UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators	Docket No. RM15-24-000

COMMENTS OF THE AMERICAN PUBLIC POWER ASSOCIATION AND THE NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION

The American Public Power Association ("APPA") and the National Rural Electric Cooperative Association ("NRECA") jointly submit these comments pursuant to the Notice of Proposed Rulemaking ("NOPR") issued in this docket.[1]

INTERESTS OF APPA AND NRECA

APPA is the national service organization representing the interests of not-for-profit, state, municipal, and other locally owned electric utilities throughout the United States. More than 2,000 public power systems provide over 15 percent of all kWh sales to ultimate customers, and serve over 48 million people, doing business in every state except Hawaii. Public power systems own approximately 10.6% of the total installed generating capacity in the United States. APPA utility members' primary goal is providing customers in the communities they serve with reliable electric power and energy at the lowest reasonable cost, consistent with good environmental stewardship. This orientation aligns the interests of APPA-member electric utilities with the long-term interests of the residents and businesses in their communities.

[1] 80 Fed. Reg. 58,393 (Sept. 29, 2015)

NRECA is the national service organization for more than 900 not-for-profit rural electric cooperatives and public power districts providing retail electric service to more than 42 million customers in 47 states. NRECA's members include consumer-owned local distribution systems and 65 generation and transmission ("G&T") cooperatives that supply wholesale power to their distribution cooperative owner-members. All or portions of 2,500 of the nation's 3,141 counties are served by rural electric cooperatives. Collectively, cooperative service areas cover 75 percent of the United States landmass and represent a significant segment of the energy industry. Cooperatives are incorporated as private entities in states in which they reside and have legal obligations to provide reliable electric service, at the lowest reasonable cost, to their customer members.

Together, APPA and NRECA represent utilities serving nearly 90 million electric customers in all 50 states. All of their respective members are publicly owned or not-for-profit load-serving entities whose purpose is to provide reliable service at the lowest reasonable cost. Their members participate in all of the organized wholesale electricity markets throughout the Nation, and APPA and NRECA have participated in all of the major Commission rulemakings and other proceedings in recent years implicating the rules governing price formation in these markets.

COMMUNICATIONS

Service should be made on, and communications directed to, these persons:

Randolph Elliott
Regulatory Counsel
American Public Power Association
2451 Crystal Drive, Suite 1000
Arlington, VA 22202
202-467-2952
relliott@publicpower.org

Elise Caplan
Manager, Electric Market Analysis
American Public Power Association
2451 Crystal Drive, Suite 1000
Arlington, VA 22202
202-467-2974
ecaplan@publicpower.org

Paul M. Breakman
FERC Counsel
National Rural Electric Cooperative Association
4301 Wilson Boulevard
Arlington, VA 22203
703-907-5844
paul.breakman@nreca.coop

Paul McCurley
Chief Engineer
National Rural Electric Cooperative Association
4301 Wilson Boulevard
Arlington, VA 22203
703-907-5867
paul.mccurley@nreca.coop

COMMENTS

I. Introduction and Summary

APPA and NRECA recommend that the Commission apply certain criteria and guidelines when considering taking action within the price-formation umbrella, consistent with our post-technical conference comments filed in Docket No. AD14-14-000 on March 6, 2015.[2] We urged then—and continue to urge now—that revisions to price formation "must promote efficiency gains for the benefit of consumers, not simply increased revenues for suppliers, and must ensure continued protection against the exercise of market power.… Most importantly, the Commission must ensure that the end result of any market rule changes will continue to produce just and reasonable rates for consumers."[3]

APPA and NRECA also continue to believe that the Commission must recognize the significant differences between the RTOs and "refrain at this time from pursuing a one-size-fits-all approach to reforming price formation rules in these markets."[4] Our

[2] Post-Technical Workshop Comments of the American Public Power Association and National Rural Electric Cooperative Association, Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators, Docket No. AD14-14-000 (Mar. 6, 2015) ("Price Formation Comments").

[3] *Id.* at 4.

[4] *Id.* at 5.

comments in this docket will therefore focus on the extent to which the reforms contained in the NOPR are likely to meet these criteria.

In the NOPR, the Commission proposes to require each RTO and ISO to reform its energy and ancillary service markets as follows:

- **Settlement interval proposal**: Settle energy transactions in the real-time markets at the same time interval as they dispatch energy, and settle operating reserves transactions in its real-time markets at same time interval as operating reserves are priced.

- **Shortage pricing proposal**: Trigger shortage pricing for any dispatch interval during which a shortage of energy or operating reserves occurs.

According to the NOPR, both of these proposals were developed to address "instances in which certain current RTO/ISO practices may fail to reflect the value of providing a given service, thereby distorting price signals and failing to provide appropriate signals for resources to respond to the actual operating needs of the market."[5]

II. Comments on Settlement Interval Proposal

APPA and NRECA appreciate the argument for using five-minute settlements as a means to provide more accurate pricing signals, but any directive requiring that the RTOs implement a five-minute settlement process should require vetting and approval by the RTOs' stakeholders.[6] The stakeholder vetting should ensure that appropriate market power mitigation measures are in place to address any unintended incentives for the exercise of market power that might result. In addition, the RTOs should assess the costs and benefits before proceeding with implementation, and also ensure that all market

[5] NOPR, P 3.

[6] Price Formation Comments at 38–39.

participants either have the necessary metering and billing systems in place or have sufficient time to add the required systems.

In theory, better price signals improve both static (short-run) efficiency and dynamic (long-run) efficiency. The NOPR focuses on the former, but indicates that there is a possible long-run benefit of encouraging the entry of new resources that can ramp up quickly to address shortages.[7] The NOPR's discussion of both types of efficiency, however, remains entirely theoretical and provides no evidence of (or even argument in favor of) the magnitude of short-run static efficiency gains or long-run dynamic efficiency gains that can be expected, if any, from real-world implementation by any of the RTOs.

APPA and NRECA also urge the Commission to limit any requirement for shorter settlement intervals to real-time markets. Short settlement intervals in the day-ahead market would add complexity, but would offer little or no benefit in pricing accuracy because of day-ahead uncertainties about market conditions.

III. Comments on Shortage Pricing Proposal

The NOPR proposes to require the RTOs to all adopt one common approach to shorting pricing triggers. This approach is contrary to APPA and NRECA's conclusion that shortage pricing is best left to the stakeholder process within the RTO.[8] Each RTO has different shortage pricing rules and different structures for other markets with which shortage pricing interacts, such as capacity markets. Moreover, the RTOs are all

[7] NOPR, P 35.

[8] Price Formation Comments at 45–46.

examining various levels of energy and ancillary services pricing reforms.[9] Seeking to apply the same approach to all RTOs ignores the fundamental differences among RTOs.

There is also the fundamental question of whether this proposal improves market efficiencies to such a degree that there are overall benefits to consumers. By expanding the potential trigger for a shortage pricing event, it is highly likely that the result of the shortage pricing proposal will be to produce a greater frequency of such events and a resulting increase in energy prices. Such an increase in prices therefore will need to be balanced against a demonstration of improvements to the energy markets benefiting consumers. We examine the potential benefits more carefully in the following section.

A. Determining the Benefits of the Shortage Pricing Proposal

The NOPR justifies both the pricing interval and shortage pricing proposals on the basis of sending "appropriate" price signals that reflect the "value" of resources responding to operating needs.[10] This "value," however, is only provided if there is a resulting change in the actions taken by resource owners. The benefit is thus largely determined by the magnitude and type of supply and demand response to the price signal.

As described in our Price Formation Comments, "the minimum duration of a shortage pricing event should be the minimum period required to prudently obtain adequate supply and demand response to alleviate the shortage conditions."[11] Not discussed in this NOPR is whether a five-minute shortage pricing event would produce a

[9] The Commission states in the "Order Directing Reports" issued on November 20, 2015 in the price-formation administrative proceeding (Docket No. AD14-14-000) that "a number of RTOs and ISOs have sufficient experience with these areas such that we may be able to discern best practices and understand unintended consequences." 153 FERC ¶ 61,221, at P 3 (2015).

[10] NOPR, PP 3–5, 8–9.

[11] Price Formation Comments at 46.

sufficient response or whether it would reflect a transient shortage that would be resolved with or without triggering shortage pricing. For example, at the workshop on scarcity and shortage pricing, offer mitigation, and offer caps on October 28, 2014, in Docket No. AD14-14-000, Adam Keech of the PJM Interconnection ("PJM") explained the reason that PJM requires a reserve shortage with a minimum duration of 30 minutes prior to triggering shortage pricing:

> [PJM doesn't] want to have large price excursions because a 30-minute start CT [Combustion Turbine] took an extra 5 minutes to come on-line. It would send out a price signal that the system is in some excruciated state when in reality a unit just took a couple more minutes to come online than it was expected.[12]

Indeed, the NOPR's shortage pricing proposal runs the risk of rewarding generators that are already on-line just because another generator has not fully ramped up yet.

A central focus of the NOPR is how the more frequent shortage pricing events will serve as incentives for suppliers. According to the NOPR:

> Implementing shortage pricing for any dispatch interval during which a shortage of energy or operating reserves occurs would provide an incentive for resources to ensure that they are available to respond to high prices, and avoid shortage pricing during subsequent dispatch intervals. This reform would also ensure that resources operating during a shortage are compensated for the value of the service that they provide, regardless of whether the shortage is short-lived.[13]

The Commission later provides additional support for this proposal from several of the comments:

> Arguments in favor of triggering shortage pricing for any shortage rely on the need to send price signals that *provide an incentive for resources to*

[12] Transcript, Workshop on Price Formation: Scarcity and Shortage Pricing, Offer Mitigation, and Offer Caps in RTO And ISO Markets, Docket No. AD14-14-000, at 48 (Oct. 28, 2014).

[13] NOPR, P 9.

> *offer their full flexibility and for market entry by reflecting actual system conditions in real time*.[14]

The Commission's argument is that more frequent shortage pricing will better reflect the value of resources that can mitigate the shortage, thus improving the "price signal" and providing a greater incentive for resources to come on-line or stay on-line to help mitigate the shortage. This is essentially a short-term benefit to the generators who are providing these services. In turn, if the resource owners respond to this price signal by improving their availability during shortage periods, then there is a potential benefit to overall reliability.

All of the RTOs have some form of shortage pricing, albeit with varying price levels and triggers, providing some real world data that can thus be examined. Available information indicates that three RTOs currently price all shortages, regardless of duration or cause: Midcontinent ISO ("MISO"), New York ISO ("NY ISO"), and ISO New England ("ISO NE").[15] But MISO and ISO NE use hourly prices, reducing the frequency of these shortages. As stated above, PJM requires a 30-minute duration of a reserve shortage prior to triggering shortage pricing, and the California Independent System Operator (CA ISO) prices shortages in advance when they are anticipated to occur.[16]

Shortage pricing may occur in different RTOs for different types of indicators. For example, in addition to known operating reserve shortages, shortage pricing also occurs in PJM when there is a voltage reduction action or a manual load dump action for

[14] NOPR, P 43 (emphasis added).

[15] Midcontinent Independent System Operator, Inc., Market Subcommittee Presentation, "FERC NOPR on *Shortage Pricing*," at 5 (Oct. 27, 2015).

[16] Staff Analysis of Shortage Pricing in RTO and ISO Markets, Docket No. AD14-14-000, at 17 (Oct. 2014).

a reserve zone or a reserve sub-zone, based on the rationale that such actions are other indications of reserve shortages.[17]

The NOPR however does not state to what degree the RTOs are already in compliance with the required change or the extent to which implementation of the shortage pricing proposal would impact the frequency of shortage pricing events or the resulting impact on prices, nor does it require the RTOs to undertake such an analysis.

As indicated by the reports from the RTOs, shortage pricing has been relatively infrequent regardless of the trigger and definition used. But there is still some variation in the frequency and magnitude of shortage pricing events.

For example, in PJM, shortage pricing was triggered on two days in 2014. One event was triggered by a voltage reduction and lasted about an hour and the other was a shortage of primary and synchronized reserves lasting about five hours in the morning, and 15-minutes in the evening. These two events equal to about .07 percent of all intervals and contributed to $0.10 or 0.2 percent of total real-time prices.[18]

Shortage pricing in MISO also occurred in very few pricing intervals in 2014 (fewer than 0.4 percent), but the total impact of shortage pricing was $2.12 or 5 percent of the total energy price.[19]

The NY ISO reports a much higher frequency of shortage pricing than PJM or MISO. Regulation shortages, the most frequent type, occurred in a little over 3,000 real-time pricing intervals (or 3 percent of the total) in 2014. Combined with the 0.2 percent

---

[17] Monitoring Analytics, State of the Market Report for PJM, January through September, at 147 (11/12/2015).

[18] Monitoring Analytics, 2014 State of the Market Report for PJM, Section 3 (3/12/2015).

[19] Potomac Economics, 2014 State of the Market Report for the MISO Electricity Markets (June 2015).

of intervals with an operating reserve shortage, shortage pricing produced a five to six percent increase in the real-time energy price in East New York.[20]

B. Short-Term Efficiency Improvements

The variations among the RTOs in shortage-pricing amounts, definitions, and triggers do provide an opportunity for an empirical analysis or at a minimum, some careful observations of the market outcomes. For example, do more frequent shortage events improve the availability or participation of fast-start resources participating in the markets? Conversely, are generators not staying on-line or not ramping up in RTOs with less frequent shortage pricing?

Logic dictates that were generators not staying on-line or not ramping up because of an absence of adequate shortage pricing triggers, one would actually expect to see a string of shortage pricing events in those RTOs. The Commission states this logic in the NOPR itself, as quoted above, concluding that improved responses to shortages can "avoid shortage pricing during subsequent dispatch intervals." Therefore, the extent to which shortage events are of short duration appears by itself to be one indicator that resources are already responding to these events.

The Commission should require the RTOs to provide evidence or to at least examine whether the theoretical benefits of the pricing proposal can be validated in actual resource decisions. Without such a determination, it is possible that increasing shortage pricing is simply paying additional revenue to generation owners that were on-line and cannot easily ramp up and down, instead of focusing incentives on resources that have more choice when determining whether to ramp up or down. Another concern is that the

[20] Potomac Economics, 2014 State of the Market Report for the New York ISO Markets (May 2015).

shortage pricing proposal may increase the earnings of financial entities that profit when there is greater price volatility and who do not contribute to upgrades on the system.

The Commission does not distinguish between supply and demand-side resources in its discussion in the NOPR. It appears unlikely that demand response (whether by retail consumers or their agents under Order No. 745 or by wholesale purchasers) would be able to respond to unpredictable transient price signals. But the same logic holds for demand response; whether the easing of shortage pricing triggers would promote additional demand response is another question to be determined.

C. Long-Term Pricing Incentives

The NOPR also mentions shortage pricing as possibly providing an incentive for market entry. Similarly, Potomac Economics states in its most recent assessment of ISO NE's electricity markets that one outcome of the increase in the Reserve Constraint Penalty Factors ("RCPFs") would be to increase "the incentives to *invest in new resources* with high availability."[21] Given that Potomac Economics also serves as the external market monitor for the NY ISO and MISO, such an opinion with regard to shortage pricing will likely be reflected in other market assessments.

There is no evidence that price signals as volatile and transient as shortage prices would be the basis for capital investments, whether to improve flexibility, to delay or avoid retirements or especially for the construction of new resources. Even where shortage pricing is more frequent, it is still highly volatile and unpredictable. Moreover, not all resources that can respond to a shortage will necessarily be dispatched during shortage pricing.

[21] Potomac Economics, 2014 Assessment of the ISO New England Electricity Markets, p. 32 (June 2015).

APPA recently analyzed the financial arrangements behind new generation capacity builds for 2014. Even with a slight uptick in merchant plant construction compared to prior years, 95 percent of the new construction was built under a contract or ownership. For new resources constructed in 2013, 98 percent was built with such arrangements. [22] Plants without purchased power agreements for the sale of the power still sought a financial hedge to guarantee a fixed revenue stream, for some multi-year period. Given this widespread interest in fixed revenue prior to making a capital investment, there is no factual basis for relying on a new shortage pricing construct to provide long-term incentives for resource planning and construction.

D. Alternatives to the Shortage Pricing Proposal

APPA and NRECA encourage the Commission to examine alternatives methods of achieving its stated goal of incentivizing the availability of resources during periods of shortage, and to ask whether such methods might achieve this goal at a lower cost to consumers. For example, in some RTOs, would separately-priced ramping products be a lower cost and therefore more efficient approach to achieving this goal? As noted in our Price Formation Comments:

> Paying for needed resource flexibility through a fast-ramping product pricing mechanism could better incent investment in such resources at a lower cost to consumers than simply paying all generators a windfall during infrequent scarcity conditions that trigger costly shortage pricing penalty mechanisms.[23]

[22] American Public Power Association, Power Plants Are Not Built on Spec: 2014 Update (Oct. 2014). The 2015 update is forthcoming.

[23] Price Formation Comments at 41.

E. Alignment of Shortage Pricing Triggers and Shortage Pricing Amounts

While the NOPR does not address the price level of the shortage pricing, to the extent that RTOs do change the shortage pricing triggers, the RTOs should also evaluate whether the shortage pricing levels are still just and reasonable. As Todd Ramey of MISO stated at the October 28 workshop in Docket No. AD14-14-000:

> The scarcity pricing during those events of short durations in time, in small shortages relative to your requirement, are deemed to have very low marginal value impacts to system reliability. So we have adjusted our curves to be reflective of that lower value.[24]

RTOs that move from longer to shorter durations of shortage pricing may need to re-evaluate whether the shortage price itself is in sync with the lower value of the shorter duration, and reform the pricing levels as needed.

F. Interaction and Overlap with Other Markets and Other Reform Proposals

Another factor in determining whether the shortage pricing proposal would improve market efficiency and benefit consumers is the extent to which there is an overlap between this proposal and other RTO market rules, especially considering the multiple changes that have occurred or are being considered to the RTO-operated capacity and energy markets. The difference among individual RTO market rules and therefore the potential for such interaction and overlap is also another argument for avoiding a one-size-fits-all approach to all RTOs.

For example, recent efforts to address capacity performance, rather than just the total megawatts of capacity, are aimed at similar goals as shortage pricing. As the Commission concluded in the June 9, 2015, order approving PJM's Capacity

[24] Tr. 43.

Performance proposal, "it is not enough simply to ensure that 'capacity,' whether in the form of existing or new resources, is procured to meet reserve targets; rather, that capacity must carry with it meaningful performance obligations, and *corresponding incentives and penalties, to ensure that those resources actually deliver when needed*."[25] Capacity performance rules are designed to reward resources to deliver when needed, while shortage pricing would reward resources that are in operation during shortage periods. Given that capacity is most needed during times when resources are constrained, these two market components have similar aims.

Some RTOs believe that scarcity pricing is an additional and separate revenue stream or can serve to reduce the reliance on capacity market revenues. For example, at the October 28 workshop, Robert Pike of the NY ISO stated that shortage pricing "is not going to replace the capacity market, but it certainly is a balance between how much money needs to be recovered in a capacity market and how much should be covered in an energy market."[26] The implication is that shortage pricing is only needed where capacity and energy revenues are insufficient. Yet there is no accounting for these multiple revenue streams to determine the extent to which individual generators are earning excess revenues beyond that which is needed to recover their costs and a reasonable return to shareholders.

ISO NE's market assessment finds that another benefit of increased RCPFs will be to reduce "the revenues required from the FCM [Forward Capacity Market] to satisfy the ISO's planning requirements."[27] Yet the FCM auctions for ISO NE increased from

---

[25] *PJM Interconnection, LLC*, 151 FERC ¶ 61,208, P 9 (2015) (emphasis added).

[26] Tr. 22.

[27] Potomac Economics, 2014 Assessment of the ISO New England Electricity Markets, p. 32 (June 2015).

an average of about $1 billion to $3 billion for the 2017/18 delivery year and $4 billion for the 2018/19 delivery year, with the second auction occurring after the increase in the RCPF.

Similarly, PJM's capacity performance rules increased payments to generators by $7.3 billion over a three-year time period.[28] If the PJM shortage pricing triggers were relaxed, this would not be accounted for in the capacity revenue which has already been committed to in these auctions.

Ongoing changes to the energy market may interact with the changes to the shortage pricing trigger. For example, PJM has proposed an increase in the offer cap to $2,000 per megawatt-hour for cost-based offers. PJM stated that the offer cap increase would likely entail a corresponding increase in the reserve penalty factors, but that it would address this change as part of this NOPR.[29] Were the total shortage pricing ceiling to be raised in addition to the offer cap, the potential revenue increase from this shortage pricing proposal would be magnified. When combined with the capacity performance revenues, the result could be an "incentive" that amounts to a flow of revenue way beyond any meaningful price signal.

G. Market Power

An increase in the frequency of shortage pricing will likely increase the incentives to exercise market power and game the rules due to the potential for higher energy and operating reserve prices above current offer caps that they afford. If the Commission moves forward with these changes, each RTO/ISO should be required to reevaluate its

---

[28] James F. Wilson, Wilson Energy Economics, PJM's "Capacity Performance" Tariff Changes: Estimated Impact on the Cost of Capacity (Oct. 2014)

[29] *PJM Interconnection LLC*, Docket ER16-676-000 (Oct.14, 2015) (filing to increase energy offer cap).

market power mitigation rules given the shortage pricing trigger change and propose new or additional mitigation measures, if necessary.

To the extent that shortages are too transient for an actual response by physical or demand-side resources, or are simply "false positives" based on mathematical artifacts, shortage events could exacerbate the potential exercise of market power or gaming. At the October 28 workshop, Jeffrey Nelson, speaking on behalf of Southern California Edison Company, stated with regard to price spikes in California: "They're transient. They're often extreme. And generally the only people that are able to capture this are virtual bidders because it's too late for the physical people to move. It's not physically signaling. It's just a financial."[30]

CONCLUSION

APPA and NRECA strongly recommend that settlement interval and shortage pricing changes be left to the RTO stakeholder processes, where other related market rules and other factors unique to each RTO can be carefully considered. If the Commission does not do so, then a more careful assessment is needed of whether the proposals will achieve discernible consumer benefits. Absent careful analysis, these proposals run the risk of increasing costs to consumers without achieving any market efficiencies.

An assessment of potential benefits should address whether shortage pricing would produce the desired short- and long-term behavior; whether other market rule changes might achieve that goal at lower cost; whether there are overlapping revenue streams aimed at the same goal; and whether the level of shortage prices themselves need

[30] Tr. 246.

to be rebalanced in light of the expanded trigger. Finally, the RTOs should examine whether the resulting volatility of prices would introduce opportunities for market power and if so, whether new mitigation measures are needed.

Respectfully submitted,

s/ Randolph Elliott
Randolph Elliott
Regulatory Counsel
Elise Caplan
Manager, Electric Market Analysis
American Public Power Association
2451 Crystal Drive, Suite 1000
Arlington, VA 22202
202-467-2900
relliott@publicpower.org
ecaplan@publicpower.org

s/ Paul M. Breakman
Paul M. Breakman
FERC Counsel
Paul McCurley
Chief Engineer
National Rural Electric Cooperative Association
4301 Wilson Boulevard
Arlington, VA 22203
703-907-5844
paul.breakman@nreca.coop
paul.mccurley@nreca.coop

November 30, 2015