UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Reliability and Resilience Pricing	**)**	**Docket No. RM18-1-000**

INITIAL COMMENTS OF PJM INTERCONNECTION, L.L.C. ON THE UNITED STATES DEPARTMENT OF ENERGY PROPOSED RULE

Craig Glazer
Vice President – Federal Government Policy
PJM Interconnection, L.L.C.
1200 G Street, NW, Suite 600
Washington, DC 20005
(202) 423-4743 (phone)
(202) 393-7741(fax)
Craig.Glazer@pjm.com

Jennifer Tribulski
Associate General Counsel
PJM Interconnection, L.L.C.
2750 Monroe Boulevard
Audubon, PA 19403
(610) 666-4363 (phone)
Jennifer.Tribulski@pjm.com

Counsel for PJM Interconnection, L.L.C

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Table of Contents

I. INTRODUCTION 1

II. COMMENTS 5

A. The DOE NOPR Incorrectly Identifies a Perceived Problem and Its Cause, and Seeks to Impose a Remedy That Is Not Supported by the Reliability and Resilience Concerns the DOE NOPR Claims to Address 5

1. *The Facts and Sources Cited by the DOE NOPR Do Not Support Its Findings or Proposal* 5

2. *The PJM Region Is Reliable, and PJM's Competitive Markets Have Been Instrumental in Helping Ensure that Reliability* 14

3. *The DOE NOPR Ignores Efforts Underway to Address Resilience through Markets* 18

4. *The DOE NOPR Provides No Basis for Singling Out RTO Markets, Much Less RTOs with Capacity Markets* 20

B. The DOE NOPR Fundamentally Undermines Competitive Markets 27

C. The DOE NOPR's Many Legal Infirmities Preclude Its Adoption 28

1. *The DOE NOPR Contradicts Congressionally Endorsed Reliance on Competitive Wholesale Electricity Markets* 28

2. *The DOE's Proposal to Guarantee Eligible Resources' Recovery of All Costs Plus a Return Is Contrary to Law* 31

3. *The DOE NOPR Proposes an Unlawful, Arbitrary and Undue Preference for Eligible Resources* 32

4. *The Commission's Comment Deadlines Do Not Provide the Meaningful Opportunity to Comment Required by the Administrative Procedure Act* 34

III. ALTHOUGH THE LACK OF BASIS FOR THE DOE NOPR AND THE ILLEGAL REFORMS IT PROPOSES SUPPORT NOT IMPLEMENTING THE PROPOSAL, PJM BELIEVES THE AUGUST DOE REPORT APPROPRIATELY HIGHLIGHTED A PROBLEM PJM IS FACING WITH PRICE FORMATION THAT SHOULD BE ADDRESSED THROUGH

REFORMS TO BE SUBMITTED TO THE COMMISISON WITHIN A COMMISSION-DIRECTED TIME FRAME 36

A. The Need for Targeted Consideration of This Change in the PJM Region 36

1. *PJM Has Observed and Adapted to Significant Market Changes in Recent Years..36*

2. *The Problems PJM Is Experiencing as a Result of Such Changes Can Be Addressed Through Price Formation Reforms in PJM 39*

B. PJM Is Providing This Framework for Price Formation Reforms that It Believes Are Needed for the PJM Region in the Near Term.....................43

1. *Marginal Cost Pricing and the Convex Condition* 43

a. *Current LMP Method*...44

b. *Extended LMP Method* 45

2. *Shortage Pricing* 47

C. PJM Suggests a Focused Commission Process 48

IV. CONCLUSION...49

Appendix A
PJM's Answers to Staff Questions

Appendix B
Letter to Mr. Stu Bresler, Sr. Vice President Operations & Markets

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PJM Interconnection, L.L.C. ("PJM") hereby submits its initial comments on the Notice of Proposed Rulemaking submitted to the Commission by the Secretary of the United States. Department of Energy ("DOE") on September 28, 2017, as revised upon publication in the Federal Register on October 10, 2017 ("DOE NOPR").[1] To assist the Commission's evaluation of the DOE NOPR, PJM also responds, in Appendix A to these comments, to the questions posed in the Commission's October 4, 2017 request for information relevant to the DOE NOPR.

I. INTRODUCTION

As shown in these Comments, the DOE NOPR is well wide of the mark both in its statement of the problem it seeks to address and in its identification of a reasonable remedy. Accordingly, PJM believes that a prudent path for the Commission should include: (a) re-focusing from the DOE NOPR's broad-brush concern with changes in the resource mix to a deeper, more meaningful, and more productive consideration of how resource mix changes are affecting each individual Regional Transmission Organization

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[1] The Secretary proposed the rule pursuant to section 403 of the Department of Energy Organization Act, 42 U.S.C. § 7173. *See* Grid Resiliency Pricing Rule, 82 Fed. Reg. 46,940 (proposed Oct. 10, 2017). The Commission noticed the proposed rule on October 2, 2017, seeking initial comments by October 23, 2017, and reply comments by November 7, 2017. *See Grid Reliability and Resilience Pricing*, Notice Inviting Comments, Docket No. RM18-1-000 (Oct. 2, 2017).

("RTO") markets, operations, and reliability and (b) directing the submission of regional solutions, as needed, subject to a filing deadline, that are more in line with the actual history and experience of each RTO given its particular resource mix, and operational and reliability needs. Through these comments, PJM will demonstrate:

- The lack of support, both legally and factually, for the DOE NOPR's identification of the stated problem;
- The legal and factual infirmities associated with the DOE's proposed cost of service remedy;
- How the problem identified by the DOE can be restated to more accurately reflect price formation issues that are in line with historic RTO experience; and
- An alternative path promising solutions that allow for regional flexibility while responding to the direction called for in the DOE Staff's August 2017 Report[2] to examine correct price formation in organized electricity markets.

Accordingly, PJM urges the Commission to find that the DOE NOPR, although referencing certain legitimate findings made in the DOE Staff Report, does not correctly state the problem nor propose a reasonable solution that meets the just and reasonable standard under the Federal Power Act ("FPA").[3] As shown in these Comments, the DOE NOPR takes observations about overall changes in the resource mix across the nation as the basis for a sweeping and unsupported conclusion that, solely in regions with capacity and energy markets, certain units, regardless of their location, performance history, or competitiveness, deserve full cost recovery through out-of-market mechanisms.

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[2] *Staff Report to the Secretary on Electricity Markets and Reliability*, U.S. Department of Energy (Aug. 17, 2017) ("DOE Staff Report").

[3] 16 U.S.C. § 824e.

Specifically, the DOE NOPR:

- Is inconsistent with very recent findings and recommendations published by the DOE on the subjects of fuel security, grid resilience and RTO market price formation;
- Does not meet basic standards of reasoned decision-making—the claimed facts do not lead to the proposed remedy;
- Contradicts the plain fact that reliability generally has been well-served in regions with capacity and energy markets;
- Would represent a radical departure from years of Commission approval of single-clearing price markets;
- Would undermine reliability and lead to substantially higher costs and economic inefficiencies;
- Contradicts Congressional endorsement of the Commission's increased reliance on competitive markets;
- Intrudes on state resource choices, include choices to rely on RTO-administered competitive markets;
- Creates distortions in investment decisions that will exacerbate seams issues and actually harm rather than enhance system reliability;
- Attempts to impose blanket, guaranteed cost recovery for numerous resources in a manner flatly contradictory to long-standing, fundamental rate-making requirements under the FPA; and
- Violates the FPA's prohibition on undue discrimination.

Given coal-fired and nuclear generators comprise just over fifty percent of all currently installed generation capacity in the PJM region,[4] if the DOE NOPR were adopted, it would remove half of all the capacity in the PJM region from the discipline of competitive market forces. Even accepting the nature and degree of the DOE's concerns,

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[4] *See* PJM Interconnection, L.L.C., http://www.pjm.com/~/media/markets-ops/ops-analysis/capacity-by-fuel-type-2016.ashx (last visited Oct. 27, 2017) (showing nuclear and coal as a combined 53% of the resource mix).

its NOPR fails to consider the most obvious alternative. Assuming there is a shortcoming in capacity and energy markets, the *first* response should be to fix such a shortcoming, which is to say, evaluate structural market changes that better define and value resources' operational and reliability attributes *within the market rather than upending market principles in their entirety*.

As noted above, PJM believes a better identification of the underlying concern, as well as PJM's proposed procedural pathway, is far more appropriate given the legal and practical infirmities of the DOE NOPR as proposed. For its part, PJM has seen changes in the workings of its market traceable to resource mix changes and other industry changes over recent periods. Those observed changes raise clear concerns about market price formation under current rules, including treatment of fast-start resources, recognition of inflexible resources in clearing prices, shortage pricing, and resource characteristics and attributes that currently are not, but should be, identified and valued in the market. In these Comments, PJM describes those observed impacts, and clearly shows the concerns those impacts raise.

In section III herein, PJM explains why reforms are needed in PJM now to ensure that (i) the cost of serving load is reflected in LMP to the fullest extent possible, (ii) uplift is reduced, and (iii) proper economic incentives are maintained. Enhanced energy market price signals will strengthen performance incentives in PJM's markets and is in line with other reforms being considered by PJM. The Commission should act now to ensure that essential reliability services that resources provide are maintained. PJM understands not all regions face the same need for action. An extensive record has been developed to date in this area in the Commission's price formation proceedings, as confirmed by the August

DOE Report. Thus, to move forward, the Commission should direct each RTO/ISO to identify for the Commission whether changes in the resource mix has created issues in their respective regions that are currently not addressed in the market. If any issues exist, the RTO/ISO should prioritize the issues of most consequence to that region and provide, within a Commission-specified deadline that is in the near term, for the submission of proposals, if necessary.[5] In the alternative, the Commission could expand the scope of its existing open price formation NOPRs to provide for regional solutions around the issues it has broadly identified in those dockets.

II. COMMENTS

A. The DOE NOPR Incorrectly Identifies a Perceived Problem and Its Cause, and Seeks to Impose a Remedy That Is Not Supported by the Reliability and Resilience Concerns the DOE NOPR Claims to Address

The DOE NOPR misidentifies a problem, misstates the cause, and then proposes a radical solution that is antithetical to clear Congressional and Commission policy in favor of promoting competitive energy markets. The DOE NOPR assumes without support that there is a resilience crisis that is urgently unfolding because coal and nuclear units are retiring, that market prices are to blame, and that the only solution is to incentivize those coal and nuclear units to remain in service by providing them with guaranteed cost of service rate recovery regardless of whether they are needed for resilience or actually provide measurable resilience benefits. The DOE NOPR does this to the detriment of competitive markets.

[5] The Commission could require that, to the extent an ISO/RTO identifies no changes are necessary for its region, the ISO/RTO would be required to submit a report to the Commission within that time frame, in place of a tariff proposal.

Given its scope and applicability, the DOE NOPR is a transparent attack on those RTOs and ISOs that operate capacity markets generally[6]—and possibly PJM specifically[7]—without any showing that the misidentified problem exists in PJM or those other markets and exists exclusively in those markets. While claiming to address an imminent threat to the "resilience" of the electric grid from looming retirement of so-called "fuel-secure" baseload resources, the DOE NOPR fails to demonstrate that any such threat is imminent, that retirements are to blame, that competitive markets and specifically capacity markets are forcing retirements that would not have otherwise occurred, or that its proposed solution will actually address the perceived problem. The DOE NOPR's compensation mandate is wholly unjustified and the Commission should reject it.

The DOE NOPR conflates resilience with reliability. The DOE NOPR does not explain how maintaining a 90-day supply of fuel will enable quick restoration of service following a catastrophic grid event, which is a cornerstone concept of resilience. Instead, the proposal seeks to keep coal and nuclear units online all the time as baseload resources, indicating the DOE NOPR's concern is reliability, not resilience. The DOE NOPR proposes to maintain otherwise uneconomic coal and nuclear units by affording them cost of service rate recovery, enabling them to offer into the markets at unrealistically low prices, clear, and operate continuously as "baseload." While secure fuel and a robust resource mix contribute to both reliability and resilience, the DOE

[6] As the publication of the DOE NOPR in the Federal Register makes plain, *capacity markets* are the sole target of the DOE NOPR's mandates. *See* DOE NOPR at 46,944.

[7] Notably, PJM is the only RTO mentioned in the DOE NOPR.

NOPR fails to show that acquiring 90 days' worth of fuel, and rewarding those units that are able to do so, is necessary to ensure either reliability or resilience.

In fact, the DOE NOPR provides no definition of resilience at all, and further fails by neglecting to identify any performance standards or metrics to evaluate the resilience characteristics, effectiveness, and performance of various resource types. In place of such standards, the DOE NOPR establishes blanket eligibility for any resource that participates in competitive energy markets outside of retail cost of service rate regulation, satisfies an arbitrary 90-day fuel supply requirement, and satisfies other minimum characteristics, regardless of whether the resource is needed to provide reliability or resilience services to the grid.

In short, the DOE NOPR's identification of the perceived problem is not correct, and its proposed imposition of cost of service pricing will not only fail to fix the perceived problem but will have severe adverse effects on competitive markets that the Commission and RTOs like PJM have labored for decades to develop.

1. The Facts and Sources Cited by the DOE NOPR Do Not Support Its Findings or Proposal

Rather than attempting to offer concrete evidence of a looming resilience crisis caused by mass retirement of coal and nuclear units that can only be fixed by destroying competitive markets, the DOE NOPR relies on hollow assertions that the resilience of the nation's electric grid is imminently threatened by premature retirement of so-called fuel-secure baseload resources[8] and self-evident observations like winter is coming.[9] The DOE NOPR provides no justification for imposing onto competitive energy markets a

[8] DOE NOPR at 46,941.

[9] DOE NOPR at 46,945 (urging the Commission to "take action before the winter heating season begins").

large new out-of-market cost burden for certain select generation resources, and certainly no compelling explanation of why such action is urgently needed to stave off an imminent crisis.

The thin reed upon which the DOE NOPR's call for urgency and its proposed remedy is built is the notion that generation resource retirements are occurring and unusual weather events have presented challenges to grid operators in the past few years. Specifically, the DOE NOPR cites select discussion from the January 2017 Quadrennial Energy Review[10] and the recent DOE Staff Report regarding recent and anticipated future retirements of coal and nuclear units and weather anomalies such as the 2014 Polar Vortex.[11] None of these sources, however, support the DOE NOPR's radical replacement of competitive markets with federal cost of service ratemaking for certain favored generators. And in fact, PJM's system remained reliable despite nearly 14,000 MW of coal retirements in the recent past due in part to changing environmental rules. The unusually high unforced outage rate during the Polar Vortex has been mitigated—as can be seen in Figure 1—through various measures, including PJM's Capacity Performance reforms and steps it has taken for winter preparedness, discussed herein and in PJM's responses to OEPI's questions in Appendix A hereto.

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[10] Quadrennial Energy Review, *Transforming the Nation's Electricity System: the Second Installment of the Quadrennial Energy Review*, Department of Energy (Jan. 2017), https://energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20(Full%20Report).pdf.

[11] DOE NOPR at 46,942.

Figure 1: Weighted-Average EFORd Projected for DY

The drop in Weighted Average EFORd projected for 2021 is due to:

- Large amount of deactivations with high EFORd (7,150 MW with 14.56% Weighted Average EFORd)
- Large amount of additions with low EFORd (16,980 MW with 4.42% Weighted Average EFORd). Additions include only those queue projects that had executed an ISA by April 17, 2017.

The DOE NOPR appears to blame competitive market pricing and rules as the sole or primary impetus for retirement of coal and nuclear units. However, the DOE NOPR paints an incomplete picture of the findings and conclusions on which it relies. Notably, the DOE Staff Report identifies many factors contributing to retirements, including, among other things, the age of the plants in question,[12] state public policy

[12] *E.g.*, DOE Staff Report at 22 ("The age of coal plants is an important factor . . . . [T]he *vast majority* of coal-fired capacity was built before 1990, with the average of the fleet built in the mid to late 1970s.") (emphasis added); *id.* ("According to the Congressional Research Service, the service life of coal-fired generators reportedly 'averages between 35 and 50 years . . . .'" (quoting Richard J. Campbell, *Increasing the Efficiency of Existing Coal-Fired Power Plants*, Congressional Research Service, 6 (Dec. 20, 2013), https://fas.org/sgp/crs/misc/R43343.pdf)); DOE Staff Report at 21 ("Most coal-fired capacity (88%) was built between 1950 and 1990, and the capacity-weighted average age of operating coal facilities is 39 years." (citing Scott Jell, *Most Coal Plants in the United States Were Built Before 1990*, Energy

decisions,[13] federal environmental requirements,[14] and more cost-effective alternative fuels.[15] While the DOE NOPR also suggests that the retirements it identifies are "premature,"[16] it provides no analysis of whether such retirements truly have occurred prior to the end of the useful lifecycle of the resources in question, further eroding evidentiary support for the DOE NOPR's costly compensation mandate. While RTOs are examining whether market price formation rules could be revised to recognize the reliability and resilience values brought by a diversity of resource types,[17] the DOE Staff Report provides no evidentiary basis to conclude that market prices are the sole or even primary cause of coal and nuclear retirements. Subsidizing such favored units will not

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Information Administration (Apr. 17, 2017), https://www.eia.gov/todayinenergy/detail.php?id=30812)); DOE Staff Report at 23 ("Retired plants are older than the remaining fleet. The coal units that retired in 2015 were mainly built between 1950 and 1970, and the average age of those retired units was 54 years.").

[13] *E.g.*, DOE Staff Report at 16 ("Some of the nuclear units now closing are doing so because of state pressure (as with California's Diablo Canyon, New Jersey's Oyster Creek, and New York's Indian Point) . . . .")

[14] *E.g.*, DOE Staff Report at 17 ("Figure 3.3 shows that a significant amount of capacity (the highest on record) retired in 2015, *coinciding with the [Mercury and Air Toxics Standards ("MATS")] compliance deadline*, which applied to coal- and oil-fired units across the country, as well as the finalization of the *Clean Power Plan rule*.") (emphasis added); *id.* at 19 ("The compliance deadline for MATS converged with tightening pollution limits in sulfur dioxide (SO_2) and nitrogen oxide (NO_x) trading programs. *Many of the coal and oil retirements in this period were plants whose owners chose to shut down a plant rather than invest in costly environmental remediation measures*.") (emphasis added); *id.* at 24 ("Most of the power plants being closed today were built in the 1940s to 1960s, *before the Clean Air Act was passed in 1970.* Many have minimal air pollution controls . . . . Many closures coincided with the MATS deadlines in 2015 and 2016 . . . " (emphasis added) (quoting Ed Malley, *Coal Power Plant Post-Retirement Options*, POWER (Sept. 1, 2016), http://www.powermag.com/coal-power-plant-post-retirement-options/)).

[15] *E.g.*, DOE Staff Report at 24 ("The increase in natural gas generation since 2005 is primarily a result of the continued cost-competitiveness of natural gas relative to coal." (quoting Augustine Kwon, *Natural Gas Generation Make Up the Largest Share of Overall U.S. Generation Capacity*, Energy Information Administration (Apr. 20, 2017), https://www.eia.gov/todayinenergy/detail.php?id=30872)).

[16] *See, e.g.*, DOE NOPR at 46,941 ("The resiliency of the nation's electric grid is threatened by the *premature retirements* of power plants . . . .") (emphasis added).

[17] *See infra* Section A(3).

ward off other externalities that the DOE's own staff has identified as contributing to plant retirements.

Similarly, the 2017 QER Report provides no basis to conclude that there is an imminent resilience emergency that can best be solved by distorting competitive markets through imposition of cost of service rate recovery for coal and nuclear resources. Quite the contrary, in its recommendations on "Grid Operations and Planning for Electricity System Reliability, Security and Resilience," the 2017 QER Report recommends such initiatives as (among others): (1) providing incentives for energy storage; (2) improving data for grid security and resilience; (3) requiring states to consider the value of distributed energy resources; (4) enhancing coordination among the industry; (5) encouraging cost effective use of advanced technologies that improve transmission operations; and (6) improving data, monitoring, and analysis capabilities.[18] Absent from the 2017 QER Report's list of resilience recommendations is anything resembling the DOE NOPR's proposal to subsidize aging and inefficient generation units to the detriment of competitive markets.

Likewise mischaracterized and misconstrued are the recent extreme weather events upon which the DOE NOPR relies. Contrary to the DOE NOPR, neither the 2014 Polar Vortex nor the recent hurricanes justify upending existing competitive energy markets. Indeed, as the DOE Staff Report acknowledges, during the Polar Vortex, "[m]any coal plants could not operate due to conveyor belts and coal piles freezing."[19]

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[18] 2017 QER Report at S-25–S-26.

[19] DOE Staff Report at 98. The DOE Staff Report also concluded that "[w]hile coal facilities typically store enough fuel onsite to last for 30 days or more, extreme cold can lead to frozen fuel stockpiles and disruption in train deliveries." *Id.* at 11-12.

While fuel delivery was an issue during the Polar Vortex, it was not the driving factor behind outages that occurred during the extreme weather event, nor was gas-fired generation the villain, nor coal and nuclear the savior, that the DOE NOPR suggests them to be. Specifically, during the Polar Vortex, of the approximately 40,200 MW of forced generator outages in PJM, coal steam outages (considering all sources of failure) were the largest outage category, at 13,700 MW (representing 34% of the outages), and nuclear outages totaled 1,400 MW.[20] Having a 90-day fuel supply would not have cured these outages, for it was not a lack of fuel that caused them. Additionally, as PJM has explained, all resource types, except for wind and demand response, performed sub optimally during the extreme weather event:

> At the time of the peak demand hour on January 7, approximately 22 percent of total installed generation capacity in PJM (of all fuel types) was unavailable because of forced outages associated with routine equipment breakdowns, *problems related to operating in extreme cold temperatures* and, fuel-supply issues. Although there has been much focus on gas issues associated with interruptible transportation, *overall the gas interruptions were not the major driver of the high forced outage rates* experienced in the PJM region. *Natural gas interruptions, although significant, removed less than five percent of the total capacity* required to meet demand on January 7, *while equipment issues associated with both coal and natural gas units made up the far greater proportion of forced outages*.[21]

Notwithstanding these significant challenges, as the DOE Staff Report explains, PJM and other "grid operators generally met demand, even under these severe conditions."[22] Fuel

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[20] *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events*, PJM Interconnection, L.L.C., 26 (May 8, 2014), http://www.pjm.com/~/media/library/reports-notices/weather-related/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx.

[21] Post-Technical Conference Comments of PJM Interconnection, L.L.C., Docket No. AD14-8-000, at Appendix 1 (Statement of Michael J. Kormos Executive Vice President – Operations, PJM Interconnection, L.L.C. at 3-4) (May 15, 2014) ("Kormos Statement") (*emphasis added*).

[22] DOE Staff Report at 98.

supply was not the sole or even primary issue affecting grid operations during the Polar Vortex, and compensating *all* qualified "fuel-secure" generators for maintaining a 90-day fuel supply would not have made a significant difference in addressing the impacts of the Polar Vortex.

Likewise, the DOE NOPR's reliance on Superstorm Sandy and recent hurricanes also fails to justify its radical cost of service subsidy scheme. As an initial matter, in high wind events like hurricanes, it is often the distribution and, to a lesser degree, transmission system that are most impacted. For example, as NERC notes in its assessment of Superstorm Sandy, 16,738 MW of fossil fuel generation became unavailable during the storm, which "did not result in any capacity issues," "[b]ecause of the amount of load preemptively *off or unavailable to the distribution system*."[23] NERC also noted that "[w]hile there was sufficient generation capacity available to meet the load as restoration progressed, there were some cases where customer restoration was hindered by *local area transmission outages*."[24] In other words, even though generating power was available to serve customers, power line damage prevented it from being delivered to many customers experiencing service outages. Having 90 days' worth of fuel onsite does nothing to counteract the impact of distribution or transmission infrastructure damage that is often the cause of customer service outages during a hurricane or similar event.

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[23] *Hurricane Sandy Event Analysis Report*, NERC, 22 (Jan. 2014), http://www.nerc.com/pa/rrm/ea/Oct2012HurricanSandyEvntAnlyssRprtDL/Hurricane_Sandy_EAR_20140312_Final.pdf ("NERC Hurricane Sandy Report") (emphasis added).

[24] *Hurricane Sandy Event Analysis Report*, NERC, 22 (Jan. 2014) at 5 (emphasis added).

The evidence and events that the DOE NOPR cites do not support its assertion of a resilience crisis or its rationale for degrading competitive markets in the name of fuel resilience. As experience during extreme weather events has shown, myriad factors contribute to outages, and fuel security, while beneficial, provides no guarantee of resilience during such events. Given the paucity of evidence to support its expensive and anticompetitive cost of service guarantee, the DOE NOPR appears aimed less at truly addressing resilience concerns and more at benefitting certain preferred generators and fuels and the industries they support.

2. The PJM Region Is Reliable, and PJM's Competitive Markets Have Been Instrumental in Helping Ensure that Reliability.

As explained above, the DOE NOPR offers nothing to show that market regions in general, or the PJM Region in particular, is in any danger of failing to meet reliability or resource adequacy requirements now or in the future. This is not surprising, as the PJM Region unquestionably is reliable, and its competitive markets have for years secured commitments from capacity resources that well exceed the target reserve margin established to meet NERC requirements. And the PJM capacity market also includes rigorous performance requirements, enforced by market mechanisms—which were affirmed just this year by a U.S. Court of Appeals.[25]

First, contrary to suggestions that the DOE NOPR changes are needed to "keep[] the lights on,"[26] PJM's capacity market has consistently secured Capacity Resources above and beyond the level needed to meet the NERC standard of no more than one

[25] *Advanced Energy Mgmt. All. v. FERC*, 860 F.3d 656 (D.C. Cir. 2017).

[26] *Department of Energy Missions and Management Priorities Before the H. Comm. On Energy and Commerce Subcomm. On Energy*, 115th Cong. 3 (2017) (testimony of Secretary Rick Perry, U.S. Department of Energy).

expected loss-of-load event every ten years. For the next three Delivery Years (extending through May 31, 2021), the Base Residual Auctions resulted in reserve margins of 19.8% (2018/2019 DY), 22.4% (2019/2020 DY), and 23.3 % (2020/2021 DY).[27] These reserve margins are about four to six percentage points above the level needed to meet the NERC loss-of-load-expectation criteria.[28] These auctions also have elicited significant investments in new generation, at competitive costs generally below administrative estimates of the cost of new entry.[29] Notably, the capacity committed to the PJM Region through 2021 (and entitled to receive capacity revenues for at least that long) include coal and nuclear plants (of all ages) in megawatt amounts that rival or exceed the capacity base for those two plant types seen in any other region in the continental U.S.[30]

Second, even looking past aggregate resource commitments to consider reliability of the resource mix, PJM's initial rigorous analysis of that issue earlier this year[31] yielded encouraging results, and found no immediate (or even near-term) emergencies.[32] PJM assessed future likely and plausible generation resource mix portfolios on their ability to provide certain essential reliability services, including frequency response, voltage control, ramp, fuel assurance, flexibility, black start, environmental restrictions, and

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[27] *2020/2021 PJM Base Residual Auction Results*, PJM Interconnection, L.L.C., 6 tbl. 1 (May 23, 2017), http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2020-2021-base-residual-auction-report.ashx?la=en.

[28] *Id.*

[29] *Id.*

[30] *See* Figure 3 below, and the cited EIA source data (which shows PJM had installed coal and nuclear plant capacity at year-end 2015 in excess of 100,000 MWs).

[31] *See* PJM's Evolving Resource Mix and System Reliability (March 30, 2017), available at http://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx ("Evolving Resource Mix and Reliability Report").

[32] *Id.* at 4-5.

equivalent availability factor.[33] PJM also tested those possible future portfolios using both a standard loss-of-load analysis, and an adjusted analysis that accounted for the potential added load-loss risk of heavy reliance on intermittent resources. PJM found that "the expected near-term resource portfolio is among the highest-performing portfolios and is well-equipped to provide the generator reliability attributes."[34] That expected near-term portfolio is for 2021, taking account of trends in generator deactivation and added capacity from the PJM Generator Interconnection Queues.[35] More work and analysis needs to be done in this area, as discussed later in these comments, but the analysis to date strongly indicates that market mechanisms *can effectively meet* the challenges posed by a changing resource mix.

Third, the DOE NOPR ignores the PJM competitive markets' demonstrated strength as a platform for innovation and adaptation. Competitive markets are very good at quickly recognizing and rewarding efficiency gains. That inherent strength is itself an important advantage to maintaining a resource base that leverages technological change to help ensure long-term reliability. Competitive markets, therefore, have seen markedly higher development and implementation (compared to non-market areas) of highly efficient, latest generation combined cycle plants, new storage technologies, and demand response.[36] At the same time, competitive markets have not been conducive to high-risk, high-capital-cost, experimental technologies—which, more often than not, have produced

[33] *Id.* at 3.

[34] *Id.* at 4 (footnote omitted).

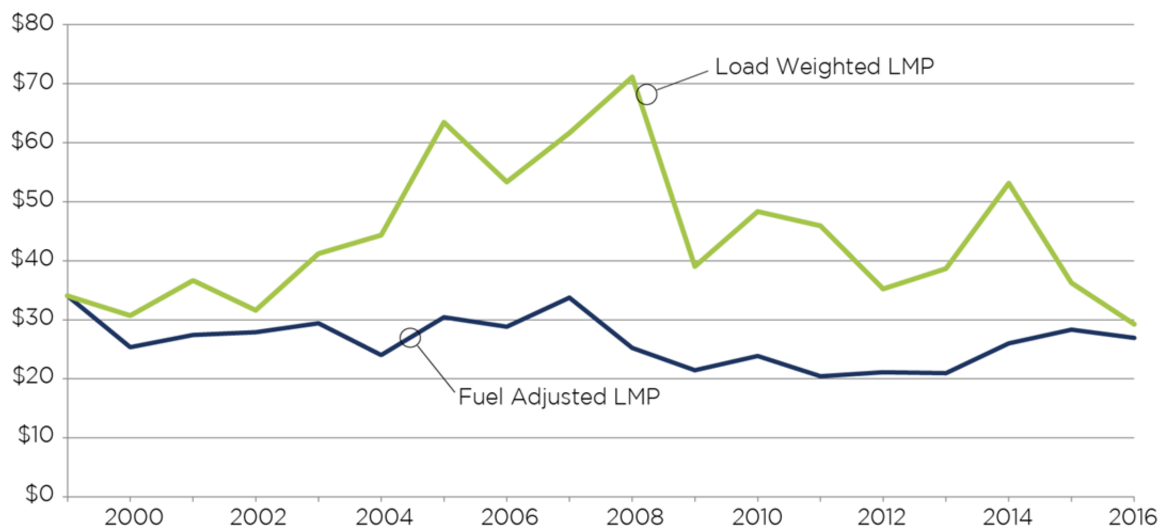
[35] *Id.* at 4 n.9.

[36] *Resource Investment in Competitive Markets*, PJM Interconnection, L.L.C., (May 5, 2016), http://www.pjm.com/~/media/library/reports-notices/special-reports/20160505-resource-investment-in-competitive-markets-paper.ashx ("PJM 2016 Resource Investment Whitepaper").

far more cost than benefit for ratepayers in the regulated areas where such projects have been pursued.[37]

Indeed, the market is able to handle changes in technologies and shifts in resource mix in a manner that resulted in lower energy market Locational Marginal Prices ("LMPs") (Figure 2). As can be seen, load-weighted LMPs peaked in 2008. Since that time, the factors discussed above (particularly the reduction in price, and increase in availability, of natural gas) have resulted in a drop of over 50% in load-weighted LMPs. By contrast, the fuel-adjusted LMP (which seeks to factor out differences in fuel cost), has changed relatively little—revealing that the observed drop in load-weighted LMP has indeed been largely driven by fuel cost changes.

Figure 2. Annual Fuel-Adjusted and Load-Weighted LMP (1999-2016)



Furthermore, for roughly two decades the PJM energy market, based on the LMP construct, has provided reliable price signals that, among other things, have helped to drive efficient resource entry and exit.[38]

[37] *Id.*

3. *The DOE NOPR Ignores Efforts Underway to Address Resilience through Markets*

PJM is examining resilience, as distinguishable from reliability, and the DOE NOPR overlooks many of what PJM would consider to be the more salient resilience issues, which relate to the transmission grid and not to supply resources. Moreover, the DOE NOPR suggests a remedy, namely cost of service compensation for resources that satisfy an on-site fuel storage criterion, which would yield few if any system reliability or resilience benefits.

On March 30, 2017, PJM issued a report that examined the reliability implications of PJM's changing resource mix, as driven by environmental regulations, the availability of low-cost natural gas, the increasing penetration of renewable resources and demand response, and the potential retirements of nuclear power plants.[39] Among other things, the Evolving Resource Mix and Reliability Report found: (1) as the potential resource mix moves in the direction of less coal and nuclear generation, generator attributes of frequency response, reactive capability, and fuel assurance decrease, but flexibility and ramping attributes increase; and (2) operational reliability can be maintained even if natural gas-fired resources replaced all coal-fired and nuclear generation resources.[40]

Notably, the Evolving Resource Mix and Reliability Report primarily examined *reliability* in the context of the bulk electric system, not *resilience*. Resilience, as PJM and other entities define it, which is the putative focus of the DOE NOPR, relates to preparing for, operating through, and recovering from a high-impact, low-frequency

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[38] PJM began operating as an independent system operator, using the LMP construct, on January 1, 1998. *See Pennsylvania-New Jersey-Maryland Interconnection, et al.*, 81 FERC ¶ 61,257 (1997); *order on reh'g*, 92 FERC ¶ 61,282 (2000).

[39] *See* Evolving Resource Mix and Reliability Report at 1; *see also* DOE Staff Report at 99.

[40] Evolving Resource Mix and Reliability Report at 5.

event. Resilience means remaining reliable even during those events. PJM believes a heavy reliance on one resource type, such as a theoretical resource portfolio composed of 86 percent natural gas-fired resources, *could* raise questions about system resilience.[41] Relying too heavily on a single fuel type could negatively impact resilience because of the potential for reduced diversity of resource attributes.[42] In general, a more diverse resource portfolio is a more resilient portfolio. PJM's resource portfolio is more diverse today than ever before, and the PJM region is less dependent on any single fuel type than other regions of the country.[43]

PJM and its stakeholders regularly examine resilience-related low-probability and high-impact events that could cause reliability impacts to the PJM system. For example, PJM recently held a stakeholder event on security and resilience,[44] including cyber and physical security, and previously held a stakeholder event on fuel diversity and resilience.[45] Also, PJM has focused particular attention on techniques to identify and mitigate natural gas infrastructure vulnerabilities. On October 10, 2017 the PJM Operating Committee reviewed information on resilience planning related to gas-electric coordination.[46] To advance resilience, PJM intends to create operating procedures that

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[41] *Id.* at 5.

[42] *Id.* at 5-6.

[43] *See* Figure 3, above.

[44] *See Grid 20/20: Focus on Security & Resilience*, PJM Interconnection, L.L.C., http://www.pjm.com/committees-and-groups/stakeholder-meetings/symposiums-forums/grid-2020-focus-on-security-and-resilience.aspx (last visited Oct. 23, 2017).

[45] *See Grid 20/20: Focus on Resilience (Fuel Mix Diversity & Security)*, PJM Interconnection, L.L.C., http://www.pjm.com/committees-and-groups/stakeholder-meetings/symposiums-forums/grid-2020-focus-on-resilience-part-1-fuel-mix-diversity-and-security.aspx (last visited Oct. 23, 2017).

[46] *See Operationalizing Gas Pipeline Contingencies Normal and Conservative Operations*, PJM Interconnection, L.L.C., (Oct. 10, 2017), http://www.pjm.com/-/media/committees-groups/committees/oc/20171010/20171010-item-16-gas-electric-contingencies-update.ashx.

will define specific processes to be followed to evaluate the risk on the electric system of natural gas infrastructure vulnerabilities, with a clear understanding of natural gas infrastructure redundancy including generator dual-fuel capabilities such as on-site liquid fuel. Those procedures also will operationalize natural gas pipeline contingencies under normal operations and external threat conditions, such as cyber and physical threats. Given the early stages of this collaboration, the next steps for PJM and its stakeholders include defining metrics for resilience and criteria for evaluating potential mitigating actions not limited to generation as was the focus of the DOE NOPR, but, rather also to include market changes, operational changes such as reserves, transmission upgrades and evolving distributed energy resource technologies and resources. PJM is also highly engaged with stakeholders in incorporating resilience as a driver or a factor in the transmission planning process with the objective of minimizing or eliminating in some cases the criticality of facilities.

4. The DOE NOPR Provides No Basis for Singling Out RTO Markets, Much Less RTOs with Capacity Markets

The DOE NOPR bemoans the spate of "premature" retirements of coal and nuclear generation resources as causing a resilience crisis that demands federal government intervention in the form of cost of service subsidies. According to the DOE NOPR, this phenomenon appears to occur only in competitive RTO-administered markets, which purportedly favor cheaper, but less fuel-secure, natural gas to the detriment of coal and nuclear. The DOE NOPR ties the increased reliance on natural gas (and corresponding decreased reliance on coal and nuclear) to an asserted reduction in resilience that can be fixed by only reverting these markets from competitive back to cost of service rate recovery – but only for such purported fuel-secure generators.

The narrowed scope of the DOE NOPR (from when it was originally issued to its publication in the Federal Register)[47] essentially expresses the opinion that States that have elected to rely on RTO markets to assure resource adequacy exclusively through revenues offered in their energy and capacity markets have made the wrong choice. The Federal Power Act creates a collaborative, federal-state scheme of regulation of the electricity industry, and expressly reserves to the states control over in-state "facilities used for the generation of electric energy,"[48] which includes determining the "[n]eed for new power facilities, their economic feasibility, and [retail] rates and services."[49] By rejecting cost of service regulation in favor of markets – a decision in many cases made at the insistence of the predecessor companies that today are demonstrating a kind of buyer's remorse – states have exercised their authority under the FPA's jurisdictional split. The DOE NOPR implies that these States have made dangerous decisions that have brought on a resilience crisis caused by markets forcing a "premature" retirement of "fuel-secure" resources. The radical response suggested by the DOE NOPR is not merely encouragement or some form of directive that affected states reverse course and "re-regulate" generation under cost of service principles. Instead, the DOE NOPR calls for federal ratemaking that would pre-empt state preferences, frustrate state legislative

[47] *Compare Grid Resiliency Pricing Rule, Notice of Proposed Rulemaking*, Department of Energy, (Sept. 28, 2017),https://energy.gov/sites/prod/files/2017/09/f37/Notice of Proposed Rule making.pdf ("The requirements of this rule shall apply to Commission-approved independent system operators or regional transmission organizations with a day-ahead and a real-time market or the functional equivalent."), *with* DOE NOPR at 46,948 ("The requirements of this rule shall apply to Commission-approved independent system operators or regional transmission organizations with *energy and capacity markets and a tariff that contains* a day-ahead and a real-time market or the functional equivalent.").

[48] 16 U.S.C. § 824(b)(1); *see Hughes v. Talen Energy Mktg., LLC*, 136 S. Ct. 1288, 1292 (2016).

[49] *Pacific Gas & Elec. Co.* v. *State Energy Resources Conservation and Development Comm'n*, 461 U. S. 190, 205 (1983).

actions and impose (contrary both to the Federal Power Act and to longstanding judicially clarified divisions of federal and state responsibilities as relates to resource adequacy) a Washington-based federal solution in lieu of actions individual states might take to meet resilience objectives. Accordingly, the DOE NOPR's singular focus on regions with capacity markets (and possibly on PJM in particular) is arbitrary and unsupported, which calls into question whether the claimed focus of the rule—i.e., resilience—is not a pretext for other objectives, such as supporting certain politically-favored resources.

The DOE NOPR provides no explanation why RTO's with capacity markets in general or PJM's capacity market specifically are to blame for the so-called resilience crisis. In fact, evidence from the DOE's own data demonstrates that RTOs are no more affected than any other region, by resource retirements and changes in the resource mix. First, RTO regions do not rely more heavily on natural gas for winter capacity[50] than non-RTO regions, as demonstrated by Energy Information Administration data for winter 2015.[51] Indeed, as shown by Figure 3, PJM's winter capacity mix showed nearly the

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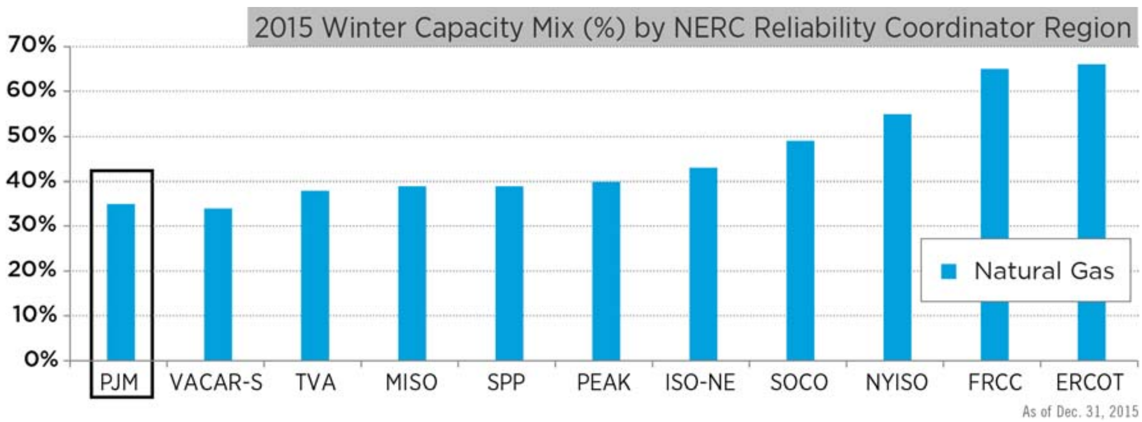
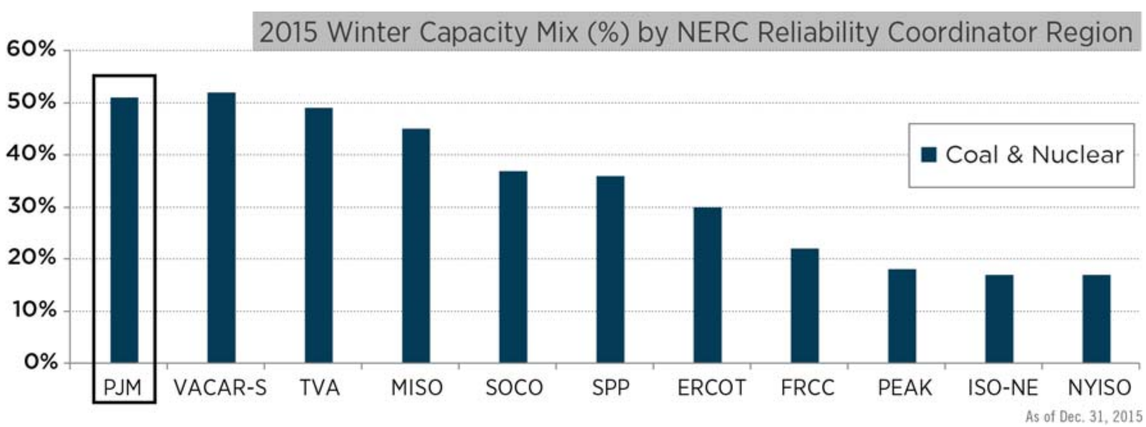
[50] PJM chose to review winter data because the DOE NOPR suggests that the resilience crisis is heightened in the winter due to a heavy reliance on natural gas both for power generation and heating fuel. *E.g.*, DOE NOPR at 46,942 ("Using these retiring units enabled utilities to meet customer demand during a period when already limited natural gas resources were diverted from electricity production to meet residential soheating needs. Once retired, however, these units will not be available for the next unseasonably cold winter.").

[51] The Energy Information Administration's 2015 Form EIA-860 Data - Schedule 3, 'Generator Data' (Operable Units Only), at columns: *Technology*; *Winter Capacity (MW)*; and Data - Schedule 2, 'Plant Data'; Winter Capacity (MW); at columns: *Balancing Authority*; https://www.eia.gov/electricity/data/eia860/, (both retrieved Oct. 16, 2017), were the primary source for bar charts in Figure 3, supplemented with data from "NERC Balancing Authorities and Reliability Coordinators;" North American Electric Reliability Corporation; http://www.nerc.com/comm/OC/RS%20Landing%20Page%20DL/Related%20Files/BA_Bubble_Map_20160427.pdf; http://www.nerc.com/pa/rrm/TLR/Pages/Reliability-Coordinators.aspx; (Retrieved Oct. 16, 2017); and "Report on the Capacity, Demand and Reserves (CDR) in the ERCOT Region, 2017-2026;" The Electric Reliability Council of Texas; at p. 32; Dec. 15, 2016;

lowest winter reliance on natural gas and a significantly greater contribution of combined coal and nuclear resources to fulfill winter needs than almost all other NERC regions in the continental U.S.

Figure 3. 2015 Winter Capacity Mix: Natural Gas v. Coal & Nuclear Combined





As the 2015 winter capacity data demonstrate, among the regions most reliant on natural gas were ERCOT, Florida, and the Southern Company areas—all of which operate outside of Commission-approved RTOs and without RTO-administered capacity markets. PJM's reliance on gas-fired generation is among the lowest of the regions studied. Likewise, PJM's proportion of coal and nuclear in its winter fuel mix is higher

http://www.ercot.com/content/wcm/lists/96607/CapacityDemandandReserveReport-Dec2016.pdf (Retrieved Oct. 16, 2017).

than any region (except for VACAR, which has had about the same percentage reliance on coal and nuclear) further demonstrating that the DOE NOPR's worry about overreliance on natural gas or mass retirements of coal and nuclear are no more applicable in PJM specifically or capacity markets generally, than they are in other areas of the country. Under the DOE NOPR's narrow view that "fuel-secure" resources are needed to ensure reliability and resilience, the PJM region is more fuel diverse and resilient than vast regions without capacity and energy markets, and would remain so even if PJM reduced its reliance on coal and nuclear (to, for example, the level maintained by the Southern Companies region), or increased its reliance on natural gas (to, for example, the level maintained in Florida or ERCOT).

This comparison underscores that the DOE NOPR's criteria and scope are either arbitrary and irrational or motivated by altogether different objectives than those offered as the basis for urgent action. Reliability and resilience are far more complex than the mere maintenance of a preferred class of allegedly fuel-secure resources, and the DOE NOPR offers nothing to show that there is a greater concern with either reliability or resilience in the areas, like PJM, served by capacity and energy markets.

PJM assessed the probability of generator retirements in PJM versus those in "regulated environments" (i.e., areas outside of competitive markets), and found that the "probability of the mathematically average generator retiring in PJM is lower than in the regulated environment."[52] The analysis concludes that "[a] statistical examination of retirement data in PJM compared to regulated environments refutes any assertion that

[52] PJM 2016 Resource Investment Whitepaper at 32.

PJM markets are prematurely retiring economically viable generation."[53] Regarding the changing resource mix, PJM has explained,

> [t]he electricity resource mix has shifted throughout PJM's history, and the PJM system has proven reliable in the face of change. Adequacy and security are two key aspects of reliability. The PJM planning process and capacity market maintain resource adequacy by ensuring sufficient resources to meet demand under extreme conditions.[54]

Indeed, the performance of the PJM system in response to incredibly taxing events like the 2014 Polar Vortex demonstrate the reliability and resilience of the system created by effective transmission planning and development and the energy and capacity markets. The DOE NOPR's singular focus on capacity markets, therefore, is unjustified.

PJM and other markets also are adaptable to changes that impact reliability or resilience. The Polar Vortex presents a compelling example. Despite serving customers reliably throughout the Polar Vortex, in response to the level of forced generation outages and performance failures, PJM and other regions set about to study the underlying causes and provide solutions. PJM determined that primary operational challenges presented by events such as the Polar Vortex could be mitigated if generation suppliers made investments in weatherization or increased operations budgets.[55] PJM's "Capacity Performance" reforms adopted market solutions to the generation challenges wrought by events like the Polar Vortex by: (1) incentivizing better performance by paying generators for performance and allowing recovery of investments to enhance operational

[53] *Id.* at ii.

[54] Evolving Resource Mix and Reliability Report at 8.

[55] Reforms to the Reliability Pricing Market ("RPM") and Related Rules in the PJM Open Access Transmission Tariff ("Tariff") and Reliability Assurance Agreement Among Load Serving Entities ("RAA") of PJM Interconnection, L.L.C., Docket No. ER15-623-000, at 19 (Dec. 12, 2012).

reliability (e.g., firming fuel supply, investing in dual-fuel capability, increased staffing, capital investments for better operational flexibility, and cold-weather testing on alternate fuels); and (2) discouraging poor performance by imposing a strong monetary penalty (with limited exceptions).[56] Other regions affected by the Polar Vortex undertook similar market-oriented reforms in response.[57] The DOE NOPR fails to mention or consider the import of these reforms and the ability of the organized markets to address emerging needs effectively through market-based mechanisms in line with the Commission's long-standing policy of promoting competition, as opposed to the regression to cost of service ratemaking proposed in the DOE NOPR.

Moreover, the DOE NOPR flatly ignores the many tools and benefits that RTOs and their markets provide to promote resilience and reliability in the face of extreme events. RTOs possess dispatch control over extensive resources within their regions, cohesively manage transmission system reliability over large regions to ensure the delivery of those resources, provide reliability coordination and other services over a vast transmission system, optimize operating and other reserves over a wider area, and develop mechanisms such as day-ahead energy and capacity markets to ensure sufficient capacity prior to real-time. The shortsightedness of the DOE NOPR in failing to recognize these benefits suggests that reliability and resilience may not be the underlying goals of the DOE NOPR's proposal.

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[56] *See PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208, at P 9 (2015), *order on reh'g*, 155 FERC ¶ 61,157, at P 26 (2016), *aff'd sub nom. Advanced Energy Mgmt. All. v. FERC*, 860 F.3d 656, 670 (D.C. Cir. 2017); *ISO New England Inc.*, 147 FERC ¶ 61,172 (2014), *reh'g denied*, 153 FERC ¶ 61,223 (2015), *appeal pending sub nom. New England Power Generators Ass'n v. FERC*, No. 16-1023 (D.C. Cir. Jan. 19, 2016).

[57] *See ISO New England, Inc.*, 149 FERC ¶ 61,009, at P 17 (2014).

PJM's experience and analysis demonstrates that the DOE NOPR's focus on competitive capacity markets as the root of any perceived resilience problem is misplaced. The DOE NOPR provides no justification for undermining competitive markets in regions that have adopted robust capacity markets, while assuming that there is no similar problem outside of such markets.

B. The DOE NOPR Fundamentally Undermines Competitive Markets.

The DOE NOPR is a direct assault on competitive markets that the Commission and RTOs have spent years building and refining. By subsidizing one category of resources with full cost of service rate recovery, the DOE NOPR provides an anticompetitive advantage that will lead to uneconomic outcomes in the market. The Commission should decline to adopt the DOE NOPR as contrary to Commission and Congressional policy, and not reverse course on decades of promoting greater competition in the energy industry.

As the Commission is aware, RTO markets like PJM's are single-clearing price auctions in which the RTO clears the total amount of generation needed to serve load reliably at the clearing price that is expected to represent the marginal cost of supply. The Commission has endorsed the concept of single-clearing price markets as being superior to cost of service ratemaking:

> Such competitive market mechanisms provide important economic advantages to electricity customers in comparison with cost of service regulation. For example, a competitive market with a single, market-clearing price creates incentives for sellers to minimize their costs, because cost-reductions increase a seller's profits. And when many sellers work to minimize their costs, competition among them keeps prices as low as possible. While an efficient seller may, at times, receive revenues that are above its average total costs, the revenues to an inefficient seller may be below its average total costs and it may be driven out of business. This market result benefits customers, because over time it results in an

> industry with more efficient sellers and lower prices. By contrast, sellers have far weaker incentives to minimize costs under cost-of-service, because regulation forces a seller to reduce its prices when the seller reduces its cost.[58]

Subsidizing certain categories of generators to prevent them from retiring fundamentally undermines the competitive market structure and displaces least cost, more efficient resources that would otherwise clear the market. Guaranteeing full cost of service recovery to certain resources permits those often higher-cost resources to offer into the market at artificially-low prices in order to guarantee that they will clear the market, knowing that they will be made whole by the subsidy. The effect is to crowd out lower cost, most efficient resources from clearing the market. Subsidies also drive down clearing prices, which provides a disincentive to invest in newer generation and new technologies, leaving in place aging, less efficient generation resources, while at the same time encouraging early retirement of lower cost, more efficient generators that cannot compete on price with subsidized generators. In short, providing full cost of service rate recovery to favored resources severely distorts market prices and investment signals, significantly degrading competitive markets, and leaves in place uneconomic, aging assets that would be forced into retirement but for the subsidy.

C. The DOE NOPR's Many Legal Infirmities Preclude Its Adoption.

The DOE's NOPR offers no defensible legal rationale for its proposal. In fact, the proposal simply cannot be reconciled with the Federal Power Act or with the policies Congress has embedded in the statute.

1. *The DOE NOPR Contradicts Congressionally Endorsed Reliance On Competitive Wholesale Electricity Markets.*

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[58] *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331, at P 141 (2006).

Commencing with its Order No. 888,[59] the Commission has required open access transmission and has encouraged the ongoing development of wholesale power markets, including the organized, regional markets administered by ISOs and RTOs. The overriding purpose of these efforts has been pursuit of Congress's "goals of creating more competitive bulk power markets and lower rates for consumers."[60] Indeed, the Energy Policy Act of 2005, in the Commission's view, embodies a national policy "to foster competition in wholesale electric power markets"[61] and "affirmed a commitment to competition in wholesale natural gas and electricity markets as national policy."[62]

The DOE NOPR openly and irreconcilably conflicts with this national policy objective. The DOE's proposal is targeted specifically at Commission-approved RTOs and ISOs with capacity and energy markets.[63] If adopted, the proposed rule would

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[59] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 1991–1996 FERC Stats. & Regs., Regs. Preambles ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, 1996–2000 FERC Stats. & Regs., Regs. Preambles ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *reh'g denied*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in part & remanded in part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

[60] Order No. 888 at 31,673; *see also id.* at 31,644 (stating a "goal of the Energy Policy Act [of 1992] was to promote greater competition in bulk power markets"); 31,683 (stating no-action alternative would be "counter to the direction from the Congress in the Energy Policy Act and the needs of the marketplace and electricity consumers").

[61] *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 2008–2013 FERC Stats. & Regs., Regs. Preambles ¶ 31,281 at P 1 (2008), *as amended*, 126 FERC ¶ 61,261, *order on reh'g*, Order No. 719-A, 2008–2013 FERC Stats. & Regs., Regs. Preambles ¶ 31,292, *reh'g denied*, Order No. 719-B, 129 FERC ¶ 61,252 (2009). *See also* Order No. 719-A at P 122 (in the Energy Policy Act of 2005, Congress ratified the "Commission's policy . . . to promote competition in wholesale electric power markets").

[62] *Transparency Provisions of Section 23 of the Natural Gas Act*, Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,614, at P 11 (2007).

[63] DOE NOPR, 82 Fed. Reg. at 46,948 (proposed amended version of 18 C.F.R. § 35.28(g)(10)(ii)). The DOE's proposed regulatory language is not entirely clear. The quoted provision would state that "[t]he

require each affected ISO/RTO to create and collect cost of service rates for each "eligible resource" under the new rule. Coal-fired and nuclear generators comprise just over fifty percent of all currently installed generation capacity in the PJM region,[64] meaning that the DOE NOPR proposal, if adopted would remove half of all the capacity in the PJM region from the discipline of competitive market forces. This outcome is clearly incompatible with "the Congressional mandate in the Energy Policy Act of 1992 to encourage competition in electricity markets."[65] The DOE NOPR nevertheless does not even attempt to reconcile its proposed regulatory retrenchment with clear Congressional and Commission policy preference for competitive markets as reflected in the Energy Policy Acts of 1992 and 2005. This reason alone justifies rejection of the DOE's proposal.

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requirements of this rule shall apply" only to the indicated subset of ISOs/RTOs. However, the ensuing proposed subsection would state that "[e]ach Commission-approved [ISO and RTO] shall establish a tariff" that incorporates the rule's proposed cost-plus pricing guaranty for "eligible grid reliability and resiliency resources" as the proposed rule defines them. *Id.* (proposed amended version of 18 C.F.R. § 35.28(g)(10)(iii)). For present purposes, PJM interprets "this rule" in proposed subparagraph (g)(10)(ii) to refer to the proposed regulatory language as a whole, and thus to mean that the DOE intends the new rule to apply only in the subset of regions meeting that subparagraph's criteria. Should PJM be mistaken about the true scope of the proposal, it reserves its right to assert any objections that it may have to the proposal in its full, intended scope, regardless of whether such objections may be additional to or different from those articulated in these comments.

[64] *See supra* note 4.

[65] Order No. 888-A at 30,183.

2. *The DOE's Proposal To Guarantee Eligible Resources' Recovery Of All Costs Plus A Return Is Contrary To Law.*

The United States Supreme Court has stated that "regulation does not assure that the regulated business make a profit."[66] The Court later added that "[t]he due process clause . . . has not and cannot be applied to insure values or to restore values that have been lost by the operation of economic forces."[67] The DOE NOPR, in contrast, would require "pricing to *ensure* that each eligible resource … *recovers its fully allocated costs and a fair return on equity*,"[68] even though the DOE Staff Report acknowledges that displacement of coal-fired and nuclear generation is due in large measure to the persistently low price of natural gas—i.e., the very "economic forces" from which regulation under the FPA does not protect regulated public utilities.[69] Moreover, the DOE NOPR's generic mandate of cost recovery improperly ignores the well-established rights of states and wholesale customers to challenge the prudence of particular utility costs.

As written, therefore, the DOE NOPR would require the Commission to direct the targeted ISOs/RTOs to provide eligible resources with exactly the kind of assurances of

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[66] *Mkt. St. Ry. Co. v. R.R. Comm'n*, 324 U.S. 548, 566 (1945) (citing *FPC v. Hope Nat. Gas Co.*, 320 U.S. 591, 603 (1944) ("*Hope*")). *Accord FPC v. Nat. Gas Pipeline Co.*, 315 U.S. 575, 590 (1942) ("[R]egulation does not insure that the business shall produce net revenues . . . .").

[67] *Mkt. St. Ry. Co.* at 567.

[68] DOE NOPR at 46,948 (proposed revised text of 18 C.F.R. § 35.28(g)(10)(iii)(B)) (emphasis added). Eliminating all doubt that this language would guaranty cost recovery plus a profit for each eligible resource, the proposal goes on to clarify that "[c]ompensable costs shall include, *but not be limited to*, operating and fuel expenses, costs of capital and debt, and a fair return on equity and investment." *Id.* (proposed revised text of 18 C.F.R. § 35.28(g)(10)(iv)) (emphasis added).

[69] *Mkt. St. Ry. Co.* at 567; *see also Associated Gas Distribs. v. FERC*, 824 F.2d 981, 1001 (D.C. Cir. 1987) ("*AGD*") (observing the Supreme Court's rulings that "the due process clause affords no protection from losses inflicted by market conditions" (citing *Hope*, 320 U.S. 591; *Mkt. St. Ry. Co.*, 324 U.S. 548)).

profit and protection from market forces to which the Supreme Court long ago held regulated entities are not entitled. Accordingly, the Commission cannot lawfully adopt the DOE's proposal.

3. *The DOE NOPR Proposes An Unlawful, Arbitrary and Undue Preference For Eligible Resources.*

Like the companion Natural Gas Act, the Federal Power Act "fairly bristles with concern for undue discrimination."[70] While not all discrimination is prohibited,[71] discrimination must be "undue" which occurs "when the classes are not similarly situated."[72] Courts will accept disparate treatment "if FERC offers a valid reason for the disparity."[73]

The DOE NOPR is *unduly* discriminatory and, therefore, unlawful in at least two critical respects. First, it offers no sound basis for the preferential pricing it proposes for eligible resources. Second, it explains no rationale for creating a new pricing regime for eligible resources to apply only in ISO/RTO regions that have capacity and energy markets, while leaving unchanged the jurisdictional rates of all generators (including

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[70] *AGD*, 981 F.2d at 998.

[71] *BP Energy Co. v. FERC*, 828 F.3d 959, 967 (D.C. Cir. 2016) ("No undue discrimination exists where there is 'a rational basis for treating [two entities] differently' and such differential treatment is 'based on relevant, significant facts which are explained."(alteration in original) (quoting "*Complex*" *Consol. Edison Co. of N.Y., Inc. v. FERC*, 165 F.3d 992, 1012-13 (D.C. Cir. 1999)).

[72] *PJM Interconnection, L.L.C.*, 137 FERC ¶ 61,145, at P 109 (2011).

[73] *Black Oak Energy, LLC v. FERC*, 725 F.3d 230, 239 (D.C. Cir. 2013) (alteration in original) (internal quotation omitted) (citation omitted). *See also Ark. Elec. Energy Consumers v. FERC*, 290 F.3d 362, 367 (D.C. Cir. 2002) ("A rate is not 'unduly' preferential or 'unreasonably' discriminatory if the utility can justify the disparate effect." (quoting *Metro Edison Co. v. FERC*, 595 F.2d 851, 857 (D.C. Cir. 1979)); *Elec. Consumers Res. Council v. FERC*, 747 F.2d 1511, 1515 (D.C. Cir. 1984) (same).

those that otherwise might qualify as eligible resources if located in a targeted ISO/RTO footprint) in all other regions of the nation.

The courts have recognized that it may be reasonable for the Commission to draw distinctions between types or classes of resources for some purposes. PJM's minimum offer price rule[74] and Capacity Performance[75] reforms provide two such examples, which underscore the DOE NOPR's critical omission: Unlike the DOE NOPR, in adopting the PJM rules, the Commission provided a sound rationale, supported by substantial evidence, for distinguishing between certain types of resources.

Critically, in support of its proposal, the DOE cites not a single incident or event when the on-site availability of 90 days' fuel supply was or would have been the difference in maintaining reliable electric service in any of the targeted ISO/RTO regions (or anywhere else). Indeed, the DOE NOPR fails to connect its proposed 90-day on-site fuel supply criterion with prevention or mitigation of any outage or other reliability issue in any targeted market at any time. Likewise, the DOE fails to articulate why the problem only exists in RTOs and ISOs with capacity markets.[76]

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[74] The Commission approved applying PJM's minimum offer price rule to natural gas-fueled generators, but not to intermittent renewable resources like wind and solar generation. *See supra* note 72, *PJM Interconnection, L.L.C.*, 113 FERC ¶ 61,145 at PP 109-111, *aff'd sub nom. N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d 74 (3d Cir. 2014).

[75] The Commission and the courts accepted PJM's "Capacity Performance" reforms, which limited participation in the PJM capacity market to resources that are capable of providing energy or reducing demand on a year-round basis. *See supra* note 56.

[76] *See supra* Section II.A.4.

Because the DOE NOPR fails to articulate any rational connection between the facts it marshals, the problem it identifies, and the solution it seeks to inflict, the Commission cannot lawfully adopt it.[77]

4. *The Commission's Comment Deadlines Do Not Provide The Meaningful Opportunity To Comment Required By The Administrative Procedure Act.*

Section 553(c) of the Administrative Procedure Act requires an agency, after publishing notice of a proposed rule, to "give interested persons an opportunity to participate in the rule making through submission of written data, views, or arguments."[78] The purposes of these procedural requirements are to "assure[] fairness and mature consideration of rules having a substantial impact on those regulated,"[79] and to "educate[] the agency, thereby helping to ensure informed agency decisionmaking."[80] These objectives dictate that an agency must provide a "meaningful opportunity" to comment.[81] Therefore, according to the drafters of the Act, matters "of great importance, or those

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[77] *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (stating that an agency must articulate "a 'rational' connection between the facts found and the choice made'" (quoting *Burlington Truck Lines v. United States*, 371 U.S. 156, 168 (1962))).

[78] 5 U.S.C. § 553(c).

[79] *Pennzoil Co. v. FERC*, 645 F.2d 360, 371 (5th Cir. 1971).

[80] *Chocolate Mfrs. Ass'n v. Block*, 755 F.2d 1098, 1103 (4th Cir. 1985); *see also Nat'l Tour Brokers Ass'n v. United States*, 591 F.2d 896, 902 (D.C. Cir. 1978) (explaining that the purpose of the notice-and-comment procedure is "to allow the agency to benefit from the experience and input of the parties who file comments . . . and . . . to see to it that the agency maintains a flexible and open-minded attitude towards its own rules."); *N.C. Growers' Ass'n, Inc. v. United Farm Workers*, 702 F.3d 755, 763 (4th Cir. 2012) ("The important purposes of this notice and comment procedure cannot be overstated. The agency benefits from the experience and input of comments by the public, which help 'ensure informed agency decisionmaking.'" (quoting *Spartan Radiocasting Co. v. FCC*, 619 F.2d 314, 321 (4th Cir. 1980)).

[81] *Prometheus Radio Project v. FCC*, 652 F.3d 431, 450 (3d Cir. 2011) (quoting *Rural Cellular Ass'n v. FCC*, 588 F.3d 1095, 1101 (D.C. Cir. 2009)).

where the public submission of facts will be either useful to the agency or a protection to the public, should naturally be accorded more elaborate public procedures."[82]

The DOE proposes nothing less than for the Commission to reverse two decades of resolute reliance on market forces to ensure just and reasonable wholesale prices for electricity—a bedrock policy which, as the Commission has observed on a variety of occasions, Congress first encouraged and later ratified. The Commission's own staff has published an extensive (though certainly not billed as exhaustive) list of questions and issues that the DOE NOPR presents, but does not address.[83] Nevertheless, interested parties were given a mere 13 days to comment after the DOE NOPR was published in the Federal Register.

The courts strictly enforce the APA's procedural steps, and a comment period of "exceedingly short duration" will support a finding that an agency has failed to offer the public a meaningful opportunity to comment on a proposed rule.[84] The "instances actually warranting" a comment period as brief as the Commission is permitting here "will be rare," and "are generally characterized by the presence of exigent circumstances in which agency action [is] required in a mere matter of days."[85] When considered in the light of the import, scope, and potential costs to consumers of the DOE's proposal, the DOE NOPR fails utterly to justify the extremely expedited schedule the Commission has

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[82] Administrative Procedure Act: Legislative History, S. Doc. No. 79-248, at 259 (2d Sess. 1946); Charles H. Koch Jr., 1 Administrative Law and Practice 329-30 (2010 ed.).

[83] *Grid Reliability and Resilience Pricing*, Letter Requesting Information, Docket No. RM18-1-000 (Oct. 4, 2017).

[84] *N.C. Growers Ass'n, Inc.*, 755 F.2d at 763, 770.

[85] *N.C. Growers Ass'n, Inc.*, 755 F.2d at 770 (citations omitted).

established, resulting in a procedural schedule that plainly falls short of the APA's minimum requirements.

III. ALTHOUGH THE LACK OF BASIS FOR THE DOE NOPR AND THE ILLEGAL REFORMS IT PROPOSES SUPPORT NOT IMPLEMENTING THE PROPOSAL, PJM BELIEVES THE AUGUST DOE REPORT APPROPRIATELY HIGHLIGHTED A PROBLEM PJM IS FACING WITH PRICE FORMATION THAT SHOULD BE ADDRESSED THROUGH REFORMS TO BE SUBMITTED TO THE COMMISISON WITHIN A COMMISSION-DIRECTED TIME FRAME

A. The Need for Targeted Consideration of This Change in the PJM Region

PJM notes at the outset that the DOE NOPR itself has directed its reforms solely to regions with energy and capacity markets. Further, given its focus on coal and nuclear units, it is clear that the region to which the DOE most directs its remedy is the PJM Region since the PJM Region has an abundance of coal and nuclear units still in service.[86] Thus, the DOE has already 'carved out' the PJM region for special recognition by the Commission. Although PJM disputes the rationale supporting the DOE's NOPR, the DOE's recognition of the need for targeted action in PJM is one with which PJM concurs.

1. PJM has Observed and Adapted to Significant Market Changes in Recent Years.

PJM's markets are resource agnostic, and have evolved over the years to include a variety of resource types including coal, natural gas steam, natural gas combustion turbine, oil steam, oil combustion turbine, nuclear, solar, wind, hydroelectric, battery/storage, and demand response. In recent years, the industry has experienced a significant fuel and technology shift to natural gas and renewable resources, prompted by

[86] *See supra* Figure 3.

low-cost shale gas, the efficiency improvements of combined-cycle gas turbines, and the improving economics of renewable energy driven in part by government incentives. Between 2010 and 2016, coal resources comprised 79 percent of the capacity retired in PJM,[87] and natural gas and renewable resources comprised 87 percent of the new capacity in PJM.[88] By 2016, PJM's installed capacity consisted of 33 percent coal, 33 percent natural gas, 18 percent nuclear, and 6 percent renewables (including hydro).[89]

PJM points out the following signs that the current environment is an opportune time to examine whether prices in the PJM energy market are formed as efficiently as possible. First, the competitive economics of combined-cycle gas turbines, assisted by low-cost shale gas and increasing renewables with zero fuel costs, has led to steadily flattening supply curves (Figure 4). The impact of this trend is particularly strong from 120,000 megawatts to 150,000 megawatts of load, the range in which peak load levels typically occur in the summer and winter. As Figure 4 shows, in 2015 and 2016 the supply curve remained relatively flat throughout this range, never reaching the point at which supply prices begin to increase significantly.

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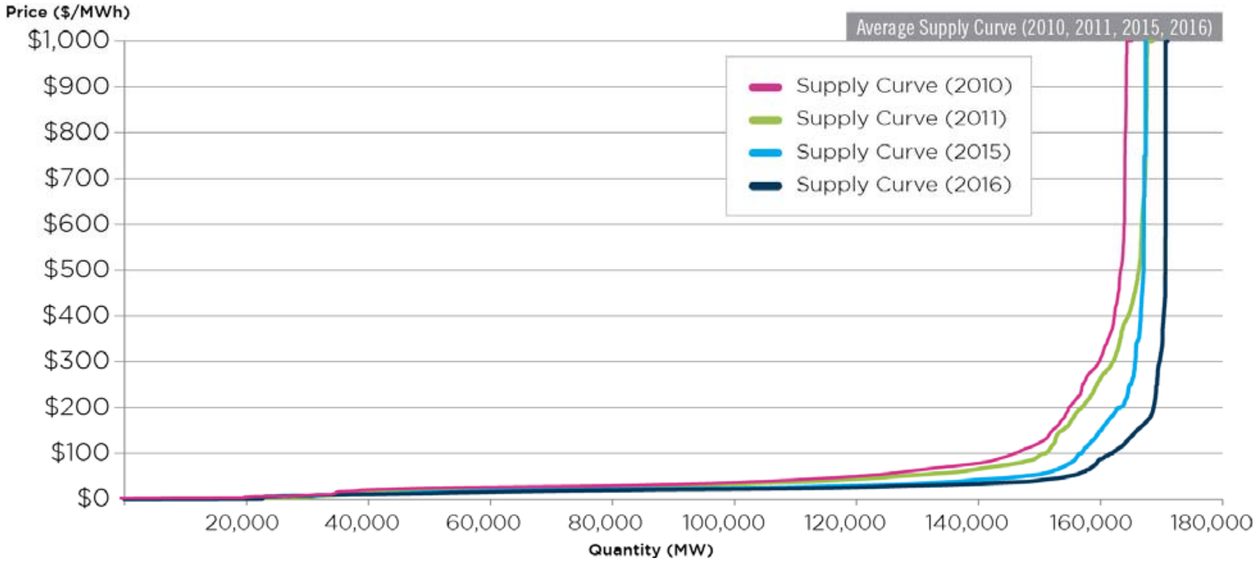
87 *See Generation Activation Summary Sheets*, PJM Interconnection, L.L.C., http://www.pjm.com/planning/generation-deactivation/gd-summaries.aspx (last visited Oct. 23, 2017).

88 *See PJM Generation Queues: Active (ISA, WMPA, etc.)*, PJM Interconnection, L.L.C. (Oct. 22, 2017, 11:35 a.m.), http://www.pjm.com/planning/generation-interconnection/generation-queue-active.aspx. Queue project megawatts are based on "MW placed in service" with Status Codes of IS, UC-ISP, or Active-ISP, and represent the new generation capability added to the system. Actual capacity interconnection rights may be lower based on limitations for certain fuel types or rights as specified in individual interconnection agreements.

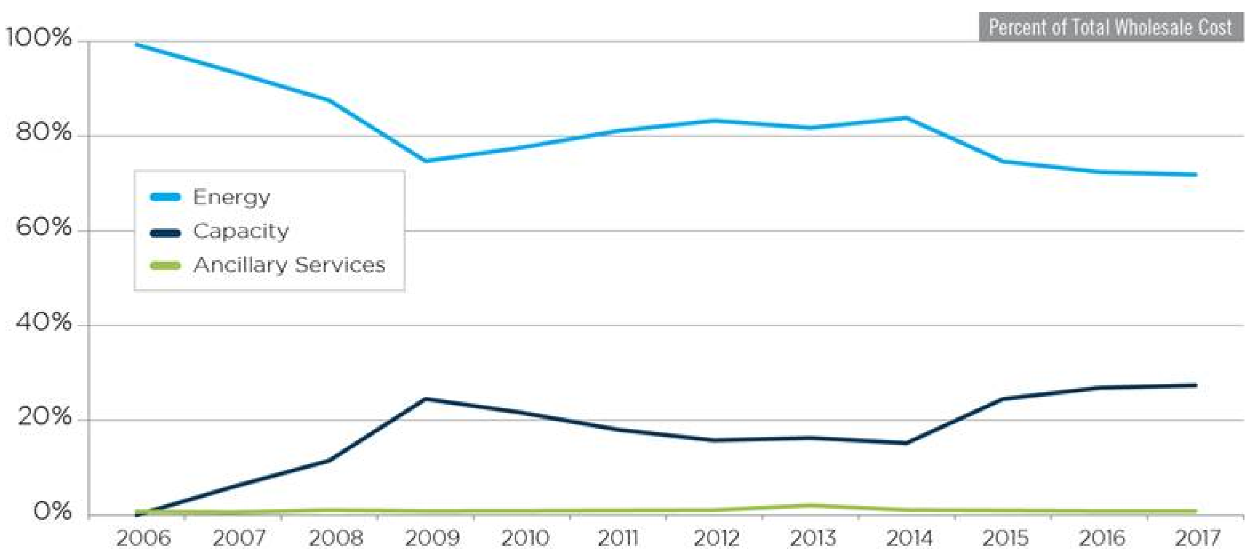
89 *See* PJM Interconnection, L.L.C., http://www.pjm.com/~/media/markets-ops/ops-analysis/capacity-by-fuel-type-2016.ashx (last visited Oct. 23, 2017).

Figure 4. Average Supply Curves (2010, 2011, 2015, and 2016)



Also, as energy market revenues in PJM have declined, capacity market revenues have played a more significant role in generators' total revenues. (Figure 5).[90]

Figure 5. Revenue Segments



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[90] Revenues from the energy and capacity markets were 74.3 percent and 22.9 percent, respectively, of the total generation revenue in 2015, and 71.1 percent and 26.6 percent, respectively, in 2016. The total payments for ancillary services represent 2.8 percent of the total generation revenue in 2015 and 2.3 percent in 2016.

To the extent that these phenomena are strictly the result of supply and demand fundamentals, there would be no problem to be resolved. However, upon observance of these trends, PJM has endeavored to research whether energy market prices are accurately reflecting the value of the resources being utilized to maintain system reliability, both from the standpoint of meeting system demand as well as providing the flexibility the system operator needs to meet constantly changing conditions. Improved price formation will result in a better, more transparent reflection of the marginal resources on the system as well as create incentives for units to follow dispatch instructions and to make their units more flexible to respond to changing load demands. In general, improved price formation, as discussed more fully below, may help to ensure an appropriate mix of resources that can meet future grid demands and have clear incentives to follow dispatch instructions.

2. *The Problems PJM is Experiencing as a Result of Such Changes can be Addressed through Price Formation Reforms in PJM.*

In the case of the need for price formation reforms, the Commission should note the following characteristics which identify the PJM region as eligible for prompt remedy of the particular price formation problem noted above.

For instance, in light of the reforms to PJM's capacity market in moving to the Capacity Performance construct, reliability pricing has supplemented energy pricing to help attract efficient resource investment to meet the resource adequacy needs. However, beyond the aggregate resource attributes such as maximum economic generation and forced outage rate, the capacity market is not intended to reward flexibility attributes such as short starting time, short minimum running time, low minimum economic generation and fast ramping rate that are essential to efficiently meet operational needs.

As the availability of an appropriate mix of these flexibility attributes is essential for reliable system operation, the value of flexibility should be appropriately reflected in energy and reserve market pricing to incent the attributes needed to maintain system reliability efficiently. Going forward, this is particularly important because of, among other things, the anticipated continuing increase in distributed, intermittent resources and demand response coming on to the PJM system.

PJM believes that price formation reforms in PJM should ensure that efficient commitment and dispatch solutions are supported by efficient prices and settlement with reduced uplift and improved incentives are accomplished in ways that will be more consistent with several other ISOs/RTOs, including its neighbors MISO and NYISO that have adopted energy pricing enhancements previously and will lessen the seams issue.

Another characteristic of PJM which identifies the PJM region as eligible for prompt remedy is that, as PJM noted in its comments in response to the Commission's Fast Start Pricing NOPR,[91] PJM has not yet adopted the level of reforms as other regions with respect to fast-start pricing. Other regions have already experienced the benefit of more flexible pricing methods whereas PJM has yet to make similar enhancements. Additionally, given the demographics of PJM's fleet such as the significant penetration of relatively large combined cycle natural gas units, PJM feels that an expansion is necessary to fully address price formation in PJM. Simply, PJM does not have many

[91] *See Fast-Start Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators,* Notice of Proposed Rulemaking, at P 54 (2016) ("Fast Start Pricing NOPR").

units that meet the FERC definition of "fast-start" and therefore PJM needs a broader approach that allows for regional differences.[92]

PJM believes that the confluence of the conditions described above drives the need for a reform to certain aspects of price formation in the PJM region. The goal is to ensure price signals that foster efficient resource-investment decisions and enable participation of demand response (both energy and reserves), variable energy resources, and distributed energy resources. Efficient energy and reserve price formation, under both shortage and non-shortage conditions, would more accurately and transparently value all of the resources on the system that are needed to reliably serve load. Enhancing energy market price formation represents a beneficial and essential first step. PJM has explained its conceptual proposal to address price formation to Dr. William Hogan, Ph.D., described below. In a letter to PJM, Dr. Hogan expressed his concurrence stating:

> PJM staff is proposing to reform the existing pricing model in order to ensure that the cost of serving load is reflected in LMP to the fullest extent possible, uplift is reduced and incentives are maintained. This follows the principles of sound market design. Enhanced energy market price signals will strengthen performance incentives in PJM's markets and is complementary to other reforms being considered by PJM. Given my knowledge of the PJM resource profile, this reform would be an appropriate step forward in price formation for the PJM region.[93]

While enhancements to the LMP calculation in these other ISOs/RTOs have focused on fast-start resources, PJM believes it needs to enhance price formation as it

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[92] PJM Interconnection, L.L.C. Comments to Notice of Proposed Rulemaking, Docket No. RM17-3-000, at 4 (Feb. 28, 2017).

[93] Letter to Mr. Stu Bresler, Sr. Vice President Operations & Markets, PJM Interconnection, L.L.C. from William W. Hogan, RE: PJM Price Formation, October 23, 2017, included as Appendix B.

relates to all resource types. PJM's resource mix is different than other regions. In particular, natural gas resources in PJM are not limited to fast-start combustion turbines, but rather are represented by significant quantities of larger, combined cycle units. These resources are competing directly with other resource types, and it therefore does not make sense to limit the price-setting contribution discussed here to only the fast-start class of units, but rather to enhance price formation such that it is neutral to fuel source or resource class such that all units have the opportunity to compete comparably.

Identification of the need for price formation reforms will not create new seams issues between PJM and its neighbors. For one, MISO and PJM already depart from how prices are formed with MISO utilizing its ELMP method. By the same token, New York does currently employs a hybrid-pricing methodology that appropriately allows inflexible resources to set prices in their region when needed. These differences in pricing practices have not inhibited efficient coordination on the seams and have not resulted in any reliability concerns. Further, neither of those regional changes have inhibited the free flow of energy across the various borders PJM has with its neighbors. The RTOs have worked hard to address those seams issues over the years. The mere existence of different pricing regimes is already inherent in the Commission's deference to regional solutions. To now use this as a sword to thwart an individual region's initiatives will drive the nation to a 'lowest common denominator' solution which serves no region well in the long run.

B. PJM is Setting Forth a Framework for Price Formation Reforms Needed in the PJM Region in the Near Term.

PJM describes herein price formation reforms it is considering to address the problems identified above in the near term. The framework below explains the issue in terms of convexity and non-convexity, in recognition of a technical condition that is essential to addressing the concerns raised with inflexibility. In basic terms, PJM finds itself increasingly in a state of non-convexity which in turn requires payments be made to resources outside of LMP through make whole payments which in turn has led to increased uplift, reducing incentives for flexibility. PJM proposes a way in which such uplift can be minimized.

1. Marginal Cost Pricing and the Convex Condition

Fundamentally, energy price formation is built on the foundation of marginal cost pricing. Marginal cost pricing means that the price is set equal to the incremental cost to produce the last unit of output or, equivalently, the potential increase in system cost if the last-cleared competitive unit were unavailable to serve the demand. In principle, marginal cost pricing enables full cost recovery in competitive markets under the "convex condition." The convex condition means that the incremental cost of production rises when a generating unit's output increases, and declines when a generating unit's output decreases. Under the convex condition, the last-cleared unit is always the highest-ranking unit in the merit order with the highest cost. The optimal strategy under the convex condition is for each generating unit to bid its true costs and physical characteristics.

An inflexible generating unit with a minimum operational limit fails the convex condition because when the output decreases below the minimum operational limit, the cost rises, making it uneconomical to run the unit in that range.[94] Under non-convex conditions, producers may incur losses if the price is set at marginal cost. Fundamentally, in the presence of non-convexity, there are no market prices that can support competitive market solutions without requiring additional payments through, for example, make whole payments and resulting uplift mechanisms. In wholesale electricity markets with LMP, two different LMP pricing methods have been used to support competitive market solutions under the condition of non-convexity: the restricted LMP method and the extended LMP method.

a. Current LMP Method

The current LMP method was chosen for the initial implementation of the PJM energy market primarily because of its simplicity. The current LMP method ignores the presence of non-convexity in its price-setting logic and assumes that certain units, or certain output ranges of units, are ineligible to set price when they fail the convex condition. It employs a single security-constrained economic dispatch ("SCED") model for both dispatch and pricing purposes. In the SCED model, only flexible units are eligible to set price, and the costs for inflexible units are excluded in the pricing run, calculating the marginal system costs and determining the market clearing prices.[95]

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[94] In electricity markets, non-convexity also arises for other technical reasons, such as fixed start-up/no-load costs, economies of scale and inflexibilities such as minimum-generation or block-loading requirements.

[95] FERC recently sought to address the ability of inflexible fast-start units in the Fast-Start Pricing NOPR. FERC's proposal would require the dispatch and pricing of the system to be done separately so that inflexible fast-start units could be made flexible in order to set prices. FERC's proposal also sought to include startup and no load for these resources in pricing.

As a result, there have always been circumstances where prices could fail to reflect all elements relevant to sending the right market signals. Specifically, when certain inflexible units are required to serve load but ineligible to set price, and the current LMP method inappropriately lowers energy prices, an uplift payment to the inflexible units is required in order to ensure that their costs are fully recovered. These uplift payments are detrimental to the overall operation of the market because market participants that must pay these costs are unable to predict or hedge against them.

Significant effort has been invested in minimizing these uplift costs over time, including putting limitations on the physical parameters that generating units may submit as part of their offers into the market. However, efficient dispatch processes can only minimize the resulting uplift so much. PJM has been required to create rules to limit physical parameters over the years due to the incentives created by the uplift payments. Currently, resource operators have the incentive to make units as inflexible as possible while still being committed by PJM in order to maximize the uplift payments they can collect.

b. Extended LMP Method

PJM is actively exploring a transition to the extended LMP method.[96] In the extended LMP method, the conditions that cause non-convexities are relaxed in a pricing run executed separately from the dispatch run in a procedure known as convex relaxation. A dispatched inflexible unit needed to serve load would be treated like a flexible unit and be allowed to set price. Prices that reflect the incremental costs of the most expensive

[96] For a description of the extended LMP method, *see* Gribik, P. R., W. W. Hogan, and S. L. Pope, *Market-Clearing Electricity Prices and Energy Uplift*, John F. Kennedy School of Government, Harvard University (2007).

units needed to serve load benefit supply resources with lower costs, making offers from flexible or inflexible units competitive. As a beneficial result, the extended LMP method effectively rewards flexibility, reducing reliance on the uplift payments with improved price signals that incent resource performance in market operations. These incentives will be necessary in the future, as the PJM system continues to experience further penetration of intermittent resources.

A defining characteristic of the extended LMP method is that it bifurcates the SCED model into two separate runs: the dispatch run and the pricing run.[97] This bifurcation already occurs in regions such as MISO, ISONE, and NYISO who all have a sophisticated procedures for fast-start pricing. In the method PJM is investigating, the dispatch run is the same as in the current LMP method and the pricing run is a convex relaxation of the SCED dispatch run. In the pricing run, the inflexible generation units compete with the flexible units and are eligible to set the energy price when they are needed to meet the demand or control transmission constraints. With appropriately designed uplift payments, extended LMP can support efficient commitment and dispatch solutions, because market participants should have no incentive to deviate from the solution and (to a large extent) have no incentive to submit offers that differ from their true costs. The Commission has already shown its comfort with different price setting methods given that both of these price setting methods are in place.[98]

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[97] *See supra* note 96.

[98] *Midwest Independent Transmission System Operator, Inc.*, 140 FERC ¶ 61,067 (2012).

2. *Shortage Pricing*

In addition to exploring a more robust method to determine LMPs, PJM also believes that reforms to its shortage pricing rules would benefit price formation and incentivize appropriate behavior that could mitigate operational reliability concerns. Currently, PJM implements shortage pricing if its system is short of 10-minute reserves, which from a reliability perspective would constitute a grave operating condition. Ideally, the market should appropriately incentivize activity to avoid these occurrences. However, once in that condition, market prices should reflect the severity of the condition. Modeling and invoking shortage pricing for longer-term reserve products such as 30-minute reserves would provide better incentives and information to the market regarding potentially severe operating conditions by escalating energy and reserve prices earlier and incentivizing behavior that would ameliorate the condition.

Further, PJM is examining the level and shape of its operating reserve demand curves ("ORDC"). The current ORDCs used in PJM are step functions that are based on PJM's nominal reserve requirement, which is a function of the largest unit operating on the system. As such, they do not accurately reflect the value of excess reserves on the system in a manner consistent with the reliability value of those reserves. PJM also is investigating the penalty factor levels associated with these curves to ensure they accurately reflect the value that reserves provide to the system under all operating conditions. While PJM recently made incremental changes to its ORDCs, a wholesale review of these curves has not been done since PJM implemented shortage pricing in 2012. To ensure PJM comprehensively addresses all facets of price formation, and considering potential changes to the LMP methodology and reserve products considered for shortage pricing, now is also an appropriate time to review shortage pricing in PJM.

C. PJM Suggests a Focused Commission Process.

As explained herein, the Commission should act now to ensure that essential reliability services that resources provide are maintained. Reforms are needed in PJM now to ensure that (i) the cost of serving load is reflected in LMP to the fullest extent possible, (ii) uplift is reduced and (iii) proper economic incentives are maintained. Enhanced energy market price signals will strengthen performance incentives in PJM's markets and is in line with other reforms being considered by PJM. PJM understands not all regions face the same need for action. An extensive record has been developed to date in this area in the Commission's price formation proceedings, as confirmed by the August DOE Report. Thus, to move forward, the Commission should direct each RTO/ISO to identify for the Commission whether changes in the resource mix has created issues in their respective regions that are currently not addressed in the market. If any issues exist, the RTO/ISO should prioritize the issues of most consequence to that region and provide, within a Commission-specified deadline that is in the near term, for the submission of proposals, if necessary. In the alternative, the Commission could expand the scope of its existing open price formation NOPRs to provide for regional solutions around the issues it has broadly identified in those dockets.

IV. CONCLUSION

For the foregoing reasons, PJM respectfully requests that the Commission decline to adopt the DOE NOPR (as unsupported) and, in its place, issue an order as discussed herein.

Respectfully submitted,

/s/Jennifer Tribulski

Craig Glazer
Vice President – Federal Government Policy
PJM Interconnection, L.L.C.
1200 G Street, NW, Suite 600
Washington, DC 20005
(202) 423-4743 (phone)
(202) 393-7741(fax)
Craig.Glazer@pjm.com

Jennifer Tribulski
Associate General Counsel
PJM Interconnection, L.L.C.
2750 Monroe Boulevard
Audubon, PA 19403
(610) 666-4363 (phone)
Jennifer.Tribulski@pjm.com

Counsel for PJM Interconnection, L.L.C

October 23, 2017

APPENDIX A

to

PJM COMMENTS IN RM18-1-000

OCTOBER 23, 2017

APPENDIX A

PJM'S RESPONSES TO SPECIFIC QUESTIONS RAISED BY OEPI IN DOCKET NO. RM18-1-000

I. Need for Reform

Question 1

What is resilience, how is it measured, and how is it different from reliability? What levels of resilience and reliability are appropriate? How are reliability and resilience valued, or not valued, inside RTOs/ISOs? Do RTO/ISO energy and/or capacity markets properly value reliability and resilience? What resources can address reliability and resilience, and in what ways?

PJM Response

For PJM, resilience means the ability to prepare, operate through, and recover from high-impact, low-frequency threats such as extreme weather, electromagnetic pulses, geomagnetic disturbances, earthquakes, cyber and physical attacks, and fuel security limitations.[1] PJM defines the three elements of resilience as:

- Prepare – evaluating and cost-effectively mitigating risks
- Operate – managing through a high-impact disruption
- Recover – regaining essential functions as rapidly as possible

Resilience requires coordinated efforts with operations, transmission and infrastructure planning, business continuity, cyber and physical security, risk management and markets.

PJM is required to plan for and operate transmission system in a manner that meets the mandatory reliability standards under the section 215 of the Federal Power Act, 16 U.S.C. section 824o, as developed and proposed by the North American Electric Reliability Corporation ("NERC") and accepted by the Commission. These standards address all aspects of reliability including Resource and Demand Balancing, Critical Infrastructure Protection, Communications, Emergency Preparedness and Operations, Facilities Design, Connection, and Maintenance, Interchange Scheduling and Coordination, Interconnection Reliability Operations and Coordination, Modeling, Data, and Analysis, Nuclear, Personnel Performance, Training and Qualifications, Protection and Control, Transmission Operations, Transmission Planning, and Voltage and Reactive. "Reliable operation" is defined under the FPA as:

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[1] Industry groups have similar definitions. *See, e.g.*, the North American Transmission Forum in September 2017 paper on transmission system resilience which can be found at the following URL: http://www.natf.net/docs/natf/documents/resources/transmission-system-resiliency-an-overview.pdf.

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> operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.[2]

The PJM system meets existing standards of reliability.

Resilience addresses challenges and emerging risks *that reliability standards do not address* in order to withstand a prolonged, large-scale outage. Resilience for the bulk-electric system entails:

- Maintaining reliability in the face of significant events
- Incorporating high-impact, low-frequency threats into planning and procedures
- Slowing disruptive events, mitigating their impacts and quickly recovering essential functions
- Protecting essential systems based on assessed risks and hazards
- Improving grid flexibility and control to be able to adapt efficiently and quickly to changed conditions

As discussed in the body of PJM's response[3] PJM regularly considers factors that could impact the reliability and resilience of the PJM system. Further, PJM and its stakeholders are continuing to examine resilience-related low-probability and high-impact events that could cause reliability impacts to the PJM system.

Given the changing nature of the fleet and a new set of threats that were not anticipated under the current NERC standards, prudent planning and operations requires the anticipation and mitigation of potential future occurrence of events, such as:

- sustained supply-chain issues
- environmental restrictions that limit operations of an entire fleet of fossil generators
- a nuclear disaster, which causes regulatory reaction for new and existing nuclear fleet
- a single incident causing major, multiple pipeline or supply disruptions for the natural gas fleet or oil fleet
- a major impact to a large portion of the transmission infrastructure that forces an outage lasting for days, such as a major natural disaster that impacts large sections of grid including resources and the infrastructure that connects the resources to consumers

[2] 16 U.S.C. § 824*o*(a)(4) (2010).

[3] PJM Comments at sections II.A.2 and 3.

To that end, PJM has created a Resilience Roadmap[4] to use in exploring opportunities with its stakeholders, through the stakeholder committees, for addressing resilience. This includes review resilience opportunities from the perspective of transmission planning, operations, including gas/electric coordination and fuel security, markets, and cyber and physical security. Detailed discussions of these efforts are held at the Operating Committee, the Markets and Implementation Committee and/or the Planning Committee, as appropriate. And, to further collaboration with a variety of government and industry stakeholders, PJM is increasing its emphasis on cross-sector coordination.

Given the early stages of this collaboration, the next steps for PJM and stakeholders include defining metrics for resilience and criteria for evaluating potential mitigating actions not limited to generation as was the focus of the DOE NOPR, but rather also to include transmission, operations, cyber and physical security, and advanced system restoration.

<u>Question 2</u>

The proposed rule references the events of the 2014 Polar Vortex, citing the event as an example of the need for the proposed reform. Do commenters agree? Were the changes both operationally and to the RTO/ISO markets in response to these events effective in addressing issues identified during the 2014 Polar Vortex?

<u>PJM Response</u>

As described more fully in the body of PJM's comments,[5] there is no valid basis for the proposed reform, including the 2014 Polar Vortex or any other extreme weather events cited. Indeed, NERC's Polar Vortex Review found:

> Extreme cold weather also had a major impact on generator equipment. Of the approximately 19,500 MW of capacity lost due to cold weather conditions, over 17,700 MW was due to frozen equipment. Many outages, including a number of those in the southeastern United States, were the result of temperatures that fell below the plant's design basis for cold weather. At the height of generation outages (January 7 at 0800) the southeastern United States accounted for approximately 9,800 MW of the outages attributed to cold weather.[6]

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[4] The Resilience Roadmap can be found at the following URL: http://pjm.com/~/media/committees-groups/committees/oc/20170606/20170606-item-18-resilience-roadmap.ashx.

[5] PJM Comments at sections II.A, B, and C.

[6] NERC Polar Vortex Review – 2014 at 12. The report can be found at the following URL: http://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf .

And, of the generation that was lost due to fuel supply, all generation resource types, with the exception of wind and demand response, performed poorly. PJM explained to the Commission that at the time of the peak demand hour on January 7:

- approximately 22 percent of total installed generation capacity in PJM (of all fuel types) was unavailable because of forced outages associated with routine equipment breakdowns, problems related to operating in extreme cold temperatures and, fuel-supply issues.

- gas interruptions were *not* the major driver of the high forced outage rates experienced in the PJM region.

- Natural gas interruptions removed less than five percent of the total capacity required to meet demand on January 7

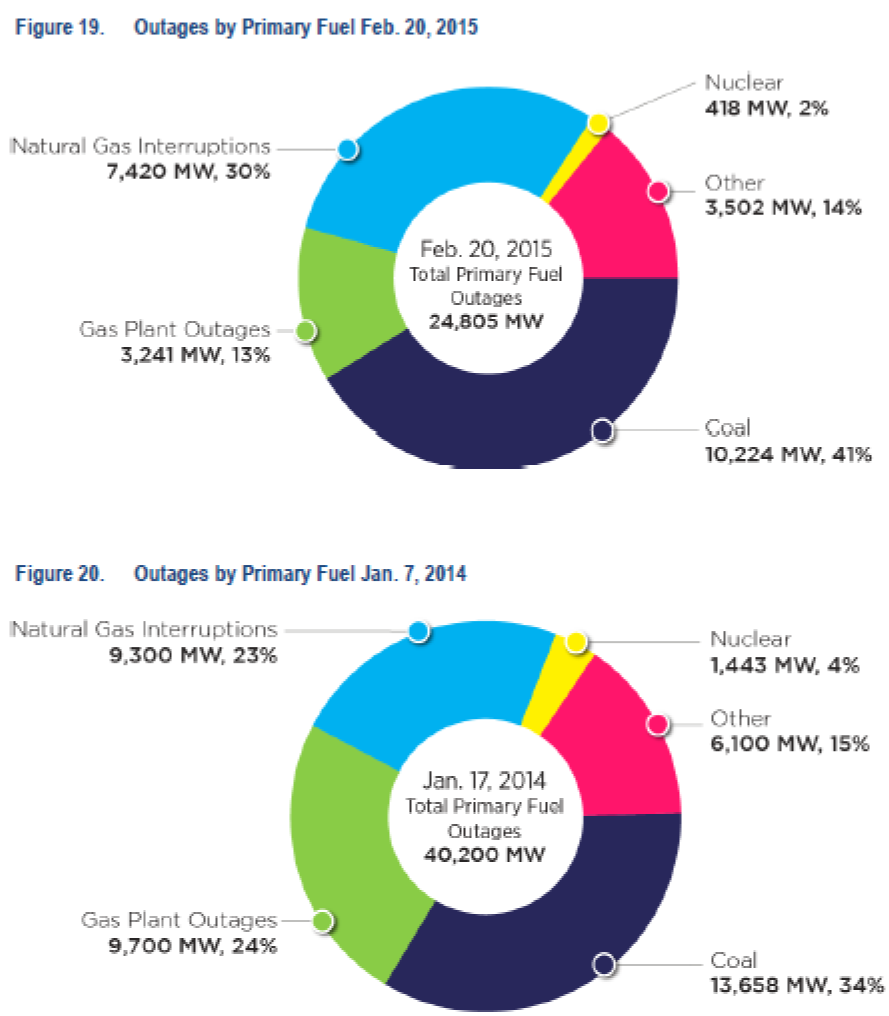
- Equipment issues associated with both coal and natural gas units made up the far greater proportion of forced outages[7]

To be sure, the 2014 Polar Vortex exposed some electric industry vulnerabilities associated with the transportation of natural gas to generators in the PJM region. This is a work in progress.

PJM has taken a number of actions since the 2014 Polar Vortex to improve generation performance, many of which were implemented by winter of 2015 and did result in a reduction in total forced outages of 15,395MWs (38.3%) on the two dates shown in Figure 1 below under similar temperature, weather and system loads.

[7] *Winter 2013-2014 Operations and Market Performance in Regional Transmission Organizations and Independent System Operators,* Statement of Michael J. Kormos Executive Vice President – Operations, PJM Interconnection, L.L.C. at 3-4, Docket No. AD14-8-000 (May 15, 2014) ("Kormos Statement").

Figure 1: Comparison of Outages by Primary Fuel[8]



Changes implemented in advance of the 2015 winter included:

- Development of a Cold Weather Preparation Guideline and Checklist.
    - Utilized annually to prepare generators for extreme cold weather
    - PJM Manual 14D: Attachment N

- Implementation of the Generation Resource Operational Exercise.

[8] See *2015 Winter Report* at 21 (May 13, 2015) which can be found at http://pjm.com/-/media/library/reports-notices/weather-related/20150513-2015-winter-report.ashx?la=en.

    - PJM identifies units that did not operate, or operate on its alternate fuel, in the 8 weeks prior to Nov 1st, and also on a rolling two week basis through mid-December, and will schedule a test of the unit to ensure operability on either the primary or alternate fuel.

    - PJM also provides cost recovery for the tests for any non-Capacity Performance units.
- Improved generator fuel supply surveys with enhanced focus on fuel supply and emissions limitations.

- Improved gas-electric coordination including secure data exchange with information sharing of pipeline restrictions and gas fired generation nominations in the day ahead market.

- Improved tools for better situational awareness with a geographic information system including gas pipelines and associated generation and locational visibility to curtailable load in the Dispatch Interactive Mapping application.

These actions by PJM as well as the generation owners to improve generator performance and communications were effective in reducing generator outages. In many cases however, these actions are voluntary and thus PJM has taken other steps to improve performance.

For instance, PJM evolved its capacity market to the Capacity Performance construct which is aimed at incentivizing performance not by proscribing specific requirements for each fuel type, but, rather, incentivize better performance in a resource-neutral way. Through stricter performance requirements, incentives and charges for non-performance, Capacity Performance holds capacity resources accountable to make the necessary investments and operational improvements required to ensure delivery of energy when needed most. These investments include not only firming fuel supply, and investing in dual-fuel capability (which combines back-up oil fuel with primary natural gas fuel), but also will also provide incentive to make investments to ensure the generator equipment itself will perform better under extreme cold (more insulators, heaters, etc.), increased staffing, capital investments for better operational flexibility, and cold-weather testing on alternate fuels. These investments are based on risks to performance that a resource can anticipate, plan for, budget for and implement.

Another area in which PJM has made improvements relates to the operating challenges that the daily market timing differences in the two industries pose for generators scheduling gas. In effect, gas delivery to generators begins ten hours after PJM's operating day begins at midnight. Generators must straddle two consecutive gas operating days to cover one electric operating day, thus complicating gas procurement for generation. To mitigate this operational challenge and at the direction of the Commission in Order No. 809,[9] PJM changed the timing of the Day-Ahead

[9] *Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities*, Final Rule, 151 FERC ¶ 61,049 (2015).

Market to better align with the natural gas pipelines' nomination timelines. Under the new schedule, PJM posts Day-Ahead Market results by no later than 1:30 p.m. eastern, which is in advance of a new 2 p.m. eastern Timely Nomination cycle deadline for generators to procure the delivery of natural gas to their units. These changes went into effect on April 1, 2016.

As a result of the described changes, PJM believes it is well prepared for an extreme winter event.

Question 3

The proposed rule also references the impacts of other extreme weather events, specifically hurricanes Irma, Harvey, Maria, and superstorm Sandy. Do commenters agree with the proposed rule's characterization of these events? For extreme events like hurricanes, earthquakes, terrorist attacks, or geomagnetic disturbances, what impact would the proposed rule have on the time required for system restoration, particularly if there is associated severe damage to the transmission or distribution system?

PJM Response

As explained in more detail in the body of PJM's comments[10] PJM does not agree with the proposed rule's characterization of the listed weather events. To the contrary, extreme weather events impact distribution and in some cases transmission much more readily than generation resources' operational failures or lack of fuel supply. And, as a result of the impacts to the transmission and distribution systems, generation resources typically are rendered undeliverable during and immediately following such weather events, regardless of the status of the resource itself.

This point is supported by NERC's "Hurricane Sandy Event Analysis Report," which evaluated the storm's impact on the bulk power system, including both generation and transmission assets. NERC found that "[w]hile there was sufficient generation capacity available to meet the load as restoration progressed; there were some cases where customer restoration was hindered by local area transmission outages."[11] NERC's evaluation found that "[o]ver the course of the event, 20,007 MW of generation capacity was rendered unavailable,"[12] including what

[10] PJM Comments at section II.A.

[11] *Hurricane Sandy Event Analysis Report*, North American Electric Reliability Corporation at 5 (Jan. 2014), http://www.nerc.com/pa/rrm/ea/Oct2012HurricanSandyEvntAnlyssRprtDL/ ("NERC Hurricane Sandy Report").

[12] *Id.*

DOE calls "fuel secure" nuclear, coal, and other fossil fuel resources.[13] The same can be said with respect to the devastation caused by hurricane Maria, where roughly 80% of the transmission system in Puerto Rico is above ground, and they lost approximately 75% percent of that infrastructure (in other words, 60% of all their transmission towers/lines were knocked down). As far as distribution goes, the loss was higher with about 85% of all lines/pole damaged or destroyed. The lead time associated with getting those pieces back is the true reason behind the length of this outage. Capacity was available within 72 hours of the event (and still is), but they can't get it connected to load.

Another factor that underscores the lack of basis concerning the DOE NOPR is that coastal nuclear facilities located in the PJM Region adhere to varying protocols whereby they may choose to shut down when sustained high winds, in some cases as low as 42 MPH, are expected.

Question 4

The proposed rule references the retirement of coal and nuclear resources and a concern from Congress about the potential further loss of valuable generation resources as a basis for action. What impact has the retirement of these resources had on reliability and resilience in RTOs/ISOs to date? What impact on reliability and resilience in RTOs/ISOs can be anticipated under current market constructs?

PJM Response

Resource diversity is a valid topic of study, and PJM regularly examines the potential reliability impacts of a changing resource mix, including impacts associated with coal plant retirements driven by the high compliance costs of the United States Environmental Protection Agency's Mercury and Air Toxics Standards. As discussed above, the retirement of those resources has had no significant impact on reliability as defined by the relevant NERC criteria, and PJM has not identified the retirement of coal and nuclear resources as a material reliability concern under current market constructs. As discussed in the Evolving Resource Mix and Reliability Report, PJM can operate reliably at much higher levels of natural gas and renewables, and much lower levels of coal and nuclear. PJM's analysis revealed that operational reliability would be maintained even if all coal and nuclear resources in the expected near-term portfolio retire, and are replaced exclusively by natural gas.[14]

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[13] NERC also identified "[s]everal generation operation risks" from the storm, including: (1) increased potential for Loss of Off-site Power to nuclear facilities; (2) possibility of LOOP due to switchyard damage, or loss of normal condenser cooling and loss of availability of service water due to high water; (3) precipitator fly ash buildup and higher gas flow pressure due to operating without auxiliary feeds; (4) curtailments due to wet coal, which is normal with any significant precipitation; (5) danger from the loss of building siding; and (6) potential lack of fuel due to damage to the fuel provider's facilities. *Id.* at 23.

[14] *See PJM's Evolving Resource Mix and System Reliability* at 5 & n.15 (March 30, 2017) ("Evolving Resource Mix and Reliability Report"), which can be found at the following URL: http://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx

"Resilience" (or lack thereof) within the resource context, as distinguishable from reliability, was not adequately defined in the DOE NOPR, but PJM understands it generally as a risk metric that potentially could be addressed through resource portfolio diversification. Therefore, in a theoretical sense, some improved measure of resource or fuel diversity or flexibility could potentially improve resilience because of a more diversified portfolio of resilience-related attributes, however identified or defined. For example, on-site liquid fuel for dual-fuel combustion turbines, as acknowledged under PJM's Capacity Performance construct, narrowly could be viewed as a resilience-related attribute under some reliability scenarios associated with the natural gas pipeline infrastructure and gas-electric coordination. However, resilience, as distinct from reliability, typically is not viewed only within a narrow resource context. Instead, resilience typically is viewed within the context of the entire bulk electric system, and relates to preparing for, operating through, and recovering from a high-impact, low frequency event.[15] Resilience involves protecting the bulk electric system as a whole and must take into consideration myriad aspects of the system such as transmission and distribution infrastructure, fuel security such as through gas/electric coordination, markets, physical and cyber security, and advanced system restoration. Therefore, the DOE NOPR's emphasis on resilience as a resource issue is mostly misplaced.

Question 5

Is fuel diversity within a region or market itself important for resilience? If so, has the changing resource mix had a measurable impact on fuel diversity, or on resilience and reliability?

PJM Response

Yes, fuel diversity within a region or market is important for resilience. The current resource mix in PJM is the most fuel diverse it has ever been, and recent changes in the resource mix have positively impacted fuel diversity by incorporating a larger percentage of natural gas and renewables. If we proceed from the theoretical proposition that portfolio diversity reduces risk, we can reasonably surmise that PJM's increased fuel diversity, and the flexibility it provides, has *reduced* resilience and reliability risks. However, as indicated in the Evolving Resource Mix and Reliability Report, more focused research on the topic of resilience may be needed, including identifying and defining resilience attributes.[16]

Indeed, while PJM has taken steps such as its Capacity Performance reforms and winter preparedness in response to the extreme weather conditions during the 2014 Polar Vortex, PJM believes more work should be undertaken with respect to ensuring resource performance and fuel security. That is, even though PJM's resource mix is diverse, PJM will continue efforts to review system resilience from a fuel security perspective and will continue to evaluate generation performance incentives.

[15] *See Id.* at 5 and n.16.

[16] *Id.* at 6-7.

II. Eligibility

A. General Eligibility Questions

Question 1

In determining eligibility for compensation under the proposed rule, should there be a demonstration of a specific need for particular services? What should be the appropriate triggering and termination provisions for compensation under the proposed rule?

PJM Response

Yes, there must be a demonstration of need to support compensating any resource on our system on an out-of-market basis for any wholesale service it provides. RMR agreements today need to be justified before the Commission and are limited both in scope and duration. PJM does not believe that a sweeping designation of all units, irrespective of their location, cost structure or performance record is an appropriate substitute for market-based solutions and the very limited and targeted out-of-market solutions as a backstop. For all the reasons presented in the body of PJM's comments[17] PJM does not believe there has been a demonstration of need for the proposed cost-of-service compensation to, in effect, coal and nuclear resources.

Nevertheless, to the extent the Commission seeks to value the resilience attributes of a resource through a cost-of-service rate, an approach similar to a reliability must run[18] concept, which is in place today, could, under certain limited circumstances under RTO-specific rules, could provide a far more appropriate model. First, there would need to be well-defined criteria for determining if the resource is, in fact, needed for resilience to ensure a resource is actually needed for such service. Second, just like PJM's reliability must run provisions which are time-limited to the time between when a resource would seek to retire, and the time it takes to mitigate the impact of such retirement, so too should any RMR-like cost recovery be limited to the time in which the resilience attributes defined by the criteria are replaced.

Question 2

As the proposed rule focuses on preventing premature retirements, should a final rule be limited to existing units or should new resources also be eligible for cost-recovery? Should it also include repowering of previously retired units? Alternatively, should there be a minimum number of MW or a maximum number of MW for resources receiving cost-of service payments

[17] PJM Comments at section II.A., B., and C.

[18] PJM's reliability must run rules are contained in the deactivation section of its Open Access Transmission Tariff ("Tariff"), Part V. These rules provide a mechanism for compensating a generation resource to remain on line despite a documented plan to retire, if loss of such unit presents a reliability issue. But, the compensation is provided only until such time any reliability mitigation measures, such as a new generation resource coming on line or a transmission solution is in service, are in place.

for resilience services? If so, how should RTOs/ISOs determine this MW amount? Should this also include locational and seasonal requirements for eligible resources?

PJM Response

PJM does not agree with the premise of the proposal.

Question 3

Are there other technical characteristics that should be required for an eligible unit besides on-site fuel capability? If so, what are those technical characteristics and what benefits do they provide? What types of resources can meet the proposed eligibility criteria of the proposed rule? What proportion of total current generating capacity does this represent?

PJM Response

See prior responses in this section.

Question 4

If technically capable of sustaining output for a sufficient duration (and meeting other relevant requirements), should resources such as hydroelectric, geothermal, dual-fuel with adequate on-site storage, generating units with firm natural gas contracts, or energy storage (each of which might have a demonstrable store of energy to draw upon to sustain an electrical output, if not necessarily fuel) also be eligible? Why or why not? If technical capability is the appropriate criterion for eligibility, what specific technical capability should be required to be eligible?

PJM Response

The Staff's noting of the attributes of these particular resources in this question points out the unworkability of the DOE's arbitrary designation of a more narrow set of resources when different types of units provide different but needed reliability attributes to differing degrees.

Question 5

The proposed rule would require that eligible resources be able to provide essential energy and ancillary reliability services and includes a non-exhaustive list of services. What specific services should a resource be required to provide in order to be eligible?

PJM Response

See response to prior questions in this section.

Question 6

The proposed rule would limit eligibility to resources that are not subject to cost of service rate regulation by any state of local regulatory authority. How should the Commission and/or RTOs/ISOs determine which resources satisfy this eligibility requirement?

PJM Response

The DOE NOPR requires an examination of the regulatory structure as well as revenue streams available to individual coal and nuclear units. This is not an easy task given that in a number of cases, states do not operate under pure cost of service ratemaking which ties specific dollars to specific plants. As a result of rate settlements and the bundled nature of ratemaking, returns are not established on a unit by unit basis in the state ratemaking process. For this reason, PJM is not clear how the DOE intends FERC to actually implement this identification. Nevertheless, this examination and categorizing of different regulatory regimes is not a matter that should be assigned to the RTOs as it is outside of their core mission or area of expertise.

B. 90-day Requirement

Question 1

The proposed rule defines eligible resources as having a 90-day fuel supply. How should the quantity of a given resource's 90 days of fuel be determined? For example, should each resource be required to have sufficient fuel for 24 hours/day and sustained output at its upper operating limit for the entire 90-day period? Would there be any need for regional differences in this requirement?

PJM Response

For the reasons stated in PJM's response to the question on the Need for Reform, as well as discussed in the body of PJM's comments PJM does not believe there is a basis for the DOE's proposal. That said, the 90-day requirement is arbitrary at best. For instance, recent studies, including the Black Sky/Black Start Protection Initiative, suggest that 30 days of fuel inventory would be required to adequately respond to Black Sky type events.[19] And, even if a resource has 90 days of supply, it does not mean it will be able to operate during extreme weather events where a coal pile freezes or the threat of sustained high winds may cause a nuclear facility to shut down, as discussed above.

[19] *See* Black Sky/Black Start Protection Initiative which can be found at the following URL: http://eiscouncil.org/App_Data/Upload/BSPI.pdf

Question 2

Is there a direct correlation between the quantity of on-site fuel and a given level of resilience or reliability? Please provide any pertinent analyses or studies. If there is such a correlation, is 90 days of on-site fuel necessary and sufficient to address outages and adverse events? Or is some other duration more appropriate?

PJM Response

PJM is not aware of any such showing.

C. Fuel Supply Requirement

Question 1

The proposed rule requires that resources must be in compliance with all applicable environmental regulations. How should environmental regulations be considered when determining eligibility? For example, if a unit that was capable of keeping 90-days of fuel on-site was subject to emission limits that would prevent it from running at its upper operating limit for 90 days, should that unit be eligible under this proposed rule?

PJM Response

For the reasons stated in PJM's response to the question on the Need for Reform, as well as discussed in the body of PJM's comments PJM does not believe there is a basis for the DOE's proposal. Nevertheless, environmental restrictions should be taken into account when evaluating the eligibility of a resource to be compensated pursuant to a well-defined resilience reason (which resilience criteria is lacking in the DOE NOPR). Absent the ability for the generator to run for 90-days without being emissions restricted, it would not make sense to guarantee 100% compensation for a unit that is environmentally related.

Question 2

As the proposed rule references the need for resilience due to extreme weather events, including hurricanes, should there be any other eligibility criteria for the resource or fuel supply (e.g., storm hardening)? What considerations should be given to the vulnerability of 90-day fuel supplies to natural or man-made disasters such as extreme cold temperatures, icing, flooding conditions, etc. that may impact the on-site fuel supply?

PJM Response

It is unclear to PJM how the 90-day fuel supply requirement proposed by the DOE will improve resilience during extreme weather events. Recent examples of hurricanes Sandy and Maria have shown that the distribution system as well as the transmission system are limiting factors in maintaining electricity delivery to loads during extreme weather events. PJM believes that shifting the focus to hardening the distribution network and enhancing the planning requirements of the transmission system to include such severe weather events would have a much more significant impact on the resilience of the power system.

Question 3

Does the vulnerability or non-availability of on-site fuel supplies vary depending upon fuel type, location, region, or other factors?

PJM Response

Fuel type is just one component of a unit's availability in a given situation. One cannot generalize to 'select' one set of fuels over another. Rather, PJM urges consideration of analysis of reliability attributes consistent with PJM's recent analysis.[20] Ongoing review of fuel security and generation performance is also important to ensure a resilient system. That analysis was cited approvingly in the DOE August study but seems to have been disregarded for purposes of the DOE proposed NOPR.

III. Implementation

Question 1

How would eligible resources receiving cost of service compensation under the proposed rule be committed and dispatched in the energy market?

PJM Response

Such resources should be required to offer into the energy market at no less than their actual cost. Because such resources would be receiving cost of service compensation, they may have an incentive to offer into the energy market at below their actual cost. Doing so, however, would inappropriately suppress energy market prices, thereby distorting the price signals provided by the market for efficient resource entry and exit.

The DOE NOPR overlooks the fact that even with full cost of service recovery for the existing nuclear and coal fleet, PJM will still need to call on merchant generation in order to meet load in many hours. Yet the DOE subsidy of these units does serious violence to the market signal which the market is intended to send as to the value of all resources. Moreover, it will be harder to attract capital for new merchant generation which still will be needed to meet load, given that investors will flock to the new 'guarantee' created by DOE.

Question 2

How would eligible resources receiving cost based compensation under the proposed rule be considered in the clearing and pricing of centralized capacity markets?

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[20] Evolving Resource Mix and Reliability Report.

PJM Response

Such resources should be required to offer into centralized capacity markets at no less than their actual going forward costs. Alternatively, resources could offer into these markets at below their going forward costs, if the market operator has adopted a mechanism by which the clearing price determined in those markets can be reconstituted to the competitive price for the purpose of compensating all unsubsidized resources in the market. Not adopting one of these two requirements would result in inappropriate price suppression in the capacity markets that would distort price signals and interfere with the markets' ability to drive efficient resource entry and exit.

However, even with these market safeguards, the distorting impact of the DOE subsidy will discourage investment in the kind of resources that do not meet the DOE-defined eligible class even though they will continue to be needed to meet load demands.

Question 3

What is the expected impact of this proposed rule on entry of new generation, reserve margins, retirement of existing resources, and on resource mix over time?

PJM Response

To the extent these resources are uneconomic and would otherwise retire and exit the market, even with the above protections the rule would have a negative impact on the markets' ability to drive efficient resource entry and exit. The continued operation of uneconomic resources in the market due to the presence of outside-the-market subsidies suppresses clearing prices, erodes investor confidence and stifles the innovation that has made the market successful and resulted in more reliable electric service at the lowest reasonable cost to consumers.

The impact on the reserve margin is dependent on the performance of the resources. To the extent the performance is, on average, worse than the average performance of the PJM fleet, then it will increase the Installed Reserve Margin.

Question 4

Should there be performance requirements for resources receiving compensation under the proposed rule? If so, what should the performance requirement be, and how should it be measured, or tested? What should be the consequence of not meeting the performance requirement?

PJM Response

Yes, the performance requirements on such resources should be identical to the performance requirements applied to all units in the market. Further, and critically, any penalties for non-performance, whether financial or physical, should not be recoverable through the cost-of-service rates envisioned in the rule. Allowing such recovery of performance penalties would nullify the intended impact of the penalties to drive resource performance that supports system reliability.

<u>Question 5</u>

Should there be any restrictions on alternating between market-based and cost-based compensation?

<u>PJM Response</u>

This should be a one-time choice for any given unit. To allow switching between compensation methods would invite gaming by market participants based upon expectations as to where the greatest revenue could be earned at the expense of load.

IV. Rates

<u>Question 1</u>

The proposed rule lists compensable costs that should be included in the rate as operating and fuel expenses, costs of capital and debt, and a fair return on equity and investment. Are there other costs that would be appropriate to be included in the rate? Would any of the listed costs be inappropriate for inclusion?

<u>PJM Response</u>

PJM does not take a position on this question.

<u>Question 2</u>

Should wholesale market revenues offset any cost of service payments stemming from the proposed rule?

<u>PJM Response</u>

Although clearly wholesale revenues should be offset from cost of service recovery to avoid over-recovery, the distorting impact of this 'true up' for a select set of 'eligible' resources points out the discriminatory and unworkable nature of the DOE proposal.

<u>Question 3</u>

How should RTOs/ISOs allocate the cost of the proposed rule to market participants?

PJM Response

While PJM does not believe that the proposed rule meaningfully improves reliability or resilience, if it is accepted, it will be on the belief that it does. Therefore, if accepted, the costs should be allocated to the expected beneficiaries which would be real-time load and exports. Further, because the proposal is sweeping and requires compensation without regard to the locational value of any eligible resource, an allocation pro-rata across all load and exports would be consistent with the sweeping nature of the proposal itself given that it is difficult to identify specific loads as benefiting more than others from the DOE proposal and allocating costs along traditional "cost causation" grounds.

Question 4

How would the requirement that eligible resources receive full cost recovery be reconciled with the requirement, as stated in the regulatory text, that resources be dispatched during grid operations?

PJM Response

This question points out another inconsistency in the DOE proposal. Units are entitled to receive 'full cost recovery' including a return irrespective of whether they actually operate. The only way to reconcile this is to limit recovery to those hours when the units are determined to be needed to meet specific locational or system-wide reliability conditions during emergencies. Of course, this limitation appears inconsistent with the DOE's proposal making the two difficult to reconcile.

V. Other

Question 1

The proposed requirement for submitting a compliance filing is 15 days after the effective date of any Final Rule in this proceeding, with the tariff changes to take effect 15 days after the compliance filings are due. Please comment on the proposed timing, both to develop a mechanism for implementing the required changes and to implement those changes, including whether or not such changes could be developed and implemented within that timeframe.

PJM Response

PJM incorporates by reference the response of the ISO/RTO Council to this question.

Question 2

Please comment on the proposed rule's estimated burden of $291,042 per respondent RTO/ISO, to develop and implement new market rules as proposed, including the potential software upgrades required to do so.

PJM Response

PJM incorporates by reference the response of the ISO/RTO Council to this question.

Question 3

Please describe any alternative approaches that could be taken to accomplish the stated goals of the proposed rule.

PJM Response

Please refer to the body of PJM's comments in section III concerning PJM's review of price formation reforms for the PJM Region.

Question 4

What impact would the proposed rule have on consumers?

PJM Response

Given the lack of details provided in the DOE NOPR, and the extremely short time frame in which to provide comments, PJM has not conducted analyses to provide a meaningful response to this question.

Question 5

The Commission may take notice of relevant public information, including information in other Commission proceedings. If a commenter views information in another Commission proceeding as relevant to the proposed rule, please identify that information and explain how it is relevant to the proposed rule. Such information may include a filing previously submitted by the commenter.

PJM Response

Below is a partial list of public information and Commission proceedings relevant to the proposed rule. Please also refer to the various proceedings and reports referenced throughout the body of PJM's comments.

(1) PJM's October 19, 2017 presentation to the Commission on winterization, which includes information on PJM's resilience-related activities and studies associated with gas-electric coordination, natural gas pipeline modeling and contingencies, cyber security, and potential storm surge impacts, https://www.ferc.gov/industries/electric/indus-act/rto/10-19-17-A-4-PJM.pdf. This information is relevant to the proposed rule because it demonstrates the scope and breadth of PJM's resilience-related activities, unrelated to an arbitrary on-site fuel requirement for favored resources.

(2) PJM's report on price formation issues submitted on February 17, 2016 in Docket No. AD14-14-000, *Price Formation in Energy and Ancillary Services Markets in Regional Transmission Organizations and Independent System Operators,* which summarize PJM's price formation issues and activities up to that time. The report is relevant to the proposed rule because it provides information on PJM's price formation efforts to promote resource flexibility and performance, as discussed in these comments.

(3) PJM's Report on Fuel Assurance Activities, submitted on February 18, 2015 in Docket No. AD14-8-000, *Winter 2013-2014 Operations and Market Performance in Regional Transmission Organizations and Independent System Operators*, in which PJM reported on the status of its efforts to address market and system performance issues associated with generator access to sufficient fuel supplies and the firmness of generator fuel arrangements. These fuel assurance activities are relevant to the proposed rule because they represent concrete actions that PJM already has taken to ensure fuel availability during extreme events, such as potential events similar to the Polar Vortex.

(4) The Commission proceedings in Docket Nos. ER15-623 and EL15-29 regarding PJM's Capacity Performance construct, which better ensures that committed capacity resources will perform when called upon to meet the reliability needs of the PJM region. The Capacity Performance construct is relevant to the proposed rule because it demonstrates concrete action that PJM already has taken to ensure resource availability and reliability during extreme events, such as potential events similar to the Polar Vortex.

(5) PJM's post-technical conference comments submitted on May 15, 2014 in Docket No. AD14-8-000, *Winter 2013-2014 Operations and Market Performance in Regional Transmission Organizations and Independent System Operators*, which reference the PJM report entitled *Analysis of Operational Events and Market Impacts during the January 2014 Cold Weather Events*, http://www.pjm.com/~/media/library/reports-notices/weather-related/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx (May 8, 2014). The comments and report are relevant to the proposed rule because they describe actual extreme events, associated with the Polar Vortex, to which PJM already has responded with concrete action to ensure resource availability and reliability.

APPENDIX B

to

PJM COMMENTS IN RM18-1-000

OCTOBER 23, 2017

HARVARD Kennedy School
JOHN F. KENNEDY SCHOOL OF GOVERNMENT

October 23, 2017

Mr. Stu Bresler
Senior Vice President Operations & Markets
PJM Interconnection
2750 Monroe Blvd
Audubon, PA 19403

SUBJECT: PJM Price Formation

Dear Mr. Bresler:

I participated with the PJM staff and Board members in the discussion of an important initiative in the evolution of the PJM energy market. PJM staff is proposing to reform the existing pricing model in order to ensure that the incremental cost of serving load is reflected in LMP to the fullest extent possible, uplift is reduced and incentives are maintained. This follows the principles of sound market design. Enhanced energy market price signals will strengthen performance incentives in PJM's markets and is complementary to other reforms being considered by PJM. Given my knowledge of the PJM resource profile, this reform would be an appropriate step forward in price formation for the PJM region.

The market design in PJM follows the basic principles of bid-based, security-constrained, economic dispatch with locational prices. This design is the only approach that is consistent with an efficient energy market under the principles of open-access and non-discrimination. A crucial element of this model is that the prices and related payments support the efficient dispatch. In particular, it serves to achieve the goal that market participants who take prices as given would have no incentive to deviate from the dispatch, and would help make bids and offers consistent with their underlying costs.

The foremost element of this market design is the use of locational marginal prices. Under certain simplifying assumptions, these locational marginal prices provide all that would be needed to support the efficient dispatch. Relying on the locational marginal prices has served the PJM markets well for many years, even though in some circumstances additional payments have been required.

I have discussed with PJM staff the circumstances that deviate from the simplifying assumptions required for locational marginal prices alone to provide full support for efficient operations. Most prominent are conditions where the problem expands to include commitment decisions with start-up costs and associated constraints such as minimum output levels and minimum run-times. Under these conditions, locational marginal prices alone cannot always be guaranteed to support the efficient outcome and additional associated payments are made that must be recovered as part of an "uplift" charge. The additional payments in aggregate equal the foregone profits from following the dispatch. PJM has explained that within the PJM region, its resource profile, flattening price curves and reduced infra-marginal rents have brought the limitations of the locational marginal prices to the forefront and that the PJM market as a whole would benefit from the proposed enhancements for price formation.

The use of locational prices is still indicated, but the choice of these prices has effects on the amount of the uplift. There is an argument for choosing the locational prices, that cover the bulk of the energy revenues, to come as close as possible to minimizing the need for the additional uplift payments. As I have discussed with PJM staff, this ideal case both supports the dispatch and minimizes the uplift.[1] However, this approach presents computational requirements that would be challenging under the best of circumstances, and even more difficult to apply in the short intervals required for the real-time spot market.

A natural approximation to the minimum-uplift model is available in the "integer relaxation," as PJM intends to propose. This approach employs a pricing model that relaxes the complicating commitment constraints and restores the simplifying assumptions to ensure that the marginal price of the system will not decrease when demand increases. The locational marginal prices from this relaxed model would be easy to obtain. Under certain conditions, the prices from the integer relaxation would be the associated minimum-uplift prices. In general, the integer-relaxation prices should be close to providing the minimum uplift results.

Importantly, the enhanced price formation PJM intends to propose would be compatible with other reforms that are part of the larger discussion in PJM. For example, the enhanced pricing would be extended in practice to deal with multi-period problems where ramp rates and other flexibilities are important. Furthermore, the enhanced pricing model could accommodate improved scarcity pricing which should play a prominent role in adapting to changing market conditions with increasing supplies of intermittent or distributed resources.

I support the energy pricing method PJM intends to propose. But I do not expect it likely to produce a dramatic change or have as significant an impact as improved scarcity pricing. Currently PJM's rules for shortage pricing do not accurately value energy and reserves during

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[1] This is known as the "minimum uplift" or "convex hull" approach. See (Gribik, Hogan, & Pope, 2007).

reserve shortages. Based on the current penalty factors, the value of energy and reserves do not approach the estimated value of lost load (VOLL). Additionally, PJM's demand curves do not articulate the reliability value of reserves to the system. To fully address price formation, reforms are required to PJM's shortage pricing approach as well. Nonetheless, PJM's proposal to implement integer relaxation is a beneficial and essential first step toward solving the bigger issue of a more comprehensive enhancement of energy and reserve price formation. And given the circumstances faced by PJM as described above, I am supportive of this approach as a reasonable and appropriate step to be proposed by PJM as a means to address needed price formation reforms in the PJM market.

Very truly yours,

William W. Hogan[2]
Raymond Plank Professor of Global Energy Policy
John F. Kennedy School of Government
Harvard University
Mail Box 84
79 John F. Kennedy Street
Cambridge, MA 02138

Reference

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[2] Note: These comments are those of William Hogan, and do not necessarily represent the views of anyone else. The work has been supported by PJM and FTI Consulting.