Measuring the Performance of Wholesale Electricity Markets

A Review of the Primary Market Assessments and Recommendations for Improvement

AMERICAN PUBLIC POWER ASSOCIATION

80 Years of Powering Strong Communities

Measuring the Performance of Wholesale Electricity Markets

A Review of the Primary Market Assessments and Recommendations for Improvement

By Elise Caplan, Director, Electric Market Analysis
American Public Power Association

Published March 2020

AMERICAN PUBLIC POWER ASSOCIATION
80 Years of Powering Strong Communities

The American Public Power Association is the voice of not-for-profit, community-owned utilities that power 2,000 towns and cities nationwide. We represent public power before the federal government to protect the interests of the more than 49 million people that public power utilities serve, and the 93,000 people they employ. We advocate and advise on electricity policy, technology, trends, training, and operations.

Contents

Introduction

In the 20 years since the restructuring of the wholesale electricity markets and the formation of Regional Transmission Organizations and Independent System Operators (RTO/ISOs), these RTO/ISO-operated markets have undergone multiple changes – from expanding their geographic reach to creating additional markets and adjusting countless rules. The RTO/ISO markets are often contentious, with stakeholders holding differing views. Ongoing comprehensive assessments of these markets therefore provide an important foundation for an evaluation of the markets as currently structured as well as proposed changes.

This paper examines the primary assessments of the RTO/ISO-operated markets, evaluates the comprehensiveness and consistency of the market assessments, and provides recommendations for improvements. While research and data on these markets are provided from an array of sources, this analysis focuses on three sets of resources: the Federal Energy Regulatory Commission ("FERC" or "the Commission") annual State of the Market Reports; the annual market assessments issued by the RTO/ISO market monitors; and the FERC performance metrics. The annual market monitor assessments are the most comprehensive source of data on these markets.

There is a wealth of data on the RTO/ISO-operated markets, but inconsistencies and gaps in the data are present. Market stakeholders would greatly benefit from access to a more comprehensive and consistent set of data. Below are the primary recommendations for improving such analyses:

- The Commission should provide a more comprehensive annual State of the Market report and use that report to delve into where the markets are providing benefits and identifying areas for improvement.
- The Commission should establish market monitoring best practices to ensure that the important data and analyses are included in all state-of-the-market reports, and to provide for greater consistency among the data.
- All FERC and market monitor state-of-the-market reports should provide data on transmission costs, including within the all-in price, and assess how transmission spending impacts congestion costs.
- Data on the types of ownership, sources of funding and on the financial arrangements behind the procurement of generation provide a context for the evaluation of the markets and should be included in all market monitor reports.
- The price-cost markup can be a useful measure of competition, but is not reported consistently by all RTO/ISO market monitors. A consistent calculation of this measure, which removes any cost adders, would be beneficial.
- In addition to the price-cost markup, the RTO/ISO market monitors should provide data on price spikes that occur in certain regions and time periods.
- The net revenue analysis should be reported along with data on reserve margins or other indicators of capacity surplus or deficits, as well as indicators of whether resource investments are made by utilities with an obligation to serve customers or by merchant generation owners and developers.
- Data on the net revenue earned by existing units should be provided by RTO/ISOs, especially for those primarily characterized by merchant generation owners.
- All market monitors should provide data on the profits from virtual transactions and financial trading rights separately for financial and physical entities.
- A comprehensive evaluation of the benefits and risks of financial entity participation in the RTO/ISO-operated markets is warranted.

These recommendations are based upon the following key findings of this assessment:

- The Commission's annual State of the Market report does not provide a comprehensive assessment of the performance of the wholesale electricity markets, as it had in the past, leaving the RTO/ISO market monitors as the primary source of information.
- The market monitor reports contain a voluminous amount of valuable information on the wholesale markets. However, the data are neither presented in a consistent manner nor is all critical data provided across all RTO/ISO state of the market reports.
- The Commission's performance metrics are limited in scope because they rely primarily on data collected by the RTO/ISOs or their market monitors.

- There is some benefit in the reports on the performance metrics issued by the Commission as a source of consistent measures of certain data across the RTO/ISOs.
- These performance metrics reports have not been provided in a timely manner, with the most recent metrics report covering data through 2014. But the Commission staff's recent proposal of revised performance metrics is a positive step.
- Little or no data on transmission costs are provided by the market monitors, and only two RTO/ISO market monitors include transmission costs as part of the all-in cost.
- Although the energy markets are found to be competitive overall, several market monitors find that there are opportunities for the exercise of market power within certain constrained geographic areas and during certain hours.
- Not all market monitors provide a breakdown of profits from virtual trading and financial transmission rights according to financial and physical entities. Where such data are provided, it generally shows significantly greater profits accruing to financial entities.
- Several RTO/ISOs report a shortfall in financial transmission right funding that is paid for by load, while others report that these instruments do not provide a complete hedge for congestion costs.
- It is not clear from the market monitor data whether financial entity participation in the RTO/ISO markets provides benefits.

The goal of this effort is to improve the data issued on these markets for all stakeholders, and the American Public Power Association welcomes comments and feedback on the data provided in this paper and on these findings and recommendations. Feedback can be sent to Elise Caplan, Director of Electric Markets Analysis at **ECaplan@PublicPower.org.**

The remainder of this paper provides an overview and history of each of these resources, followed by a review and critique of the data and assessment of the wholesale markets provided by each resource. A companion paper provides a more detailed summary of the key data provided by these resources.

FERC State of the Market Reports

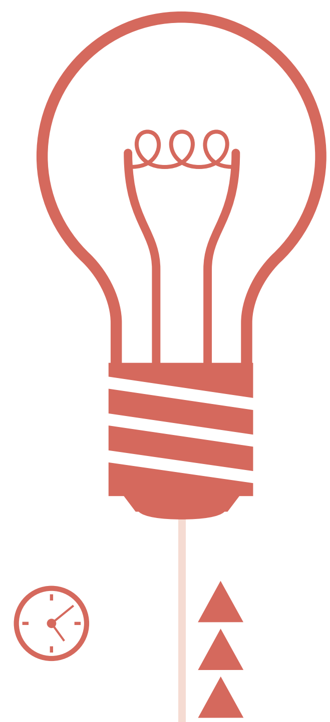
The primary FERC staff-issued assessment of the RTO/ISO markets is the annual State of the Markets (SOM) report, which covers both natural gas and electricity markets. The first such report was issued in January 2004, covering both 2002 and 2003.[1] In that first SOM report, FERC staff discussed the relevance of this assessment of the markets, stating that:

> *This report fulfills the Commission's commitment to Congress to provide a comprehensive assessment of energy markets that uses market data and performance criteria, improving the Commission's ability to identify and correct trouble spots in the market before they become serious. This report also establishes a framework for performing future analyses of energy markets in order to better assess performance and improvements over time.*

This first SOM report provided a comprehensive and wide-ranging analysis of the RTO/ISO and non-RTO/ISO markets with about sixty pages devoted to electricity markets, covering market structure and indicators of competition, prices and price volatility, market participation, the extent of bilateral trading, short- and long-term contracting, transmission congestion, mitigation, price spikes, price transparency, price risk management tools, virtual bidding, financial transmission rights, RTO credit policies, and generation and transmission investment.

Over time, the FERC SOM reports transitioned to more abbreviated presentations of general trends in pricing and the construction of capacity. The reports shifted from the original detailed analyses to shorter PowerPoint presentations after the 2006 SOM.[2] The most recent FERC SOM report, issued in April 2019, and covering 2018 market performance,[3] represents the shortest and most limited in scope, with six pages covering the wholesale electricity markets (Note: FERC issued the 2019 SOM report while this report was in production). The report covers only RTO/ISO energy and capacity prices, trading hub prices, generation additions and retirements, and identifies a few general trends.

The 2006 SOM reports states that "the annual State of the Markets Report will now consist of a summary of significant national electric and natural gas market developments over the previous year. Regional detail will be provided, and updated more regularly, within the Web pages themselves." However, the Commission has not provided this "regional detail." The individual RTO/ISO market pages within the FERC Market Assessments section of the Commission's website consist primarily of links to the RTO/ISO websites and do not include FERC data or analyses.[4] Moreover, the data provided in the "At a Glance" section for each RTO/ISO has not been recently updated.[5] A return to a similar level of detailed data as was provided in the initial FERC-staff produced SOMs would provide a beneficial resource for RTO/ISO market stakeholders.



[1] *Available at: https://www.ferc.gov/legal/maj-ord-reg/land-docs/som-2003.pdf.*
[2] *Available at: https://www.ferc.gov/market-assessments/reports-analyses/st-mkt-ovr/som-rpt-2006.pdf.*
[3] *Available at: https://www.ferc.gov/market-assessments/reports-analyses/st-mkt-ovr/2018-A-3-report.pdf.*
[4] *See https://www.ferc.gov/market-assessments/market-assessments.asp.*
[5] *For example, the PJM data cites the 2016 PJM Annual Report as its source. See: https://www.ferc.gov/market-assessments/mkt-electric/pjm/elec-pjm-glance.pdf*

RTO/ISO Market Monitoring

History and Overview of Market Monitoring

The market monitoring function was established almost twenty years ago by the Commission's Order 2000,[6] which laid out the minimum characteristics and functions for a grid operator to become an RTO.[7] In Order 2000, the market monitoring function is described as "an important tool for ensuring that markets within the region covered by an RTO do not result in wholesale transactions or operations that are unduly discriminatory or preferential or provide opportunity for the exercise of market power."[8]

While providing flexibility to each individual RTO to design their own market monitoring plan,[9] the Commission in Order 2000 established basic standards,[10] including the provision of objective information; proposals for appropriate action on opportunities for efficiency improvement, market design flaws, or market power; an evaluation of the behavior of market participants to determine whether their behavior adversely affects the ability of the RTO to provide reliable, efficient and nondiscriminatory transmission service; and a periodic assessment of whether other markets in the RTO's region affect RTO operations and how RTO operations affect the efficiency of other markets. FERC concluded that such market monitoring "will be a useful tool to provide information that can be used to assess market performance. This information will be beneficial to many parties in government as well as to power market participants."[11]

In 2005, the Commission issued a Policy Statement on Market Monitoring Units,[12] further specifying that the market monitors' reviews should include analyses and evaluations of: market prices of ISO/RTO-administered products and the extent to which the prices reflect competitive outcomes, not market power abuses; the structural competitiveness of the wholesale markets and the effectiveness of bid mitigation rules to remedy potential exercise of market power; the effectiveness of the markets in signaling needed investment in generation, transmission, and demand response infrastructure and potential barriers to such investments. FERC also stated that the MMU should be proactive in recommending changes to the ISO/RTO. In the final paragraph, the Commission concludes that: "Since these markets ultimately exist for the benefit of customers, the MMU should focus on how efficiently the markets are responding to customers' needs for reliable electricity supply at the lowest long run cost to customers."

"Since these markets ultimately exist for the benefit of customers, the MMU should focus on how efficiently the markets are responding to customers' needs for reliable electricity supply at the lowest long run cost to customers."

Federal Energy Regulatory Commission, 2005

Order 2000 and the 2005 Policy Statement show that the Commission viewed one critical function of the RTO/ISO market monitors as evaluating the performance of the RTO/ISO-operated markets, and specifically whether those markets are providing benefits to customers.

Each RTO/ISO's market monitor issues annual assessments of the RTO/ISO-operated markets, often known as State of the Market reports. According to the RTO/ISO market monitor websites, the first of these reports was issued in 1999, covering California ISO (CAISO) operations in 1998, followed by reports for PJM Interconnection, LLC (PJM) operations in 1999, New York ISO (NYISO) for 2000, Midcontinent ISO (MISO) for 2002, ISO-New England (ISO-NE) for 2003, Southwest Power Pool (SPP) for 2009, and Electric Reliability Council of Texas (ERCOT) for 2012. These annual assessments have been issued every year since their inception.

---

6 *Order 2000, Federal Energy Regulatory Commission, 89 FERC ¶ 61,285 (December 20, 1999). All of the market monitoring provisions were upheld in the rehearing order.*

7 *Some RTOs use the word "ISO" in their name, and others are an ISO by virtue of being a single state entity but perform the functions of an RTO. The term RTO/ISO is therefore used throughout this paper.*

8 *Order 2000 at 462.*

9 *Id.*

10 *Id. at 463*

11 *Id. at 464*

12 *Policy Statement on Market Monitoring Units, Federal Energy Regulatory Commission, Docket PL05-1-000 (May 27, 2005), available at: https://www.ferc.gov/whats-new/comm-meet/052505/E-5.pdf*

Review of 2018 RTO/ISO Market Assessments

The annual assessments issued by the RTO/ISO market monitors provide a voluminous amount of data and extensive analyses of the restructured wholesale electricity markets.

This paper does not cover the full scope of the data or assessments of the markets, nor does it cover the extensive set of recommendations issued by each market monitor. Instead this paper focuses on the following topic areas, which are central to an evaluation of the RTO/ISO-operated markets:

- RTO/ISO wholesale market costs.
- Ownership and resource procurement.
- Measures of market power and competition.
- Net revenue analysis and discussions of resource adequacy.
- Virtual trading, financial transmission rights and the participation of financial entities.

Wholesale Market Costs

Each of the RTO/ISO market monitors begins with the "all-in" cost of participating in the RTO/ISO markets and the components of that cost on a per megawatt-hour (MWh) basis. In 2018, these costs ranged from $27.70 per MWh in SPP to $79 in ISO-NE. These costs increased for all RTO/ISO in 2018, compared to 2017, largely due to natural gas cost increases but also because of a greater incidence of extreme weather patterns. The highest costs were in the three Eastern RTOs with mandatory capacity markets (ISO-NE, NYISO and PJM).

This all-in cost does not include the cost of transmission, which is provided only by the PJM and ISO-NE market monitors (showing that when added to the all-in costs, transmission costs account for 15 percent of the total in PJM and 19 percent in ISO-NE).

ISO-NE transmission costs exceed the other RTO/ISO costs by a greater amount than the reduction in congestion, raising questions about the justification for greater transmission spending.

The exclusion of transmission costs from the all-in cost measure does not mean that the market monitor reports are devoid of information on transmission. All provide detailed information on the specific constrained portions of the transmission system. SPP and PJM also provide details on the transmission planning process and on new transmission projects. But an absence of transmission costs for five of the RTO/ISOs is a shortcoming in these reports. The cost of transmission is an important variable to consider when evaluating the markets, and transmission can impact other components of the cost. For example, transmission can reduce congestion costs, which are a component of the energy cost, or transmission expansion can serve as an alternative to construction of new generation if it provides greater access to underused capacity. At the same time, multiple stakeholders have expressed concerns about increasing transmission costs.[13]

Theoretically, greater spending on transmission should translate into reductions in congestion costs. The ISO-NE's external market monitor conducts an analysis of both transmission spending and congestion costs in four RTO/ISOs, showing that the ISO-NE transmission costs exceed the other RTO/ISO costs by a greater amount than the reduction in congestion, raising questions about the justification for greater transmission spending.

In sum, including transmission costs within the all-in cost figures and showing how congestion costs compare to transmission spending would be useful data points.

Resource Ownership and Procurement

The nature of the ownership and procurement of resources is relevant to an analysis of the wholesale markets, but limited data on this topic are provided in the market monitor reports. In some RTO/ISOs (PJM, ISO-NE and the NYISO), most of the states have implemented retail choice, and as a result, investor-owned utilities no longer

[13] *See Joint Letter to the Federal Energy Regulatory Commission, August 23, 2019, available at: https://www.publicpower.org/system/files/documents/Joint_Letter_Final.pdf*

have an obligation to serve their customers and do not own generation. (Public power and cooperative utilities have retained this obligation to serve.) In these RTO/ISOs, market prices and rules have more of an impact on the development of generation by merchant owners. But where investor-owned utilities have not restructured, wholesale markets are not a primary source of the revenue earned by generation. A key indicator of the impact of such restructuring is the distribution of generation ownership. Where the utilities have largely retained their obligation to serve, then utilities would also comprise the greatest ownership category.

SPP's SOM report provides data on the ownership of generation within the RTO/ISO, showing that independent power producers and marketers own just 14 percent of the generating capacity, with the remainder owned by investor-owned utilities, municipal utilities, electric cooperatives, and federal and state agencies.[14] Another approach is to look at the sources of funding for capacity. PJM's market monitor examines whether the installed capacity is funded by market or non-market revenues (including cost-of-service rates for a regulated utility and subsidies), finding that 83 percent of the capacity relies on market funding.[15]

A related data point is the share of power that is purchased on the spot market, procured through bilateral contracts, or generated by utility-owned resources. Power provided by owned or contracted resources is not as directly impacted by wholesale market prices as are spot purchases, although contracts are often influenced by such prices. Moreover, as ERCOT's market monitor notes, "bilateral and other financial contract obligations can affect a supplier's potential market power. For example, a small supplier selling energy only in the real-time energy market may have a much greater incentive to exercise market power than a large supplier with substantial long-term sales contracts."[16]

Only PJM's market monitor provides data on the sources of energy, showing that 30 percent of the power purchased in PJM is through the energy markets. Bilateral contracting accounts for about 59 percent and self-supply for the remainder. (Self-supply and bilateral contracting are measured at the parent company level meaning that self-supply could include power generated by a generation-owning entity and sold to a distribution utility affiliate under the same holding company.) The share of bilateral contracts would be greater if these affiliate transactions were included as contracts. Not reported is a distribution of contracts by length, however.

Data on the types of ownership, sources of funding and on the procurement of generation for each of RTO/ISO would provide a context for the evaluation of the markets and should be included in all of the market monitor reports. Data on the sources of funding should be provided not only for installed capacity but for new capacity that began generating electricity during the year of the market monitor report. Such data should specifically cover whether the capacity is owned by a utility or end-use customer; procured through bilateral contracts with utilities or with customers; or merchant – where no revenues are received from ownership or contracts.

Resource Mix

Another relevant characteristic of the RTO/ISOs is their resource mix. All market monitors provide data on the generation by technology, showing significant variation in the resource mix. The greatest share of electric generation from natural gas in 2018 was in ISO-NE (almost 50 percent); from renewables was in SPP (24 percent wind, minimal solar) and CAISO (9 percent wind, 15 percent solar); and from coal was in MISO (46 percent).

[14] *2018 State of the Market, Southwest Power Pool Market Monitoring Unit (SPP SOM), May 15, 2019, at 20, available at: https://www.spp.org/documents/59861/2018%20annual%20state%20of%20the%20market%20report.pdf.*

[15] *2018 State of the Market Report for PJM (PJM SOM), Monitoring Analytics, LLC – Independent Market Monitor for PJM, March 14, 2019 at 263, available at: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018.shtml.*

[16] *2018 State of the Market Report for the ERCOT Electricity Markets (ERCOT SOM), Potomac Economics - Independent Market Monitor for ERCOT, June 2019 at 131, available at: https://www.potomaceconomics.com/wp-content/uploads/2019/06/2018-State-of-the-Market-Report.pdf.*

The mix of megawatts (MW) of capacity is not provided by all market monitors, nor are the additions and retirements of capacity, although such data is available in the FERC SOM. It would be helpful if data on the installed capacity, additions, and retirements were provided by technology. These data should also include the financial arrangements behind the installed and new capacity, as noted in the prior section.

Net Revenue and Resource Adequacy

A consistent component of all market monitor reports is whether the net revenues received from all RTO/ISO-operated markets (plus Renewable Energy Credits and Zero Emission Credits) would cover the annualized costs of constructing and maintaining a hypothetical new generating unit. Net revenue is determined by subtracting the short run marginal costs of energy production from total gross revenue and is therefore available to cover a generator's annualized fixed costs (also referred to as the Cost of New Entry or "CONE"), including return on investment, depreciation, income taxes, and avoidable costs. Avoidable costs represent the costs that must be incurred each year to keep a unit in operation, such as certain fixed operation and maintenance costs. According to the PJM market monitor, such a comparison of net revenue to fixed costs, is "a measure of the overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets."[17]

It would be helpful if data on the installed capacity, additions, and retirements were provided by technology.

PJM, ISO-NE find that a hypothetical combined-cycle and combustion turbine unit recovered their CONE in 2018,[18] while the other RTO/ISOs did not show sufficient net revenues to cover CONE.

Also relevant is the extent to which net revenue covers the avoidable cost of an existing unit – a question that is addressed by the PJM, NYISO and SPP market monitors to varying degrees. PJM, SPP and the NYISO find that combined-cycle and combustion turbine units generally recover their avoidable costs.[19] PJM's market monitor looks at the full population of existing units, and the other RTO/ISOs analyze existing units based on a typical or average unit. The PJM market monitor finds, for example, that combined-cycle and combustion turbine plants with median avoidable costs recover between 500 to 750 percent of those costs, showing the high earnings potential for existing units.[20]

Such an analysis of existing units would be helpful for other RTO/ISOs with a significant proportion of capacity owned by merchant entities and could show the extent to which existing units may be recovering more from the markets than is needed for these units to continue to operate.

These net revenue analyses should be interpreted within the context of two factors: 1) whether there is a surplus or deficit of resources; and 2) the extent to which generation in the RTO/ISO is funded by vertically integrated utilities or by merchant developers dependent upon market revenues. The PJM, NYISO, ISO-NE, and SPP market monitors report a surplus of capacity, while MISO, CAISO and ERCOT market monitors note concerns about resource adequacy. Net revenues at times of surplus should not signal the need for new resources. But in contrast to these reported surpluses, PJM and ISO-NE report net revenues in excess of CONE for new units.

Net revenue analyses are not as relevant for an RTO/ISO where capacity is primarily provided by utilities with an obligation to serve load than by merchant generation owners that rely on market revenue. This connection is acknowledged by several of the market monitors. The CAISO market monitor states that "the CPUC's long-term procurement process and resource adequacy program are currently the primary mechanisms to ensure investment in new capacity when and where it is needed."[21]

17 *PJM SOM at 330.*

18 *For PJM, combustion turbines covered their net revenue in eleven zones, but not in the other nine zones, PJM SOM at 336.*

19 *The NYISO does not analyze combined cycle units.*

20 *PJM SOM Table 7-34 at 347.*

21 *2018 Annual Report on Market Issues and Performance, California ISO Department of Market Monitoring, (CAISO Annual Report), May 2019 at 16, available at: http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf.*

The net revenue analysis would be more valuable were it to be reported along with data on reserve margins or other indicators of capacity surplus or deficits, as well as indicators of whether resource investments are made by utilities with an obligation to serve customers or by merchant generation owners and developers.

The MISO market monitor reports that "regulated utilities serve load in a large portion of MISO. Hence, these regulated utilities may invest in new resources and maintain needed existing units because they receive supplemental revenues through the state regulatory process. However, MISO also relies on a large quantity of supply owned by competitive unregulated companies that rely entirely on MISO's wholesale market price signals to make long-term investment and retirement decisions."[22] But no data are provided on the relative shares of each.

SPP's market monitor finds that while "the SPP markets on their own may offer low incentives for new growth in renewable generation and storage resources, some additional reasons for these investments include federal and/or state incentives, expansion of corporate goals, and emission reduction plans among others."[23] ISO-NE's internal market monitor reports that "state policies continue to be a key driver of renewable and energy efficiency resources."[24]

Finally, merchant generators may also earn revenue through bilateral contracts rather than the markets. ERCOT's market monitor notes that the net revenue analysis does not account for such contracts and that "some developers may have bilateral contracts for unit output that would provide more revenue than the ERCOT market did in 2018."[25]

In sum, the net revenue analysis would be more valuable were it to be reported along with data on reserve margins or other indicators of capacity surplus or deficits, as well as indicators of whether resource investments are made by utilities with an obligation to serve customers or by merchant generation owners and developers.

Measures of Market Power and Competition

An important role of the market monitors is to assess the level of competition, the potential for market power, and whether market participant behavior indicates the exercise of market power, and then to take steps to mitigate such market power.

MARKET STRUCTURE

Market structure measures can indicate that there may be greater risk for the exercise of market power, but not necessarily whether such behavior is occurring. The primary market structure measures are the concentration of ownership of resources and whether there are pivotal suppliers.

A common measure of market concentration is the Herfindahl-Hirschman Index (HHI), which is calculated by squaring the market share of each firm competing in the market and then summing the resulting numbers. For example, if one firm owned 50 percent of the generating capacity and two other firms each owned 25 percent, the HHI for capacity would be:

$$50^2 + 25^2 + 25^2 = \\ 2{,}500 + 625 + 625 = \\ 3{,}750$$

According to the U.S. Department of Justice, markets with an HHI between 1,500 and 2,500 points are considered to be moderately concentrated, and markets in which the HHI is in excess of 2,500 points are considered to be highly concentrated.[26]

---

[22] *2018 State of the Market Report for the MISO Electricity Markets, Potomac Economics - Independent Market Monitor for the Midcontinent ISO (MISO SOM), June 2019 at 110, available at: https://cdn.misoenergy.org/2018%20State%20of%20the%20Market%20Report364567.pdf.*

[23] *SPP at 150.*

[24] *2018 Annual Markets Report, ISO New England, Inc. Internal Market Monitor, (ISO-NE Internal Market Monitor Report) May 23, 2019 at 168, available at: https://www.iso-ne.com/static-assets/documents/2019/05/2018-annual-markets-report.pdf.*

[25] *ERCOT SOM at 118.*

[26] *US Department of Justice, Antitrust Division, Herfindahl-Hirschman Index, available at: https://www.justice.gov/atr/herfindahl-hirschman-index*

The market monitors for PJM, MISO, SPP, and ISO-NE all provide some measure of the HHI for different markets, finding that there are zones in MISO and markets and time periods in PJM where the HHI values indicate high levels of concentration.

In addition to or instead of HHIs, the market monitors report on generation ownership shares as shown in the chart below. Three suppliers own 30 percent or more of the capacity in MISO, PJM, and the ISO-NE Connecticut and Boston zones and over 70 percent in MISO South. SPP also reports that in 35 percent of the hours, the energy market share for the largest supplier was above 20 percent in 2018,[27] noting that a 20 percent market share threshold is "one of the generally accepted metrics that would indicate structural market power."[28]

While the concentration measures provide some indication of potential market power opportunities, a third measure—the presence of pivotal suppliers—is seen by the market monitors as a more important measure. A single supplier is pivotal when its resources are necessary to satisfy load or manage a transmission constraint. Several market monitors explain that market share data do not address the actual levels of supply and demand within certain geographic areas or during times of high demand that may provide opportunities for the exercise of market power even where HHIs or market shares are low. For example, SPP's market monitor states that "neither market share nor the HHI metric alone would be sufficient for the assessment of market power particularly in today's spot electricity markets where load pockets formed by transmission congestion may lead to market power with much smaller market shares and/or HHI values."[29]

The pivotal supplier analyses performed by the market monitors find that there are opportunities for the exercise of market power, especially within certain constrained geographic areas and during certain hours.

The markup data generally show competitive participant behavior in the energy markets.

MARKET PARTICIPANT BEHAVIOR

While market structure measures demonstrate opportunities for the exercise of market power, indicators of market participant behavior are intended to reveal where such market power may be exercised. One such measure is the price-cost markup, which is the average amount by which the clearing price exceeds the short-run marginal cost of the resource setting the price. (However, these data do not provide information about the earnings of infra-marginal units, which offer below the clearing price and earn the differential between the clearing price and their marginal costs.)

The data on the price-cost markup is not consistently provided in terms of whether it is a percentage or dollar amount, if it is provided for the day-ahead or real-time market, or both. Moreover, the ISO-NE uses the Lerner Index, which divides the price-cost differential by the price. By using the price instead of cost as the denominator, the Lerner Index produces a lower percentage than the price-cost markup.

Aside from these variations, the markup data generally show competitive participant behavior in the energy markets. It is worth noting, however, that the two RTOs with higher markups – PJM and ISO-NE – also have capacity markets and therefore generators receive revenues from outside the energy market. MISO and SPP have negative markups, an indication that, on average, the marginal resource is offered at a price below the short-run marginal cost of that unit. One reason for the negative markup finding may be that the actual marginal cost of the price-setting unit is lower than the market monitor's determination of the marginal cost.

One factor impacting these markups is whether a cost adder is included in the calculation. For example, PJM's market monitor, said an "adder was included prior to

[27] *SPP SOM at 210.*

[28] *SPP SOM, Footnote 142 at 210.*

[29] *Id.*

the implementation of PJM markets in 1999, based on the uncertainty of calculating the hourly operating costs of CTs [combustion turbines] under changing ambient conditions. The owners of coal units, facing competition, typically exclude the additional 10 percent from their actual offers."[30] PJM's market monitor therefore also provides an adjusted markup that excludes this adder, producing a lower denominator and higher markup. Similarly, the CAISO market monitor said that "because a significant amount of gas-fired supply is bid at prices lower than the unit's default energy bid (which includes a 10 percent adder), using default energy bids tends to overestimate the competitive baseline price."[31] The CAISO market monitor addresses this overestimate by using the minimum of the energy bid for that hour or the default energy bid as the cost estimate.[32] Information is not provided by the other market monitors on the existence of an adder in their mark-up estimates. If so, an adjusted markup should be provided with this adder removed.

"Because a significant amount of gas-fired supply is bid at prices lower than the unit's default energy bid (which includes a 10 percent adder), using default energy bids tends to overestimate the competitive baseline price."
CASIO market monitor

Although average markups do not present competitive concerns, data on markups during certain times do indicate uncompetitive behavior. PJM's market monitor said some marginal units had substantial markups, with the highest reaching $500.[33] CAISO's market monitor said "prices have been significantly in excess of competitive levels in some hours."[34] ERCOT's market monitor conducts an analysis of price spikes, defined as intervals when the load-weighted average energy price is greater than natural gas-cost-indexed thresholds that "typically exceed the marginal costs of virtually all on-line generators in ERCOT."[35] These price spikes were found to contribute $7.28 or 30 percent of the real-time price.[36] Such an analysis of the price spikes would be a useful metric for other market monitors to include.

In addition to the mark-ups, the market monitors examine measures of potential economic and physical withholding. Economic withholding is the practice of constraining supply by offering generation at a price that is too high for the generating unit to clear the market, thereby constraining supply and potentially increasing prices paid to the units that do clear the market. One indicator of this practice is the "output gap," which measures quantity of power not produced from resources whose operating costs are below the clearing price. The market monitors that analyzed the output gap (NYISO, ISO-NE, MISO, SPP and ERCOT) did not find indicators of competitive concerns.

Potential physical withholding is also examined by some market monitors and involves practices such as derating a unit or providing inaccurate information on its operating characteristics to reduce its dispatch. To assess physical withholding, short-term generator deratings are analyzed during different load levels and for the larger suppliers, based on the rationale that during periods of higher loads, prices would be the most sensitive to withholding. The market monitors that examined the potential for physical withholding (MISO, ISO-NE, NYISO, SPP and ERCOT) did not find any patterns indicating competitive concerns. MISO's market monitor said it has imposed sanctions on physical withholding cases involving deviations from dispatch instructions.[37]

Physical withholding could also entail a longer-term strategy of retiring generation units that are still earning more than their avoidable costs to constrain supply and

[30] *PJM SOM at 151.*
[31] *CAISO SOM at 154.*
[32] *CAISO SOM at 155.*
[33] *PJM SOM at 105-106.*
[34] *CAISO SOM at 154.*
[35] *ERCOT SOM at 12.*
[36] *Id. at 12.*
[37] *MISO SOM at 43.*

benefit the remainder of the owner's generation fleet. SPP's market monitor notes that "a strategically motivated generator retirement, particularly in a congested area, may create structural and market power issues that may potentially amount to physical withholding. Creating a shortage through a retirement may lead to sustained price spikes and/or may benefit generators affiliated with the retiring generator(s)."[38] SPP has an initiative underway to develop a process to evaluate generator retirements.[39] PJM's market monitor performs an analysis of the economics of all units that plan to retire to "verify that the units are not economic and there is no potential exercise of market power through physical withholding,"[40] and ISO-NE reviews retirement bids submitted in the capacity auctions "to establish if the bid may be an attempt to inflate clearing prices above competitive levels."[41]

The market monitors, while generally finding the markets to be competitive, also raise concerns about the potential exercise of market power and uncompetitive price levels within certain local areas and during peak times.

In sum, the market monitors, while generally finding the markets to be competitive, also raise concerns about the potential exercise of market power and uncompetitive price levels within certain local areas and during peak times.

While the market monitors generally focus the assessment of competition on the energy markets, PJM's market monitor provides a far more comprehensive assessment of competition in each of the markets, finding the following to be either non-competitive or only partially competitive in 2018:

- local energy market structure;
- aggregate energy market structure (partially competitive);
- capacity market structure, participant behavior and market performance;
- reserve and regulation market structure;
- and Financial Transmission Rights market structure and participant behavior (partially competitive).[42]

MITIGATION

Market monitors have the ability to mitigate energy market offers to prevent the exercise of market power. Generally, energy market mitigation occurs upon a finding that a seller is pivotal, either by itself or in combination with two other sellers and is located within a constrained area with limited capability to import power. Entities that are pivotal within constrained areas will then have their offers capped at a proxy measure of a competitive offer, equal to the short-run marginal cost. Such mitigation rarely occurs—generally in fewer than 1 percent of the hours in the real-time and day-ahead markets. However, the NYISO said mitigation was about 10 percent of the hours in the day-ahead market and 6 percent of hours in the real-time market in some load pockets.[43]

ISO-NE's internal market monitor expressed the concern that "mitigation measures for system-level market power in the real-time energy market provide suppliers a considerable degree of deviation from competitive marginal-cost offers before the mitigation rules would trigger and mitigate a supply offer. The potential impact of structural market power in the real-time market and the effectiveness of existing mitigation thresholds will be further evaluated."[44]

Mitigation is also undertaken in the capacity markets. In the PJM capacity market, known as the Reliability Pricing

[38] *SPP SOM at 233.*

[39] *Id.*

[40] *PJM SOM at 571.*

[41] *ISO-NE Internal Market Monitor Report at 167.*

[42] *PJM SOM at 6 – 9.*

[43] *2018 State of the Market Report for the New York ISO Markets, Potomac Economics – Market Monitoring Unit for the NYISO, May 2019 (NYISO SOM), Appendix at A-43, available at: https://www.nyiso.com/documents/20142/2223763/2018-State-of-the-Market-Report.pdf/b5bd2213-9fe2-b0e7-a422-d4071b3d014b?t=1557344025932*

[44] *ISO-NE Internal Market Monitor Report at 3.*

Model (RPM), all capacity has failed the three-pivotal-supplier test each year since RPM's inception in 2007. Thus, offers into the capacity auction from existing resources are subject to caps. But the PJM market monitor has filed a complaint with FERC showing that the default offer cap is set at an excessive level that allows the exercise of market power.[45] In the most recently held auction for the 2021/22 delivery year, no sale offers were mitigated, and most resources (84 percent) offered at the cap.[46]

In the ISO-NE Forward Capacity Market (FCM), the internal market monitor evaluates de-list bids, which are requests to remove an existing capacity resource from the auction if capacity prices fall below a specified level. If the internal market monitor determines that a de-list bid is uncompetitive and the supplier fails the pivotal supplier test, then the bid is mitigated. In the eighth through thirteenth capacity auctions, mitigation lowered the offer price for 59 percent of the number of delist bids, equal to 73 percent of the capacity in these bids.[47]

In the NYISO capacity market, an offer cap is applied to pivotal suppliers in the spot auction and penalties can be assessed on withheld capacity.[48] The extent of these actions is not reported.

PJM, ISO-NE and the NYISO also mitigate sale offers from new resources into the capacity auction to prevent the theoretical exercise of buyer-side market power that would lower prices. Such "buyer-side mitigation" generally involves the mitigation of capacity offers to a minimum price. ISO-NE's market monitor reports that in all of the capacity auctions held thus far, 347 resources representing 15,200 MW of capacity submitted requests to offer below the minimum price threshold (known as the Offer Review Trigger Price), of which 158 (8,800 MW) were denied, including 102 (5,900 MW) that offered in the auction at a higher mitigated price and 56 (2,800 MW) that withdrew from the auction.[49] The impact of such mitigation on the price is not reported, however.

The New York ISO's market monitor said buyer-side mitigation exemption requests were filed for seven new resources that began service in 2017. Four of these resources were granted exemptions, and the other three exemption requests are still being determined.[50] Aside from data on exemptions, the NYISO does not report on the extent of such mitigation. PJM's market monitor also does not provide data on the extent of buyer-side mitigation.

Market power mitigation of sellers in all markets is an essential role of the market monitors. At the same time, the mitigation imposed on the buyer-side in the PJM, ISO-NE and NYISO capacity markets has not been justified.

Financial Entity Participation in the Markets

Banks, hedge funds, and other entities which do not own generation or serve load, can participate in the RTO/ISO-operated markets using financial instruments--virtual transactions and purchases of Financial Transmission Rights, Congestion Revenue Rights and analogous instruments.

VIRTUAL TRADING

Virtual transactions involve a virtual sale (known as an INC) or purchase (known as a DEC) from the day-ahead market, which is then reversed through a corresponding DEC or INC in the real-time market, and earnings are produced from the day-ahead and real-time price differential. (These transactions are also known as convergence bidding.) Physical entities serving load and generating power, can also use virtual transactions as a hedging tool.

Another product, known as Up-To-Congestion in PJM and a Point-to-Point transaction in ERCOT, allow the purchaser to earn the difference in the congestion cost in the day-ahead and in real-time markets between two different locations.

[45] *Complaint of the Independent Market Monitor for PJM, Docket EL19-47, Federal Energy Regulatory Commission (February 21, 2019).*
[46] *PJM SOM at 281.*
[47] *ISO-NE Internal Market Monitor Report at 174-175.*
[48] *NYISO SOM at 16*
[49] *ISO-NE Internal Market Monitor Report at 176.*
[50] *NYISO SOM at 17.*

In PJM, Up-to-Congestion transactions accounted for 62.3 percent of the marginal resources in the day-ahead market, and INC and DECs accounted for another 26.7 percent, meaning that a virtual trade accounted for 89 percent of the marginal resources.

The RTO/ISO market monitors have differing views of the benefits of such financial entity participation. Some market monitors, including ISO-NE, MISO, and NYISO view virtual transactions as beneficial because this activity can improve the convergence between day-ahead and real-time prices.[51]

The CAISO market monitor takes a more cautious approach, noting that "the degree to which convergence bidding has actually increased market efficiency by improving unit commitment and dispatches has not been assessed. In some cases, virtual bidding may be profitable for some market participants without increasing market efficiency significantly or may even decrease market efficiency."[52] PJM's market monitor said "there is no guarantee that the results of virtual bids and offers will result in more efficient market outcomes. Where arbitrage incentives are created by systematic modeling differences, such as differences between the day-ahead and real-time modeled transmission contingencies and marginal loss calculations, virtual bids and offers cannot result in more efficient market outcomes. Such offers may be profitable but cannot change the underlying reason for the price difference. The virtual transactions will continue to profit from the activity for that reason regardless of the volume of those transactions. This is termed false arbitrage."[53] SPP's market monitor notes that virtual trading has potential value in price convergence, but "there must be sufficient competition in virtual trading; transparency in day-ahead market, reliability unit commitment, and real-time market operating practices; and predictability of market events."[54]

The SPP market monitor reports that it has extensive monitoring in place for cross-product market manipulation, a concern in all RTO/ISOs, where for example, a market participant may submit a virtual transaction to create congestion that benefits a financial transmission right position. Because such behavior generally shows up as a loss in one market and a gain in another, SPP's market monitor tracks market losses, noting that "twelve market participants lost more than $10,000 in 2018, which is only slightly more than in 2017."[55]

MISO's market monitor found that 58 percent of all cleared virtual transactions were "efficiency-enhancing."[56] The financial entity share of the efficiency-enhancing transactions (about 92 percent) was the same as for the non-efficiency enhancing.

Virtual transactions can frequently set the clearing price in the day-ahead market. In PJM, Up-to-Congestion transactions accounted for 62.3 percent of the marginal resources in the day-ahead market, and INC and DECs accounted for another 26.7 percent, meaning that a virtual trade accounted for 89 percent of the marginal resources.[57] In ISO-NE virtual transactions set the price for 23 percent of the day-ahead load, and they were marginal in 28 percent of the intervals in SPP.[58]

Although virtual products are used by both financial and physical entities, financial entities account for over 80 percent of these trades in PJM and over 90 percent of the revenues in MISO and the CAISO. In ERCOT, financial entities represented 36 percent of the Point-to-Point transaction volumes, but earned higher profits than physical entities on a MWh basis.[59] No other RTO/ISO market monitors report data on the shares of virtual trading, but

[51] *ISO-NE Internal Market Monitor Report at 119-20, MISO SOM at 28, NYISO SOM at 25.*
[52] *CAISO Annual Report at 132.*
[53] *PJM SOM at 192.*
[54] *SPP SOM at 95.*
[55] *SPP SOM at 103.*
[56] *MISO SOM at 27.*
[57] *PJM SOM at 105.*
[58] *ISO-NE Internal Market Monitor Report at 95; SPP SOM at 40.*
[59] *ERCOT SOM at 36-37.*

all report that virtual transactions were profitable in the aggregate. The available data show that virtual trading disproportionately benefits financial entities. But the RTO/ISO market monitors vary significantly on the analyses and scope of data on this topic. Clearly, there should be a comprehensive evaluation of how these virtual transactions impact the price and performance of the markets.

FINANCIAL TRANSMISSION RIGHTS

A second mechanism for financial entity participation is a right to the congestion revenue collected on a transmission pathway, which is also an important hedging tool for load-serving entities. These tools are known by different terms in different RTO/ISOs, including Financial Transmission Rights; Congestion Revenue Rights; Transmission Congestion Contracts; and Transmission Revenue Rights, but will generally be referred to here as FTRs, unless otherwise specified. These rights may be allocated to load-serving entities with the remainder sold in an auction (CAISO, MISO, ERCOT) or directly sold through auctions (ISO-NE, NYISO), or the RTO/ISO may allocate Auction Revenue Rights (ARRs) that allow load-serving entities to receive the revenue from the auctions or convert the ARRs to FTRs (PJM, SPP).

There are two relevant analyses of these tools. First is their overall adequacy as an offset to the total congestion paid by load, which examines the portion of congestion paid recovered through the FTR and ARR revenues. Second, is whether there is adequate revenue to cover the obligations to FTR owners, including financial entities. If the financial entities are purchasing the FTRs in the auction at a price that does not reflect the value of the congestion revenue received, then there will be a shortfall between the price paid and the revenue owed to the FTR owners. This differential may be funded by load, which in turn reduces the offset to congestion. PJM's market monitor said these two analyses may not have the same outcome. In PJM, the FTRs are fully funded, but the combination of FTRs and ARRs offset only 50 percent of congested load between June 2017 and May 2018.[60] Yet, financial entities earned 82 percent of the profits in that same time frame.[61]

In CAISO, the market monitor reported a $131 million shortfall in 2018 Congestion Revenue Right (CRR) funding that was paid by ratepayers and primarily received by financial entities. Financial entities earned $91 million in profits from CRRs, while load-serving entities lost $9 million.[62] However, CAISO proposed and received approval for rule changes to the CRR auctions that have somewhat mitigated these losses. As a result, ratepayers losses dropped to $34 million during 2019, and financial entities received profits of $33 million.[63] ERCOT reports a $134 million shortfall in funding for congestion in 2018 that was paid for by consumers.[64]

In contrast to other RTO/ISOs, SPP reports that Transmission Congestion Right and ARR payments to load-serving entities exceeded their congestion costs by $77.4 million, and non-load serving entities and financial entity costs by $18.8 million.[65] In the NYISO, owners of Transmission Congestion Contracts (TCCs) earned a profit of $47 million from November 2017 through October 2018.[66] ISO-NE's internal market monitor reports that profits for FTR holders increased to $33 per MW-month in 2018, compared to $15 in 2017 and $10 in 2016, as a result of greater payouts than the cost of the FTRs.[67] But neither of these RTO/ISOs provided data on the types of entities owning FTRs and the distribution of the profits, or on the value of FTRs as a hedge to load. However, the ISO-NE internal market monitor said that FTR ownership is extremely concentrated, with four entities owning two-thirds of the FTR megawatts.[68]

---

60 *PJM SOM at 653 – 65; MISO SOM at 27; CAISO Annual Report Table 5.1 at 138; MISO SOM Analytical Appendix, Table A-8 at 46, available at: https://cdn.misoenergy.org/2018%20State%20of%20the%20Market%20Analytical%20Appendix376746.pdf*

61 *Calculated from data in PJM SOM, Table 13-24 at 642.*

62 *CAISO Annual Report at 202-203*

63 *Report on Results of 2019 Congestion Revenue Rights Auction, Department of Market Monitoring California Independent System Operator, January 27, 2020, available at: http://www.caiso.com/Documents/ReportonResultsof2019CongestionRevenueRightsAuction-Jan272020.pdf*

64 *ERCOT SOM at 72.*

65 *Calculated from Table 5-15, SPP SOM at 76.*

66 *NYISO SOM at 38*

67 *ISO-NE Internal Market Monitor at 129.*

68 *ISO-NE Internal Market Monitor at 131.*

The market monitors provide no evidence of any benefit from financial entity participation in the markets. As noted by the PJM market monitor: "It is not clear, in a competitive market, why FTR purchases by financial entities remain persistently profitable. In a competitive market, it would be expected that profits would be competed to zero."[69] The NYISO market monitor does not view the continued TCC profitability as contrary to competition, stating that "in a well-functioning market, the price for the TCC should reflect a reasonable expectation of the day-ahead congestion. Perfect convergence cannot be expected because many factors affecting congestion are not known at the time of the auctions."[70]

One extreme demonstration of the potential harm from such participation is the June 2018 default of the GreenHat company in PJM, which had amassed the largest portfolio of FTRs in PJM history before defaulting and saddling the remaining market participants with hundreds of millions of dollars in costs.[71]

As with virtual transactions, a more detailed evaluation of the benefits and risks of financial entity participation in the FTR markets would shed light on the risks and benefits these entities bring to the RTO/ISO-operated markets.

Summary of Market Monitor Data

The following table summarizes this review of the market monitor reports by showing which data or analyses are provided by the market monitor reports and demonstrates the variability in the provision of information among these reports. The benefits of the market monitor reports would be maximized were all market monitors to provide the data and analyses listed in this table and to do so in a consistent manner.

Table 1. Summary of Market Monitor Provision of Key Data

Data Type	CAISO	ERCOT	ISO-NE	MISO	NYISO	PJM	SPP
Transmission within All-In Energy Costs			X			X	
Ownership of Generation by Type							X
Sources of Funding for Capacity						X	
Bilateral Contracting, Self-Supply and Market Purchases						X	
Net Revenue Analysis for Existing Units					X	X	X
HHI and/or Market Shares			X	X		X	X
Price-Cost Markup	X		X	X		X	X
Price Spikes	X	X				X	
Economic Withholding		X	X	X	X		X
Physical withholding		X	X	X	X		X
Exercise of Buyer-Side Mitigation/MOPR			X		X		
Financial Entity Share of Virtual Trading or Profits	X	X		X		X	
Financial Entity Share of FTRs or Profits	X					X	

69 *PJM SOM at 642.*

70 *NYISO SOM at A-82*

71 *See Report of the Independent Consultants on the GreenHat Default, March 26, 2019, available at : https://www.pjm.com/-/media/library/reports-notices/special-reports/2019/report-of-the-independent-consultants-on-the-greenhat-default.pdf*

FERC RTO/ISO Performance Metrics

The impetus for the development of Performance Metrics for the RTO/ISOs was a 2008 Government Accountability Office (GAO) finding that "there is no consensus about whether RTO markets provide benefits to consumers or how they have influenced consumer electricity prices. FERC officials believe RTOs have resulted in benefits; however, FERC has not conducted an empirical analysis of RTO performance or developed a comprehensive set of publicly available, standardized measures to evaluate such performance."[72]

Following this report, in consultation with the RTO/ISOs, FERC staff developed a set of metrics covering three topic areas: market benefits; organizational effectiveness; and reliability, which were issued for public comment and then finalized. The RTO/ISOs submitted data on those metrics, which was compiled by the Commission in a Report to Congress, issued in 2011.[73] Jon Wellinghoff, the Chairman of the Commission at the time, stated in the 2011 report that the next steps in the metrics process would be the development of performance metrics in non-RTO regions, followed by development of common metrics for both ISOs/RTOs and non-RTO regions, "thereby allowing for comparisons across all electric regions and markets."[74]

[72] *Electric Restructuring—FERC Could Take Additional Steps to Analyze Regional Transmission Organizations' Benefits and Performance, US Government Accountability Office (September 2008) at 43, available at: https://www.ferc.gov/industries/electric/indus-act/rto/gao-report.pdf*

[73] *Performance Metrics for Independent System Operators and Regional Transmission Organizations: A Report to Congress in Response to Recommendations of the United States Government Accountability Office, Federal Energy Regulatory Commission (April 2011), available at: https://www.ferc.gov/industries/electric/indus-act/rto/metrics/report-to-congress.pdf*

[74] *Id. at 5.*

Below are the initial set of market-related performance metrics.[75] (Metrics in the categories of reliability and organizational effectiveness are not listed below.) These measures generally overlapped with those reported in the RTO/ISO market monitor reports and did not therefore provide much new data.

Since the first *Report to Congress* on these measures, the Commission collected additional data on the performance metrics from utilities outside of RTO/ISO regions. The most recent metrics report, issued in 2016 and revised in 2017,[76] includes data on some of these metrics from seven non-RTO/ISO utilities that voluntarily submitted data.

Table 2. FERC Performance Metrics for RTO/ISO-Operated Markets

A. Market Competitiveness 1. Price Cost Mark Up 2. Generation Net Revenues 3. Percentage of hours offers are capped due to mitigation
B. Market Pricing 1. Load-Weighted Locational Marginal Prices 2. Components of Total Power Costs based on Load-Weighted Locational Marginal Prices (e.g., fuel costs, transmission charges, RTO costs, etc.) 3. Load-Weighted, Fuel-Adjusted Locational Marginal Prices 4. Impacts of Demand Response on Market Prices
C. System Lambda (cost of the marginal unit)
D. Energy Market Price Convergence 1. Absolute dollar difference between day-ahead and real-time prices 2. Percentage difference between day-ahead and real-time prices
E. Congestion Management 1. Congestion charges per megawatt-hour of load served 2. Percentage of congestion dollars hedged through ISO/RTO-administered congestion management markets
F. Resource Availability 1. RTO forced outage rate 2. Demand Response Availability
G. Fuel Diversity in terms of energy, installed capacity and actual production
H. Renewables 1. Renewable megawatt-hours as a percentage of total energy 2. Renewable megawatts as a percentage of total capacity

[75] *ISO/RTO Performance Metrics Commission Staff Report, Appendix B, Federal Energy Regulatory Commission (October 21, 2010), available at: https://www.ferc.gov/industries/electric/indus-act/rto/metrics/staff-report-metrics.pdf*

[76] *Common Metrics Report, Staff Report, Federal Energy Regulatory Commission (August 2016 – Revised August 2017), available at: https://www.ferc.gov/legal/staff-reports/2016/08-09-common-metrics.pdf*

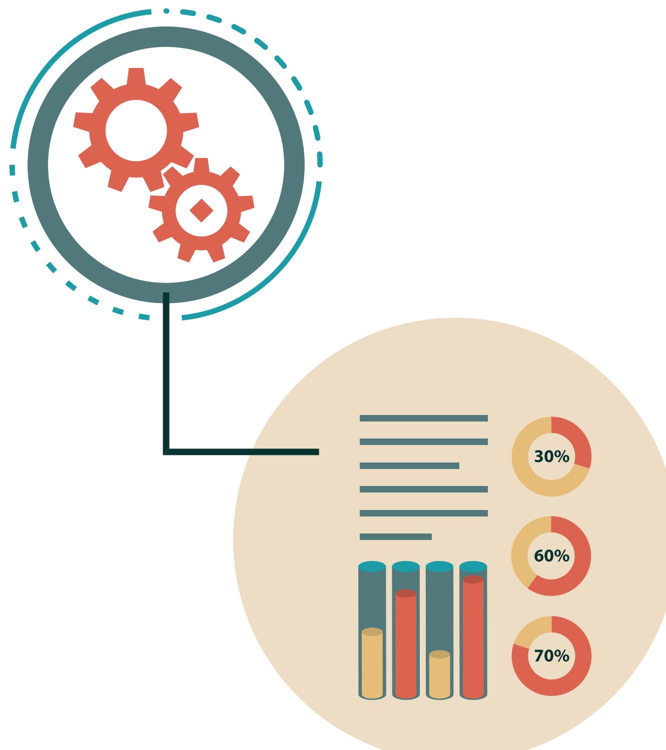
Data on many of the market metrics were submitted only by the RTO/ISOs. Despite the Commission's initial stated intent to compare the different market structures, FERC staff discouraged any comparison between the RTO/ISOs and non-RTO/ISO utilities, asserting that "several limitations preclude all but the most basic observations about the metrics submitted by RTOs and ISOs relative to those submitted by non-RTOs and ISOs."[77]

In the 2017 metrics report, presenting data through 2014, the Commission reached the following general conclusions:

- RTOs and ISOs managed the dispatch of energy from a diverse set of generating fuel-types from 2010-2014.
- RTO and ISO regions maintained adequate power supplies, in accordance with planned reserve margins from 2010-2014.
- RTOs and ISOs report the approval of a large number of transmission projects for reliability purposes from 2010-2014.
- Administrative costs per megawatt-hour varied across RTOs and ISOs from 2010-2014.

These findings are far from a comprehensive assessment of whether the RTO/ISO markets are providing benefits to consumers. Soon after this last metrics report was issued, a 2017 GAO analysis of the capacity markets found that "comprehensive, consistent information is not available on resource adequacy or the costs of ensuring it in regions with and without capacity markets."[78] The GAO also reported problems with the quality of the data in the metrics reports and found that "FERC could improve the quality of its data if it used standardized definitions for the metrics and included more quality checks in its data collection process... Instead, FERC accepts data however it is provided by the RTOs and non-RTO electricity suppliers, according to FERC officials."[79]

FERC staff issued a revised set of performance metrics for RTOs/ISOs (and a set of metrics applicable to utilities located outside of an RTO/ISO) for public comment in July 2019, which were then submitted to the Office of Management and Budget in January 2020.[80] Data on these metrics would be collected for the years 2014 through 2018. These metrics, listed below, would provide greater detail than the prior set of metrics, and also address capacity markets. All of the new metrics are highlighted in Table 3.



[77] *Id. at 9.*

[78] *Four Regions Use Capacity Markets to Help Ensure Adequate Resources, but FERC Has Not Fully Assessed Their Performance, US Government Accountability Office (December 2017) at 23, available at: https://www.gao.gov/assets/690/688811.pdf*

[79] *Id. at 34-35*

[80] *Commission Information Collection Activities (FERC-922); Comment Request, Docket AD19-16, Federal Energy Regulatory Commission (January 24, 2020), available at: https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=15302413*

Table 3. 2019 Proposed RTO/ISO Performance Metrics

Collected from all respondents
Reserve Margins
Average Heat Rates
Fuel Diversity
Capacity Factor by Technology Type
Energy Emergency Alerts (EEA Level 1 or Higher)
Performance by Technology Type during EEA Level 1 or Higher
Resource Availability (Equivalent Forced Outage Rate Demand)
Collected from the RTOs/ISOs
Number and Capacity of Reliability Must-Run Units
Reliability Must-Run Contract Usage
Demand Response Capability
Unit Hours Mitigated
Wholesale Power Costs by Charge Type
Price Cost Markup
Fuel Adjusted Wholesale Energy Price
Energy Market Price Convergence
Congestion Management
Administrative Costs
New Entrant Net Revenues
Shortage Price Intervals and Reserve Price Impacts
Collected only from RTOs/ISOs with capacity markets
Net Cost of New Entry (Net CONE) Value
Resource Deliverability
New Capacity (Entry)
Capacity Retirement (Exit)
Forecasted Demand
Capacity Market Procurement and Prices
Capacity Obligations and Performance Assessment Events
Capacity Bonus Payments for Over-Performance and Penalty Payments for Under-Performance

The American Public Power Association filed comments[81] supporting the reinstatement of the metrics and making the following recommendations:

- Use Commission reports on metrics data to critically evaluate the RTO/ISO-operated markets and not solely to support broad conclusions about the benefits of the markets.
- Do not limit the scope of the performance metrics to those already collected or reported by RTOs/ISOs or their market monitors.
- Useful information being provided by only one or two RTO/ISO market monitors can serve as a model of a best practice that could then be incorporated into the metrics.
- Improve or expand Commission staff quality checks of the data submitted, as recommended by the Government Accountability Office.
- Identify opportunities to compare the collected RTO/ISO metrics information with aggregate data on non-RTO/ISO regions available from other sources.
- Expand some of the proposed metrics as follows:
  - Remove any adder to the cost denominator in the price-cost markup.
  - Show congestion revenue from FTRs, ARRs and other instruments as a portion of the actual congestion costs paid by load.
  - Show how revenue for new generators compares to the cost of new entry.
  - Break down new generation by the technology of the new capacity, as well as the financial arrangement (including ownership by a utility or end-use customer; bilateral contracts with utilities or with customers; or merchant – where no revenues are received from ownership or contracts).
- Add the following metrics for all RTOs/ISOs, both with and without capacity markets.
  - A comprehensive transmission metric that includes more detailed data on transmission costs.
  - Aggregated data on cost recovery by existing capacity resources.
  - The market share of capacity for the largest three generation owners for both the total RTO/ISO and by zone, but without necessarily identifying the owners.
  - The relative shares of virtual trades and associated profits by financial and physical entities, the portion of virtual trades that enhance efficiency, and the relative shares of financial trading rights (FTRs) and similar instruments held by financial and physical entities.
  - A governance metric showing the number of proposals and percentage of total proposals for market rule changes that were submitted to the Commission each year that had received a vote opposing the proposal by one or more stakeholder committees.
  - Retain the RTO/ISO metric on customer satisfaction, with such data broken down by sector.

Commission staff did not accept these proposed changes. Staff acknowledged the lack of consistency in RTO/ISO data gathering, but used such inconsistency as a justification for not expanding the metrics, finding that "[s]ome of the additional metrics recommended by commenters may be calculated by certain RTOs/ISOs or non-RTO/ISO utilities but not by others, thus losing the commonality and comparability of the Common Metrics desired by Commission staff."

[81] *Comments of the American Public Power Association, Performance Metrics for ISOs, RTOs and Regions Outside of ISOs and RTOs, Federal Energy Regulatory Commission, Docket AD19-16, (September 9, 2019), available at: https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=15346446*

Conclusion

This review shows that there is a wealth of data available on the RTO/ISO-operated markets, but inconsistences and gaps in the data are present. Market stakeholders would greatly benefit from having access to a more comprehensive and consistent set of data. The Commission can play an important role by issuing more comprehensive annual state of the market reports, expanding the performance metrics, and establishing best practices for the RTO/ISO market monitors.