market

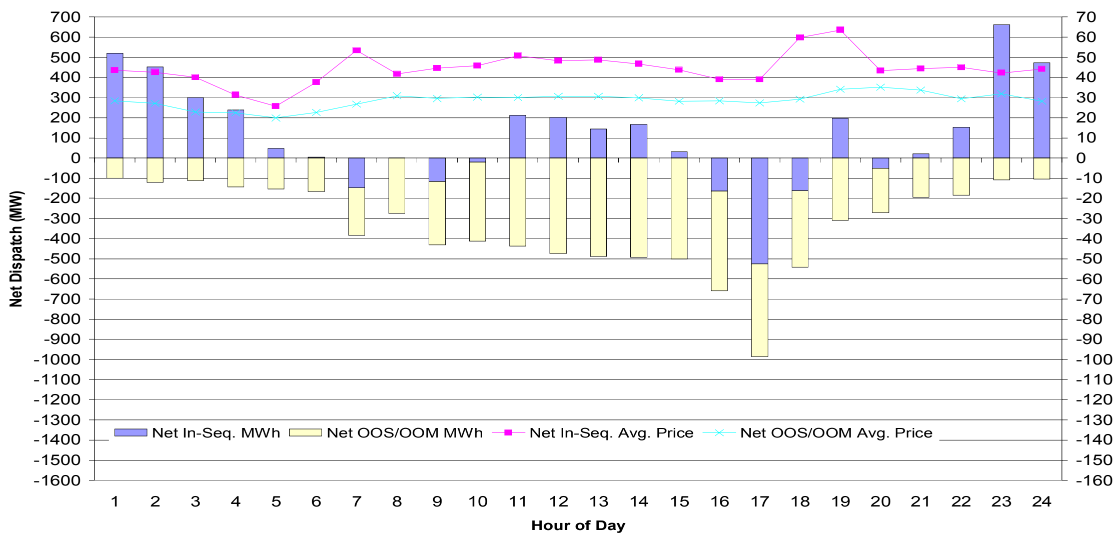
- *Real-time prices also softened, thanks to robust supply conditions*
- *Fewer zonal market splits due to return of nuclear unit*
- *Decrease in must-offer commitment*

Increased supply relative to demand in January resulted in significantly lower cost to load per megawatt-hour for in-sequence energy in January. The price paid to suppliers to increment generation above schedules was at its lowest point in over two years, averaging $54.23/MWh. The increase in supply was unusually high, with incremental energy averaging 788 MW, nearly double the figure for December, and occurring heavily in off-peak hours. Overall, the average price for real-time in-sequence, out-of-sequence (OOS), and out-of-market (OOM) energy was $42.25/MWh, compared to $49.17/MWh in December. Despite the unusually high incremental activity, most real-time instructions to generators were decremental dispatches, with an overall net average of 286 MW in the decremental direction in January, compared to average net of 490 MW in the decremental direction in December. The table immediately below shows monthly average prices, total net dispatched energy, and average loads and underscheduling in January. The chart that follows shows hourly average net dispatch of in-sequence and OOS/OOM energy and average prices of each for January.

Table 2. Average Real-Time Prices, Total Instructed Energy, and Average Loads and Underscheduling for January

	In-Seq. RT Dispatch	OOS/OOM Dispatch	Total Dispatch	Average Loads and % Underscheduling
PEAK	$ 49.00 /MWh	$ 30.29 /MWh	$ 44.69 /MWh	27,478 MW
	1.2 GWh	(176.2) GWh	(175.0) GWh	1.2%
OFFPEAK	$ 39.23 /MWh	$ 25.26 /MWh	$ 37.84 /MWh	21,580 MW
	80.7 GWh	(36.7) GWh	44.0 GWh	3.2%
ALL	$ 45.20 /MWh	$ 29.33 /MWh	$ 42.27 /MWh	24,878 MW
	81.8 GWh	(212.9) GWh	(131.1) GWh	2.0%

Figure 8. Average Real-Time Net Dispatch and Price by Hour for January



Price Spikes. Price spikes continue to occur frequently in the real-time market, most often when the real-time market application (RTMA) exhausts the incremental bid stack as it balances generation with actual load. However, the characteristics of incremental price spikes are different from those seen in November and December 2004. In particular, spikes that occurred as a result of the management of intra-zonal congestion at the Miguel Substation were almost all systemwide in January. These spikes, which tend to have durations of more than a couple intervals at a time, were usually limited to SP15 in November and December. The return of San Onofre Nuclear Generation Station ("SONGS") Unit 3 has relaxed the Southern California Import Transmission ("SCIT") constraint, so that generators in NP15 can be equally responsive to load ramps. As a consequence, the market was rarely split by zone. In contrast, December regularly saw zonal splits and spikes. The following charts show the count of dispatch intervals per hour, for January 2005 and December 2004, by zone.

Figure 9. Count of Incremental Price Spikes by Hour of Day in January 2005

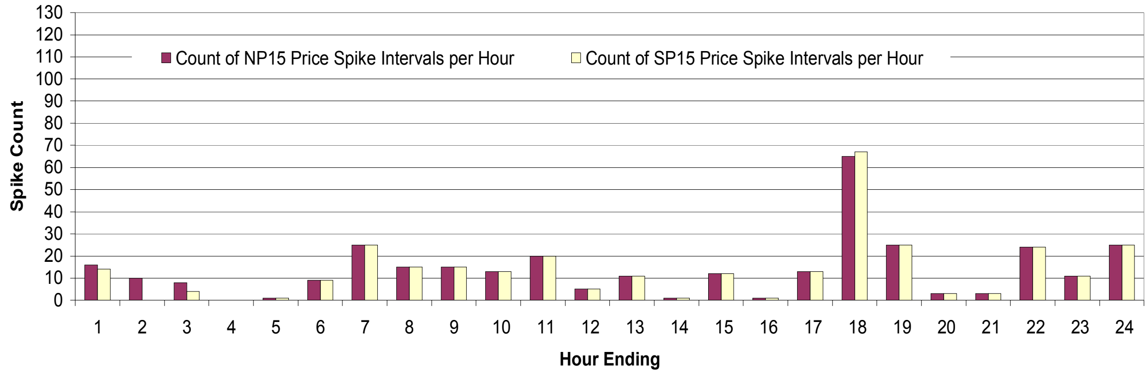
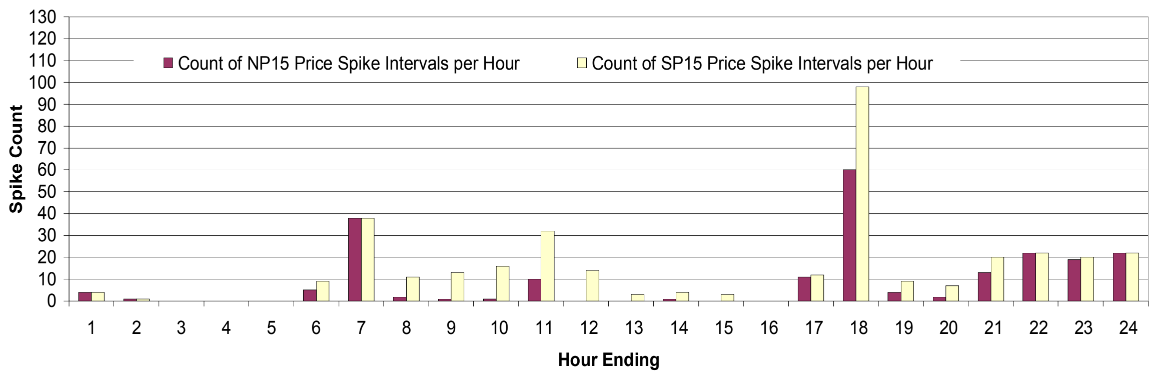


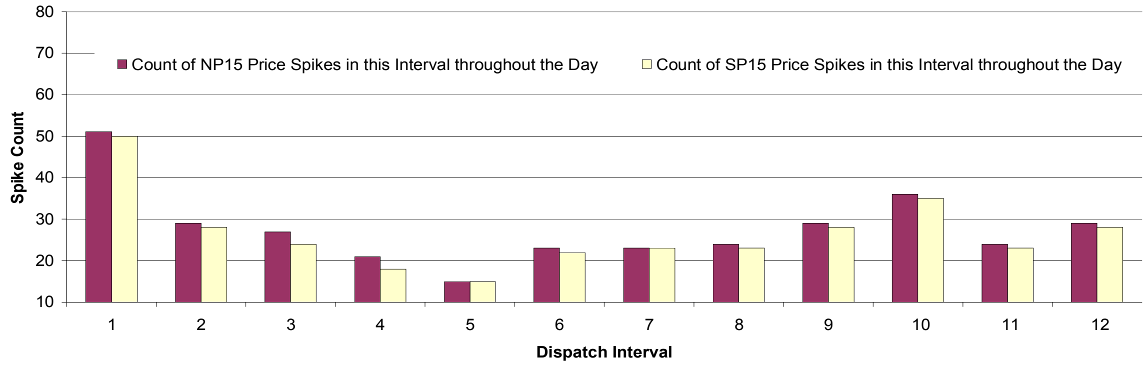
Figure 10. Count of Incremental Price Spikes by Hour of Day in December 2004



Additionally, certain units that had bid very high prices into the real-time market through December have stopped doing so. The reason for this may be the relaxation of ramp rate constraints on these units, which have RMR contracts, enabling these units to be dispatched more flexibly. As a result, these units may be bidding more competitively because they no longer need to signal their actual inflexibility only through their bids. DMA is investigating this issue and will be reporting in greater detail in future reports.

Some trends in price spikes seen in recent months remain in the real-time market. In particular, most price spikes are short, lasting one or two intervals, usually in the first interval of the hour. As in previous months, these spikes tend not to be limited to a single zone. As a result, the number of spikes in the first interval of the hour was approximately double that of all other intervals in January. This is shown in the following chart.

Figure 11. Count of Incremental Price Spikes by Interval of Hour in January 2005

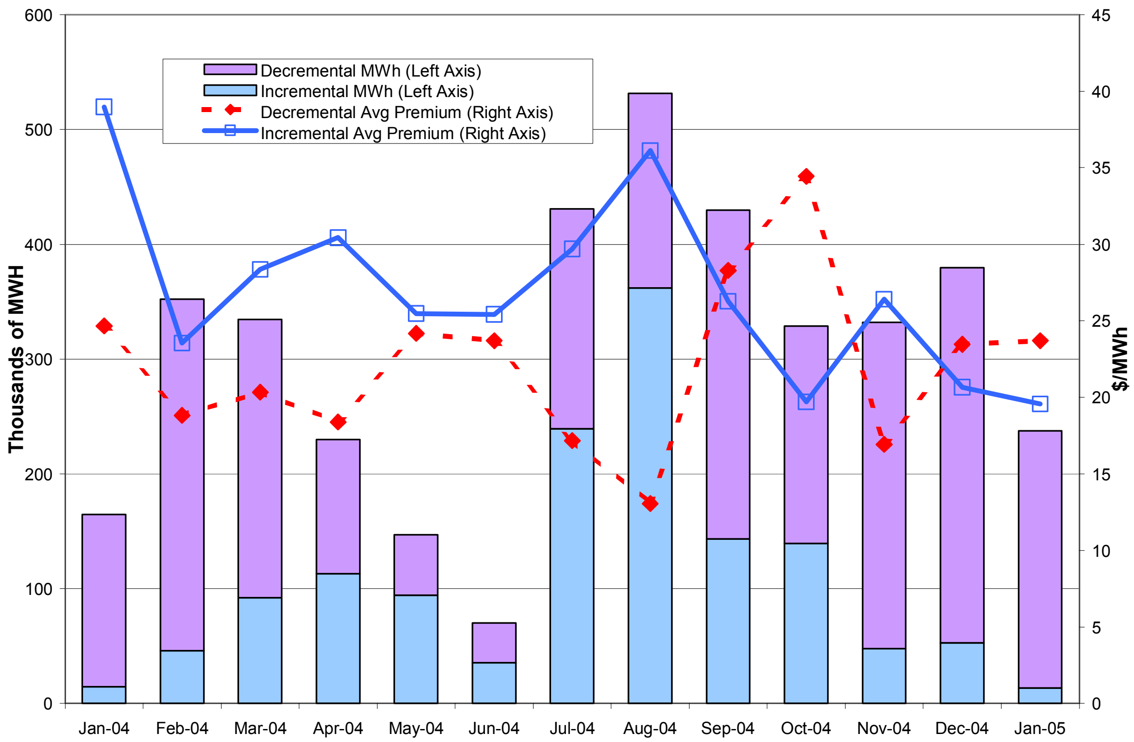


Intra-zonal Congestion Costs. Total intra-zonal congestion costs across the ISO grid consist of the summation of three different cost components: a real-time redispatch premium, the uplift above the real-time market clearing price paid to units dispatched out of sequence for congestion relief; minimum-load cost compensation (MLCC) for units procured pursuant to the Must-Offer Obligation; and reliability-must run (RMR) payments to units under an RMR contract and dispatched to relieve intra-zonal congestion. Due to the unavailability of data, the following discussion covers only the cost of redispatch premiums.

In January both incremental and decremental congestion volumes decreased. This resulted in a decrease in both the incremental and decremental redispatch premium costs, although the decrease in the incremental premium was more pronounced. January OOS dispatches resulted in a net cost (redispatch premium) of approximately $5.6 million. Total OOS dispatch volume was 237 GWh (INC plus DEC) and the average redispatch premium was $23.46/MWh, an increase from December. Figure 10 shows the premium graphically for recent months.[7]

[7] OOS net cost or redispatch premium is calculated as total redispatch cost minus unconstrained dispatch cost, which is the equivalent dispatch cost at zonal MCP. The premium reflects the increased cost of redispatch and any potential mark-up above marginal cost.

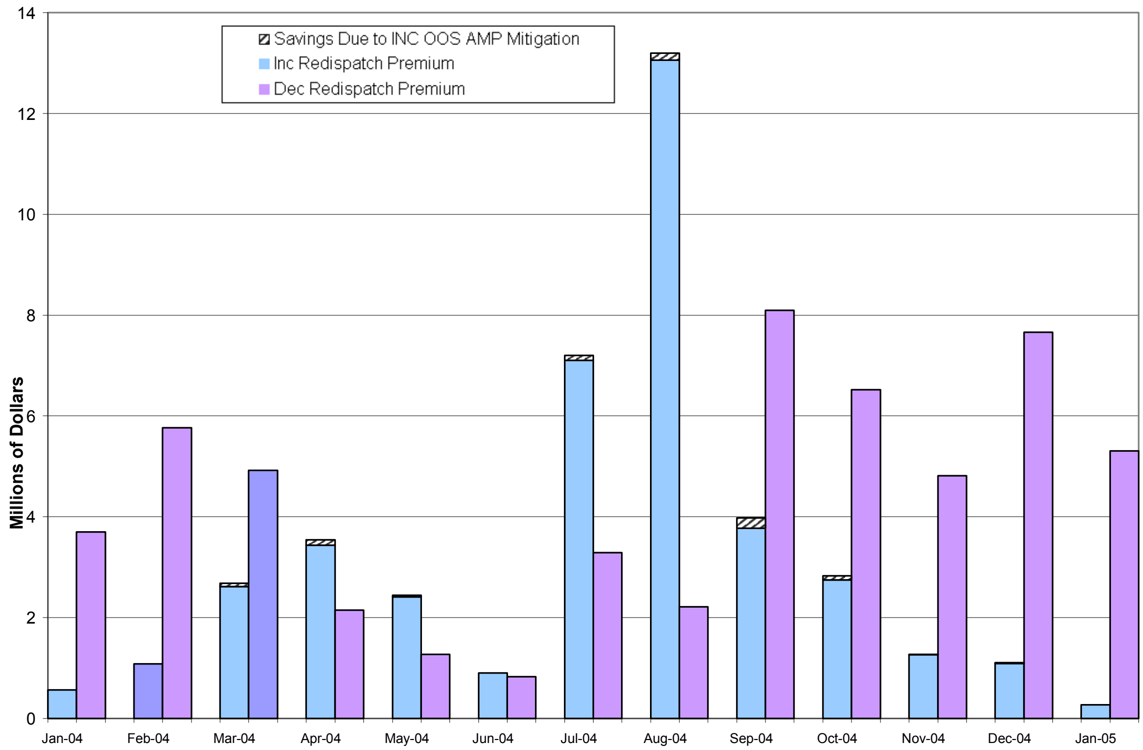
Figure 12. Out-of-Sequence Volume and Average Redispatch Premium



Incremental OOS Dispatches. ISO operators called a total of 13,529 MWh of incremental energy out-of-sequence (OOS) to address intra-zonal congestion in January. The average price paid was $65.30/MWh in January, and the re-dispatch premium in excess of the market clearing price (MCP) was approximately $265,000 or $19.56/MWh.

Local market power mitigation of incremental dispatches (AMP LMPM) resulted in moderate savings of $412 or approximately 0.2 percent of the incremental redispatch premium. All incremental OOS dispatches are subject to mitigation. Figure 11 shows the re-dispatch premiums for both decremental and incremental congestion as well as the savings due to mitigation of incremental OOS dispatches. As shown in the chart, very little bid mitigation has taken place due to the large thresholds in AMP for local market power.

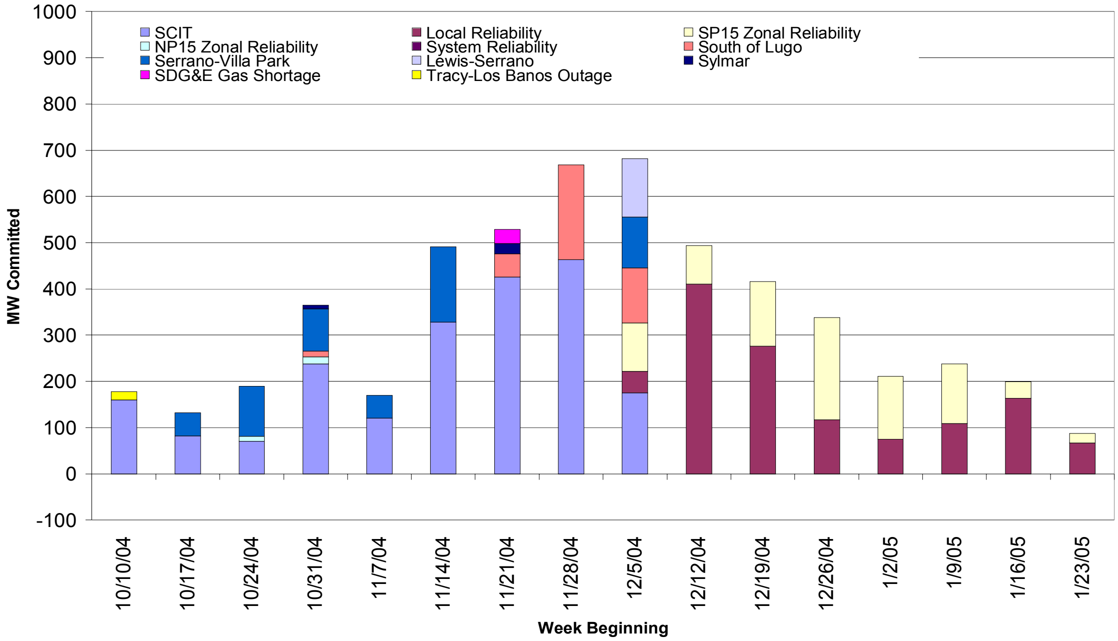
Figure 13. Re-dispatch Premiums and INC OOS Mitigation Savings



Decremental OOS Dispatches. A total of 224 GWh of decremental energy was dispatched out of sequence in January. The average price paid was $22.28/MWh, a decrease of 44 percent from December. The re-dispatch premium in excess of the market clearing price (MCP) was approximately $5.3 million or $23.70/MWh. This energy is settled according to the provisions of the Amendment 50 mitigation measures approved by FERC. As in previous months, almost all of the decremental activity was due to intra-zonal congestion in the San Diego region. The return of SONGS Unit 3 and lower loads over the winter holidays reduced, but did not eliminate, intra-zonal congestion in the San Diego area.

Minimum Load Cost Compensation (MLCC) for Must-Offer Commitment. As noted previously, with the return of in-state nuclear resources, the ISO has decreased its commitment of generation to operate at minimum load pursuant to the Must-Offer Obligation. The following chart shows such minimum-load commitment on a weekly average basis, by region (when such data are available).

Figure 14. Weekly Average Minimum-Load Generation Committed per Must-Offer Obligation through January: Mondays-Saturdays, 11:00 a.m. – 8:00 p.m.[8]



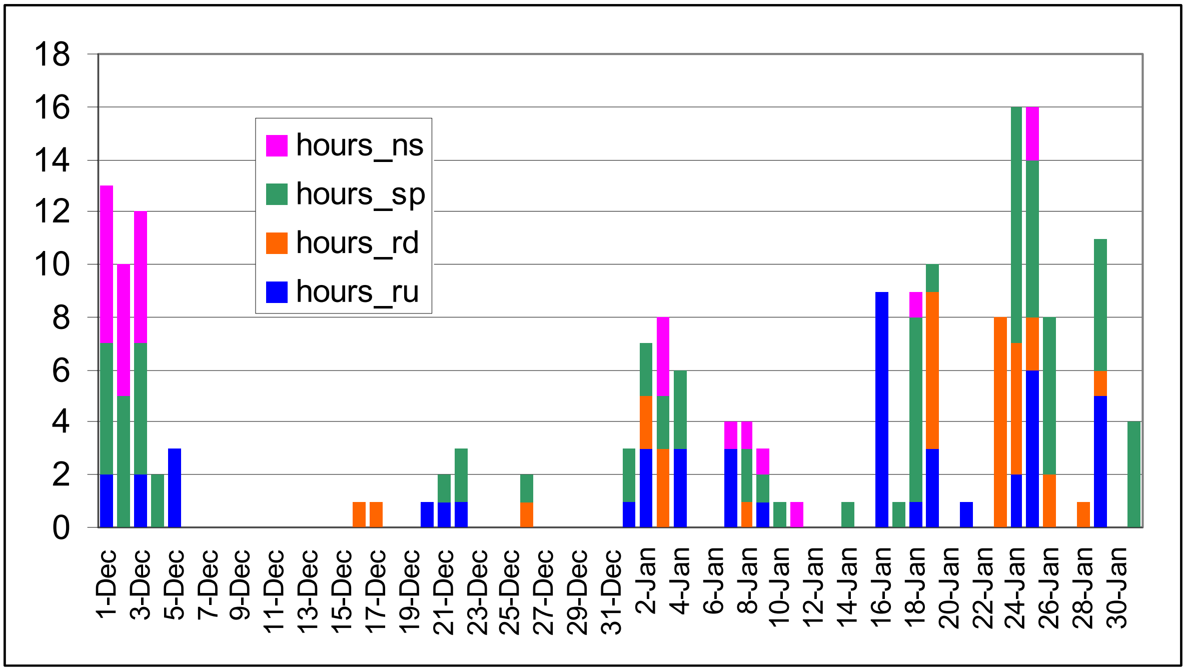
II. Ancillary Services Markets

- *Increase in bid insufficiency*

January 2005 had greater bid insufficiency than December 2004. The average prices for all services spiked upward, before moderating later in the month. Figure 13 shows the number of bid insufficient hours for each service in the day-ahead market in December and January.

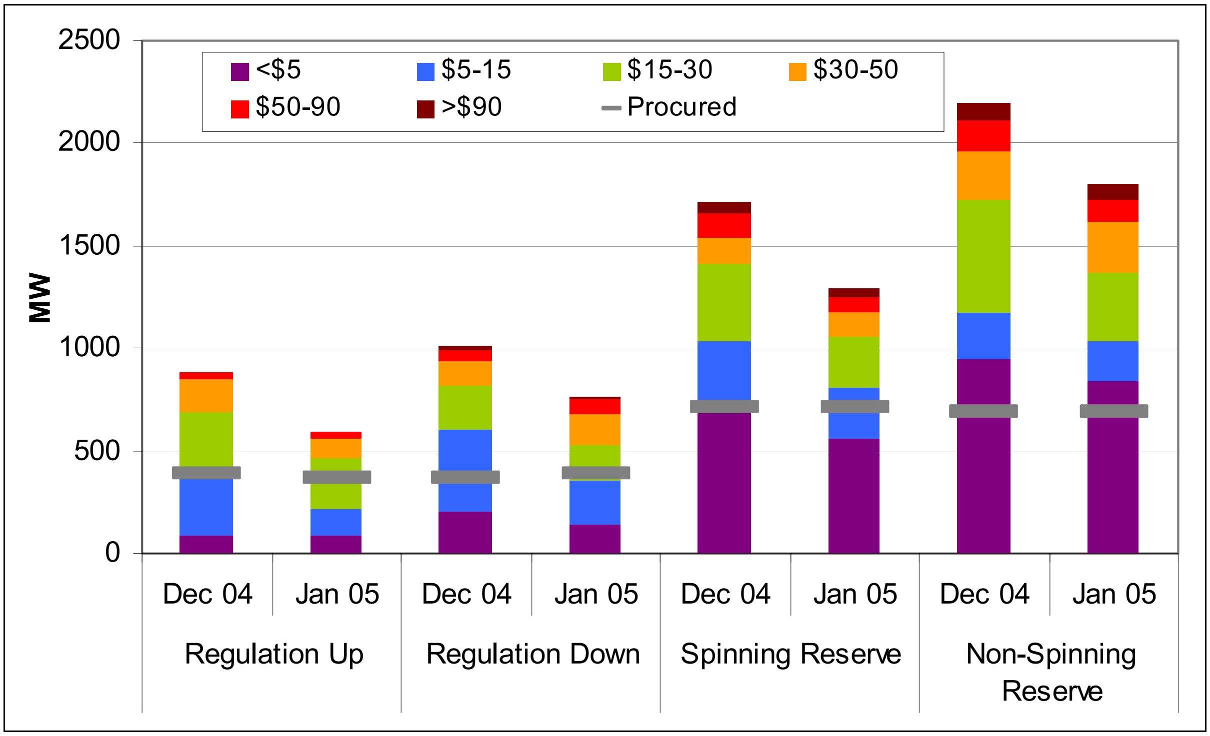
[8] At the time of writing, generation region was categorized through early December 2004. Volume and category data are subject to change.

Figure 15. Number of bid insufficient hours in November and December 2004



Market Supply. Supply of capacity to the ancillary service (A/S) markets decreased between December and January. This resulted in procurement being made from units higher in the bid stack across the board and is, in part, responsible for the increased prices. Figure 14 shows bid volumes by price bin in December 2004 and January 2005.

Figure 16. Ancillary Service Day-Ahead Average Bid Volume by Price Bin



Market Prices. Increased bid insufficiency resulted in higher A/S market prices in January 2005, compared to December 2004. The weighted average prices of all services increased substantially with the exception of Non-Spin where the increase was minor. Table 3 below shows ancillary service product requirements and average prices for December and January.

Table 3. Average Ancillary Service Requirements and Prices

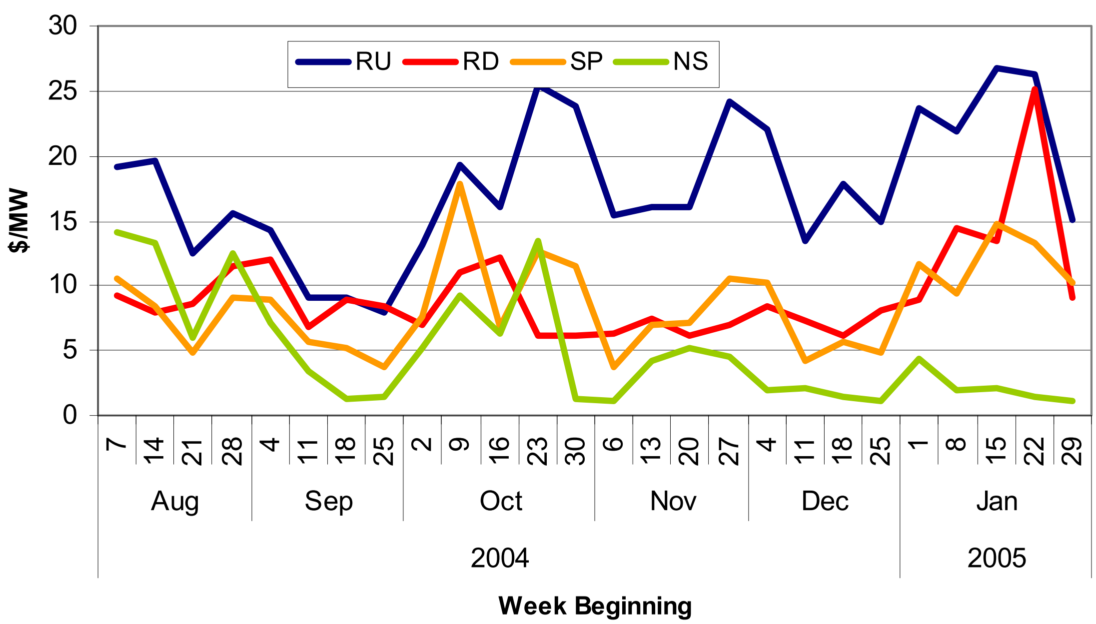
	Average Required (MW)				Weighted Average Price ($/MW)			
	RU	RD	SP	NS	RU	RD	SP	NS
Dec 04	389	373	755	735	$ 18.20	$ 7.29	$ 7.41	$ 2.20
Jan 05	377	389	773	771	$ 23.64	$ 14.86	$ 12.01	$ 2.37

Overall A/S procurement increased 2.7percent between December and January. The weighted average price of ancillary services increased from $7.55 in December to $11.17 in January, an increase of almost 48 percent. Table 4 summarizes the A/S procurement and Figure 15 shows price trends over the past six months.

Table 4. Peak and Off-Peak Ancillary Service Procurement and Pricing

		Average AS Procured (MW)			Weighted Average Price ($/MW)		
		On-Peak	Off-Peak	All Hours	On-Peak	Off-Peak	All Hours
Dec 04	RU	396	375	389	$ 20.38	$ 13.59	$ 18.20
	RD	379	360	373	$ 6.29	$ 9.40	$ 7.29
	SP	791	682	755	$ 9.29	$ 3.05	$ 7.41
	NS	772	660	735	$ 2.63	$ 1.21	$ 2.20
	Total	2338	2077	2251	$ 8.39	$ 5.43	$ 7.48
Jan 05	RU	383	366	377	$ 26.10	$ 18.51	$ 23.64
	RD	394	380	389	$ 10.58	$ 23.75	$ 14.86
	SP	810	700	773	$ 14.80	$ 5.55	$ 12.01
	NS	810	693	771	$ 2.83	$ 1.32	$ 2.37
	Total	2397	2140	2311	$ 11.86	$ 9.63	$ 11.17
Difference	RU	-13	-8	-11	$ 5.71	$ 4.93	$ 5.44
	RD	15	19	16	$ 4.28	$ 14.35	$ 7.57
	SP	19	19	19	$ 5.51	$ 2.50	$ 4.60
	NS	38	34	36	$ 0.20	$ 0.11	$ 0.17
	Total	59	63	60	$ 3.47	$ 4.20	$ 3.69

Figure 17. Weekly Weighted Average Ancillary Service Prices



III. Inter-Zonal Congestion Costs

- *Eight branch-groups expired on December 31, 2004 and seventeen new branch-groups were activated on January 1, 2005 due to the WAPA transition to the SMUD control area and several Southern California municipals joining the ISO.*
- *Inter-zonal congestion costs totaled $4.2 million in January, largely due to transmission constraints on the Palo Verde and California-Oregon Interties.*
- *Significant congestion also occurred on the new IPPDCADLN and TRACYWAPA branch groups.*

Due to the transition of certain WAPA facilities to the SMUD control area and several southern California cities (Anaheim, Azuza, Banning, Riverside, Vernon, and Pasadena) joining the ISO and becoming Participating Transmission Owners (PTOs), eight branch groups expired on December 31, 2004, and seventeen new branch groups were created and activated on January 1, 2005. The ISO's new transmission network model containing the new branch groups was successfully implemented into the day and hour-ahead markets. The new network model, shown in the diagram below, provides immediate and necessary scheduling enhancements and increased transmission availability for the Southern PTOs. Table 5 provides a summary of the expired and new branch groups.

Figure 18. California ISO Network Model Effective January 1, 2005

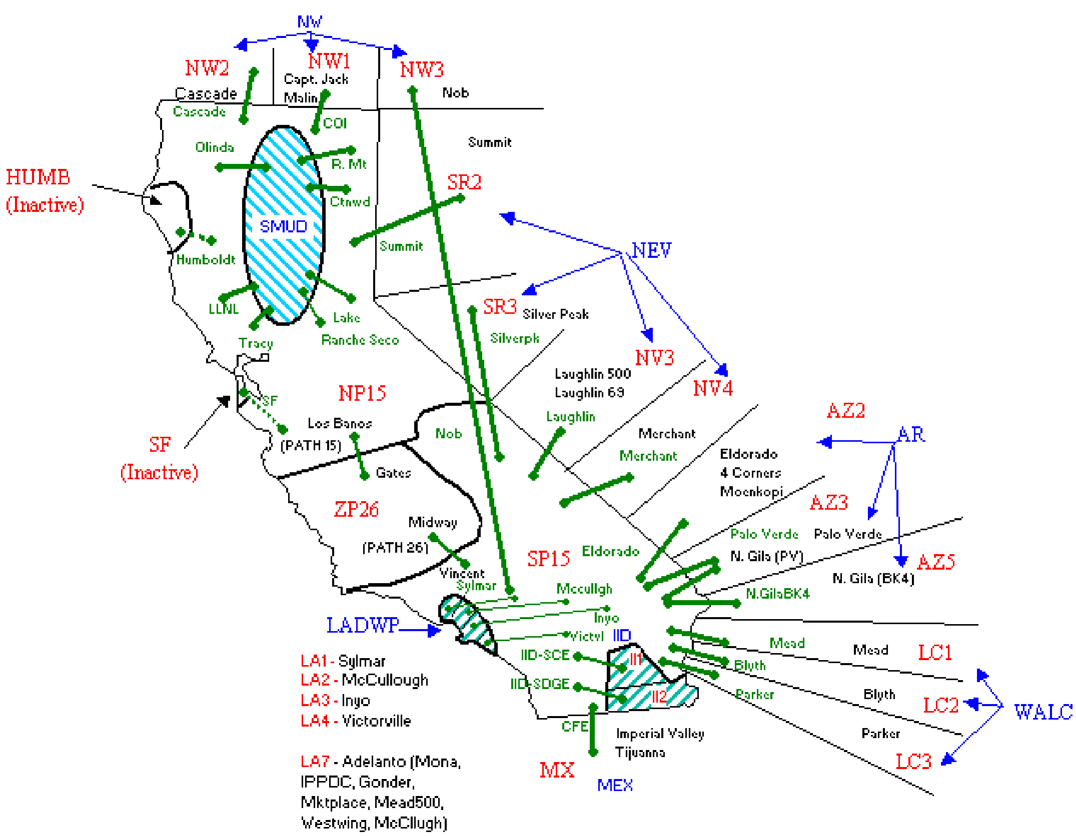


Table 5. Summary of New and Expired Branch Groups

BRANCH GROUP	FROM ZONE	TO ZONE	INTERCON-NECTING CONTROL AREA	TIE_POINT	ACTIVE / INACTIVE	Effective Date	Comments
ELVTHRLY _BG	SMDW	NP15	SMUD	ELVRTA_2_ELVRTW HURLEY_2_ELVRTW	Expire	12/31/2004	
LUGOMKTPC_BG	LC4	SP15	WALC	LUGO_5_MKTPLC	Expire	12/31/2004	
LUGOMONAI_BG	PC2	SP15	PACE	LUGO_5_MONAIM	Expire	12/31/2004	
LUGOGNDRI_BG	SR5	SP15	SPP	LUGO_5_GNDRIM	Expire	12/31/2004	
LUGOWSWGI_BG	AZ7	SP15	APS	LUGO_5_WSWGIM	Expire	12/31/2004	
LUGOMONAE_BG	PC3	SP15	PACE	LUGO_5_MONAEX	Expire	12/31/2004	
LUGOGNDRE_BG	SR6	SP15	SPP	LUGO_5_GNDREX	Expire	12/31/2004	
LUGOWSWGE_BG	AZ8	SP15	APS	LUGO_5_WSWGEX	Expire	12/31/2004	
OLNDAWAPA_BG	SMD1	NP15	SMUD	OLNDWA_2_OLIND5	new	1/1/2005	SMUD-WAPA Control Area
CTNWDWAPA_BG	SMD2	NP15	SMUD	CTNWDW_2_CTTNWD	new	1/1/2005	
CTNWDRDMT_BG	SMD3	NP15	SMUD	CTNWDW_2_RNDMTN	new	1/1/2005	
TRACYWAPA_BG	SMD4	NP15	SMUD	TRCYPP_2_TRACY5	new	1/1/2005	
TRCYTESLA_BG	SMD5	NP15	SMUD	TRCYPP_2_TESLA	new	1/1/2005	
TRCYWSTLY_BG	SMD6	NP15	SMUD	TRCYPP_2_WESTLY	new	1/1/2005	
LLNLTESLA_BG	SMD8	NP15	SMUD	LLNL_1_TESLA	new	1/1/2005	
WSTWGMEAD_BG	AZ6	LC5	ARIZ	WSTWNG_5_MEAD	new	1/1/2005	Southern PTO
MKTPCADLN_BG	LC4	LA7	LDWP	MKTPLC_5_ADLNTO	new	1/1/2005	
IPPDCADLN_BG	LA5	LA7	LDWP	IPPDC_5_ADLNTO	new	1/1/2005	
MONAIPPDC_BG	PC1	LA5	PACE	MONA_5_IPPDC	new	1/1/2005	
GONDIPPDC_BG	SR4	LA5	SRRA	GONDER_5_IPPDC	new	1/1/2005	
MEADMKTPC_BG	LC5	LC4	WALC	MEAD_5_MKTPLC	new	1/1/2005	
MEADTMEAD_BG	LC6	LC5	WALC	MEADT_5_MEAD	new	1/1/2005	
MCCLMKTPC_BG	LA6	LC4	LDWP	MCCLUG_5_MKTPLC	new	1/1/2005	
ADLANTOSP_BG	LA7	SP15	LDWP	ADLNTO_5_LUGO	new	1/1/2005	
ADLANTOSP_BG	LA7	SP15	LDWP	ADELNT_2_SYLMAR	new	1/1/2005	

Inter-zonal congestion costs totaled $4.2 million in January, higher than the $3.3 million in December 2004. The vast majority of all congestion in January was on four paths: the Palo Verde branch group (66 percent), the California-Oregon Intertie (COI) (16 percent), the newly created IPP (DC) – Adelanto ("IPPDCADLN") branch group between congestion zones LA5 and LA7 (10 percent), and the newly created TRACYWAPA branch group between SMUD and NP15 (7 percent).

Table 6. Inter-Zonal Congestion Costs in January 2005

Branch Group	Day-ahead		Hour-ahead		Total Congestion Cost		Total Congestion Cost		Total Congestion Cost	Total Cost Percent
	Import	Export	Import	Export	Import	Export	Day-ahead	Hour-ahead		
COI	$669,259	$0	$7,051	$0	$676,310	$0	$669,259	$7,051	$676,310	16%
ELDORADO	$1,566	$0	$4,181	$0	$5,746	$0	$1,566	$4,181	$5,746	0%
IPPDCADLN	$416,288	$0	$692	$0	$416,980	$0	$416,288	$692	$416,980	10%
MEAD	$177	$0	$6	$0	$183	$0	$177	$6	$183	0%
NOB	$0	$0	$4	$0	$4	$0	$0	$4	$4	0%
OLNDAWAPA	$0	$0	$0	$76	$0	$76	$0	$76	$76	0%
PALOVRDE	$2,746,130	$0	$1,042	$0	$2,747,172	$0	$2,746,130	$1,042	$2,747,172	66%
PATH15	$18,169	$0	$4,565	$0	$22,734	$0	$18,169	$4,565	$22,734	1%
TRACYWAPA	$278,899	$0	$0	$0	$278,899	$0	$278,899	$0	$278,899	7%
TRCYWSTLY	$0	$0	$1	$0	$1	$0	$0	$1	$1	0%
WSTWGMEAD	$10,103	$0	$1,965	$0	$12,068	$0	$10,103	$1,965	$12,068	0%
Total	$4,140,590	$0	$19,506	$76	$4,160,096	$76	$4,140,590	$19,581	$4,160,172	100%

The Palo Verde branch group was congested in the import direction (east-to-west) for 36 percent of all hours in the day-ahead (DA) market at an average congestion price of $5/MWh, and 14 percent of all hours in the hour-ahead (HA), at an average congestion price of $7/MWh. Congestion on Palo Verde was due in large part to the wheeling of energy from the southwest to northern California where DA bilateral prices were higher.

COI was congested for 16 percent of all hours in the DA import direction (from Oregon to California) at an average congestion price of $4/MWh, and 12 percent of all hours in the HA import direction at an average price of $7/MWh. COI experienced almost daily deratings throughout the month due to various line/capacitor outages and scheduled line work. Most of the DA congestion on COI occurred during peak hours on January 19, 20, 24, 25 and 27. Part of the congestion on COI was also caused by periodical power circulation from Pacific DC Intertie (PDCI) due to continued line/capacitor work on PDCI. PDCI remained unavailable from January 10 until Jannuary 26 due to continuing work.

The new branch group, IPPDCADLN, was congested for 3 percent of all hours in the HA import direction at an average congestion price of $49/MWh, and 2 percent of all hours in the DA import direction at an average price of $ 62/MWh. Most of IPPDCADLN's DA congestion cost occurred on January 13, from hour ending (HE) 1 to HE 4, at a high congestion price of $247/MWh. This congestion was caused by a line derating from 647 MW to 421 MW in the import direction.

Another new branch group, TRACYWAPA, between SMUD and NP15, also experienced significant congestion cost in DA import direction. Normally the flow on this path is from NP15 to SMUD. However, on January 10, HE 1 through HE 5, the scheduled flow reversed direction and went from SMUD to NP15, while the line was derated from 200 MW to 0 MW in that direction. This resulted in congestion prices as high as $249/MWh.

Table 7. Inter-Zonal Congestion Prices and Frequencies in January 2005

	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 _BG	0	0			0	0	$0	
COI _BG	16	0	$4		12	0	$7	
ELDORADO _BG	1	0	$0		7	0	$2	
GONDIPPDC_BG	0	1		$0	0	0		
IPPDCADLN_BG	3	0	$49		2	0	$62	
MEAD _BG	2	0	$0		1	0	$0	
PALOVRDE _BG	36	0	$5		14	0	$7	
PATH15 _BG	0	0	$4		2	0	$1	
SUMMIT _BG	0	0			1	0	$0	
TRACYWAPA_BG	7	0	$23		0	0		
WSTWGMEAD_BG	2	0	$5		3	0	$2	

IV. Firm Transmission Rights

A Firm Transmission Right (FTR) is a right that has the attributes of both financial and physical transmission rights. FTRs entitle their owners to share in the distribution of Usage Charge revenues received by the ISO (in the Day-Ahead and Hour-Ahead Markets) in connection with Inter-Zonal Congestion during the period for which the FTR is issued. FTRs also entitle registered FTR Holders to certain scheduling priorities (in the Day-Ahead Market) for the transmission of energy across a congested Inter-Zonal interface.

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 table, a high percentage of FTRs were scheduled on a few paths (84% on ELDORADO, 78% on IID-SCE, 62% on PALOVRDE, 100% on SILVERPK, and 23% on Path 26). Southern California Edison Company and municipals primarily own the FTRs on these paths.

Table 8. FTR Scheduling Statistics for January 2005*

Branch Group	Direction	MW FTR Auctioned	Avg. MW FTR Sch.	Max MW FTR Sch.	Max Single SC FTR Scheduled	% FTR Schedule
BLYTHE _BG	Import	168	20	167	167	12%
ELDORADO _BG	Import	536	448	536	536	84%
IID-SCE _BG	Import	600	470	475	455	78%
MEAD _BG	Import	624	20	50	25	3%
NOB _BG	Import	725	2	29	23	0%
PALOVRDE _BG	Import	1021	638	750	600	62%

SILVERPK _BG	Import	10	10	10	10	100%
VICTVL _BG	Import	921	3	25	25	0%
NOB _BG	Export	722	8	54	32	1%
PATH26 _BG	Export	1314	308	370	370	23%

*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 summaries the FTR revenue collected through January 2005. Only COI (import direction) and Palo Verde (Import direction) have significant positive FTR revenues, $2,904/MWh and $11,919/MWh respectively, due to a higher occurrence of congestion on these two paths.

Table 9. FTR Revenue Per MW ($/MW)

Branch Group	Direction	Net $/MW FTR Rev										Cumm Net $/MW FTRREV	Pro Rated NET $/MW FTRREV
		Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan. 2005		
BLYTHE	IMPORT	2,791	5,540	433	0	7	736	332	992	0	0	10,830	12,996
COI	IMPORT	697	5,185	16,985	2,876	1,823	8,939	6,551	7,652	7,084	2,904	60,696	72,835
ELDORADO	IMPORT	0	408	10	0	0	400	136	156	19	4	1,132	1,358
LUGOGNDRI	IMPORT	0	0	0	0	0	0	0	176	0	0	176	211
LUGOIPPDC	IMPORT	9	0	0	0	0	0	0	0	0	0	9	11
LUGOMKTPC	IMPORT	0	0	0	0	7	224	764	0	0	0	995	1,194
LUGOMONAI	IMPORT	0	0	0	0	0	408	216	99	3	0	725	870
LUGOTMONA	IMPORT	0	0	576	0	0	24	0	0	0	0	600	720
LUGOWSTWG	IMPORT	0	2	0	1	52	2,036	0	0	0	0	2,090	2,508
LUGOWSWGI	IMPORT	0	0	0	0	0	888	422	52	364	0	1,726	2,071
MEAD	IMPORT	1,223	1,168	634	464	238	930	1,114	2,386	849	1	9,007	10,808
NOB	S-N	458	2,477	26,077	5,080	1,382	1,734	0	0	638	0	37,845	45,414
PALOVRDE	IMPORT	2,666	19,474	3,159	12,220	10,508	21,496	11,321	7,791	6,645	11,919	107,200	128,640
PARKER	IMPORT	115	15	0	5	6	178	0	0	252	0	571	685
PATH15	N-S	0	98	100	25	1,435	2,983	15,525	3,759	0	26	23,952	28,742
SILVERPK	IMPORT	0	0	0	0	5	0	0	176	0	0	181	217
NOB	EXPORT	0	0	0	910	522	0	0	0	0	0	1,433	1,719
PATH26	EXPORT	1,280	82	1,071	1,720	416	65	679	0	0	0	5,314	6,377
SILVERPK	EXPORT	0	0	0	0	480	0	0	0	0	0	480	576
SUMMIT	EXPORT	0	0	608	0	39	0	0	0	0	0	647	776

FTR Auction for 2005. In the 2004 FTR Auction held in March 2004, the ISO released FTRs on COI for a nine-month duration. When the initial 2004 FTR Auction was held the ISO was aware that several Existing Transmission Contracts (ETCs) were set to terminate effective January 1, 2005. The expiration of these ETCs could free up additional capacity on COI, Path 26, and Path 15, which the ISO could make available through an additional FTR Auction. In addition, the ISO had been working with SCE to determine a rating methodology for the outbound direction of the Blythe branch Group. When the final methodology was approved the ISO planned to release any incremental capacity, if an additional 2004 FTR Auction was held. The ISO conducted the additional auction on October 28, 2004 for FTRs valid from January 1, 2005 to March 31, 2005. Results of the auction are summarized in the following table. On most paths, market-clearing prices were significantly higher than the seed prices.

Table 10. Summary of Results of FTR Auction by Branch Group

Branch Group	From	To	Dir.	Total FTR Auctioned (MW)	Total FTR Sold (MW)	Unsold FTR (MW)	Seed Price ($/MWh)	Auction Clearing Price ($/MWh)	Auction Revenue
BLYTHE	SP15	LC2	Export	43	43	0	$25	$28	$1,204
COI	NP15	NW1	Export	981	940	41	$25	$28	$26,320
COI	NW1	NP15	Import	950	950	0	$103	$2,978	$2,829,100
Path 26	ZP26	SP15	Export	173	173	0	$308	$995	$172,135
Path 15	ZP26	NP15	Import	908	908	0	$25	$1826	$1,658,008
Total				3055	3014	41			$4,686,767

(FTR Term January 1, 2005 through March 31, 2005)

Table Column Definitions:

Total FTR Auctioned (MW): The amount of FTRs in MW released on each branch group and direction is based on 100% of the capacity at a given interface, in a specific direction given a 99.5% availability level (net of ETC rights).
Total FTR Sold: This is the final MW clearing the auction. The difference between Total FTR Auctioned and Final MW sold can be either due to some FTRs not sold or the residual FTR allocation option exercised in the auction.

Auction Seed Price: The seed price for each branch group is the starting price of the simultaneous multi-round auction.
Auction Clearing Price: This is the market-clearing price.
Auction Revenue: This is equal to the product of Auction Clearing Price and Total FTR Sold.