

Memorandum

To: ISO Board of Governors
From: Eric Hildebrandt, Executive Director, Market Monitoring
Date: February 1, 2021
Re: Department of Market Monitoring update

This memorandum does not require Board action.

EXECUTIVE SUMMARY

This memo summarizes initial analysis by the Department of Market Monitoring (DMM) on market issues and performance of California's wholesale energy markets and the Western energy imbalance market in 2020.

Energy prices

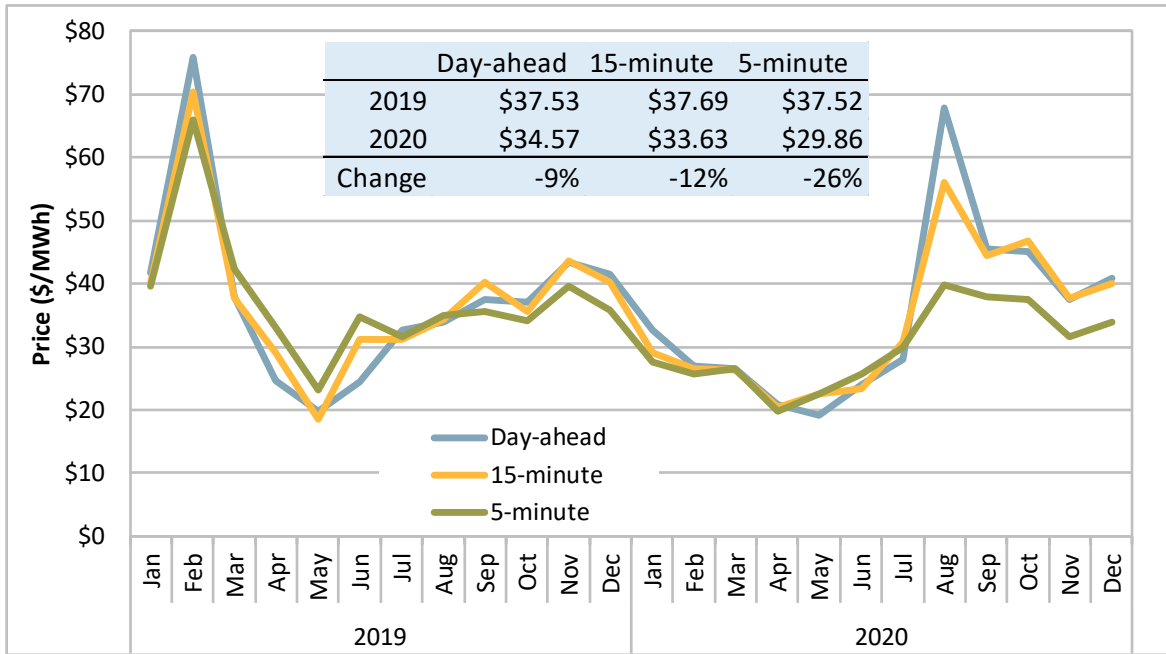
As shown in Figure 1, average day-ahead prices dropped by about 9 percent to \$34.57/MWh in 2020 compared to 2019. In the real-time market, average 15-minute prices dropped by 12 percent to \$33.63/MWh, while 5-minute prices fell by 26 percent to \$29.85/MWh. Some of this decrease in electric prices was due to lower gas prices at Socal Citygate, which fell about 8 percent. Average daily gas prices rose about 16 percent at PGE Citygate.

While average power prices over the entire year dropped, prices were significantly higher in the high load months of August to October of 2020 compared to 2019. During these high load months, average day-ahead prices were driven 26 percent higher than last year by a series of very high price spikes during region-wide heat waves from mid-August to early September. Factors driving these price spikes are discussed in DMM's recent report on market performance during the August and September heat waves.¹

Average prices in the 5-minute market also continued to be significantly lower than day-ahead and 15-minute prices during most months. From August through December, 5-minute prices were over 30 percent lower than day-ahead prices and 25 percent lower than 15-minute prices.

¹ *Report on Market Conditions, Issues and Performance – August and September 2020.*
<http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf>

Figure 1. Average ISO energy market prices (2019 and 2020)



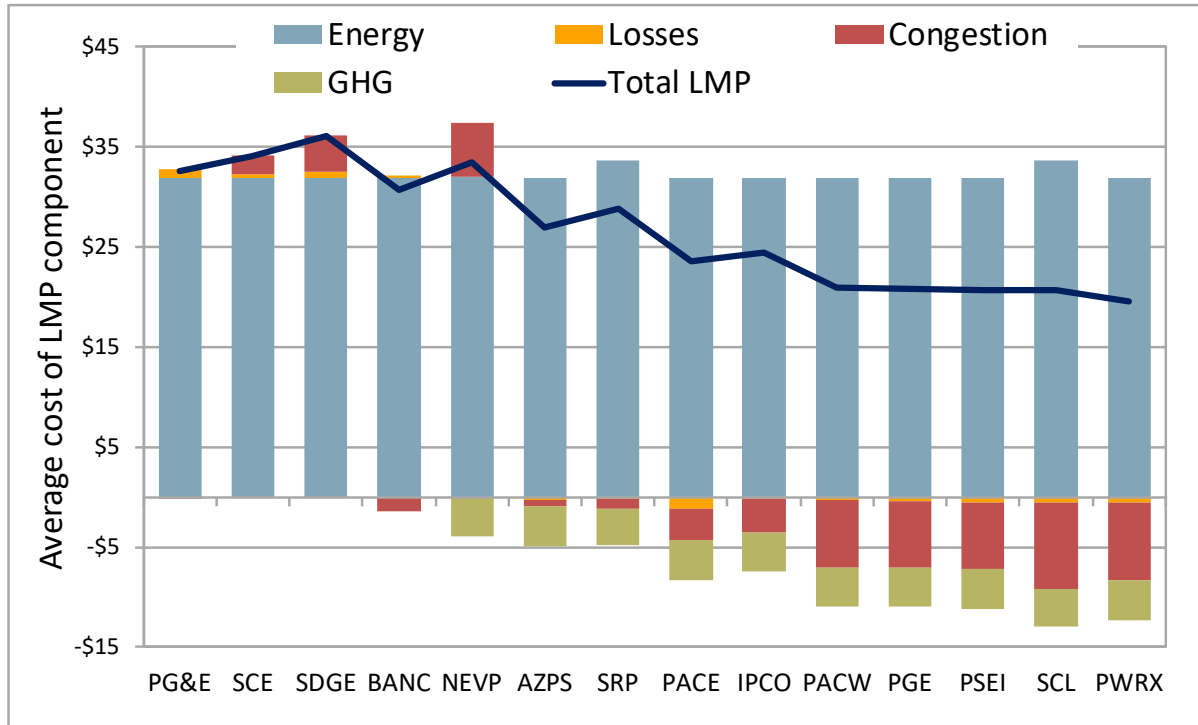
Energy imbalance market

The energy imbalance market continued to grow in 2020 with the addition of the new balancing areas (Seattle City and Light and Salt River Project). As shown in Figure 2 (by the red bars), prices in different balancing areas reflect transmission limitations on transfers of energy from lower cost balancing areas in the northwest into the ISO and southwest.

- Congestion drove prices in Idaho Power and PacifiCorp East about \$3.20/MWh (or 10 percent) lower than the system marginal energy price.
- North-to-south congestion drove average annual prices from other pacific northwest balancing areas about \$7/MWh (or 23 percent) lower than the system marginal energy price.²
- Congestion into the Nevada Power balancing area drove prices up about \$5.40/MWh (or 17 percent) higher than the system marginal energy price.
- Congestion out of the other southwest balancing areas (Arizona Public Service and Salt River Project) reduced average annual prices less than \$1/MWh (or about 2.5 percent) lower than the system energy price.

² Pacific Northwest balancing areas include PacifiCorp West, Portland General Electric, Puget Sound Energy, Seattle City Light and Powerex.

Figure 2. Average energy imbalance market prices (15-minute market, 2020)



As shown in Figure 2 (by green bars), average prices in all balancing areas outside of California were about \$4/MWh lower than within the ISO due to the impact of California greenhouse gas (GHG) emissions costs. These costs are reflected in the system marginal energy cost within the ISO balancing area but are included in energy imbalance prices within balancing areas outside of California.

Resources that are deemed delivered to California in the energy imbalance market are paid the GHG component of the energy price shown in Figure 2. This GHG component reflects the GHG costs of the marginal resources deemed delivered to California (typically a gas fired unit). This GHG payment to resources being imported is designed to cover the costs of complying with California’s GHG obligations for these imports.

For resources with lower or no GHG compliance costs (such as hydro), these GHG payments (which averaged about \$4/MWh) represent an additional source of net revenue from imports to the ISO through the energy imbalance market. Over the last year, hydro resources account for about 62 percent of energy imbalance market transfers into California, while gas resources accounting for about 37 percent.

Day-ahead market competitiveness

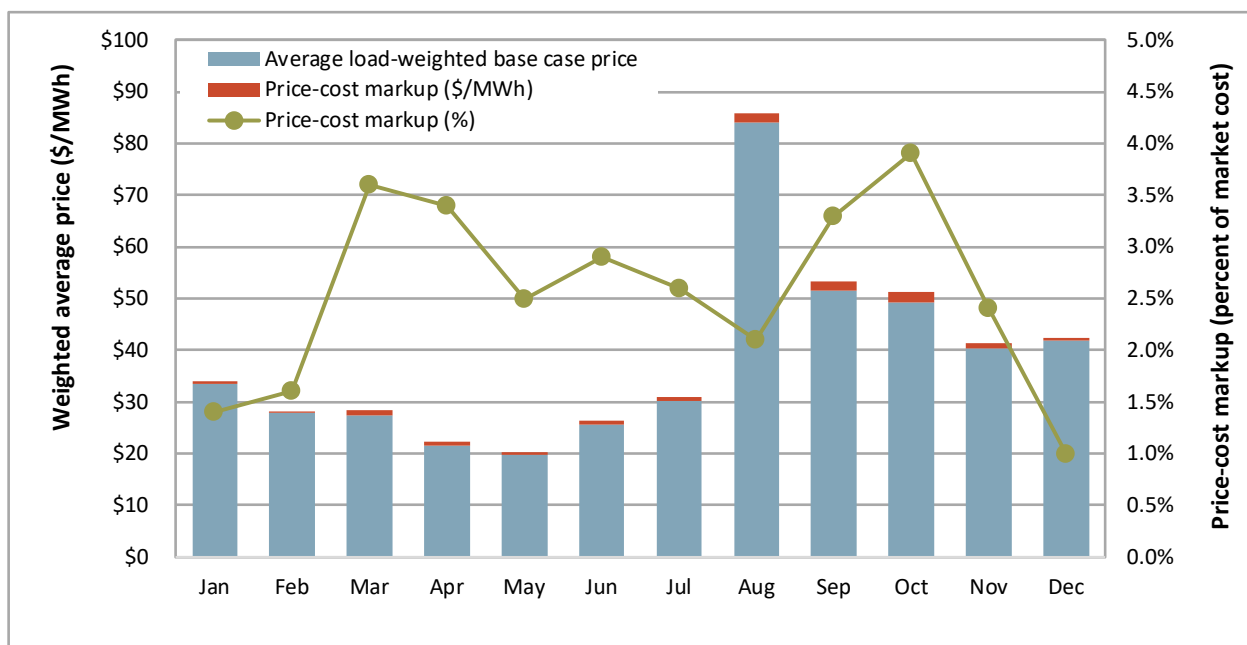
The performance of California’s wholesale energy markets remained competitive in 2020, with prices during most hours being at or near the marginal cost of generation. DMM assesses the competitiveness of overall market prices can be assessed based on the *price-*

cost markup, which represents a comparison of actual market prices to an estimate of prices that would result in a highly competitive market in which all suppliers bid at or near their marginal costs.³

DMM estimates competitive baseline prices by re-simulating the day-ahead market after (1) replacing the market bids of all gas-fired units with the lower of their submitted bids or their default energy bids, (2) capping gas resource commitment cost bids at 110 percent of reference proxy cost (rather than 125 percent used in the market), and (3) replacing the market bids of imports with the lower of their submitted bids or a relatively high default energy bids based on bilateral price indices. This methodology assumes competitive bidding of both imports and gas-fired resources and is calculated using DMM's version of the actual day-ahead market software.

As shown in Figure 3, results of this analysis indicate that the price-cost markup in the day-ahead market was relatively low throughout the year, with an average markup of only about 2.5 percent of under \$1/MWh. The price-cost markup was highest in the months of August to October, during which the markup averaged just over 3 percent or about \$1.80/MWh.

Figure 3. Day-ahead market price-cost markup (2020)



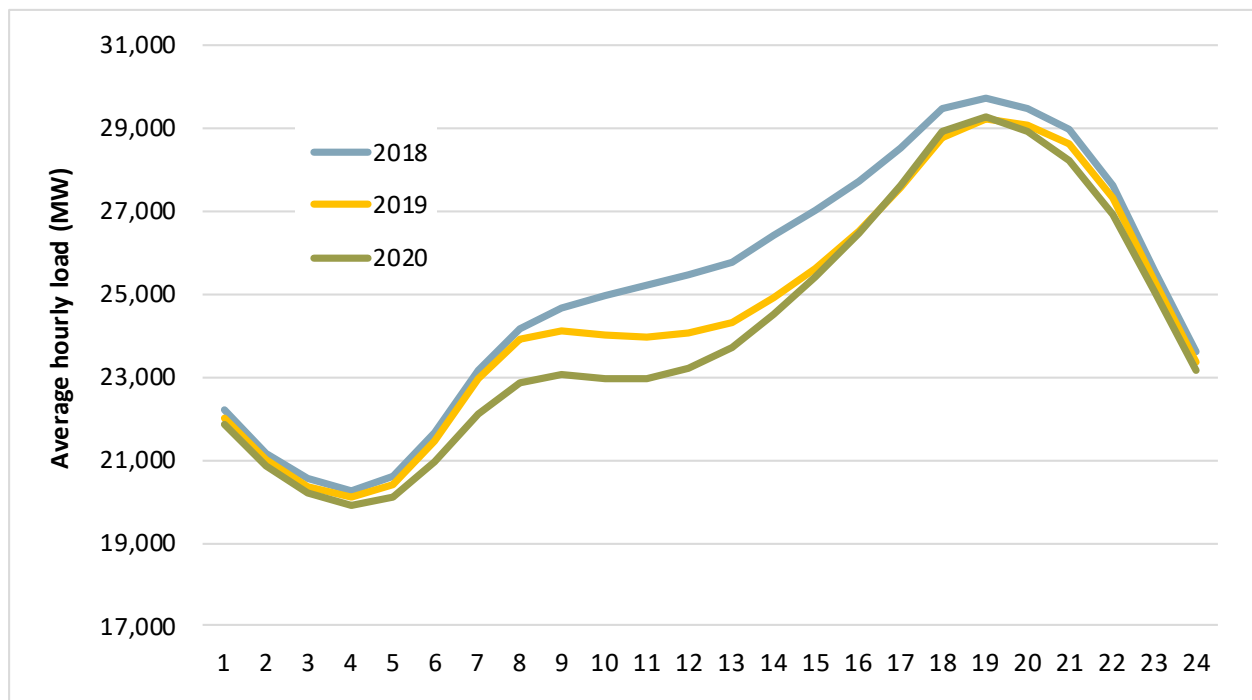
³ DMM calculates the price-cost markup index as the difference between base case market prices and prices resulting under this competitive baseline scenario. For example, if base case prices averaged \$55/MWh and the competitive baseline price was \$50/MWh, this would represent a price-cost markup of \$5 or 10 percent.

Loads

Peak loads and net peak loads were significantly higher in 2020 during the series of heat waves from August into October. Total system peak increased about 7 percent to about 47,236 MW.

Despite the series of heat waves from August into October, total annual load dropped almost 2 percent from 2019. The decrease in overall loads has been attributed mainly to the reduction in economic activity due to COVID. As shown in Figure 4, average loads dropped most in the morning hours from 6 am to noon. Average loads during the net peak hours were about the same as in 2019, reflecting an increase in residential loads during these hours.

Figure 4. Average hourly loads (2018-2020)



Resource mix

In 2020, total generation from hydroelectric, solar, and wind resources decreased by about 14 percent compared to 2019 (see Figure 5). This decrease is due primarily to a decrease in hydroelectric generation, which decreased by about 43 percent. Wind and solar production increased by about 1 percent and 7 percent, respectively.

The 43 percent decrease in hydroelectric generation in 2020 was offset by a 9 percent increase in imports and an 8 percent increase in natural gas generation. During ramping periods, there was an increase in natural gas generation, hydroelectric generation, and imports, as shown in Figure 6.

Figure 5. Average hourly hydroelectric, wind and solar generation by month

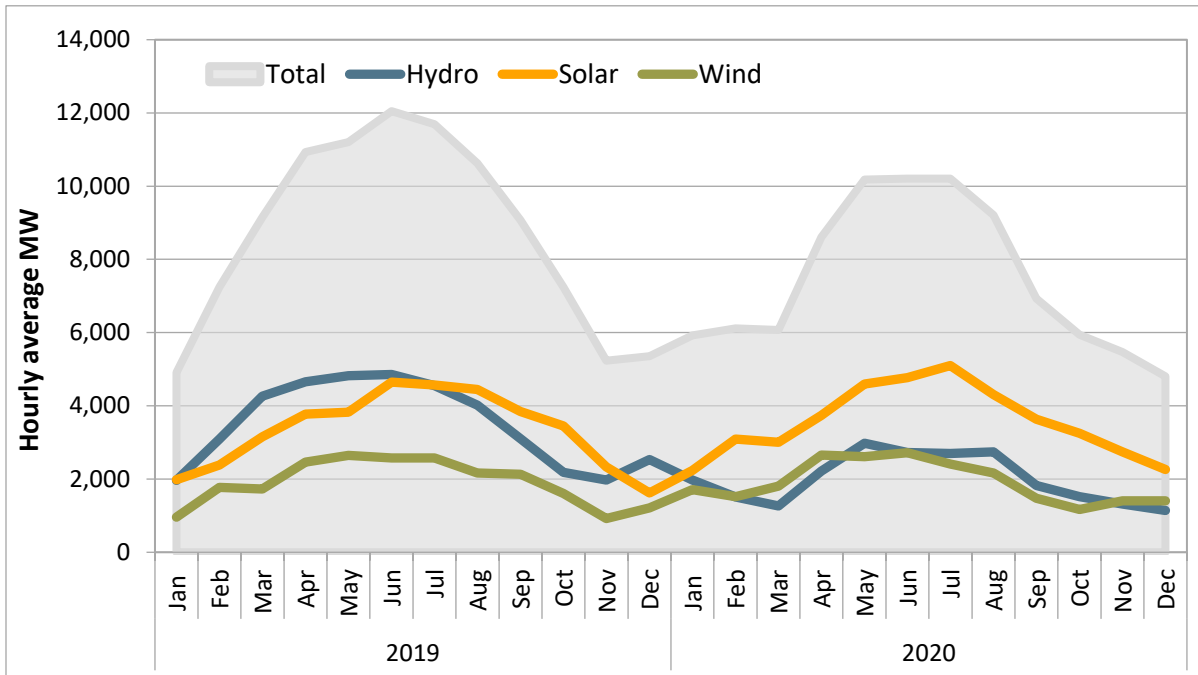


Figure 6. Average hourly supply (2020)

