California Independent
System Operator Corporation

Memorandum

To: ISO Governing Board

From: Alan Isemonger, Manager Market Information

Date: May 21, 2007

Re: ***Market Performance Report – March 2007***

This memorandum is a status report and does not require Board action.

The complete Market Performance Report for March 2007can be found online at http://caiso.com/1bcb/1bcbde7c25a00.pdf

EXECUTIVE SUMMARY

Highlights for March 2007:

- West Coast snowpack is well below normal, as of April 1, 2007, following a very dry winter. Limited hydro energy is likely to increase use of non-hydro resources in coming months.
- March 2007 hydroelectric generation levels in the CAISO control area were about half the levels of March 2006.
- Weekly average on-peak bilateral contract prices declined to approximately $55 in March following falling gas prices--about a $10 decline from February's average.
- Overall real-time energy prices declined from $51.25 to $41.75 on a sharp increase in decremental volume.
- On average, real-time dispatch prices were more volatile this March exceeding $250 on 131 occasions vs. 50 in February and 42 in March 2006. An outage on the Pacific DC Intertie between March 26th and March 28th combined with excessive loop flow during the later half of the month were contributing factors.
- Out-of-Sequence incremental dispatch volumes declined from February's level by 33 percent in March, and decremental dispatch volumes declined by 24 percent.
- The Average total cost of Ancillary Services increased to $0.58 in March from $0.41 in February. The overall increase was driven by large increases in Regulation costs as congestion on the Mead and PACI branch groups stranded some large dynamic system resources outside the CAISO control area.
- Total unit commitment costs declined in March to $1.3 million from $1.6 million in February. Local generation requirements were responsible for about two thirds of this month's costs.
- Total inter-zonal congestion costs increased sharply to $8.1 million in March from $1.83 million in February. A majority of congestion this month occurred on Pacific AC Intertie (PACI) and Nevada - Oregon Border (NOB) branch groups.

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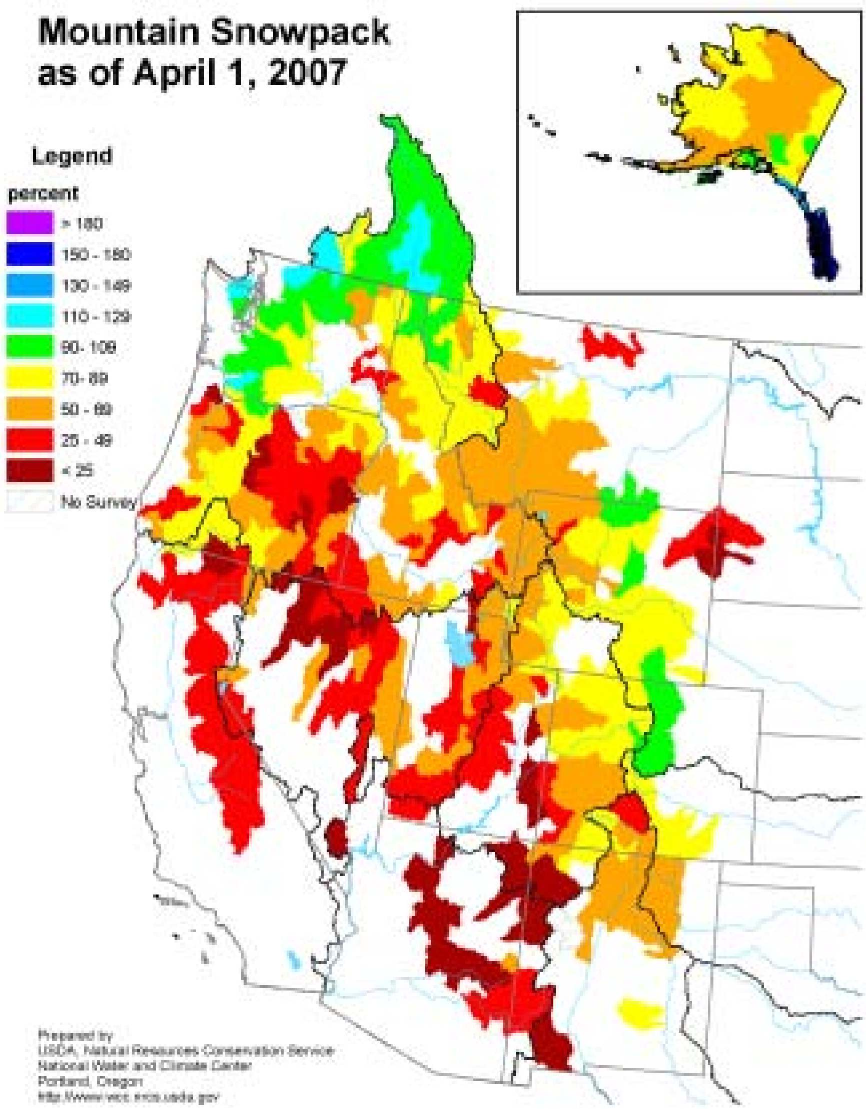
West Coast Snowpack - 2007

In sharp contrast to last year, 2007 is shaping up as one of the drier years in CAISO history. Figure 1 below shows that winter snowpack levels in most areas of California and Oregon are far below average as of April 1, 2007. While ample supplies of hydro and thermal generation capacity will be available for peak summer loads, the overall shortage of hydro capacity will require greater reliance on non-hydro resources during the coming summer months. Low stream flows can also impact generation capacity by reducing the availability of cooling water required by some large thermal generators.

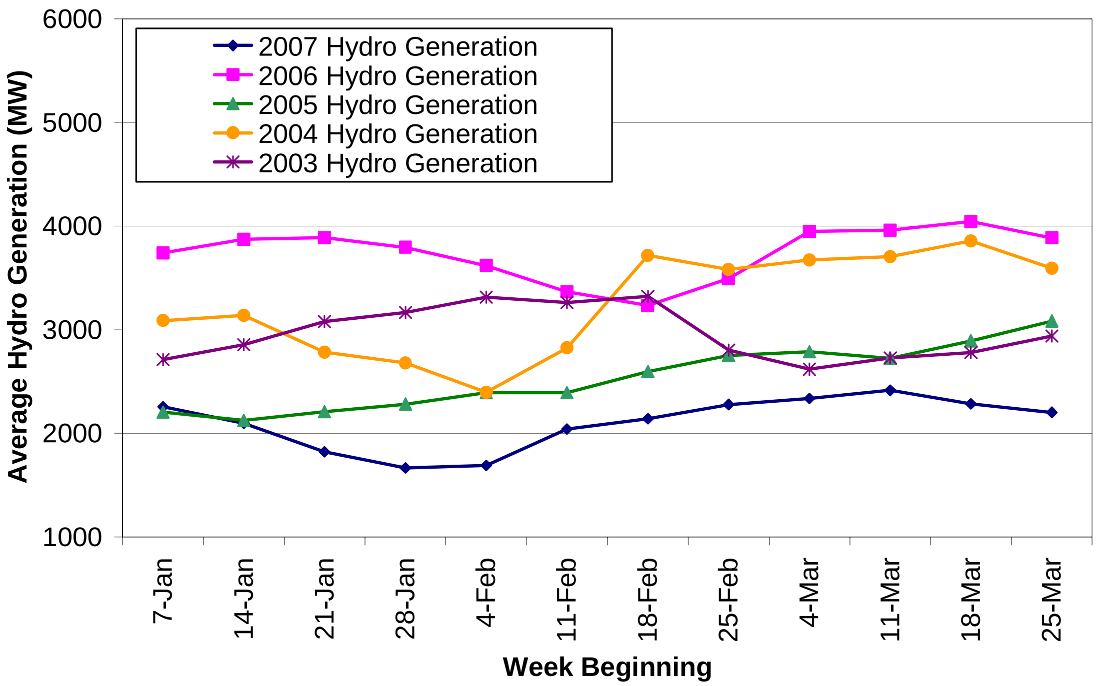
Figure 1: California and Pacific Northwest Snowpack – 2007



Hydroelectric Generation

Figure 2 compares weekly average hydro-electric generation in the CAISO balancing area in 2007 with previous years. Here the initial impact of the scant California snowpack can be clearly seen. Hydro generation in 2007 has been averaging slightly above 2,000 MW daily, which is a little more than half the level seen at this time last year. Given the limited volume of hydro capacity reflected in Figure 1, low hydro generation levels in March reflect good water management practices as generators conserve available hydro capacity for the peak summer months. Typically, hydro generation levels tend to peak during the month of June.

Figure 2: Weekly Average Hydro Generation – 2007 v. Prior Years



Prices and Volumes in the Real-Time Balancing Market

Dispatch Interval (Five-Minute) Prices

Real-time dispatch prices were more volatile this March exceeding $250 on 131 occasions versus 50 in February and 42 in March 2006. The increase in real-time price volatility was driven by two major characteristics; grid events associated with the Pacific DC Intertie being forced out-of-service, and persistent unscheduled transmission flows. There was also a series of data transfer issues between some of the CAISO software systems that run the Real-Time market, but its impact on dispatch interval prices is believed to be small.

Pacific DC Intertie Outage

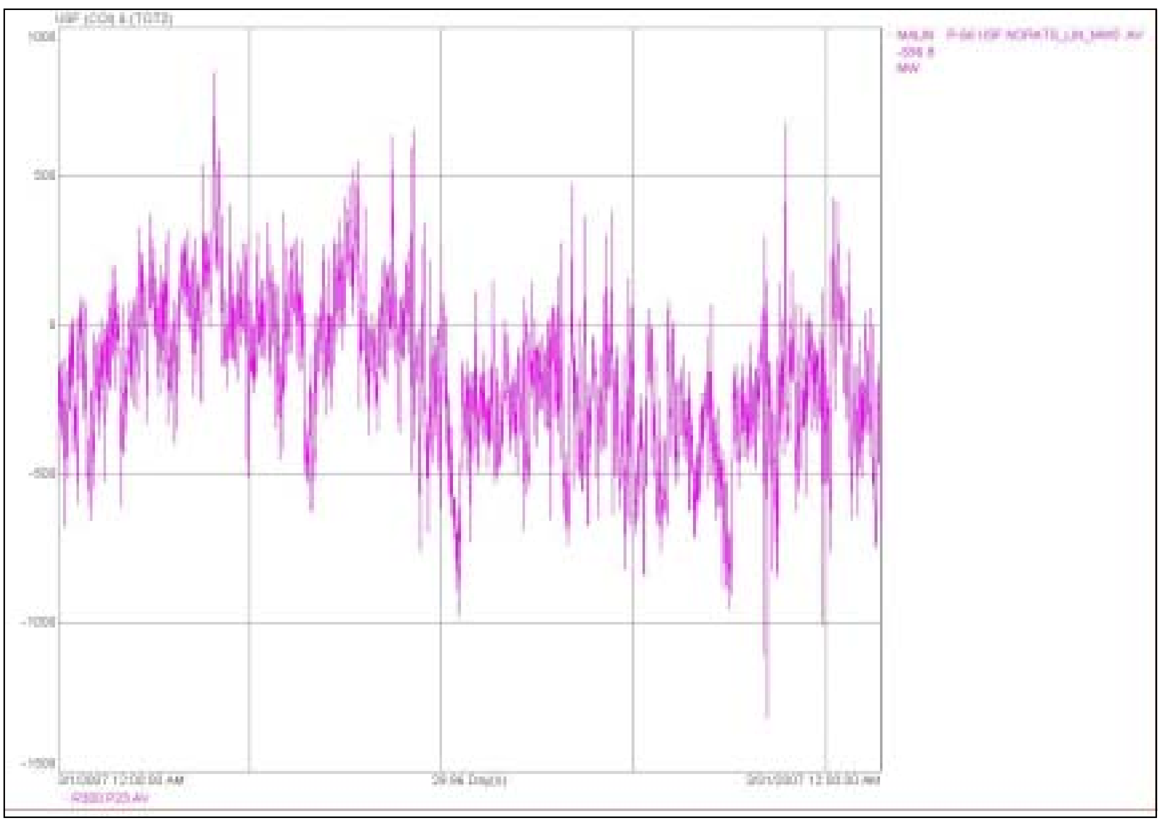
The most significant real-time price elevation in the balancing market occurred beginning March 26th and extending through March 28th. Several factors contributed to this condition. Beginning on the morning of March 26th, an outage of the series capacitors at Malin necessitated a reduction of the transfer capacity on the Pacific AC Intertie (PACI). Following that event, the Pacific DC Intertie was forced out of service, reducing the north to south transfer capacity by some 2,800 MW. The outage reduced the import capacity from the Northwest and created price elevation. The PDCI outage continued through the 27th and into the 28th. Although Scheduling coordinators are able to alter schedules to mitigate the effects of the outage, the absence of adequate north-to-south transmission will still raise the price by forcing less economical units into the market.

Unscheduled Transmission Flows

Unscheduled transmission flows (referred to as USF or loop flow) occur when electric power that is scheduled to flow on a given transmission line instead flows on a different path. It is a common occurrence since in general it is impossible to exactly control the pattern of power flow on a transmission network. The western interconnection, roughly speaking, includes a 500 kV transmission backbone that links the Northwest with California and the Southwest. Completing the loop around the western states is a 345 kV backbone running from the Northwest through Idaho, Wyoming, Utah and New Mexico to connect back to the 500 kV transmission lines in Arizona and Nevada. Together the 500kV and 345kV systems resemble a donut, and the pattern is often referred to as such.

A typical springtime pattern occurs as river flows in the Northwest peak, and power that is intended to flow southeast along the 345 kV transmission lines instead detours along the 500 kV backbone from north to south through California and then east out of the state. This creates power flows that may exceed the capacity rating of the transmission lines in the state, even though the scheduled power flows are within limits.

Figure 3: Unscheduled Loop Flow – March 2007



The first response to this situation is for California ISO grid operators to issue decremental dispatches to dispatchable interchange schedules coming in from the Northwest in anticipation of high loop flow. This reduces the flow on the transmission lines to acceptable levels, but the reduction in scheduled energy must be compensated for by increasing the incremental real-time dispatch to in-area generators. Since this increases the total amount of incremental energy, it can cause real-time balancing energy prices to rise. Managing loop flow in this manner is made even more difficult since the volume of loop flow is high variable very difficult to predict precisely.

Figure 3 illustrates the actual unscheduled flow on the Malin interface during March. Positive flow is considered to be south-to-north, negative flow north-to-south. Clearly, there was significant north-to-south unscheduled flow in the latter half of March. The graph highlights the extremely variable and therefore unpredictable pattern of loop flow in general. Also note that it is impossible to measure unscheduled flow independently of the actions that are taken to mitigate it. What is illustrated in Figure 3 is the unscheduled flow that occurred in spite of mitigation. Without mitigation, the unscheduled flow would have been greater.

Control Area Scheduler Data Transfer Issue

On February 14, 2007, CAISO launched a new software application for managing interchange schedules. The application is called the Control Area Scheduler, or CAS. Although the initial operation of the product was apparently trouble free, beginning on about March 11th problems with the transfer of data related to hourly pre-dispatched interchange schedules from CAS to the Real-Time Market Dispatch Application (RTMA) became apparent. In some cases RTMA was not receiving the pre-dispatched interchange schedules, or not receiving them in time to be incorporated into the dispatch calculations for specific time intervals. The lack of pre-dispatch information, if not manually corrected by grid operations staff, would create a situation in which the RTMA application would not dispatch the correct amount of energy to match load in real-time. This in turn could create price distortions and operational problems.

Once the problem was recognized, grid operators used the manual correction function within the RTMA application to manually enter the pre-dispatch quantity, but the manual correction process is time-critical and not as effective as the automatic transfer. Since the CAS problem did have some impact on the amount of real-time balancing energy dispatched in each interval, it had the potential for creating price deviations from the values that would have been calculated if the pre-dispatch data was being correctly transferred. It is difficult, however, to quantify exactly what the impact was, since there are a myriad of conditions that may quite properly affect the price outcome, and it is difficult to isolate the impact of any single condition. System data was reviewed and compared to similar periods from the previous year in an effort to determine what the overall impact of the CAS issue might have been.

A comparison of the overall cost of procuring balancing energy in March 2007 against costs in previous months and in March 2006 indicates that the cost impact was small. In order to compare costs and prices in a consistent manner over a series of different time periods, CAISO analyzed the amount of incremental balancing energy purchased above and below a gas-indexed reference price, so that the price of natural gas, a primary driver of electric energy prices in California, would not impact the comparison. The analysis indicated that the expenditure for incremental balancing energy purchased above the reference price increased from 40.66 percent of the total in March 2006 to 43.60 percent in March 2007. Given the multiplicity of factors that can create price impacts in the balancing energy market, this modest increase does not support a conclusion that the cost impact of the CAS data transfer problem was significant in terms of overall costs. In summary, although there do appear to have been instances where the CAS problem may have affected prices, the overall impact on incremental balancing energy costs appears to have been small in proportion to the overall balancing energy expenditure.

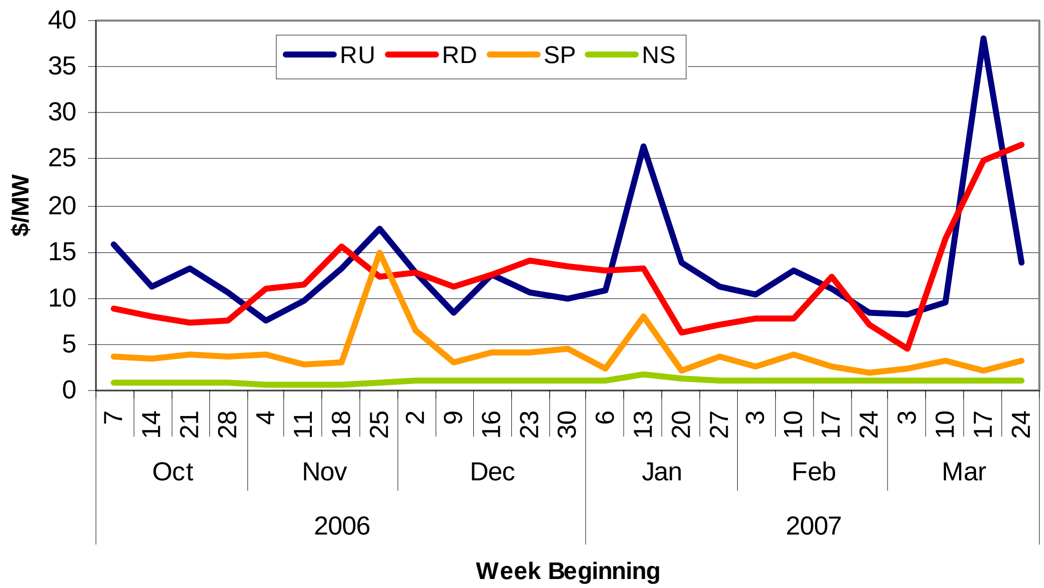
Ancillary Services Market Prices

Relative to February 2007, weighted average Ancillary Services prices for Regulation Up and Regulation Down increased sharply in March, while prices for Spin and Non-Spin services declined. High average Regulation Up prices can be attributed to congestion on the Mead and PACI branch groups between March 17th and March 19th which stranded dynamic system resources outside the CAISO control area. High average Regulation Down resulted primarily from slim offers and high accepted bids on the 20th and 21st. Table 1 below shows the requirement and price breakout for each service separately, while Figure 4 displays the six-month price trend on a weekly average basis.

Table 1: Average Ancillary Service Requirements and Prices - February and March 2007

	Average Required (MW)				Weighted Average Price ($/MW)			
	RU	RD	SP	NS	RU	RD	SP	NS
Feb 07	370	357	826	808	$ 10.94	$ 8.87	$ 2.78	$ 1.07
Mar 07	374	356	722	719	$ 16.84	$ 16.79	$ 2.76	$ 1.03
	1.0%	-0.4%	-12.6%	-11.0%	54.0%	89.2%	-0.6%	-3.8%

Figure 4: Weekly Weighted Average Ancillary Service Prices – Oct 2006 to Mar 2007



Inter-Zonal Markets

Congestion Costs

Total inter-zonal congestion costs increased to $8.1 million in March from $1.83 million in February. This is well above the average cost over the past 12 months of $4.7 million, and also above the March 2006 total of $2.16 million. A majority of congestion this month occurred on Pacific AC Intertie (PACI) and Nevada - Oregon Border (NOB) branch groups.

As shown in Table 2 below, PACI was congested 62 percent of times in the day-ahead import direction. Congestion on PACI was largely driven by over-scheduling, scheduled maintenance on transmission lines, and by transmission de-rates motivated by outages. NOB was congested 62 percent of times in the day-ahead import direction. The congestion on NOB occurred throughout most of March, and was largely due to over scheduling and derates on PACI.

Table 2: Inter-Zonal Congestion Costs – March 2007

Branch Group	Day-ahead		Hour-ahead		Total Congestion Cost		Total Congestion Cost		Total Congestion	Total Cost Percent
	Import	Export	Import	Export	Import	Export	Day-ahead	Hour-ahead		
ADLANTOSP	$235,552	$0	-$24,454	$0	$211,098	$0	$235,552	-$24,454	$211,098	3%
CASCADE	$0	$0	$176	$0	$176	$0	$0	$176	$176	0%
ELDORADO	$80,120	$0	$33,423	$0	$113,543	$0	$80,120	$33,423	$113,543	1%
IPPDCADLN	$126,865	$0	$4,345	$0	$131,210	$0	$126,865	$4,345	$131,210	2%
MEAD	$4,160	$0	$73,270	$0	$77,430	$0	$4,160	$73,270	$77,430	1%
MKTPCADLN	$1,360,947	$0	-$397,466	$0	$963,481	$0	$1,360,947	-$397,466	$963,481	12%
NOB	$2,224,359	$0	$23,964	-$3	$2,248,322	-$3	$2,224,359	$23,960	$2,248,319	28%
PACI	$4,085,827	$0	$142,038	$0	$4,227,865	$0	$4,085,827	$142,038	$4,227,865	52%
PALOVRDE	$58,524	$0	$99,266	$0	$157,790	$0	$58,524	$99,266	$157,790	2%
PARKER	$0	$0	$5,107	$0	$5,107	$0	$0	$5,107	$5,107	0%
SILVERPK	$0	$0	$192	$0	$192	$0	$0	$192	$192	0%
SUMMIT	$0	$0	$455	$0	$455	$0	$0	$455	$455	0%
TRACYCOTP	$25	$0	$2,465	$0	$2,490	$0	$25	$2,465	$2,490	0%
WSTWGMEAD	$1,714	$0	$16,654	$0	$18,368	$0	$1,714	$16,654	$18,368	0%
Total	$8,178,092	$0	-$20,566	-$3	$8,157,526	-$3	$8,178,092	-$20,569	$8,157,523	100%