California Independent
System Operator Corporation

Memorandum

To: ISO Board of Governors

From: Keith Casey, Director, Market Monitoring

Date: May 8, 2009

Re: ***Market Monitoring Report***

This memorandum does not require Board action.

Each year the Department of Market Monitoring (DMM) publishes an annual report on the performance of markets administered by the California Independent System Operator Corporation (the ISO). This memo provides a brief summary of the market performance highlights for 2008. A complete copy of the report was provided to you in early April.

DMM will be presenting highlights from the 2008 annual report at the May Board meeting. Additionally, DMM will be providing some observations and insights on how the new ISO markets have been performing since the March 31, 2009 implementation.

2008 Annual Report on Market Issues and Performance

For the seventh consecutive year (2002-2008), California's wholesale energy markets remained stable and competitive in 2008. This trend is predominately due to a high level of forward energy contracting by the state's investor owned utilities, which limits their exposure to spot market price volatility, enhances competition, and facilitates new generation investment. Over the past eight years (2001-2008), approximately 15,000 MW of new generation has been added to the ISO Control Area, enabling the retirement of 5,500 MW of older inefficient generation, resulting in a net increase of 9,500 MW of new generation. Though only 45 MW of new generation was added in 2008,[1] approximately 3,141 MW of new generation is projected to be operational in 2009, 216 MW of which are renewable energy projects.[2]

[1] Though approximately 1,660 MW of new generation was at some point on-line and tested in 2008, only 45 MW actually became commercially operable in 2008 with another 770 MW becoming commercially operable in the first quarter of 2009.

[2] The 216 MW figure is nameplate capacity. The net qualifying capacity of these resources is approximately 28 MW.

While California experienced a second consecutive year of below normal rainfall and snow pack, which raised concerns about hydroelectric supply availability during the critical summer months, relatively moderate summer temperatures mitigated this concern and produced generally competitive conditions with no major reliability issues. California experienced only one major heat wave in 2008. It occurred from June 18-21 with the annual peak load set on June 20^{th} at 46,897 MW, well below the all-time record summer peak load of 50,270 MW set in 2006 and unusually early for an annual peak, which typically occurs in July or August. The June 2008 heat wave was managed without any significant market or reliability issues.

From a grid operations standpoint, the most notable event of the year was the California wildfires that raged through large portions of Central and Northern California in June and July. During the June heat wave, dry lightning strikes ignited numerous wildfires across Central and Northern California. With spring 2008 being the driest on record for many parts of the state, the fires quickly spread to catastrophic proportions, resulting in more than 2,000 wildfires burning across the state and over 1.3 million acres burned. With many fires burning near major transmission facilities, grid conditions were challenging, requiring numerous de-rates of generation and transmission facilities, market interventions such as real-time out-of-sequence dispatches, and commitment of generation units at specific locations. Despite the challenging conditions, no major reliability events occurred during the wildfires. Most of the wildfires were contained by mid-July.

Grid operators also had to manage an unusually high level of unscheduled flows across the grid through much of the spring and early summer of 2008. These flows were driven primarily by high demand for abundant hydroelectric energy from the Pacific Northwest, high natural gas prices, and below normal hydroelectric supplies in California and other southwestern states. Unscheduled flows are largely managed through real-time re-dispatches and can result in significant market costs.

The most notable market event in 2008 was a dramatic increase in congestion costs, particularly on the major inter-ties with the Pacific Northwest. Total inter-zonal congestion cost was approximately $176 million in 2008, compared to $85 million in 2007. Most of the increase occurred in the spring and early summer, as a combination of abundant hydroelectric supplies in the Northwest and high natural gas prices increased demand and willingness to pay for using the major transmission facilities between California and the Pacific Northwest (i.e., the Pacific AC and DC Inter-ties). Congestion costs also increased significantly on a major transmission link between Southern and Northern California (Path 15) and was due primarily to one of the three 500 kV lines that comprise this path being taken out of service for scheduled maintenance during October 14 to November 7.

In terms of the general performance of the wholesale energy markets during the entire year, one of the primary metrics that DMM uses to gauge overall market competitiveness is a 12-month Market Competitiveness Index (MCI), which represents a 12-month rolling average of the estimated hourly price-cost mark-ups (i.e., the difference between actual energy prices and estimated "competitive" prices derived from cost-based simulations). MCI values below $10/MWh are considered to be reflective of a workably competitive market. The monthly MCI values estimated for 2008 were well below this level for all months of the year.

The average estimated cost of wholesale energy in 2008 was $53.01/MWh of load compared to $48.23/MWh in 2007.[3] Costs include the following components: forward scheduled energy, inter-zonal congestion, real-time imbalance energy, real-time out-of-sequence (OOS) energy redispatch premium, net reliability must run (RMR) costs, ancillary services, and ISO-related costs (transmission, reliability, and grid management charges). The increase in the costs in 2008 was primarily due to greater reliance on fossil fueled generation – due to limited hydroelectric supplies – and to increased congestion costs on major importing paths to California. The cost of natural gas historically has had a strong influence on the total energy cost estimate. To control for that exogenous factor, DMM also calculates an estimate of energy costs normalized to a fixed natural gas price. Costs normalized to a fixed gas price were slightly lower in 2008 than in 2007. This decline is due in part to lower peak loads during the critical summer months of July and August, which reduced the need to utilize more inefficient thermal generation.

One significant positive trend that has been reported in prior annual reports has been the sharp reduction in intra-zonal congestion costs. This trend did not continue in 2008 as intra-zonal congestion costs increased from $96 million in 2007 to $174 million in 2008. Intra-zonal congestion costs are comprised of three components: 1) minimum load cost compensation (MLCC) for units denied must-offer waivers, 2) real-time RMR costs, and 3) real-time redispatch costs. The increase is primarily attributable to higher MLCC payments and real-time redispatch costs. MLCC costs increased by $46 million in 2008, mainly due to the need to commit units in the summer months to relieve a transmission constraint in Southern California. The cost of real-time redispatch costs increased by $39 million in 2008. This increase was due in large part to the increased need to move resources committed at minimum load to higher dispatchable output levels where they have faster ramping capabilities. These dispatchability payments resulted in costs of approximately $12.3 million in 2008. Humboldt-area redispatches resulted in costs of nearly $23 million. Additionally, the Victorville-Lugo nomogram, which often requires the out-of-sequence dispatch of a costly steam resource in Southern California, incurred approximately $9.5 million in redispatch costs.

The RMR costs noted above only pertain to the cost of real-time RMR energy dispatches. The total cost of RMR units, which includes both fixed cost payments and variable cost payments for day-ahead and real-time dispatches, declined, from approximately $121 million in 2007 to $71 million in 2008, a reduction of approximately $50 million. This reduction is predominantly due to the reduction in the amount of capacity under RMR contracts, from approximately 3,400 MW in 2007 to 2,400 MW in 2008.

Another reliability management cost, which is relatively new, is the capacity payments made to generation units that are neither RMR units nor resource adequacy (RA) units. These capacity payments were made pursuant to the reliability capacity services tariff (RCST) and provide for both a daily capacity payment for non-RA units that are committed by the ISO and potentially monthly capacity payments if a non-RA unit is designated by the ISO as RCST. Because the ISO's new market design was delayed beyond the expiration of the RCST, a transitional capacity procurement mechanism (TCPM) was developed and approved by FERC with an effective date of June 1, 2008. The TCPM serves as a bridge between the expired RCST and the interim capacity procurement mechanism (ICPM), which the ISO implemented simultaneously with

[3] The 2007 estimate has been recalculated based upon the most recently available information.

MRTU. In 2007, the ISO did not make any forward RCST designations but did make numerous daily capacity payments to non-RA units, amounting to approximately $26 million. In 2008, RCST and TCPM payments were considerably less, amounting to approximately $3.4 million, of which $1.5 million were RCST payments and $1.9 million were TCPM payments.

In comparing the sum of the reliability management costs discussed above (intra-zonal congestion, other RMR costs, and RCST/TCPM payments) to last year, the total for 2008 is approximately 5% higher than 2007 ($232 million in 2008 compared to $221 million in 2007). Higher intra-zonal congestion costs in 2008 were largely offset by the above noted reduction in RMR costs and RCST/TCPM payments.

Another important market performance metric that DMM reports on each year is the extent to which spot market revenues for the entire year cover the annualized fixed cost of new generation facilities. The DMM's financial assessment of the potential revenues a new generation facility could have earned in California's spot market in 2008 indicates estimated spot market revenues fell short of the unit's annual fixed costs. This marks the sixth straight year that the DMM's analysis found that estimated spot market revenues did not provide sufficient fixed cost recovery for new generation investment. However, the analysis for the past four years (2005-2008) does show a positive trend of net revenues increasing for a new combined cycle unit, with estimated net-market revenues in 2008 of approximately $112/kW-year and $128/kW-year for Northern and Southern California, which equates to roughly 84% and 97%, respectively, of the estimated annualized fixed costs of $132.6/kW-year. Estimated net-market revenues in 2005 for this same type of unit covered only approximately 50% of the same estimated annualized fixed cost but this percentage has increased steadily in subsequent years.

While seven consecutive years of stable and competitive market performance is encouraging, the industry must remain vigilant in addressing its ever growing infrastructure needs, particularly for Southern California. Though approximately 7,500 MW of new generation has been added to Southern California since the energy crisis, which enabled the retirement of 4,300 MW of older inefficient generation, net generation additions for that region have only just kept pace with load growth. Consequently, reliability needs for that region continue to be met, in part, by older, less efficient generation, which cannot be sustained indefinitely. Moreover, major state environmental policies, such as greenhouse gas reductions, Renewable Portfolio Standards (RPS), and a potential ban on once-through cooling systems, will call for even more aggressive and coordinated action on addressing infrastructure issues.