Memorandum

To: ISO Board of Governors

From: Eric Hildebrandt, Executive Director, Market Monitoring

Date: May 3, 2022

Re: **Department of Market Monitoring report**

This memorandum does not require Board action.

EXECUTIVE SUMMARY

This memo provides an update on several market trends and issues by the Department of Market Monitoring (DMM).

- **Higher natural gas prices drove total wholesale costs of serving California ISO load up by about 33 percent in 2021.** After adjusting for higher gas prices and greenhouse gas costs, wholesale electric costs per megawatt-hour dropped by about 17 percent.
- **Increased real-time exports through the Western Energy Imbalance Market (WEIM) continue to help the California ISO manage high renewable penetration even during low load periods**. A combination of WEIM transfers, exports, and the charging of a growing fleet of storage resources avoided additional curtailment of renewable resources.
- **Changes to the congestion revenue rights auction implemented in 2019 have reduced, but not eliminated, losses to transmission ratepayers from the auction.** Ratepayer losses have averaged about $45 million per year after the changes, compared to average losses of $114 million per year in the 7 years before the reforms. DMM continues to recommend that the ISO consider further changes to reduce these losses.

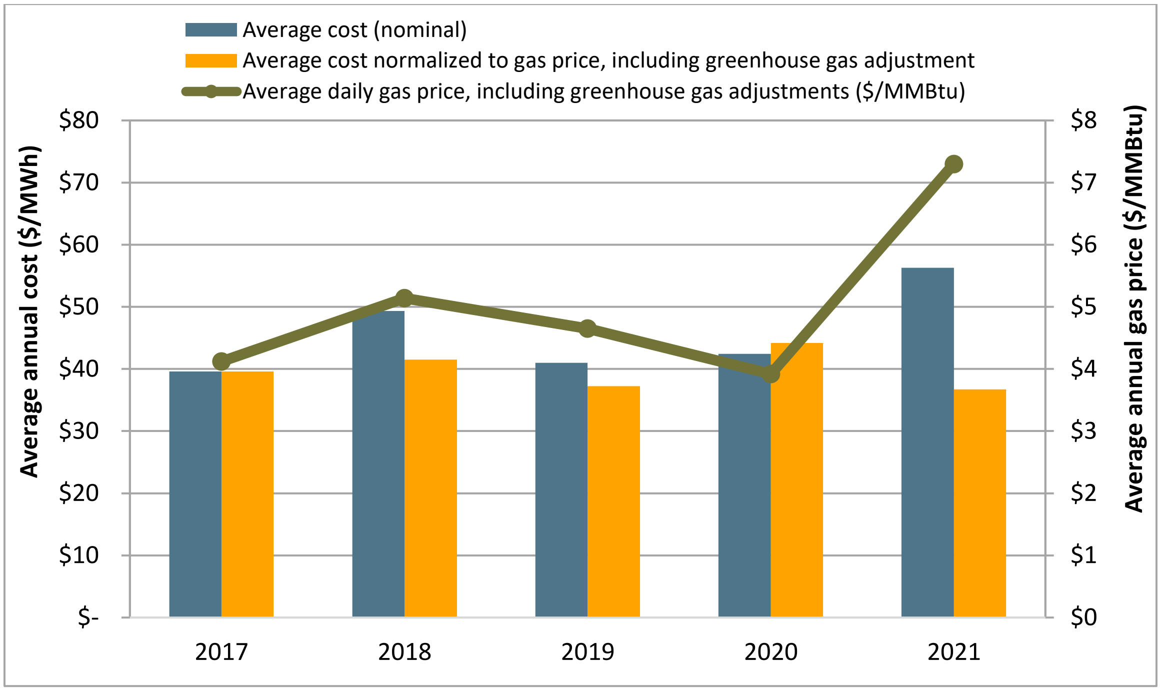
Additional details of these issues are provided in this memo and in DMM's forthcoming quarterly and annual reports on market issues and performance.

TOTAL MARKET COSTS

The wholesale cost of serving California ISO load in 2021 totaled about $12.6 billion, or about $56/MWh – a 33 percent increase from about $42/MWh ($8.9 billion) in 2020. After normalizing for natural gas prices and greenhouse gas compliance costs, DMM estimates total wholesale energy costs decreased by about 17 percent from just over $44/MWh in 2020, to about $37/MWh in 2021.

Figure 1 shows total estimated wholesale costs per megawatt-hour of system load from 2017 to 2021. Wholesale costs are provided in nominal terms (blue bar) and normalized for changes in natural gas prices and greenhouse gas compliance costs (gold bar). The green line represents the annual average daily natural gas price, including greenhouse gas compliance.

Figure 1 Total annual wholesale costs per MWh of load



Wholesale energy cost increases were primarily driven by an 86 percent increase in natural gas prices in 2021. Figure 2 shows monthly average natural gas prices at key delivery points in Northern California (PG&E Citygate) and in Southern California (SoCal Citygate) as well as for the Henry Hub trading point, which is a point of reference for the national market for natural gas.

Electricity prices in western states typically follow natural gas price trends because natural gas units are often the marginal source of generation in the ISO and other regional markets. The sustained increase in natural gas prices was one of the main drivers of high system marginal energy prices across the ISO and WEIM footprint.

Figure 2 Monthly average natural gas prices (2019-2021)

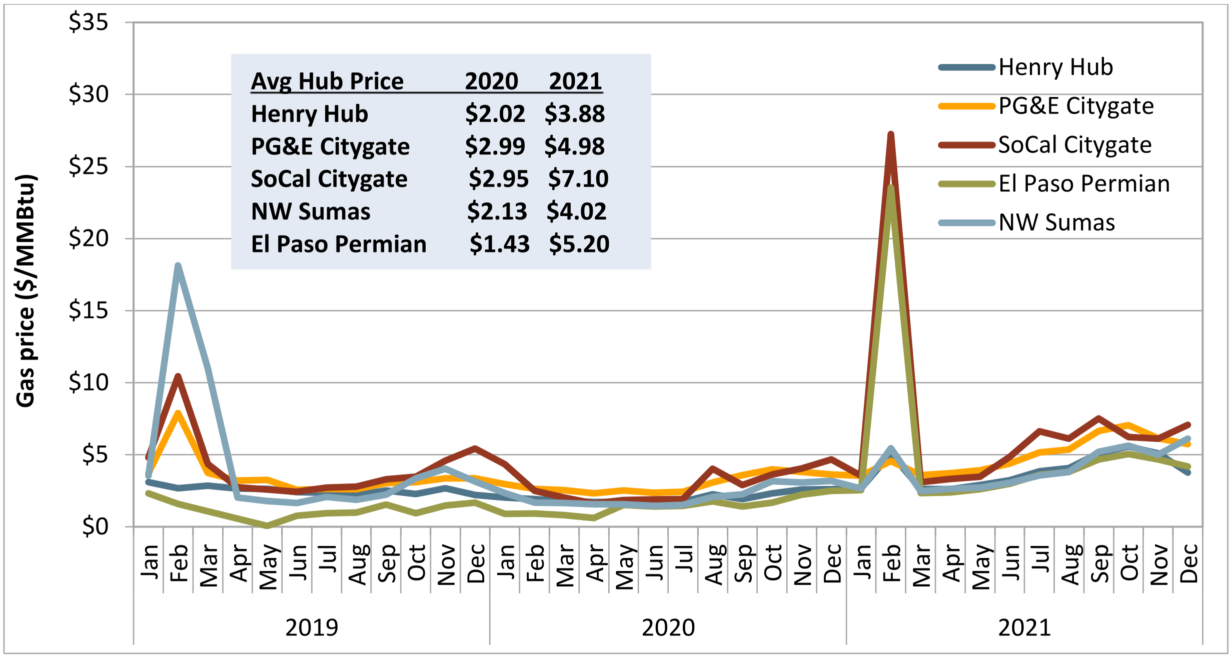
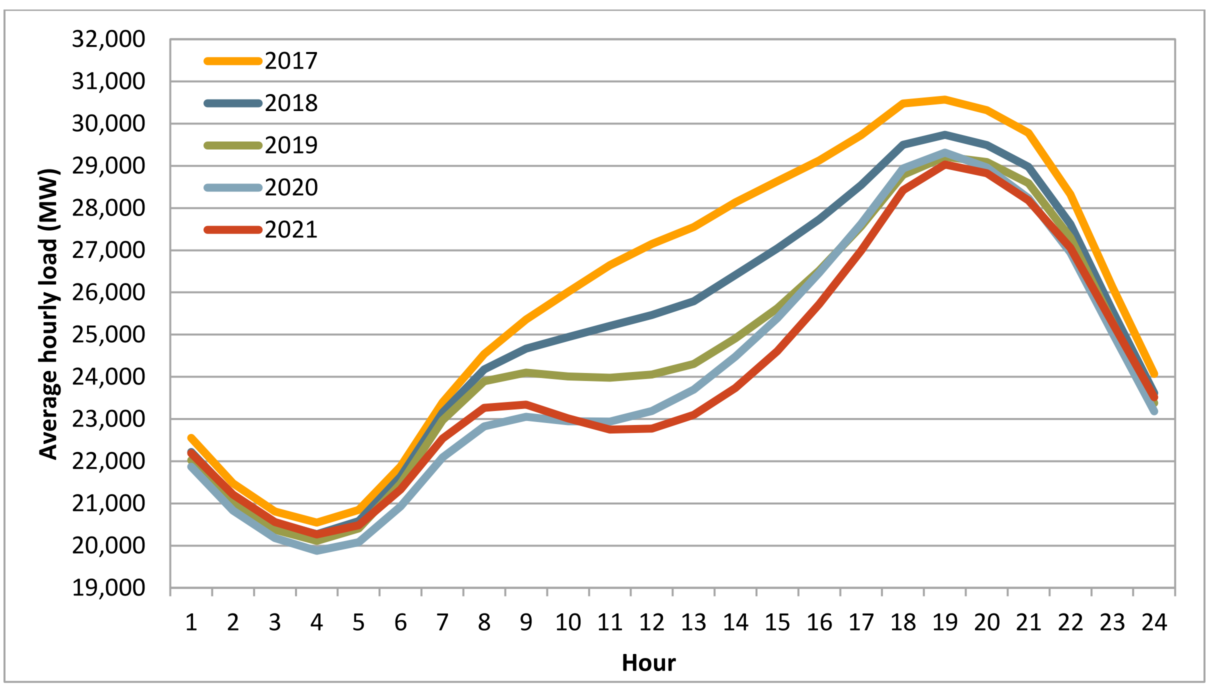


Figure 3 Average hourly load (2017-2021)



Despite record setting heat in the West, relatively mild weather on the California coast contributed to lower load in peak hours in the California ISO in 2021, as shown in Figure 3. The lack of region-wide heat waves helped keep prices lower after adjusting for gas prices.

REAL TIME EXPORTS AND RENEWABLE ENERGY

Higher solar and wind production also contributed to lower prices after adjusting for higher gas costs. Since 2015, solar capacity has grown from 6.5 GW to 15.1 GW, and wind has grown from 5.6 MW to 6 GW. Over the same time, demand response grew from 0 GW to 3.8 GW.

While solar, wind, and demand response nameplate capacity have exceeded reductions in gas capacity, variable energy and demand response resources generally have limited energy and availability compared to gas capacity. Batteries, which can be more flexible than these other resource types, are currently the fastest growing resource type, increasing from 300 MW in June 2020 to 3.4 GW of projected online capacity by June 2022.

As solar, wind, and other renewable resources are added to the California ISO fleet, rates of renewable curtailment have increased, particularly in the spring months when loads tend to be low and run-of-river hydro is at its peak.[1] Storage resources absorb some of the low or negative price renewable supply and help reduce renewable curtailment. However, the largest factor mitigating oversupply is the California ISO's integration with the broader regional market. Rather than being curtailed, low price renewable supply is exported through both exports scheduled in the day-ahead and real-time markets as well as exports in the Western Energy Imbalance Market.

As shown in Figure 4, mid-day exports have increased in 2022, as the California ISO has hit new record levels of renewable energy production. **Error! Reference source not found.** shows generation and exports on April 3, a day when the California ISO was supplied by close to 100 percent renewable supply for a single interval.[2] As shown in the figure, internal gas-fired resources were also generating during this period. However, this was offset by substantial amounts of renewable energy and increased real-time exports through the WEIM. As shown in Figure 5, storage resources also helped utilize renewable generation by charging during the peak solar hours.

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1 For California ISO renewable curtailment values, see the California ISO oversupply website: http://www.caiso.com/informed/Pages/ManagingOversupply.aspx. Almost all oversupply is not curtailment of self-schedules. Instead, this is economic downward dispatch of renewable resources with economic bids above their locational price.

2 https://www.caiso.com/Documents/California-ISO-Hits-All-Time-Peak-of-More-Than-97-Percent-Renewables.pdf

Figure 4 Average hourly imports and exports (March-April, 2021 and 2022)

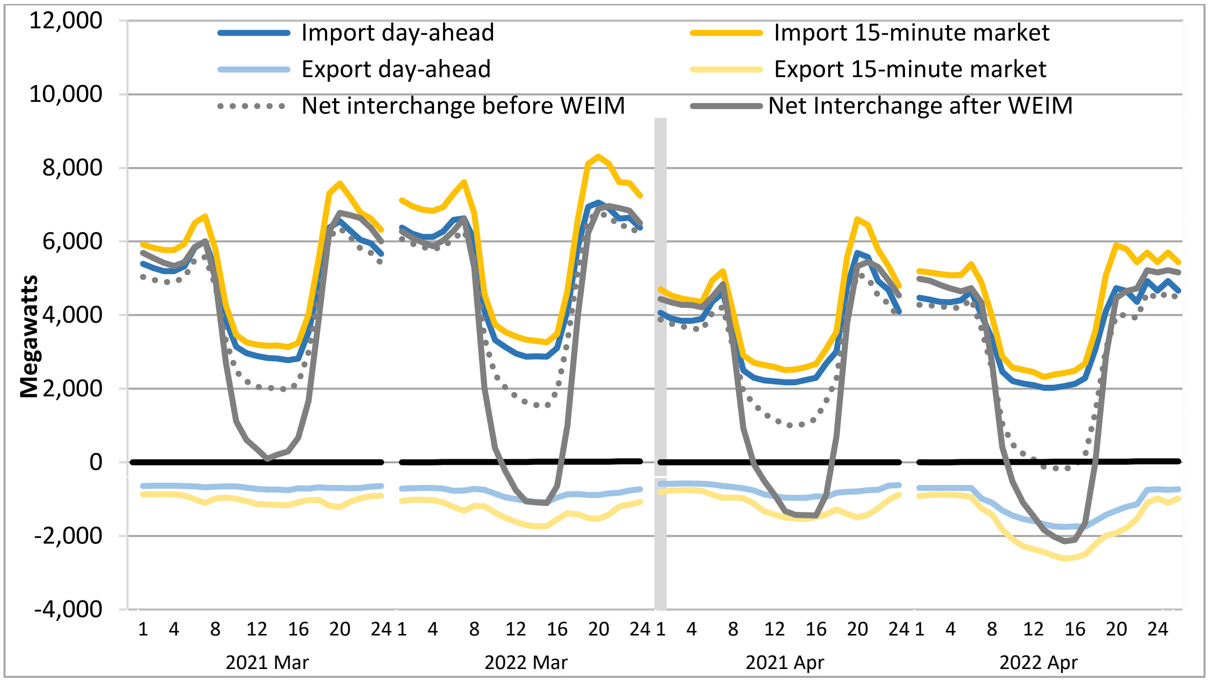
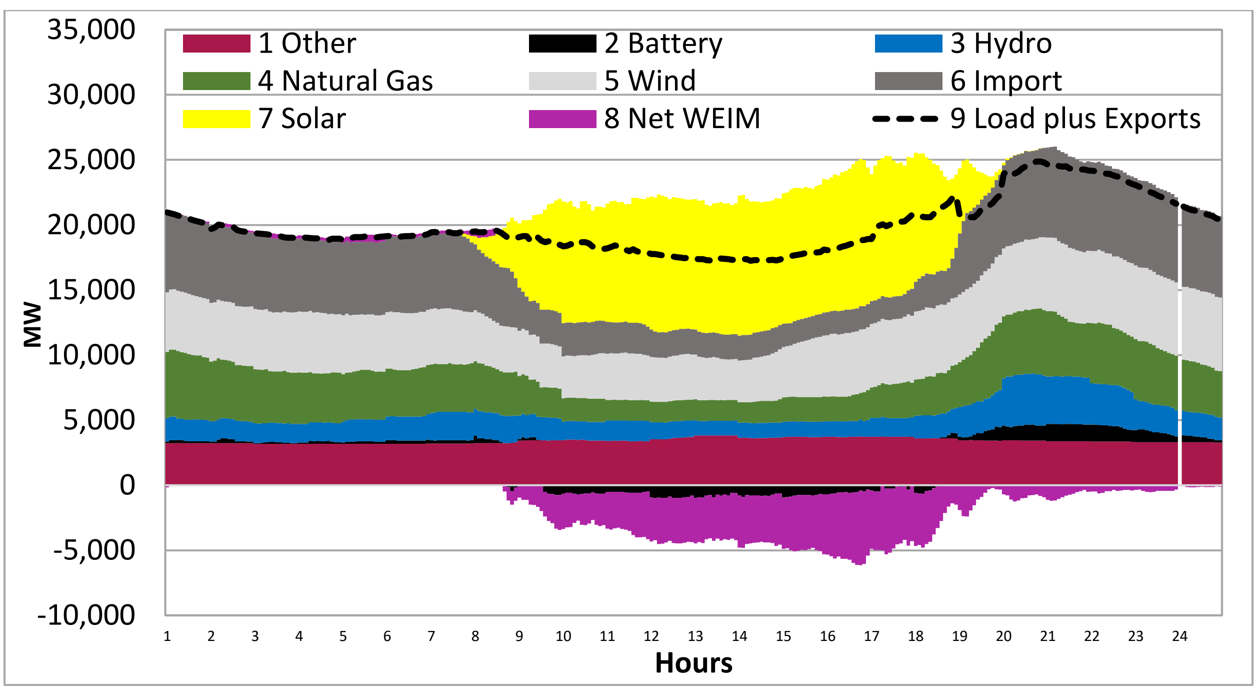


Figure 5 Generation, transfers and load by fuel type on April 3, 2022



CONGESTION REVENUE RIGHTS

Auction changes have reduced but not eliminated ratepayer losses

In 2019, the ISO implemented two sets of changes to the congestion revenue rights auction process. The first reduced the number and pairs of nodes at which congestion revenue rights can be purchased in the auction (Track 1A). The second reduced the net payment to a congestion revenue right holder if payments to congestion revenue rights exceed associated congestion charges collected in the day-ahead market on a targeted constraint-by-constraint basis (Track 1B). These reductions are referred to as *revenue adequacy deficit offsets.*

The changes implemented in 2019 have reduced, but not eliminated, ratepayer auction losses. Figure 6 shows auction revenues received by ratepayers (blue bars) and payments to congestion revenue rights sold in the ISO's auction (dark green bars). Ratepayer losses (shown by the yellow line) averaged $114 million in the 7 years before the reforms, compared to average losses of $45 million per year after the changes.

The light green bars in Figure 6 show revenue adequacy deficit offsets implemented in 2019 under Track 1B changes. The deficit offsets reduced payments to auctioned congestion revenue rights by an average of 29 percent or $57 million per year. Some financial entities warned that the risk of deficit offsets would significantly reduce the willingness of entities to pay for congestion revenue rights and reduce auction revenues. Before the reforms, auction revenues averaged $106 million per year, and have averaged $96 million since.

Figure 7 shows two other key metrics which summarize ratepayer losses from sales of congestion revenue rights.

- The blue line shows auction revenues as a percent of payments to auctioned congestion revenue rights. Prior to the reforms, ratepayers were paid an average of 48 cents per dollar paid to auctioned congestion revenue rights. Since the reforms, auction revenues average 68 cents per dollar paid out.
- The yellow line shows auction losses as a percent of day-ahead congestion rent. In the three years since, the changes auction losses have averaged 9 percent of day-ahead congestion rent, down from 27 percent before the changes.

Since the auction changed in 2019, financial entities have continued to receive the most auction profits averaging $25 million per year. Marketers have averaged $14 million in profits per year with generators receiving an average of $6 million per year in profits.

Figure 6 Auction revenues compared to payments to auctioned CRRs

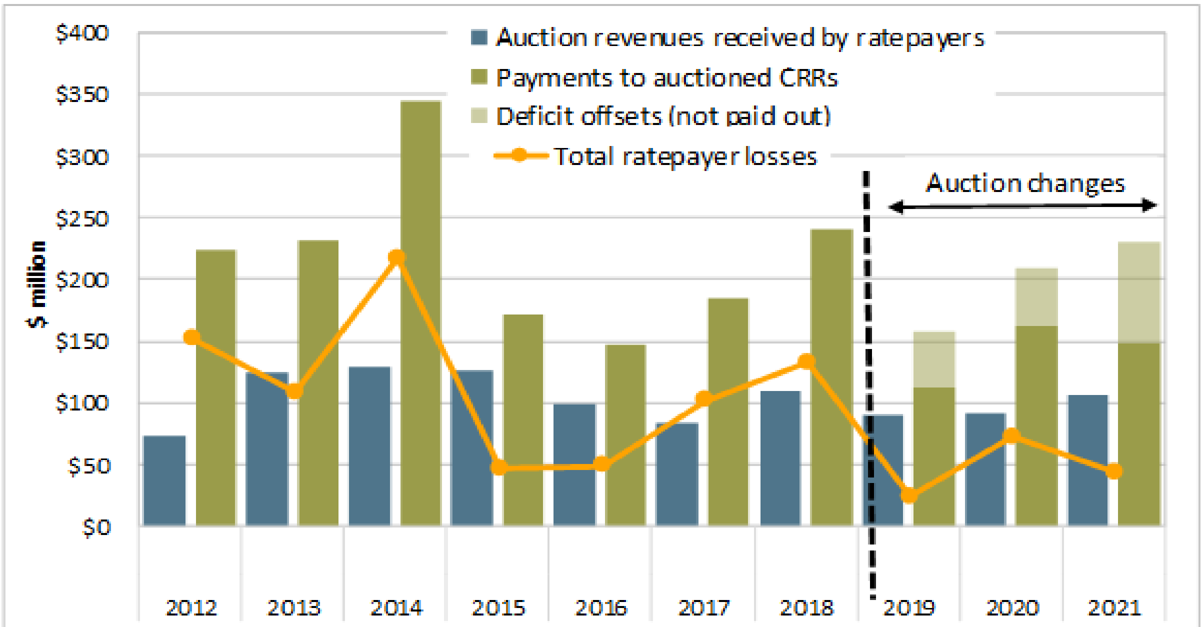
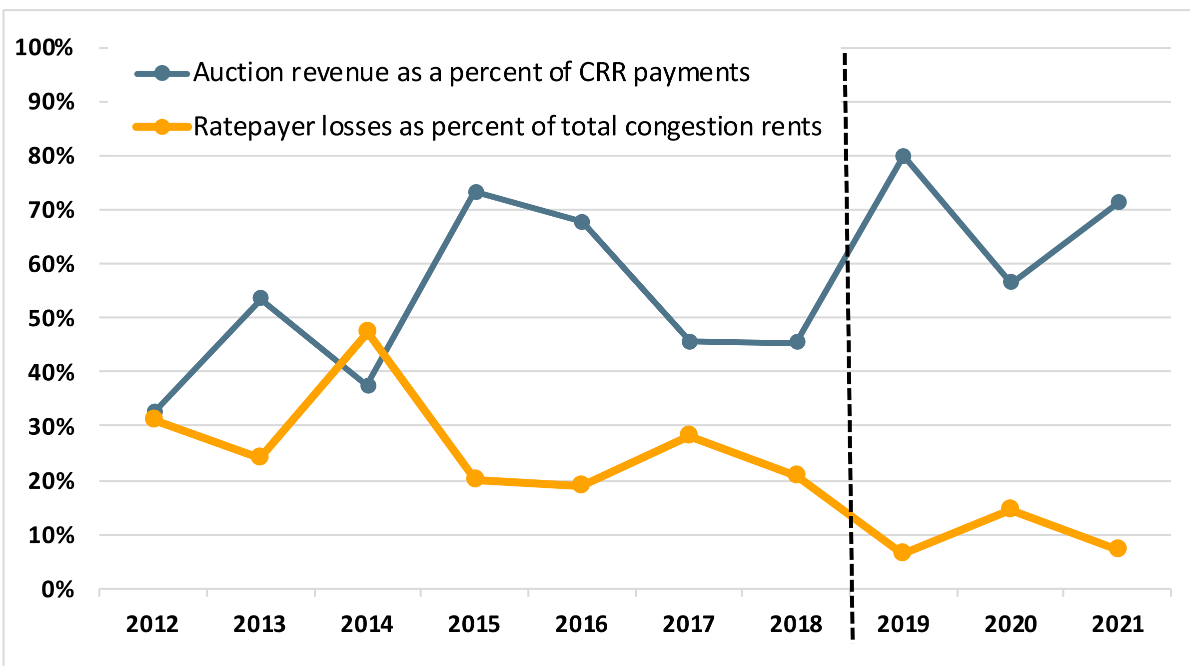


Figure 7 Auction revenues as percent of CRR payments and ratepayer losses as percent of day-ahead congestion rent



Recommendations

DMM continues to believe the current auction is unnecessary and could be eliminated, with all congestion rents being returned to transmission ratepayers. If the ISO believes it is beneficial to the market to facilitate hedging, DMM believes the current auction format could be changed to a market for congestion revenue rights or locational price swaps based on bids submitted by entities willing to buy or sell congestion revenue rights.

Building on the existing reforms could further reduce ratepayer losses. Auction losses could be further reduced by reducing the amount of rights auctioned, either generally or from specific locations with significant underpricing. Reducing the amount of rights could be achieved by lowering auction constraint limits.

Some load serving entities have pointed out that ratepayer losses could also be reduced by raising (rather than lowering) constraint limits in the allocation process. This could reduce the amount of rights that could be sold in the auction without reducing rights allocated to load serving entities, as could occur if constraints were de-rated in the allocation and auction.