AMERICAN PUBLIC POWER ASSOCIATION
Powering Strong Communities

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Wholesale Electricity Markets and Regional Transmission Organizations

Summary

In the U.S., roughly five billion megawatt hours of electricity are sold at the wholesale level, i.e., sold to a utility or other entity reselling that energy to residential, business, or industrial customers. There is no single national market for these wholesale electricity sales. In some regions, these sales are conducted bilaterally, through direct contact and negotiation, through a voice broker, or through an electronic brokerage platform, such as the Intercontinental Exchange (ICE). In other regions, specifically in the Northeast, Mid-Atlantic, Midwest, California, and Texas, there are wholesale electricity markets operated by large entities known as regional transmission organizations (RTOs) and Independent System Operators (ISOs)—collectively referred to as "RTOs." Bilateral transactions can also occur in RTO regions, but through separate settlements and in compliance with complex RTO rules. These RTO markets provide for the wholesale sale of electric energy (both day-ahead and real-time purchases), as well as ancillary services. Some RTOs also operate capacity markets.[1]

Public power utilities, state utility commissions, consumer- and low-income advocates, and industrial electric power customers have raised significant concerns about RTO-run wholesale electricity markets, which do not function as we traditionally think of markets functioning, but are rather highly complex and opaque administrative constructs. Such concerns initially revolved around high and volatile prices. More recently, the leading concerns have been the cost and effects of mandatory markets for capacity run by some RTOs. The American Public Power Association (Association or APPA) has developed a policy proposal to address our concerns with capacity markets. In addition, the Association strongly supports congressional oversight of Federal Energy Regulatory Commission (FERC) market policies including, but not limited to, the problems associated with capacity markets and lack of transparency in RTO dealings. Congress needs to delve into the intricacies of FERC policies to ensure fairness.

[1] See APPA Issue Brief, *RTO Capacity Markets and Their Impacts on Consumers and Public Power,* for more information.

Wholesale Markets Overview

In regions not controlled by an RTO, wholesale sales are conducted bilaterally, through direct contact and negotiation, through a voice broker, or through an electronic brokerage platform, such as the ICE. They also have forums that serve to create robust bilateral markets in these non-RTO regions. For example, the Western Systems Power Pool provides a standardized power sales agreement that provides for a liquid wholesale power market with transparent price information reported through multiple indices. Generally, these regions are where "traditional vertically integrated utilities" (i.e., utilities owning generation, transmission, and distribution facilities) continue to operate. (Some RTOs are also predominantly categorized by vertically integrated utilities as discussed below.)

RTOs were formed as some state and local regulators changed retail electricity markets rules to encourage or require traditional vertically integrated utilities to sell their generation facilities and give retail utility customers the ability to purchase power from other generators. As a result, private utilities were forced to purchase their power on the wholesale market. (Most states exempted not-for-profit, locally governed public power utilities from these requirements, though for unrelated reasons these utilities generally must make wholesale purchases of power). This "deregulation" was intended to apply to the sale of electricity and related products, such as energy management, beyond traditional utilities, and spur competition. In fact, many utilities simply sold their generation facilities to a parent holding company that continued to sell the majority of electricity purchased by the utility's customers.

Meanwhile, at the federal level, RTOs were authorized by FERC in 1996 to "remedy undue discrimination in access to the monopoly owned transmission wires that control whether and to whom electricity can be transported in interstate commerce." (FERC Order No. 888, April 24, 1996.) RTOs have functional control, but not ownership, of the transmission system in their "footprint." They provide non-discriminatory access to transmission lines to sellers and purchasers of electricity and eliminate rate "pancaking" (charging multiple transmission fees for one transaction). RTOs also coordinate regional planning for new transmission lines.

The RTO markets were also authorized to administer wholesale markets for the sale of electric energy (both day-ahead and real-time purchases), electric power capacity, and ancillary services. RTOs do not own the power plants that generate the power bought and sold in the market, but do exercise extraordinary controls over power generation. They decide which generators will run and at what levels, grant (or deny) the transmission services needed for transactions to occur, and run the billing systems for payments for power.

Prices paid in these markets are not set through bilateral exchanges, but are centrally determined by the RTO. Customers can, however, engage in bilateral contracts with separate settlements at different prices. All RTOs have centralized markets for the day-ahead and real-time purchase of wholesale electric power. The prices are set (either every five minutes or every hour) based on the bids that sellers submit to the RTO. The RTO takes all bids in ascending order and stops with the last incremental bid needed to supply power to buyers in that time interval. The price all sellers in that time interval receive, however, is based on the last bid the RTO accepted—this is known as a "single clearing price" market. Bids need not reflect the sellers' actual costs of generating power, as FERC formerly required. As a result, low-cost generation can reap substantial financial windfalls. RTOs generally limit the maximum price of a bid, typically $1,000 per megawatt-hour (MWh), although RTOs all have some form of "shortage pricing" where electricity prices can spike above these caps during times of system stress (prices paid in these markets also strongly influence the price of electricity charged by generators outside these markets in bilateral or "standard offer" contracts.) One RTO, the PJM Interconnection (PJM) allows prices to exceed $1,000 per MWh, up to $2,000, if the marginal generator setting the price has costs exceeding that amount.

In some cases, congestion on power transmission lines may prevent all available generation from being delivered to customers in a "constrained zone." As a result, the RTO may allow more expensive generation located within the zone to meet that demand, and customers in the zone must pay the higher price. The difference between the lower price in the RTO generally and the higher price being charged in the constrained zone is called the "congestion charge." This congestion pricing system is known as "locational marginal pricing" (LMP). In theory, LMP should incentivize construction of new generation or additional transmission facilities, or reduce power usage through conservation or shifting of the times when energy is consumed. In reality, generation and transmission development has not been greater in LMP regions. There are financial instruments available to hedge this congestion, such as Financial Transmission Rights or Congestion Revenue Rights, but some RTO market monitors, notably in PJM and the California Independent System Operator (CAISO) have expressed concern in recent years that the hedges are being used to generate earnings for financial traders rather than provide a hedge for load-serving entities. A recent FERC order that would further increase the share of PJM's FTR revenue flowing to financial entities is the subject of several circuit court appeals by multiple load representatives, including public power.

One way to ensure that peak load is met is for a utility is to pay a generator to stand ready to provide power, i.e., to have the "capacity" necessary to meet peak load. Capacity can also be met by securing an obligation from customers that they will curtail power at times of peak load. The cost of capacity is in addition to the price paid for the actual delivery of power and other ancillary services. Most RTOs (other than the Southwest Power Pool (SPP) and CAISO) operate markets for capacity. Like RTO-run wholesale markets for energy, RTO capacity markets rely on a centrally determined single clearing price (again allowing windfall profits for low-cost units); are subject to locational pricing; and can impose dollar caps on bids. Capacity prices are established in periodic auctions – typically on an annual basis. In contrast to energy markets, several RTO capacity markets (ISO New England (ISO-NE), PJM, and New York ISO (NYISO)) also include mechanisms to prop up prices for generators, such as minimum offer price rules or buyer-side mitigation rules.[2]

Market Concerns

While participating in the RTO-operated wholesale energy markets can produce benefits for public power in terms of cost savings and additional opportunities to sell power, there are still some potential problems with the markets that require vigilant oversight. Concerns with the RTO-operated markets include the ability of some generators to strongly influence market prices, also known as exercising market power; highly complex rules; and problematic governance processes. These problems have arisen, and remain, because of a lack of sufficient FERC oversight. In recent years FERC has undertaken enforcement actions against financial entities that have clearly manipulated these markets. Although electricity prices have declined with the drop in natural gas costs and increased levels of renewable energy, the merchant generators[3] operating in the markets still have the opportunity to extract excess revenues—either operating within the existing rules or obtaining FERC's approval for changes to the existing rules to generate excess revenues. For its part, FERC

2 See APPA's issue brief, *RTO Capacity Markets and Their Impacts on Consumers and Public Power* for a more detailed discussion.

3 A merchant generator is a generating plant built with no energy sales contract in place.

continues to impose a strict reliability standard on these RTOs, while taking a hands-off approach as to whether resulting rates to customers are still "just and reasonable."

Ironically, when RTOs first established wholesale markets, proponents said switching from a cost-based rate to a market-based rate would increase price competition, and consumers would benefit both from lower prices and greater investment in new infrastructure necessary for the future reliable operation of the grid. Instead, the opposite has occurred. Electricity prices are, on average, higher in those RTO regions where the states are no longer vertically integrated, and there is scant evidence that these higher prices have produced greater levels of reliability or significant infrastructure. Baseload plant retirements, primarily that of nuclear plants, are more of a problem inside RTO regions than outside RTO regions, and several states have established additional revenue streams to ensure the continued operation of these plants.[4]

FERC initiated a new effort in late 2014, in response to generation owner recommendations, to examine price formation in the energy and ancillary services markets. This docket has led to two final rules that could significantly increase prices. In June 2016, FERC approved its first rule under the price formation effort. One problematic component of the rule is to require all RTOs to trigger price spikes, known as shortage prices, during any time period when a shortage of energy or operating reserves occurs, rather than requiring a shortage to have a minimum duration before such shortage pricing occurs. APPA and NRECA filed comments, as did many other parties, questioning the benefits of shortage pricing for such transient shortages relative to the costs. A second rule, issued in November 2016, would allow energy market offers to exceed the current cap of $1,000 per megawatt-hour (MWh), as long as the seller of energy believed its costs are likely to exceed that amount. APPA and American Municipal Power (AMP) have requested a rehearing of that problematic rule because the removal of the offer cap represents the elimination of a key protection against market power abuses. FERC granted rehearing of that rule, but has not yet acted on it. Two additional and highly complex proposed price formation rules were issued in 2017; one on pricing for fast-start resources only proposed to require pricing rule changes that would increase prices; and the other on "uplift" payments to generators whose costs are not recovered through LMPs proposes to continue to allow allocation of such costs to load in some RTOs, even when load was not the cause of such uplift.

Congressional Action

The Association and other like-minded organizations continue to encourage the leadership in both the Senate Energy & Natural Resources and House Energy & Commerce Committees to investigate the functionality of these RTO-run electricity markets themselves. They have also urged FERC to undertake an investigation of these markets. On September 7, 2016, the House Energy & Commerce Committee held a hearing entitled, "Federal Power Act: Historical Perspectives," to begin an inquiry into the blurring of lines between historic federal and state jurisdictional divides; how regulated and "competitive" markets continue to fare under both FERC's and the states' oversight; how reliability and security of the grid, innovation, and distributed energy resources are prioritized in the current system; and how other external factors, such as tax policy and renewable mandates factor in to the functioning of competitive markets. The committee may continue to look at these matters under new Chairman Greg Walden (R-OR).

American Public Power Association Position

The Association has long had concerns about the RTO markets, particularly related to cost to electricity customers and market manipulation. In recent years, APPA has focused intensely on the problematic mandatory capacity markets operated by the Eastern RTOs. As discussed above, many questions have been raised about whether these markets can provide reasonably priced and reliable long-term service to electricity customers. In response, the Association has developed detailed proposals for both long- and short-term solutions to the problems in these markets. For the long-term, APPA's Competitive Market Plan proposes to retain the RTO functions that are working well—principally those associated with planning for and operating the regional transmission grid—and replace or minimize those functions that are not benefiting consumers, mainly the design and operation of the capacity markets. The Association has also developed a policy proposal to more immediately address issues with capacity markets.[5]

Finally, APPA continues to support congressional oversight of FERC market policies including, but not limited to, the problems associated with capacity markets and lack of transparency in RTO dealings. Congress needs to delve into the intricacies of FERC policies to ensure fairness. Association staff have met with members of Congress and their staff regarding these

[4] "Five nuclear [1]power plants have retired in recent years, amounting to 4.7 gigawatts of capacity. Owners of nuclear power plants claim that reduced electricity prices in RTO-operated markets are a primary factor in lowering needed nuclear plant revenue and spurring retirements. Such price drops have resulted from decreases in the price of natural gas and growth of wind power, Because of these lower earnings, nuclear plant owners have sought to increase their revenues through state programs to direct additional revenue to the plants, such as recently passed legislation in Illinois and an order from the New York Public Service Commission; and for overall changes in the wholesale markets that would boost electricity rates."

[5] See APPA's issue brief, *RTO Capacity Markets and Their Impacts on Consumers and Public Power,* for more information.

issues and will continue to conduct such outreach to increase their understanding of RTO-related problems.

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A Description of the RTOs

There are seven RTOs operating in the U.S.: ISO New England (ISO-NE); New York ISO (NYISO); PJM Interconnection (PJM); Midcontinent ISO (MISO); California ISO (CAISO); Southwest Power Pool (SPP), and Electric Reliability Council of Texas (ERCOT). Of the seven only ERCOT, which operates entirely within the state, is not subject to FERC jurisdiction.

California ISO (CAISO)

CAISO operates only in California, but it is under FERC's jurisdiction because the state's transmission grid is interconnected with the rest of the West. Some public power utilities in the state have chosen not to turn over operational control of their transmission facilities to CAISO, but all public power utilities are impacted by CAISO's energy market prices and provision of transmission service due to the web of business relationships among market participants in the state. In October 2014, the ISO began operating an energy imbalance market (EIM) with PacifiCorp, which was joined by NV Energy in November 2015. The EIM is operated separately from CAISO markets. Several public power utilities are either exploring joining the EIM or planning to do so. The Balancing Authority of Northern California, the Sacramento Municipal Utility District, Seattle City Light, and the Salt River Project have announced their intent to join the EIM. PacifiCorp and the ISO have begun the process of possibly incorporating PacifiCorp into CAISO, most likely in early 2019, were it to come to fruition. CAISO does not operate a capacity market.

ISO-New England (ISO-NE)

ISO-NE operates in Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, and Connecticut. The region is facing numerous challenges from growing reliance on natural gas without a corresponding increase in natural gas pipeline capacity, retirements of nuclear and coal plants, and rising energy and capacity prices. Since the end of 2013, the ISO has implemented a Winter Reliability Program involving direct payments to oil and dual-fuel generators to increase oil inventories, for natural-gas-fired generators to contract for liquefied natural gas, and for new demand-response resources. ISO-NE operates a mandatory capacity market, called the forward capacity market (FCM), which procures capacity three years in advance.

Midcontinent ISO (MISO)

MISO operates in all or parts of Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, Ohio, Pennsylvania, South Dakota, Texas, Wisconsin, and Manitoba, Canada. MISO has seen both defections by transmission-owning utilities—First Energy and Duke left MISO to join PJM and a significant expansion of its territory to include what is known as "MISO South." Many industry observers believe the former MISO utilities that joined PJM did so to receive lucrative capacity market payments not available from MISO, while MISO's revisions to its capacity market was one of the incentives for the southern expansion. In 2012, FERC approved a voluntary locational capacity market for MISO, but ruled against mandatory participation or a minimum offer price rule in that market. MISO filed a proposal in 2016 to create a mandatory capacity auction in those regions where there is retail choice and the utilities are not responsible for supplying power to their customers, which was later rejected by FERC.

New York ISO (NYISO)

NYISO operates only in New York, but is FERC-jurisdictional because the state's transmission grid is interconnected with the rest of the region. New York City is a very transmission-constrained area within NYISO, which requires substantial mitigation of the power sales into that area. The ISO operates a shorter-term capacity market than in PJM and ISO-NE, but it is only mandatory within the New York City and Lower Hudson Valley zones.

PJM Interconnection

PJM operates in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM operates a three-year forward mandatory capacity market, called the reliability pricing model (RPM).

Southwest Power Pool

SPP operates in all or parts of Arkansas, Kansas, Louisiana, Mississippi, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. SPP has approached RTO formation and market development on a slower and more conservative track than many other RTOs. SPP transitioned to a full RTO with both a day-ahead and real-time market in March 2014, but has not implemented a capacity market.