

Auction (“BRA”) scheduled in May 2012 for the 2015-2016 Delivery Year. EPSC supports many of the elements of the PJM Refinements Filing, which provides improvements to the overall RPM design, and should be viewed favorably by the Commission. However, EPSC does protest and seek modification of several proposed changes as reflected in the comments below. Additionally, EPSC provides a statement of principles to highlight how industry and policymakers should focus on improving market design and rules to ensure a reliable power grid can deliver the full benefits of competition to the nation in the 21st century, including ensuring that regions with centralized capacity markets provide stable and sustainable price signals for capacity needed to meet resource adequacy requirements.

I. BACKGROUND

As part of the triennial review required by its Tariff, PJM proposes revisions to the Cost of New Entry (“CONE”), shape of the Variable Resource Requirement (“VRR”) Curve, and the Energy and Ancillary Services Revenue (“EAS”) Offset methodology. As part of the required performance assessment, PJM proposes elimination of the “hold-back” against the minimum requirements for two resource categories, i.e., Annual and Extended Summer Resources. PJM proposes that these and other changes reflected in the filing become effective on January 31, 2012, because they affect key parameters that will govern the next BRA and that PJM is required to post by February 1, 2012. Additionally, PJM commits to further develop in the stakeholder process a

voluntary, non-discriminatory, long-term auction to supplement RPM, with a proposed tariff filing by August 2012.

II. COMMENTS AND LIMITED PROTEST

EPSA and its members have been vocal advocates for the benefits that properly structured forward capacity markets can provide (in the regions where such capacity market mechanisms have been established), including RPM, with the recognition that market design and rules can and should be improved as necessary based on changes in the market. EPSA's members have been active participants in the extensive stakeholder process leading to development of the RPM Refinements Filing, and other related PJM stakeholder efforts.

Further, EPSA supports The Brattle Report's primary finding that "RPM is working well."⁴ Importantly, the key findings include, among other things:

- RPM has been successful in attracting and retaining cost-effective capacity sufficient to meet resource adequacy requirements in the RTO and in all Locational Deliverability Areas ("LDAs"), in spite of environmental and other challenges faced by suppliers.
- Since implementation of RPM, a total of 28,400 MW of installed capacity from new resources has been committed, representing additions of 11,800 MW of demand side resources, 6,900 MW of increased imports and decreased exports, and 4,800 MW of new generation.
- In all LDAs, net resource additions have been more than sufficient to meet reliability requirements.
- RPM has greatly facilitated competition among various types of capacity resources, attracting commitments from new generation and new DR resources, retaining existing generation, and supporting the upgrade of existing plants at prices below the cost of new generation.
- Competition in RPM has allowed owners of aging coal plants to make more informed decisions about whether to invest in environmental retrofits or start planning to retire the units, particularly in the most recent auction for the 2014-2015 Delivery Year.

⁴ The Brattle Report, Executive Summary at i.

- BRA prices have been consistent with the supply and demand for capacity, with prices volatile due to market fundamentals, but below Net CONE after the transition period, reflecting that new generation was not needed to maintain resource adequacy given the availability of lower-cost alternatives.⁵

In addition to these generally positive findings, the Report makes a number of recommendations and identifies several performance risks stemming from the RPM design that should be addressed to ensure that resource adequacy will be met going forward, many of which are incorporated in the RPM Refinements Filing, including with respect to treatment of the EAS Offset, the 2.5% “hold-back” provision and consideration of the voluntary long-term auction process that will be the focus of a further stakeholder process. EPISA offers the following comments on these issues, as well as the calculation of the RTO region-wide Net CONE value, as they are of particular importance to members.

A. 2.5% “Holdback” Provision

With respect to the 2.5 % Short-term Resource Procurement Target (“STRPT” or “hold-back”) provision, EPISA appreciates and supports the progress reflected in the RPM Refinements Filing on this issue, but protests this aspect of the RPM Refinements Filing as the Commission should direct PJM to fully eliminate the 2.5% hold-back provision. EPISA submits that under-procuring required capacity is not good market design, results in inefficient price signals and artificial price suppression, and ultimately threatens reliability.

Specifically, PJM proposes in the filing to retain the hold-back that defers resource procurement for a portion of the overall load from the BRA to the

⁵ Id., Executive Summary at ii-iv.

Incremental Auctions. However, PJM proposes to eliminate the current application of the 2.5% hold-back to the separate minimum procurement requirements for two (new) distinct resource categories, i.e., Annual Resources and Extended Summer Resources.⁶ This change is based on The Brattle Report and PJM's analysis of the May 2011 BRA, where these three resource categories and their associated minimum procurement targets went into effect for the first time.⁷ Specifically, the analysis identified certain unintended consequences under application of the hold-back to the two new resource categories, including that “[t]he result of this approach is that the [short-term resource procurement target] quantity held back is Annual capacity, which means the resources procured in the incremental auctions for the 2014/15 Delivery Year will be primarily for Annual capacity.”⁸ The RPM Refinements Filing states that the changes in the filing will correct this unintended effect – noting the perverse signals created by the current design, as most Annual Resources overwhelmingly consist of generation resources that plan and participate in RPM

⁶ PJM Refinements Filing at 3.

⁷ “The STRPT was introduced into RPM beginning with the 2012/2013 Delivery Year (“DY”) and “holds back” 2.5 % of the total reliability requirement targeted for procurement in the BRA to allow Demand Resources that may be unable to commit as capacity three years before the DY an opportunity to commit in an Incremental Auction closer to the DY....Earlier this year, the Commission approved PJM’s proposal to establish two new types of Demand Resource products...PJM also modified its Tariff at this time to apply the full STRPT to both the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement. In other words, just as PJM reduces its overall resource procurement target in the BRA by the amount of the holdback, and then seeks to recover that quantity in the IAs, the new rules direct PJM to reduce in the BRA the minimum quantities of these two new resource types that it will seek to procure, and then seek to recover the remainder of those minimum quantities in the IAs.” See RPM Refinements Filing, Affidavit of Dr. Paul M. Sotkiewicz at P 18 and P 20, Attachment C.

⁸ The Brattle Report at 143.

on a forward basis. The RPM Refinements Filing also maintains the “set-aside” for Limited Demand Resources to participate in the Incremental Auctions, and according to the filing, preserves the hold-back’s purpose of ensuring commitment opportunities closer to the Delivery Year for short lead time resources, as well as preserving flexibility for all types of Demand Resources to participate in the BRA.⁹

Of particular concern to EPSC is The Brattle Report finding that the 2.5 % hold-back of procurement of “these higher-quality [Annual and Extended Summer] resources could suppress prices.” Brattle states,

Eliminating STRPT for Annual Resources, which consist mostly of generation resources, will also add a safeguard to reduce the risk of resource adequacy challenges in the face of retirement pressures on existing coal plants from new EPA regulations. The full procurement of Annual Resources will reduce the risk that existing resources do not clear due to artificially suppressed BRA prices, which could lead to inefficient retirements of resources that may not be replaceable in the short term.¹⁰

PJM agrees with Brattle that the effect of the changes approved earlier this year focuses the hold-back on Annual Resources, few of which are the short-term resources that were the intended focus of this provision. Significantly, PJM also agrees with Brattle that,

[H]olding back Annual Resources from the BRA under the market power mitigation conditions applicable to the vast majority of Annual Resources makes it likely that the hold-back leads to inefficient price distortions and price suppression, and that it is especially important at this time to send correct price signals to generation resources that may be considering their

⁹ PJM Refinements Filing at 24-25.

¹⁰ The Brattle Report at 147.

retirement options in light of forthcoming EPA regulations affecting the industry.¹¹

Given the emerging issues related to compliance with Environmental Protection Agency regulations, and the Commission's current focus on addressing any associated reliability concerns that may be identified, EPSA submits the problems with the 2.5% hold-back highlighted by The Brattle Report should not be dismissed.

As an interim compromise measure, EPSA supports the PJM proposal to eliminate the hold-back for the two distinct resource categories and views this as a step in the right direction. However, EPSA members have raised concerns since the inception of the *overall* 2.5% holdback provision regarding the threat to reliability of under procuring capacity needed for each annual BRA. Both Brattle and PJM point to the very concerns – artificial price suppression, inefficient price signals, and uncertainty – that EPSA members have raised as concerns with utilization of the hold-back provision generally. EPSA asserts that the Commission should require PJM to fully eliminate the 2.5% hold-back provision from RPM on a going forward basis. As highlighted in The Brattle Report, there has been a significant increase in the participation of demand resources in RPM, which exacerbates problems with application of the hold-back to overall load. Importantly, the PJM Independent Market Monitor (“IMM”) has also strongly opposed this provision and in the analysis of the May 2010 BRA recommended

¹¹ PJM Refinements Filing at 28, also see n. 73.

“that the use of the 2.5 percent demand adjustment [] be terminated immediately.”¹² The IMM further stated,

...The logic of reducing demand in a market design that looks three years forward, to permit other resources to clear in incremental auctions, is not supportable. There are tradeoffs in using a one year forward or a three year forward design, but the design should be implemented on a consistent basis. Removing a portion of demand affects prices at the margin, which is where the critical signal to the market is determined. In the 2013/2014 BRA, the result was to reduce prices in the eastern part of PJM and to reduce the quantity of capacity purchased in the eastern part of PJM. The result was also to significantly reduce the clearing price for the RTO market, affecting substantial MW of capacity and reducing total payments to capacity by a significant amount.¹³

Accordingly, EPSA requests that as a necessary next step to ensure that the proper amount of capacity needed to ensure reliability is procured on an annual basis as required for each BRA, the Commission direct PJM to eliminate the 2.5 % holdback provision in its entirety as applied to overall load in the annual BRAs.

B. Calculation of RTO Region-wide Net CONE Value

A number of updates or changes are proposed by PJM related to the Net CONE value. The Net CONE value is a key input for every locational delivery area (“LDA”) and the RTO region as a whole. In particular, the Net CONE value for the RTO region must be representative of the entire PJM footprint.¹⁴ PJM

¹² *Analysis of the 2013/2014 RPM Base Residual Auction Revised and Updated at 2*, Monitoring Analytics, The Independent Market Monitor for PJM, September 20, 2010. Available at: http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2013_2014_RPM_Base_Residual_Auction_20090920.pdf

¹³ Id. at 23.

¹⁴ RPM Refinements Filing at 14.

has proposed a significant change to this methodology, despite the fact that The Brattle Report did not recommend a change to the existing practice for setting Net CONE, which was to take the lowest gross CONE value among the various CONE areas for the Reference Resource (a GE 7FA simple cycle turbine with selective catalytic reduction technology), and subtract system-side average LMPs for the energy portion of the EAS offset. The only change that PJM recommended that would have an effect on this practice was the change from an EAS calculation that considered only real-time prices to one that considered both day-ahead and real-time prices. However, without significant discussion of this issue in the stakeholder process, PJM proposes in the RPM Refinements Filing to adopt the Package 13 approach of setting Net CONE for the PJM Region (i.e., the so-called RTO Region) equal to the median of the Net CONE values calculated for the five CONE areas. Based on publicly available information, this likely would result in Net CONE for the RTO region being set by the Net CONE for Eastern MAAC (composed of AECO, DPL, JCPL, PECO, PSEG, RECO), and may well change over time depending upon changes in regional energy prices. Notably, PJM's tariff changes include one Gross CONE value that does not assume the costs of nitrogen oxide ("NOx") control technology (i.e., in the Dominion Zone or CONE Area 5), despite the fact that NOx control technology is required in most of the RTO footprint, with the exception of the Dominion zone. In the future, to the extent that the RPM auction clears as a single RTO region, the height of the VRR Curve for units in MAAC and Eastern MAAC that have stringent environmental requirements could be negatively impacted if the Net

CONE value is based on the cost of new entry for a unit without NOx controls as proposed in the Dominion Zone. Similarly, under PJM's proposal, the EAS Offset subtracted from Gross CONE will be based on a single zone, despite the fact that Locational Marginal Prices ("LMPs") diverge widely between the Eastern and Western portions of the PJM footprint and can be quite volatile if based on a single CONE area.¹⁵ The proposal contained in the RPM Refinements Filing is simply not good market design and PJM has done little to demonstrate that its proposal is just and reasonable.

EPSA has concerns regarding adoption of this approach as part of the RPM Refinements Filing and asserts that further analysis and support is required. EPSA requests that the Commission require PJM to continue to utilize its current approach with the modification related to calculation of the EAS Offset discussed below.

C. EAS Offset Methodology Change

EPSA strongly supports the proposed revision to the Energy and Ancillary Services ("EAS") Offset Methodology to reflect commitment of the Reference Resource in the Day-ahead Energy Market to the extent economic on a Peak-Hour dispatch basis.¹⁶ This issue was discussed by stakeholders both in the context of the minimum offer price rule ("MOPR") and the VRR Curve, and is supported by The Brattle Report which pointed out that "the peak-hour dispatch

¹⁵ See Motion to Intervene and Comments and Limited Protest of the PJM Power Providers Group, Testimony of Roy J. Shanker, Ph.D. (Commenting on the RTO Net Cone element of the PJM RPM Refinements Filing) (Docket No. ER12-513-000) (filed December 22, 2011).

¹⁶ RPM Refinements Filing at 16-17.

methodology only uses real-time prices, which is not consistent with the fact that the majority [of] revenues are obtained through day-ahead commitments, even for [combustion turbine generating plants].”¹⁷ Among other things, Brattle recommended the “dispatch logic should attempt to replicate realistic participation in both the day-ahead and real-time energy markets.”¹⁸ Specifically, PJM is revising the Peak-Hour Dispatch definition in the Tariff to provide that the Reference Resource will be committed first in the Day-ahead Energy Market if economic on a peak-hour basis. To the extent not committed in the Day-ahead Energy Market, the Reference Resource will be dispatched in the Real-time Energy Market if economic on a peak-hour basis.¹⁹

EPSA believes this revision more appropriately reflects actual unit commitment of capacity resources, which have a must-offer obligation in the day-ahead energy market. In addition, such methodology will capture price divergence between the Day-Ahead and Real-Time Energy Market prices, which has occurred historically and may do so more frequently once PJM’s Order No. 719 shortage pricing regime is in place.²⁰

¹⁷ The Brattle Report at 88.

¹⁸ Id.

¹⁹ RPM Refinements Filing at 17.

²⁰ PJM’s Shortage Pricing proposal in Docket No. ER09-1063-004, filed to comply with the directives of Order No. 719, remains pending after almost 18 months. PJM previously determined that its currently effective scarcity pricing rules do not conform with the requirements of Order No. 719, and explained that its current design is inflexible, lacks transparency, and yielded “unintuitive” pricing that fails to reflect true operating constraints as PJM goes into shortage conditions. The PJM Shortage Pricing proposal, with certain limited modifications, would facilitate implementation of a more transparent price signal under peak conditions that

D. Long-Term Voluntary Auction Process

Finally, as an outgrowth of stakeholder discussions surrounding the current New Entry Price Adjustment (“NEPA”) provision, PJM commits in the RPM Refinements Filing to file on or by August 1, 2012, under FPA section 205,

[A]s determined necessary by PJM following a stakeholder process, tariff changes to establish a long-term auction process as a not unduly discriminatory means to provide adequate long-term revenue assurances to support new entry, as a supplement to or replacement of this New Entry Price Adjustment.²¹

This proposed timing would allow for implementation before the May 2013 BRA. While details remain subject to further development, PJM indicates that the voluntary, long-term auction would be held in advance of each annual BRA.²² Notably, The Brattle Report supports in concept the PJM effort “to add centralized but voluntary auctions for long-term capacity products as a supplement to the three-year forward base auctions (e.g., for a duration of 3, 5 and 7 years starting with the BRA delivery year)” as a means to increase forward price transparency and facilitate bilateral long-term contracting.²³

EPSA has long been an advocate of transparent and competitive procurement processes open to all types of resources (existing and new). Therefore, EPSA supports in concept the stakeholder process to consider and

would allow resources of all types to respond more efficiently and, consequently, improve reliability.

²¹ RPM Refinements Filing at 31.

²² RPM Refinements Filing at 31. (“Such an auction would precede the BRA...”)

²³ The Brattle Report, Executive Summary at viii.

develop the important tariff details surrounding implementation of a supplemental and voluntary, long-term auction process administered by PJM. In that spirit, EPSA offers its recently issued policy paper entitled *Principles to Power America, Competitive Market Evolution: The next decade of progress* to address the importance of organized competitive markets and their design (see attachment).²⁴ Among the principles highlighted are a number of centralized capacity market improvements that are relevant for consideration by PJM and its stakeholders, and should be supported by the Commission, as EPSA and its members, as well as other stakeholders, are exploring ways to ensure these markets provide sufficient, accurate market signals to ensure reliability.

²⁴ “Principles to Power America – Competitive Market Evolution: The next decade of progress,” published by the Electric Power Supply Association, October 24, 2011. Available at: http://www.epsa.org/forms/uploadFiles/1F33E0000017.filename.EPSA_RTOISO_MARKET_PRINCIPLES_FINAL_OCT_11.pdf

III. CONCLUSION

Wherefore, EPSA respectfully requests that the Commission consider the limited protest and comments herein in rendering its decision in this proceeding.

Respectfully submitted,



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Dated: December 22, 2011

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the comments via email upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C., December 22, 2011.



Nancy Bagot, VP Regulatory Affairs

ATTACHMENT A



Principles to Power America

*Competitive Market Evolution:
The next decade of progress*



Electric Power Supply Association
*Advocating the **power** of competition*

Organized wholesale power markets already serve over two-thirds of the country and continue to expand. They work well, and deliver benefits for consumers, but can and should be improved.



FOREWORD

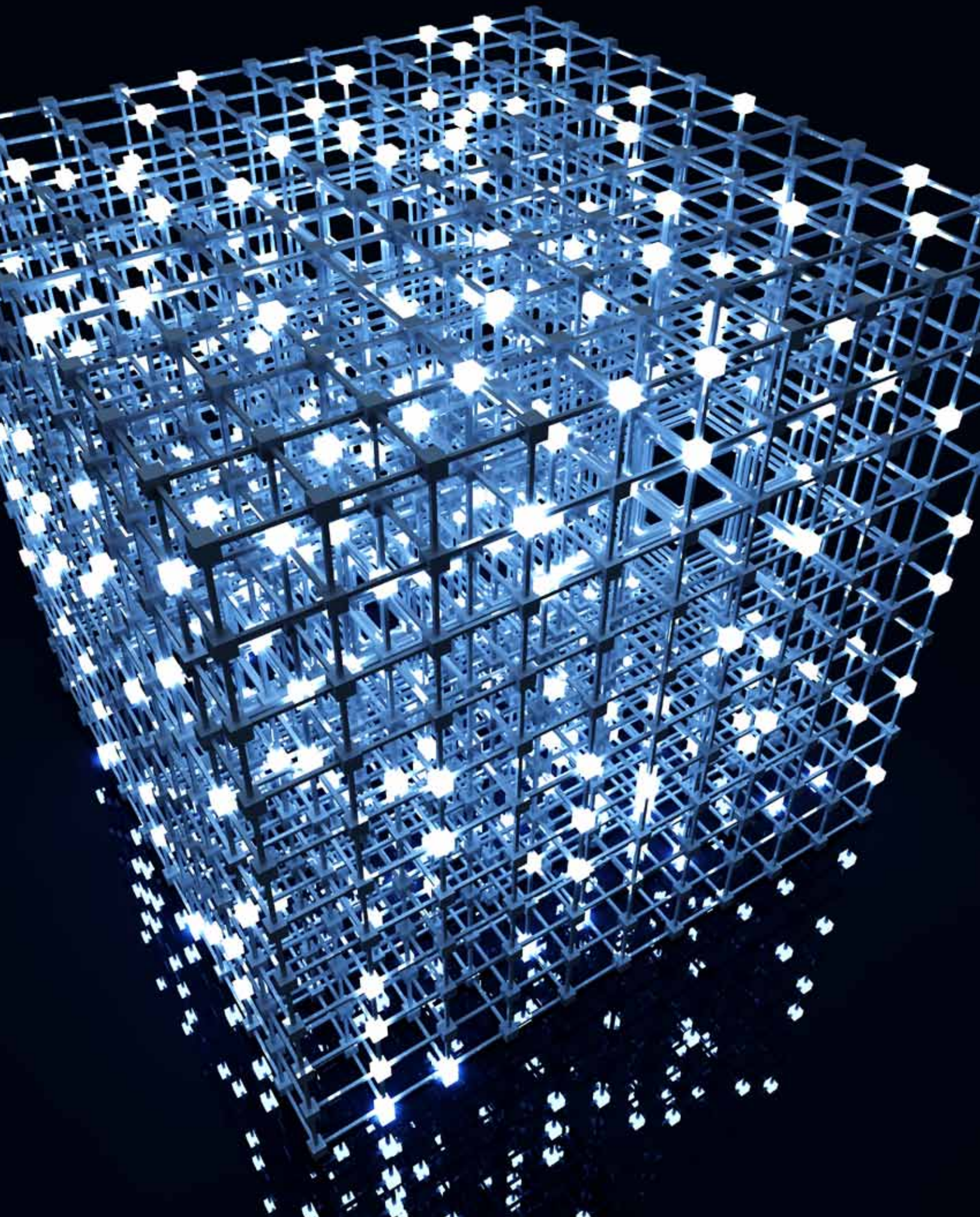
Since its inception the Electric Power Supply Association's core mission has been to harness the power of competitive electricity markets. EPSA members operate in the various types of wholesale electricity markets that exist nationwide. Having competitive markets benefits consumers in every part of the country.

This paper focuses on those wholesale electricity markets administered by Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) that have evolved over nearly two decades and today serve more than two-thirds of the country. Independent operation of the transmission grid and administration of various regional markets for electricity products and services continue to produce valuable benefits for consumers, the economy and the environment.

The design of these markets and the rules under which they operate are critical to their success. The next several years will be challenging for the entire electricity sector. Substantial investments will be required to bring our nation's power generation infrastructure forward to continue serving consumers efficiently, cleanly and reliably. Competition puts private investments to work to help meet these and other energy imperatives.

As the national trade association representing leaders of the competitive power sector, EPSA developed these principles as a framework for a continued dialogue with policymakers and other stakeholders to help spur necessary action. The focus is on how market design and rules should continue to evolve in organized markets in order to realize the full benefits of competition in the time frame the nation requires to succeed in the 21st century.

John E. Shelk
President and CEO
Electric Power Supply Association



INTRODUCTION

Congress and the Federal Energy Regulatory Commission (FERC) promote competitive wholesale power markets, and states restructured retail electricity markets, for good and sound reasons that resonate today and going forward. Organized wholesale power markets already serve over two-thirds of the country and continue to expand.

Consumers have reaped significant benefits from competitive electricity markets, including greater transparency, major innovation through new technologies, more efficient operation of existing facilities, efficient price risk management, and the shift of much of the infrastructure development risk to investors. Competition, both wholesale and retail, will continue to bring these and other benefits to consumers but market designs and rules can and should be improved consistent with sound competitive principles.

A key decade is underway for policymakers, the wholesale power supply sector (both generators and marketers) and consumers. This presents

the opportunity to take a step back and examine market design and rules on file with FERC and relevant state regulatory practices and how they can best be improved within the construct of competitive markets that continue to deliver long-term consumer benefits.

From EPSA's perspective, the organized markets under existing wholesale market designs and rules are working, broadly speaking, but they can and should be improved. Poorly designed markets and rules can produce economically inefficient outcomes that increase costs for consumers. Notably, there are no "deregulated" markets. Instead, the focus should be on the degree to which wholesale power markets are well regulated consistent with these principles.

Investment in existing and new power supply resources can and should continue to be made on a competitive basis by competitive suppliers reacting to market prices and revenues. This requires durable market designs and rules that

allow economic fundamentals to set prices and revenues consistent with the long term nature of power generation investments.

The question is what changes to current market designs and rules are needed to "get prices right" so that organized markets consistently reflect economic supply/demand fundamentals. While flawed market design and rules could artificially lower prices for a short time, doing so would undercut the critical price signals and revenue streams needed for longer term investments for reliability. Market sustainability is at risk if FERC-approved market design and rules allow prices and revenues to persist below or exceed competitive levels.

As improvements are made on particular elements it is important for there to be a period of relative regulatory stability so that market participants and their investors can rely on the enhanced market design and rules when making significant investment decisions.

ORGANIZED MARKET DESIGN PRINCIPLES

Competitive power suppliers provide energy, capacity and ancillary services to organized wholesale power markets to reliably and efficiently serve consumers. Each RTO/ISO has its own particular approach to how to design their markets for these services. EPSA offers these principles as a framework to guide further policymaker deliberations about important issues on organized market design and market rules.

1. *Consumer Benefits from Organized Markets*
2. *Open Competition Among Supply Resources*
3. *Competitive Market Price Signals*
4. *Centralized Capacity Market Improvements*
5. *Proper Role for Demand Response*
6. *Ancillary Services Pricing*
7. *Market Mitigation in Perspective*

The comments contained in this statement of principles represent the position of EPSA as an organization, but not necessarily the views of any particular member with respect to any issue.

1. Consumer Benefits from Organized Markets

Market design and rules should first and foremost result in consumers benefiting from competitive prices for the resources necessary to reliably serve them over the long term within applicable legal, policy and operational constraints (e.g., environmental and reliability rules). In other words, “the best deal for consumers” is not literally just “least cost” at any given point in time regardless of the full range of consequences for such a capital intensive industry. Market design and rules need to support development and maintenance of reliable and economically sustainable competitive wholesale power markets that match the long-term nature of power sector investments.





2. Open Competition Among Supply Resources

Market design and rules should facilitate competitively-determined, economically rational investment decisions as to existing and new supply resources. For example, market design and rules must not discriminate between supply resources on the basis of plant vintage or fuel type. This principle applies to and conditions the rest of these principles. Market rules should not seek to make all fuels and technologies economically neutral; rather market rules should be neutral to let the inherent economics of various competing options govern.



4. Centralized Capacity Market Improvements

While having the capacity to reliably serve peak consumer demand for electricity is important in each organized market, the RTOs/ISOs differ on how to do so. Some organized markets are “energy only” without a separate capacity market mechanism. Others rely primarily or entirely on bilateral contracts. Several RTOs/ISOs have implemented centralized capacity markets to compensate for overly mitigated energy markets among other concerns in their regions where bilateral contracts also continue to play an important role. The following comments apply to RTO/ISO regions with a centralized capacity market:

Centralized capacity markets should provide stable and sustainable price signals for capacity needed to satisfy reserve margins. Capacity market prices should be competitive; prices should be neither artificially suppressed nor artificially inflated. This can be achieved going forward by considering each of a series of issues, including lengthening the time period for price signals from centralized capacity markets, minimizing regulatory price volatility, and factors impacting the availability of bilateral capacity contracts.

- a) Policymakers and stakeholders should explore options for a longer term centralized capacity market price signal than provided under existing market designs and rules. It is important that this be done on a non-discriminatory basis.** Providing price signals for at least some amount of capacity up to 5 to 10 years in advance of a given year is worth exploring to allow suppliers the option of participating in capacity product mechanisms that would acquire various amounts of capacity over multiple time periods. There are trade-offs involved for consumers and suppliers that will have to be understood.
- b) Policymakers and stakeholders should explore why capacity prices are volatile.** Regulatory volatility stems from changes to rules and creates major risks that make it a challenge to finance investments in existing and new facilities that support cost-effective reliable service. Policymakers should examine how to reduce regulatory volatility to help permit centralized capacity markets to have greater liquidity and more consistent, predictable forward prices. Specific examples of issues to address include a less steep demand curve, the quantity of capacity to be procured, how reserve margins are set, when planning parameters are released in relation to the auction date, and the negative impact of subsidized demand response. A goal should be to better align capacity acquisition and transmission planning time frames.
- c) Policymakers and stakeholders should determine whether impediments exist under current rules to longer term mutually agreeable bilateral capacity arrangements.** The lack of adequate transparency as to key economic drivers appears to be the major impediment to such bilateral contracts.
- d) Policymakers and stakeholders should continue to pursue market designs and rules that prevent the exercise of market power through subsidized capacity resources, including those fostered by state mandates.** State actions can impact the integrity of the wholesale capacity markets, which are exclusively regulated by FERC. State mandates that procure or encourage the development of new capacity in amounts that exceed what is necessary to meet reliability requirements are problematic. They artificially over supply regional capacity even beyond the excess already built into reserve margins. Some states are taking actions for the express purpose (or at least with the effect) of artificially suppressing centralized

capacity market prices. Federal and state policies should allow market-based solutions to find the most cost effective ways to be sure the right amount of capacity is in place when and where necessary for reliability. Failure to do so will frustrate the efficiencies associated with regional markets and the economic and reliability benefits of organized wholesale markets. If this occurs, the centralized market for capacity will not be based on competition between the most cost-effective resources but will instead be driven by the state that offers the most subsidies. This is not the foundation for a well-functioning market.

- e) **Policymakers and stakeholders should explore the extent to which market rules for capacity and energy are properly coordinated to promote economically rational investment decisions.** This includes how and the extent to which the three principal revenue streams from energy, capacity, and ancillary services markets are linked and coordinated to ensure an overall competitive outcome. If not done properly, competitive suppliers will not see accurate price signals and revenues sufficient for long term investment decisions.

- f) **Policymakers and stakeholders should explore existing market rules to make sure that their cumulative impact has not overly mitigated capacity market outcomes below competitive results consistent with long term investments.** Centralized capacity markets were developed in response to the unique feature of reserve margins needed in electricity markets to reliably meet load needs and because of energy market price and other caps. As centralized capacity markets have evolved, new issues have arisen in part as a result of attempts to formally and informally impose “price caps” on capacity market outcomes.

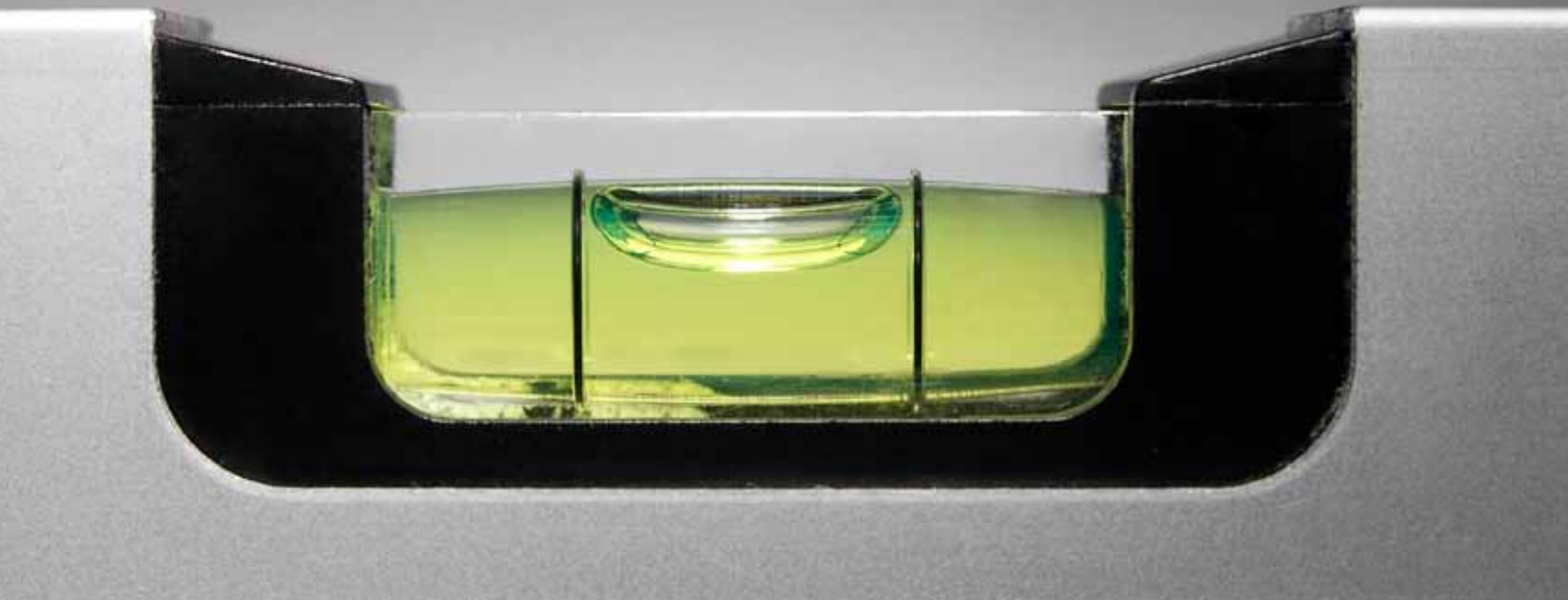
5. Proper Role for Demand Response

FERC has issued a final rule on demand response (DR) compensation in wholesale energy markets. EPSA and other trade associations have challenged FERC's jurisdiction to do so. DR market rules should result in an economically rational role for DR, not the subsidized, discriminatory role envisioned in the final rule. If, as is the case under the final rule, DR is not compensated properly consistent with the Federal Power Act, and thus adversely impacts supply resources, then no matter what other market design and rules are improved, organized markets will not produce sustainable, competitive results consistent with long term investment needs.

DR should have the same performance obligations as generation if it is to receive the same level of compensation as generation. It must provide the same level of availability, longevity, flexibility and contribution to resource adequacy as generation. Thus, for example, DR should be required to bid in to the day-ahead market and face penalties equivalent to generation facilities.

Because of the saturation level that DR has reached in certain markets it is critical that it be subject to rigorous measurement and verification tests, performance obligations and market rules. There should not be a lower threshold for DR to comply with market rules (e.g., must offer obligations and being dispatchable) than for other resources. Such market rules should define actual DR apart from conventional energy efficiency, energy conservation and "behind the meter" (or "off the grid") power generation.



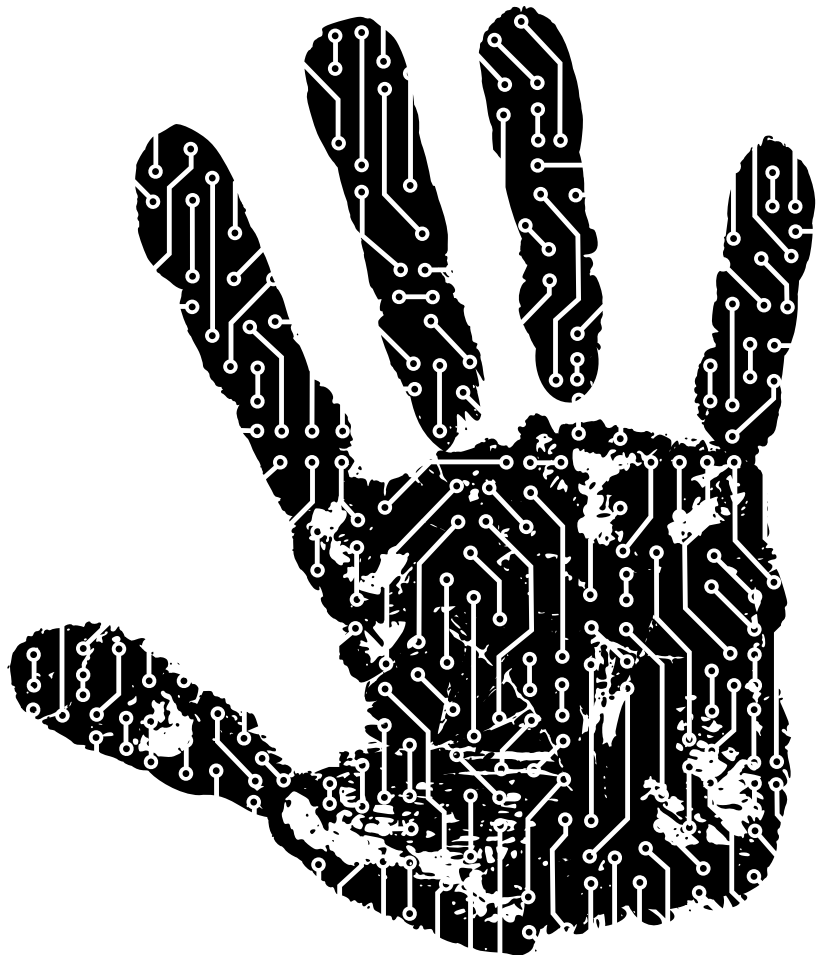


6. Ancillary Services Pricing

Ancillary services keep the grid reliable on a minute-by-minute basis. Market rules for ancillary services should reflect the flexible operational attributes and economics of the particular types of resources that can provide necessary ancillary services. These services will become an increasingly important market element as increased use of intermittent resources stress the system and result in a greater need for fast start and ramping capabilities. Market rules must send accurate competitive price signals for flexible reliable ancillary services products, including new investment, if those same services are to be available in the amounts needed as wholesale markets integrate more intermittent and non-traditional resources.

7. Market Mitigation in Perspective

The organized wholesale power markets include market rules designed to produce competitive outcomes, including price mitigation rules in energy, capacity and ancillary services markets. Market mitigation of suppliers must be approached cautiously, as over-mitigated markets distort price signals thus reducing liquidity and discouraging economically rational decisions about investments in existing and new resources. As FERC makes changes in some rules or adopts new ones in the name of achieving competitive results, FERC should pay close attention to whether such additional steps are in fact necessary based on empirical data and analysis of market results. FERC should also implement expanded use of competitively-based energy market price signals that truly reflect supply and demand during times of high demand to best allocate resources.





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