California Independent
System Operator Corporation

Memorandum

To: ISO Board of Governors

From: Keith Casey, Director, Market Monitoring

Date: July 1, 2008

Re: ***Market Monitoring Report***

This memorandum is for information only. No Board action required.

Summary

This memo summarizes two recent market issues, market performance during the May heat wave and high congestion management costs caused by power flow from the Pacific Northwest.

The first heat wave of 2008 occurred earlier than usual, from Thursday, May 15 to Monday, May 19. Though markets generally performed without incident, the real time energy market experienced isolated price spikes, higher average prices in the Ancillary Services markets and increased congestion costs as more power was imported from the Pacific Northwest. These outcomes are characteristic of market performance during heat wave periods and reflect the responsiveness of the markets to changes in demand conditions.

In addition to the heat wave, the CAISO has incurred significant costs to mitigate congestion in two distinct categories this Spring -- forward congestion on paths used to import power from the Pacific Northwest into California and near real time mitigation of seasonal unscheduled flow from the Pacific Northwest. These costs have been exceptionally high this year, over a short period of time, and the cause of both types of cost is likely to occur in future years.

For a three week period on two major branch groups connecting to the Pacific Northwest, forward congestion costs have totaled over $25 million, as a recurring maintenance outage in the Pacific Northwest impacted the transfer capacity of the Pacific AC Intertie. This cost has surpassed the historical annual congestion costs for those two branch groups and highlights CAISO's sensitivity to events in other western control areas.

The market also incurred significant costs as a result of unscheduled power flow through the CAISO control area, which, unabated, could cause power flow on major transmission paths from the northwest exceed their limits. Seasonal unscheduled flow is the result of high hydroelectric output in the Pacific Northwest , a

recurring physical issue that will not be relieved by design elements in MRTU. The CAISO used real time export energy bids to mitigate these seasonal unscheduled flows and, during some periods, balanced those exports with higher-cost internal gas-fired resources. Mitigating unscheduled flow for May and the first half of June cost over $8 million.

1. Market Performance During the May Heat Wave

The purpose of this section is to present a summary of market performance during the first heat wave of 2008, which occurred from Thursday, May 15 through Monday, May 19, and to highlight specific market events. Historically, California does not typically experience heat waves in May, when many of the larger generating resources may still be out on seasonal maintenance outages. Despite several generating units and transmission line outages during this period, CAISO markets were not significantly impacted during the heat wave. Notable market performance during the heat wave includes:

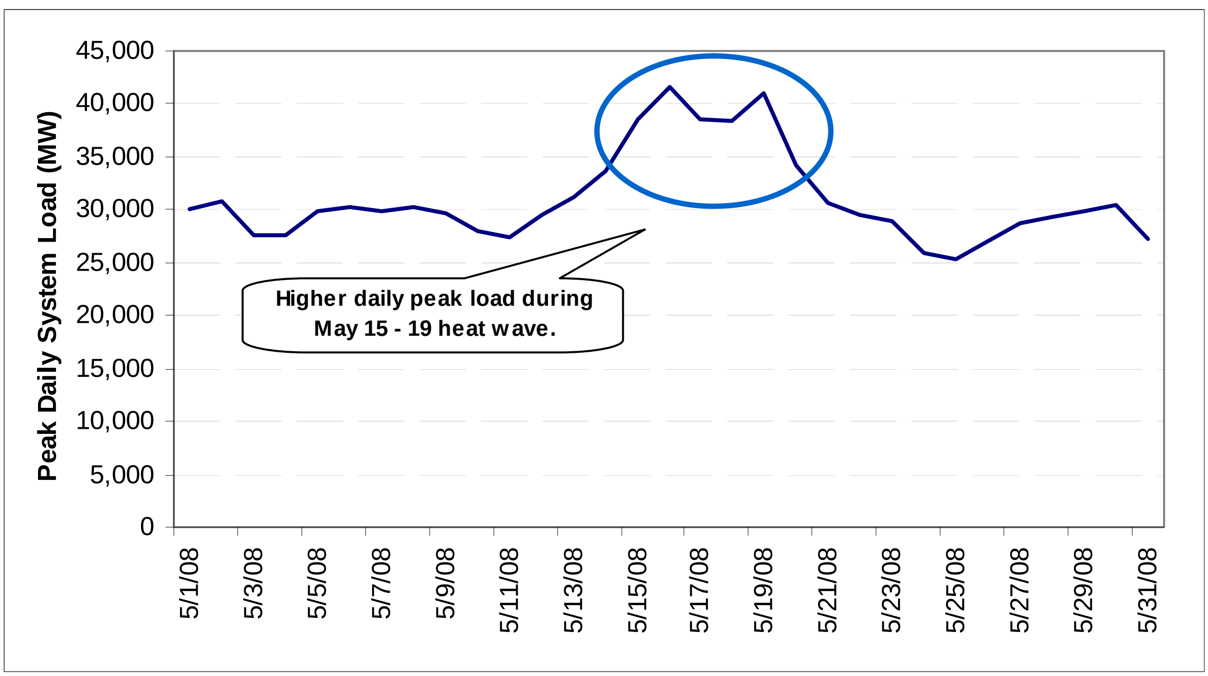
– Isolated price spikes in the imbalance energy market during peak hours, with minimal cost impact due to high forward-scheduling of load,

– Significantly higher average Ancillary Service prices and isolated reserve shortages during peak hours, and

– Congestion costs increased significantly on major branch groups.

The May heat wave is of interest because the loads were abnormally high for this time period. In contrast, annual peak loads are in the neighborhood of 47,000 MW to over 50,000 MW and typically occur in the months of July through September. The highest peak load during the May heat wave was on Friday, May 16, with a peak of 41,640 MW.

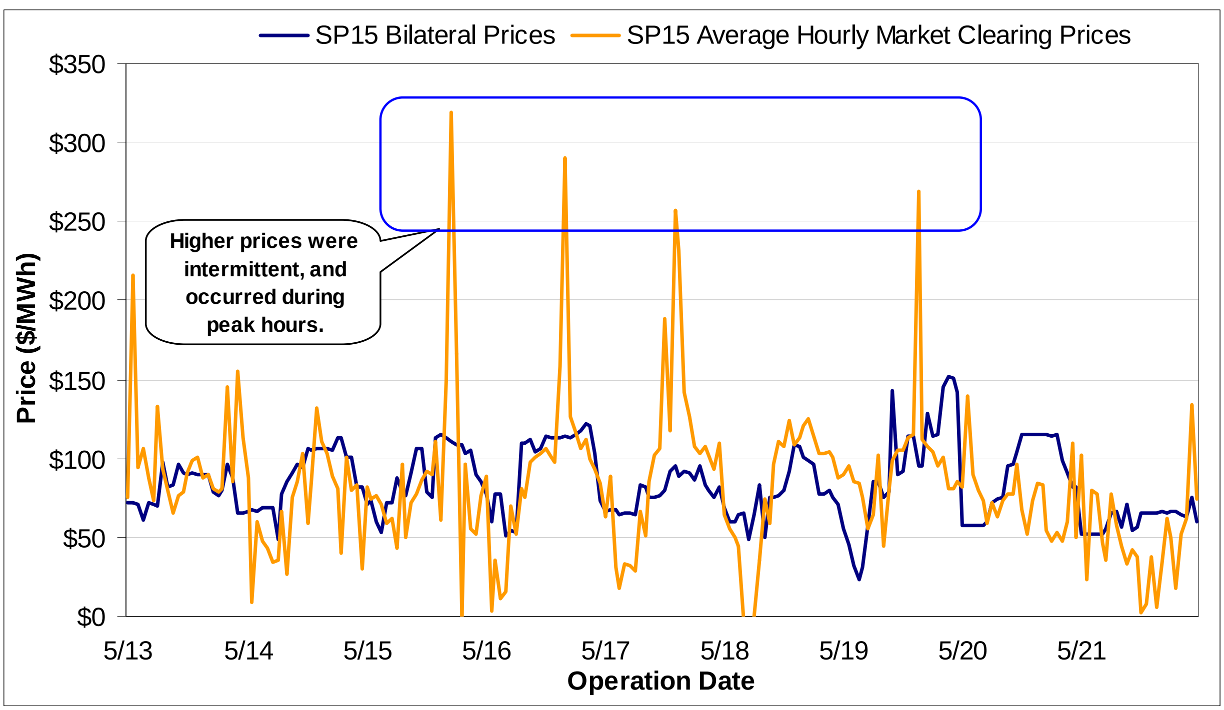
Figure 1. Daily Load Statistics for May Heat Wave



One key facet of market behavior during heat waves is the extent to which Load Serving Entities (LSEs) procure and schedule energy in advance to meet their load. This can have a significant impact on both the ISO's ability to manage the grid in real-time as well as on imbalance market prices. More energy procured in forward markets means less energy to procure in the Real Time Market. As a result we typically observe more moderate prices in the Real Time Market. For the past two summers, LSEs have shown significant forward procurement during heat waves, sometimes in excess of 100% of actual load, rather than relying on the imbalance market. Despite often higher prices for short-term forward energy during heat waves, forward procurement mitigates the risk of load curtailment when there is insufficient imbalance energy. It also reduces exposure to potentially higher imbalance market prices should we need to serve a significant load in the market of last resort.

Though we procured most energy in forward markets, the imbalance energy market still had price spikes each day, except on Sunday, as seen in Figure 2 below. Figure 2 compares hourly spot bilateral prices in SP15 to the average hourly Real Time Market clearing price (MCP) in SP15. During the heat wave, bilateral prices were typically higher than MCPs due to the high level of forward scheduling, leaving a small percentage of the load to be procured in real-time. We did experience real-time price spikes due to under-scheduling across the peak hour, load forecast accuracy, and the availability of operating reserves, among other things.

Figure 2. Hourly Spot Bilateral Price and Average Hourly Imbalance Price



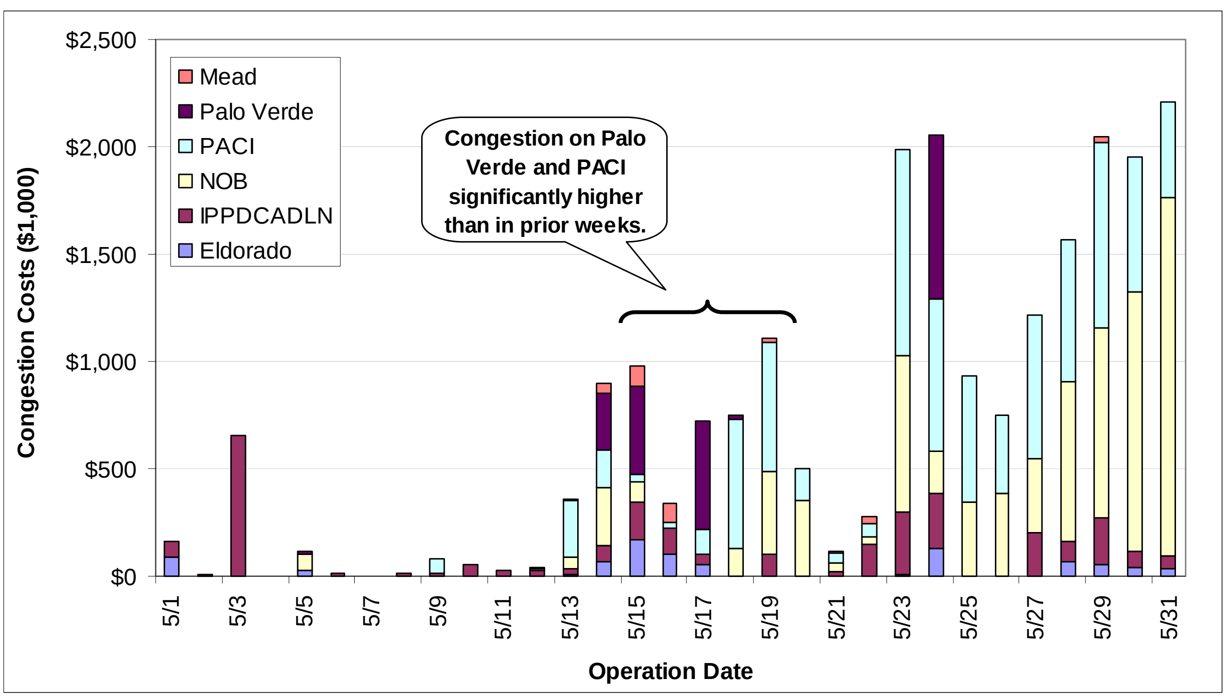
Overall, through the heat wave, forecasted load and scheduling patterns remained relatively accurate and insignificantly under- or over-scheduled. Imbalance energy price spikes occurred during super peak hours when schedules were slightly below actual load, i.e., approximately 1,000 MW under-scheduled, and did not persist throughout the day. For example, Thursday, May 15, had the most price spikes, due to a major transmission line loss in real-time, splitting the markets and causing RTMA to dispatch higher priced units in the North to serve load there. Most price spikes during the heat wave were due to grid conditions rather than a result of forecast error, under-scheduling, or under-commitment of internal resources.

Load forecast error can also significantly impact real-time prices, both directly through the amount of forward scheduled energy and the imbalance requirement and indirectly through capacity online and available to be dispatched in real-time to meet the imbalance requirement. On Thursday, May 15, because the CAISO's hour-ahead load forecast was low by roughly 1,000 MW for the peak hour, we scheduled less additional energy in the hour-ahead, leading to a higher imbalance requirement. This required dispatch of higher-priced imbalance energy bids in real-time, contributing to the price spikes seen on that day.

Market Performance for Ancillary Services (A/S) during the heat wave resulted in few notable events. Total A/S costs on the weekdays increased significantly compared to the prior week, which is expected during a heat wave. Several factors contribute to this market effect. First, A/S offer prices increase to reflect the anticipated higher energy prices. Also, demand for A/S increases during heat waves proportional to the increase in load, and supply can decline as generators enter into short-term arrangements to capitalize on higher bilateral prices. And finally, often during the spring, larger generating resources go off-line on scheduled maintenance, limiting A/S supply. In the case of the May heat wave, A/S price spikes were not caused by high forward energy prices but by decreases in lower priced available bids. Available bids across peak hours decreased significantly on Thursday and Friday, resulting in both procurement deficiencies and price spikes. Though the operating reserve level dipped below the 7% reserve level on Thursday during three intermittent intervals, the ISO did not issue an Emergency Notice.

Inter-zonal congestion costs increased on the major Branch Groups during the heat wave, as seen in Figure 3, totaling roughly \$4.4 million over the 5–day period. All of the congestion costs were in the import direction, most of which occurred in the Day Ahead Congestion Market.

Figure 3. Daily Congestion Cost on Major Branch Groups for May 1 – May 31, 2008



Most inter-zonal congestion costs during the heat wave can be attributed to increased demand for transmission capacity importing from the Pacific Northwest as loads in California increased and inexpensive hydroelectric power from the Pacific Northwest was preferred to higher-cost natural gas fired generation in California. In addition, planned transmission work resulted in a decrease in transfer capability on several importing lines which caused high Day Ahead congestion prices. As an example, because the Palo Verde – Devers 500kV line was out of service for planned work most of Saturday the 17, the Palo Verde branch group accounted for roughly 75% of the total congestion cost on that day. High congestion costs beginning later in the month are associated with a line outage in the Pacific Northwest, not related to the heat wave, and are covered in the next section.

2. Costs Associated with Congestion Management this Spring

The CAISO incurred significant costs to mitigate congestion in two distinct categories this Spring - forward congestion on paths used to import power from the Pacific Northwest into California and near real time mitigation of seasonal unscheduled flow from the Pacific Northwest. The purpose of this section is to explain the causes and magnitude of these costs and highlight the potential for recurrence.

For a three week period on two major branch groups connecting to the Pacific Northwest, the forward congestion costs totaled over $25 million, due largely to a recurring maintenance outage in the Pacific Northwest that impacted the transfer capacity of the Pacific AC Intertie. The $25 million in forward congestion costs for the three week period surpassed the historical annual total congestion costs for those two branch groups and highlights CAISO's cost sensitivity to events in other western control areas.

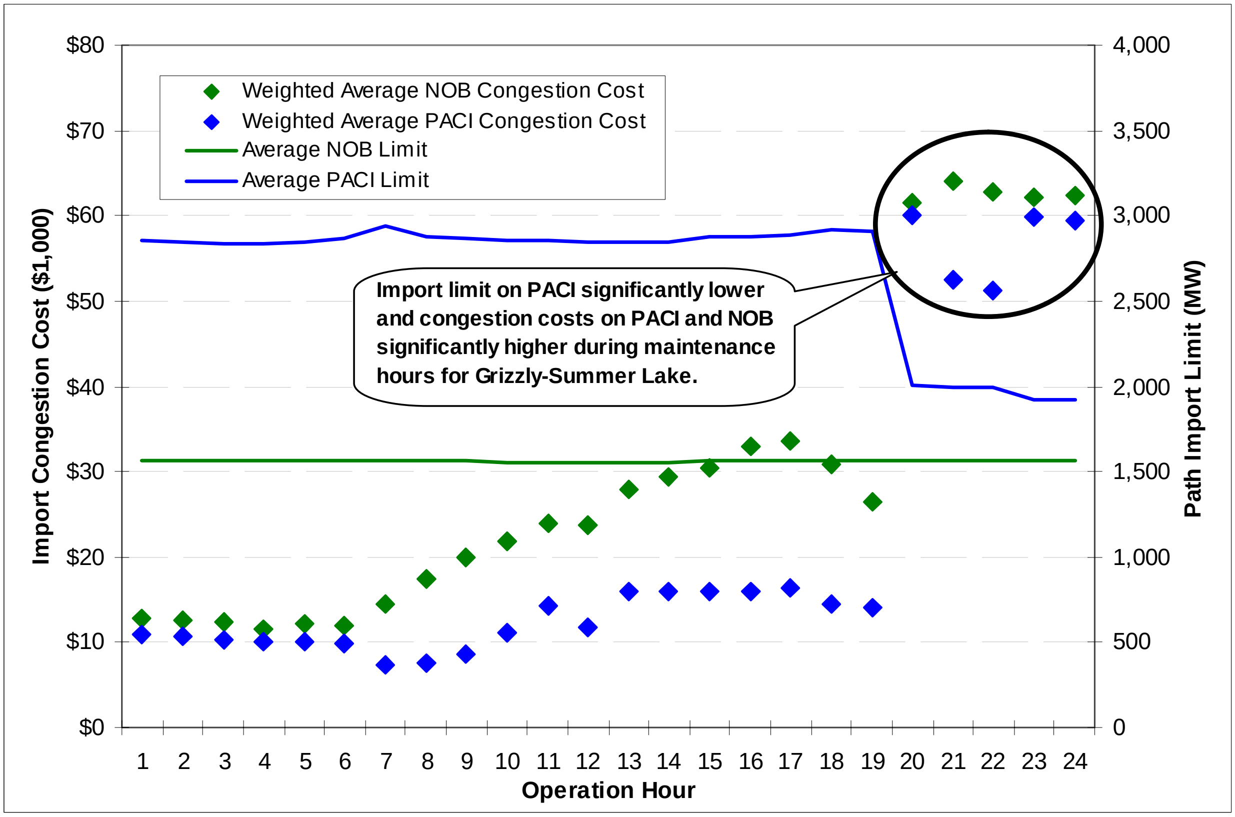
We also incurred significant costs as a result of unscheduled loop flow through the CAISO control area which, unabated, could cause the northwest interties to overload. Seasonal unscheduled flow is the result of high hydroelectric output in the Pacific Northwest, a recurring physical issue that will not be relieved by design elements in MRTU. The CAISO used imbalance export bids to mitigate these seasonal unscheduled flows and, during some periods, balanced those exports with higher-cost internal gas-fired resources. Estimated cost for mitigating unscheduled flow for May and the first half of June was over $8 million.

High Inter-zonal Congestion Costs from Pacific Northwest

Each spring the CAISO must manage reliability issues stemming from seasonal maintenance outages as well as high output levels from hydroelectric generation in Northern California and the Pacific Northwest. This year, congestion management charges for the Pacific AC Intertie (PACI) and the Pacific DC Intertie (PDCI) totaled over $25 million for the period May 23 through June 13. Congestion on these paths was impacted by maintenance work on the Grizzly-Summer Lake lines in the Bonneville Power Administration (BPA) control area. While the Grizzly-Summer Lake lines are not in the CAISO Control Area, this work resulted in BPA reducing the available capacity on PACI in the north-to-south direction during hours ending 20 through 24, when the work was being performed.

Figure 4 below shows the average hourly line rating (in the import direction) and congestion cost for PACI and NOB for the period May 23 through June 13. While PACI and NOB both had congestion across all hours of the day, most congestion charges occurred between hours ending 20 through 24 where the PACI line was derated by roughly 1,000 MW to accommodate the Grizzly-Summer Lake line work in the BPA control area. Interestingly, congestion costs on NOB also increased significantly during those hours, despite no change in the NOB path rating, as importers shifted their schedules from COI to NOB.

Figure 4. Average Congestion Cost and Average Path Limit by Hour for May 23 – June 13, 2008



These two paths were also frequently congested during hours when no derates were applied. We can explain congestion across all hours and the increased willingness to pay for transmission capacity resulting in considerably higher costs during derate hours, at least in part by the disparity between the price of hydroelectric power from the Pacific Northwest and the cost of gas-fired generation in California. During the spring hydro run-off period, hydroelectric power is often offered at very low prices since those suppliers will have to "spill" water to accommodate more snow runoff in the hydro system and are willing to accept a lower price for that energy rather than spill the water without any electricity revenues. At the same time, natural gas prices have been ranging between $9/MMBtu and $12/MMBtu, historically very high compared to prior summers. This natural gas price range implies a $90/MWh to $120/MWh electricity price, valued at the marginal cost of a relatively efficient gas fired resources with a 10,000 heat rate. Because of the spread between gas-fired costs at the higher gas prices and inexpensive hydroelectric power generated during the spring run-off period, we find greater willingness to pay for transmission for importing inexpensive Pacific Northwest power into California to meet load.

The impact of the Grizzly-Summer Lake outage on PACI rating began on May 27 and ended on Friday, June 13, after which congestion costs on both PACI and NOB have declined significantly. While it is not possible to know what the congestion costs on PACI and NOB would have been absent the late evening derates on PACI, we can provide a ball-park estimate of the additional congestion costs resulting from this outage. The additional cost is estimated by taking the difference between average hourly congestion price in hours with and without the PACI derate and applying that difference to the affected hours across the 19 days where the derate was in effect. Using this approach, we estimate that roughly $12.3 million of the

$26.1 million in congestion cost on PACI and NOB during this period can be attributed to the Grizzly-Summer Lake outage impact on PACI path limits, with the remainder attributed to seasonal import patterns and the increased willingness to pay for transmission resulting from low prices for Pacific Northwest hydro and high natural gas prices. Importantly, some Scheduling Coordinators (SCs) are hedged against these congestion costs through ownership of Firm Transmission Rights (FTRs)[1]. For imports on PACI and NOB during this period, roughly 33% of schedules that were subject to import congestion charges were hedged through FTRs, leaving SCs who scheduled imports across these lines about 67% exposed (collectively) to these high congestion charges.

Figure 5. Daily Total Congestion Cost for PACI and NOB for May 12 – June 15, 2008

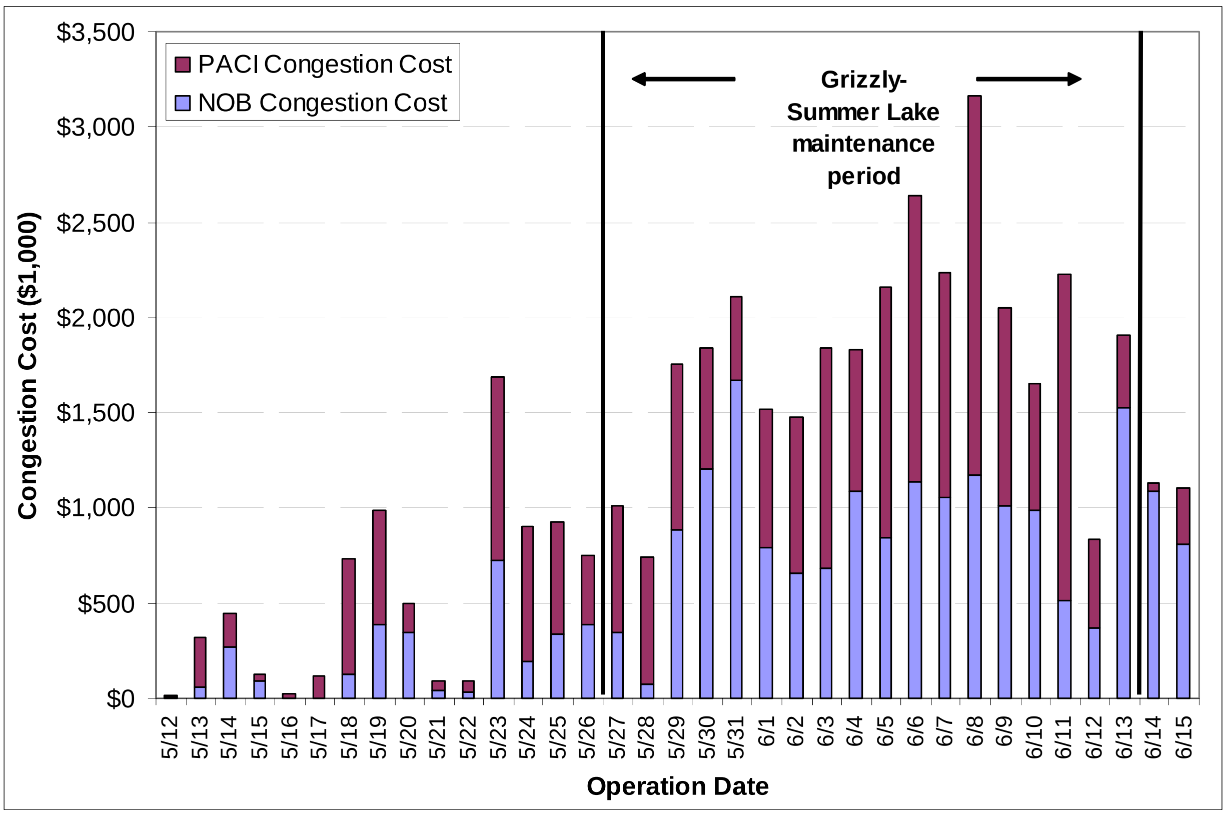


Figure 5 shows daily congestion costs for PACI and NOB from May 12 through June 15. Note that daily congestion costs were relatively low until May 23. The Grizzly-Summer Lake outage began the evening of May 27, and persistent high congestion costs on PACI and NOB began occurring the following day, largely tapering off on June 14**.**

Managing Seasonal Unscheduled Flow

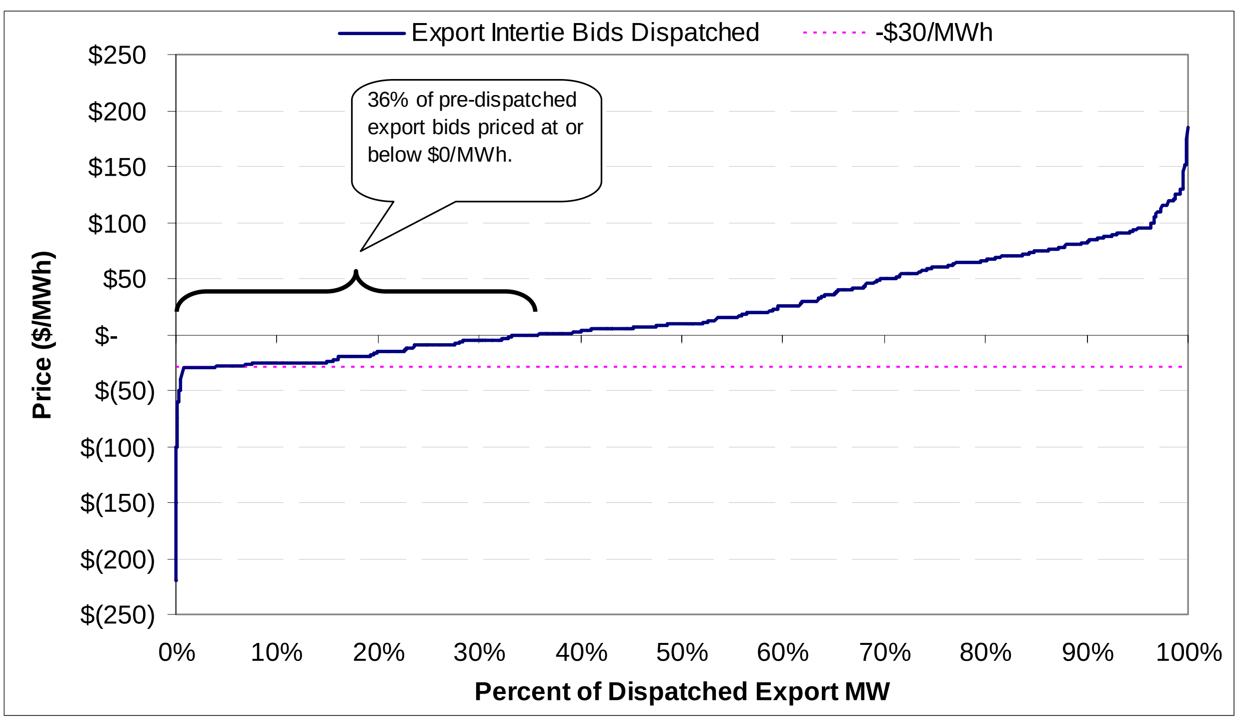
[1] FTRs are a financial instrument that provide a hedge to SCs against congestion charges in the day ahead congestion management market. A MW of energy scheduled in the day ahead market on a path in the congested direction would normally be subject to the congestion charges determined by that market. If that schedule is covered by an FTR, the day ahead market congestion charges are effectively voided. FTRs are auctioned annually through the CAISO, with subsequent secondary auctions and trades taking place throughout the year and will be replaced with Congestion Revenue Rights (CRRs) in the MRTU market.

Another related seasonal pattern that the CAISO must manage is Unscheduled Flow (USF), generally in the north-to-south direction from the Pacific Northwest through the CAISO Control Area and out to the Southwest. As the market software does not explicitly manage USF, CAISO operators must do this and require uneconomic dispatch of energy bids. Inefficiency associated with uneconomic dispatch has caused significant cost this spring, with estimates totaling over $8 million for May through the first half of June. The purpose of this section is to present the persistence of this issue, the associated cost of mitigating USF, and to propose that the CAISO explore alternatives to anticipating and mitigating USF that are less costly.

Most prevalent in the spring, USF is driven by high hydroelectric production in the Pacific Northwest, varies in magnitude from hour to hour, and must be managed in order to avoid overloading of interties and internal paths. The CAISO is not the only control area impacted by USF. Neighboring control areas and utilities, as well as those within California (i.e., SMUD, TID, LADWP) have to manage their system in light of USF.

The CAISO has several tools available to manage USF including relying on the WECC procedure for managing USF and dispatching imbalance market energy bids to provide counter flow on PACI. As a preventative measure for managing USF, the CAISO often chooses to dispatch export bids from the imbalance market to provide additional counter flow (exports) on the PACI Branch Group. In doing so, the CAISO often must dispatch very low-priced, and even negative-priced, export bids to resolve USF. A low-priced bid indicates an SC is not willing to pay much for energy exported to them from the ISO, and a negative-priced bid indicates an SC is unwilling to take energy from the CAISO unless they are paid to do so. Figure 6 shows the price distribution of export bids dispatched in the imbalance market during May 2008. To highlight the low prices at which the CAISO is selling this energy to export, bids priced at or below $0/MWh represent roughly 36 percent of the quantity dispatched.

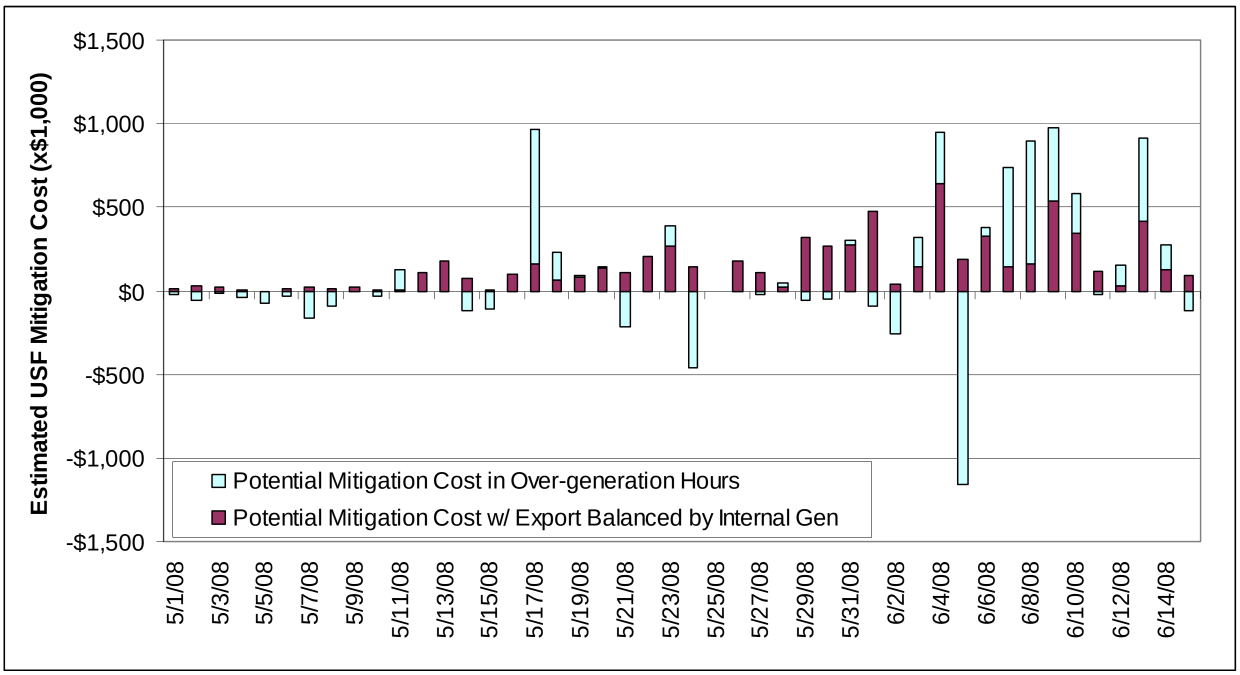
Figure 6. Price Distribution of Imbalance Export Bids Dispatched in May, 2008



In general, the CAISO must procure additional energy in the imbalance market to balance the energy exported from the control area up PACI to manage USF. Some of this energy may come from pre-dispatch import bids from, for example, the Southwest. However, often the CAISO procures the energy needed to balance these exports from internal resources, forcing the CAISO to move further up the supply curve, dispatching higher-priced bids.

This practice of selling energy at low prices for export and making up that imbalance through buying internal generation at higher prices results in increased uplift cost. Figure 7 below shows the estimated daily cost of hourly mitigating USF through the pre-dispatch of export energy bids for the period May 1 through June 15. The data used to create this figure were limited to hours where there was a net pre-dispatch export to help isolate the instances where USF was being mitigated.

Figure 7. Daily Average Estimated Cost of Uneconomic Dispatch Associated with Pre-dispatch Exports for May, 2008



Daily cost is minimal for the first half of May and begins to increase mid-May as hydroelectric production in the Pacific Northwest increases, increasing USF and requiring the CAISO to mitigate it. Estimates of potential mitigation cost are broken out into two metrics. The first measure, represented by red bars in Figure 7, measures the cost of uneconomic dispatch when the CAISO must balance mitigating export dispatches with incremental dispatch of higher-cost internal generation. The second measure, represented by the light blue bars, represents the cost of uneconomic export dispatch when the CAISO anticipates USF but is also in over generation and needs to further back-down internal resources.[2] Together, these

[2] The formula for calculating the two cost metrics both use the difference between the price of internal dispatch and the price of predispatched export bids and apply this price difference to an appropriate quantity reflecting the mitigation action. In the case where the CAISO was balancing the export with increased internal generation, the quantity is determined by the lesser of the net pre-dispatch export and the net internal incremental dispatch. In the case where the CAISO is exporting and dispatching internal resources downward, the quantity is calculates as the net pre-dispatch exports.

measures will likely over-estimate the cost directly attributable to mitigating USF but do provide an upper bound.

The estimated potential cost associated with mitigation of USF for May and the first half of June is roughly $8.1 million. With these high costs resulting from the need to manage USF within the CAISO, and the fact that this unscheduled power flow issue will persist in coming years, including MRTU, the CAISO should explore whether there are more cost effective means to manage USF such as being able to enact mitigation measures from the WECC process more proactively or incorporating USF estimates into the forward markets (e.g. Day-Ahead) so as to reduce the amount of re-dispatch required in the real-time market. Whether a more forward approach to managing USF is possible will depend in part on how accurately USF can be forecasted in advance of real-time.