Evaluation of the DOE's Proposed Grid Resiliency Pricing Rule

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Executive Summary

On September 28, 2017, the Department of Energy ("DOE") proposed a rule for final action by the Federal Energy Regulatory Commission ("FERC") that would place eligible coal and nuclear units in certain FERC-jurisdictional markets under cost-of-service tariffs. DOE referred to a significant "resiliency" risk that could be mitigated if nuclear and coal plants with 90 days of on-site fuel supply were deterred from "premature retirement" via payments that would fully cover the cost of their operations.

This report examines the premise that certain regional electricity markets currently are (or soon will be) insufficiently resilient, analyzes whether and how preserving coal and nuclear generating plants with 90 days of on-site fuel would mitigate such risk, estimates the costs of the proposed rule, and discusses how the proposed rule would affect competitive wholesale electricity markets.

In contrast to the well-developed and managed issue of electric service reliability, the understanding and analysis of electricity grid resilience is still developing. Overall, the U.S. electricity grid's reliability has withstood significant shifts in the generation fleet as well as extreme weather events, such as the Polar Vortex experienced in eastern portion of North America during January 2014. While reliability and many of its important dimensions have improved over time and are continuing to evolve, regional transmission system operators ("RTOs") and their stakeholders have been improving their wholesale power market designs, operational processes, and system planning. All of those activities are being conducted under the purview of FERC and the North American Electric Reliability Corporation ("NERC").

The emerging concept of resilience is broader than reliability and focuses on how critical infrastructure manages through and recovers from high-impact, low-probability events, such as severe weather or physical or cyber attacks. Although there are several important questions worth considering, the analyses produced thus far do not support the premise that 90 days of on-site fuel at individual power generating plants would reduce the impact or recovery time of such high impact events.

The DOE's proposed rule does not appear to be supported by an analytic process that follows a typical path of considering objectives, defining threats, adopting metrics to help analyze a range of potential responses, and evaluating the reasonableness and cost-effectiveness of such

responses. The proposal also does not make the necessary linkages between threats to resilience and the offered solution of maintaining substantial on-site fuel inventories at electricity generation facilities that operate in certain organized wholesale markets. Regional considerations are particularly absent. In fact, the proposed rule would primarily affect regions that already have (and will continue to have) the highest proportion of coal and nuclear capacity in the country, which by DOE's measure would make them the most resilient among all of the nation's regional power markets and thus not require intervention.

The proposed rule would compensate merchant generation owners of nuclear and coal plants with 90 days of on-site fuel for their operating costs as well as a fair return on investment. Because many of the potentially eligible plants are currently earning market revenues that are less than what the proposed rule defines as cost-based compensation, most of the eligible plants would receive additional payments under the rule.

We estimate that between 57,000 and 88,400 MW (57.0-88.4 GW) of coal and nuclear generating capacity in the PJM Interconnection ("PJM"), Midcontinent ISO, New York ISO, and ISO New England regions would be eligible to receive additional payments under the proposed DOE rule. Based on 2016 market conditions, these out-of-market payments would likely range from $3.7 billion to $11.2 billion per year. Approximately 60% of that, or about $2.3 billion to $7.5 billion, would occur in the PJM regional market. This is substantial in comparison to PJM's entire 2016 wholesale power market transactions of $39 billion.

Estimated Annual Out-of-Market Payments under the Proposed Rule

	Low	High
Capacity Receiving Out-of-Market Payments (GW)	57.0	88.4
Annual Cost of Out-of-Market Payments ($ billions)	$3.7	$11.2

Our estimates are based on approximations of the plants' embedded investment costs, ongoing costs, and market revenues for 2016. The wide range reflects uncertainties about the actual costs of the plants, which are merchant generating facilities for which only a limited amount of public cost data is available. FERC presumably would need to address this challenge through plant-specific cost-of-service proceedings that establish the facilities' revenue requirements under the proposed rule.

The DOE proposal would have broad market impacts beyond simply preserving solid fuel generating capacity by paying generators significant sums to remain in the market. By re-regulating and subsidizing a large portion of the existing merchant generation fleet, the proposed rule would undermine core market principles and diminish some of the most important advantages of competitive wholesale power markets. In addition, implementing the proposed rule would involve many controversial decisions, with potential unintended consequences that would be difficult to address satisfactorily, given the lack of guiding principles and the limited amount of time allowed.

Overall, the proposed rule would be costly and would conflict with the principles of competitive markets without providing any assured or measurable contribution to the electricity grid's reliability or resilience. While power system resilience is an important and multi-faceted area that the industry still needs to analyze and address, multiple industry studies and all available evidence shows that no emergency or urgency currently exists that would require immediate action, particularly not action focused on merchant generating plants with 90-days of on-site fuel storage.

I. Introduction

On September 28, 2017, the Secretary of Energy Rick Perry proposed a rule for final action by the Federal Energy Regulatory Commission ("FERC") under section 403 of the Department of Energy Organization Act.[1] The Notice of Proposed Rulemaking ("NOPR") states that the available facts indicated a significant "resiliency" risk in the organized markets in the U.S. that could be mitigated if nuclear and coal plants with 90 days of on-site fuel supply were deterred from premature retirement. Secretary Perry proposed a rule that would place eligible plants under a cost of service tariff, which would offer financial relief to these generation owners and presumably be recouped through charges administered to customers.

This report examines the proposal's premise and implied conclusion that certain regional electricity markets currently are (or soon will be) insufficiently reliable and resilient, and that preserving coal and nuclear generating plants with at least 90-days of on-site fuel storage is critical and urgent for mitigating such risk.[2] In addition, we estimate the costs and assess how the proposed rule relates to the competitive wholesale electricity markets that FERC has been supporting and developing over the past decade and a half.

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1 Department of Energy Notice of Proposed Rulemaking, Docket No. RM17-3-000 "Grid Resiliency Pricing Rule" September 28, 2017, ("NOPR") published in the Federal Register Vol. 82 No. 194 Tuesday October 10, 2017 (82 FR 46,940).

2 The terms "resilience" or "resiliency" or "resilient" are not defined in the DOE NOPR. In Appendix A we document a range of definitions used in recent studies and describe some features of resilience that motivate those analyses. In general, resilience is the ability of the overall transmission and generation system to withstand disruptive events and/or to recover to normal or adequate operations in an acceptable period of time.

II. Evaluation of the Need for the Proposed Rule

The DOE NOPR states:

> The resiliency of the nation's electric grid is threatened by the premature retirements of power plants that can withstand major fuel supply disruptions caused by natural or man-made disasters and, in those critical times, continue to provide electric energy, capacity, and essential grid reliability services. These fuel-secure resources are indispensable for the reliability and resiliency of our electric grid—and therefore indispensable for our economic and national security.[3]

This conclusion does not comport with analyses and recommendations available from the Department of Energy ("DOE"), the Federal Energy Regulatory Commission, the North American Electric Reliability Corporation ("NERC"), the National Laboratories, the National Academy of Sciences, and the regional transmission organizations ("RTOs") and independent system operators ("ISOs") themselves. These other groups present "resilience" as a concept that is only in its early stages of development, and do not identify an urgent need to prevent additional retirements of generating resources with on-site fuel.

In contrast to the emerging understanding of resilience, reliability is a fully developed, operational concept that is actively—and successfully—managed by RTOs/ISOs. These processes also evolve to address emerging challenges such as the changes in the composition of the generation fleet over time. No particular reliability metrics indicate an imminent, unmanageable threat. All indicators are that reliability criteria continue to be met in spite of recent retirements. It is difficult to discern how DOE's proposed rule to maintain the availability of generation with 90 days of on-site fuel might be necessary or would meaningfully improve on the system reliability metrics directed by NERC.

A. Indications from Traditional Reliability Metrics

Planning for reliability in the power industry consists of two main components: resource adequacy and system security. Metrics that support and enable monitoring and planning to

[3] 82 FR 46,941.

maintain resource adequacy and system security are well understood and widely accepted.[4] Neither aspect appears to be threatened with imminent reliability risk, such that major intervention would be required.

1. Resource Adequacy

"Resource adequacy" refers to having resources sufficient to meet peak loads with a high degree of certainty, taking into account the possibilities of extreme load conditions and random generation failures. A common measure of resource adequacy is the planning reserve margin, which is the percentage amount by which installed generating capacity exceeds expected peak load. This concept underlies long-established market rules and policies, many of which predate modern organized markets. The basic goal is to establish planning criteria for reserves that will be adequate during infrequent times when there is the potential for load to exceed available generation. NERC continually monitors and projects future regional resource adequacy metrics such as regional reserve margins, and assesses conditions and trends that might affect generation resource adequacy.

In turn, four RTOs/ISOs administer capacity markets to meet these resource adequacy requirements. RTOs/ISOs continually improve their market rules to address evolving needs as customer usage patterns, generation fleet characteristics, and regulatory circumstances change. Several examples of recent changes are the capacity market redesigns for ISO New England ("ISO-NE") and PJM Interconnection ("PJM") to create stronger real-time incentives for resources to perform when needed. As discussed further below, these changes were implemented after the 2014 Polar Vortex, aiming to reward more reliable resources and induce suppliers to prepare themselves better, for example by securing fuel and winterizing their plants. These specific changes address the security of the grid under new understandings of stress. There is no evidence that they are inadequate to maintain reliability or that the DOE proposal would add anything to address the underlying concerns that motivated these changes.

The most recent surveys find that current and projected resource adequacy will remain within normal bounds and that sufficient generation resources will provide a high level of reliability

[4] For example, long-term reliability planning metrics such as loss of load expectation (or probability) and various operating security contingencies constructs (while always subject to adjustment) have both been in use for decades.

against known and likely contingencies. FERC's recent *Energy Market Assessment for Winter 2017–2018* uses preliminary data from NERC's forthcoming 2017–2018 Winter Reliability Assessment to project healthy reserve margins for all assessment areas.[5] In PJM, where the largest number of retirements has occurred (and where the vast majority of plants eligible under the proposed rule reside), the latest capacity auction indicates substantial surplus: a competitive market result procuring 6.7% more than the 16.6% target adequacy reserve margin for 2020/21.[6] Over longer time scales (5 and 10 years), NERC projects that all U.S. regions will exceed target reserve margins in 2021, with only Midcontinent ISO ("MISO") falling short starting in 2022.[7]

These observations suggest that RTOs/ISOs have managed to maintain both resource adequacy and operational security through the challenges of recent market and regulatory shifts, including the retirement of old generation and the growth of gas-fired and wind and solar generation. While RTOs/ISOs have different mechanisms for ensuring resource adequacy, ranging from enforceable capacity requirements to organized forward capacity markets, none have determined that specific types of capacity require additional support payments to maintain resource adequacy.

2. System Security

"System security" refers to having the infrastructure and procedures to be able to always operate the bulk power system and transmission facilities within established limits. NERC sets system security criteria and requires RTOs/ISOs and transmission operators to follow those criteria

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5 *Energy Market Assessment for Winter 2017-2018,* FERC, FERC Docket No. AD06-3, Item A-3 on FERC October 19, 2017 Meeting, Slide 13. Available at https://www.ferc.gov/market-oversight/reports-analyses/mkt-views/2017/10-19-17-A-3.pdf.

6 *2020/2021 RPM Base Residual Auction Results*, PJM Interconnection, May 23, 2017, p. 1. Available at: http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2020-2021-base-residual-auction-report.ashx. Also see *Third Triennial Review of PJM's Variable Resource Requirement Curve* describing how the market attracted adequate replacement resources. Available at: http://www.pjm.com/-/media/library/reports-notices/reliability-pricing-model/20140515-brattle-2014-pjm-vrr-curve-report.ashx?la=en

7 These values reflect the "Anticipated Resources" case. The reserve margins are higher in the "Prospective Resources" case in which resources in earlier stages of development are considered. *2016 Long-Term Reliability Assessment*, NERC, December 2016, pp. 2-3, 6. Available at: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2016%20Long-Term%20Reliability%20Assessment.pdf

when planning the system for the future and when operating the system. Criteria include normal operating limits as well as preparedness for many different kinds of unexpected disturbances, such as outages of single generation or transmission elements and short circuits.[8] The general concept is making sure that the grid, both transmission and generation, can withstand material shocks, and then be able to return to reliable operations to serve load.

To meet NERC criteria, RTOs/ISOs and utilities plan the transmission system by studying many possible system conditions and contingencies, and planning sufficient redundancy accordingly. RTOs/ISOs further prepare for secure operations by ensuring sufficient operating reserves are online to respond to disturbances. In the operating timeframe, they maintain reliability by continually monitoring the system and enforcing conservative operating limits that allow for the possibility of losing a single large facility at any moment (so-called "N-1 operation"). Other more complex potential system failure modes are also monitored.

In addition to these planning and operating procedures, the RTOs/ISOs use wholesale markets to help meet many aspects of system security, as discussed in Section IV. Occasionally, when markets do not retain specific resources that are necessary to maintain system security (or resource adequacy), RTOs/ISOs also have the ability to grant "reliability-must-run" status to retiring generators to compensate them for remaining online until other capacity or some transmission upgrade can resolve the particular issue.

The U.S. has experienced rare instances of widespread system security failures, such as the July 1996 Western power outages and the August 2003 Northeastern power outage.[9] These have generally arisen from transmission faults, not generation failures. In response, grid operators, planners and regulators have learned from each major transmission-related failure. They address emerging issues and improve planning and operating procedures to mitigate identifiable threats to system security.

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[8] Established criteria do not, however, address widespread attacks or other extreme scenarios that might be more properly considered a resilience issue.

[9] See *The Electric Power Outages in the Western United States, July 2-3, 1996: Report to the President*, U.S. Department of Energy, August 1996 (DOE/PO-0050); also see *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,* U.S.-Canada Power System Outage Task Force, April 2004.

Overall, the U.S. enjoys exceptionally high levels of reliability, even as the composition of the generating fleet changes. According to Gerry Cauley, President of NERC, "the state of reliability in North America is strong and continues to trend in the right direction."[10] As further retirements occur and other system conditions evolve, there will be new challenges, but the institutions, procedures, market mechanisms, and private investors have proven to be able to adapt to maintain reliability.

B. THE EMERGING CONCEPT OF "RESILIENCE"

In contrast to the well-established, bedrock concepts of reliability, resilience is still emerging as an issue and has no uniformly accepted definition, let alone established metrics of preparedness. The resilience concept initially arose in the context of critical infrastructure protection (including the electricity grid) in the post-9/11 era, and was first defined in a 2009 report by the National Infrastructure Advisory Council:

> Infrastructure resilience is the ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event.[11]

The concept rose to prominence in the context of the electricity grid with NERC/DOE studies examining high-impact, low-frequency ("HILF") event risk, such as scenarios involving coordinated physical or cyber attacks on key elements of the bulk power system and geomagnetic disturbances arising from severe solar storms.[12] By definition, such HILF events have rarely or never occurred, which complicates any analysis that might help plan for such events, reduce their likelihood, or mitigate damage that might occur.

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10 "Remarks of Gerry Cauley, President and CEO Northern American Electric Reliability Corporation," FERC Reliability Technical Conference Panel I: 2016 State of Reliability Report, June 1, 2016, p. 1. Available at: https://www.ferc.gov/CalendarFiles/20160601081619-Cauley,%20NERC.pdf

11 *Critical Infrastructure Resilience: Final Report and Recommendations*, National Infrastructure Advisory Council, September 8, 2009, page 8. Available at: https://www.dhs.gov/sites/default/files/publications/niac-critical-infrastructure-resilience-final-report-09-08-09-508.pdf

12 *Severe Impact Resilience: Considerations and Recommendations*, NERC Severe Impact Resilience Task Force, May 2012. Available at: http://www.nerc.com/comm/OC/SIRTF%20Related%20Files%20DL/SIRTF_Final_May_9_2012-Board_Accepted.pdf

The in-depth conceptual analyses and studies of particular events have improved the industry's understanding of resilience. We have included a synopsis of several resilience studies in Appendix A. Compared with reliability, which rests on a foundation of empirical probabilities of (likely repeated) events, resilience focuses on broader range of more idiosyncratic, speculative events. There is much on-going analysis regarding the types of events grid operators can and should protect against, the nature of impacts arising from such events, and what kinds of attributes of the bulk power system and transmission and distribution ("T&D") networks would improve resilience. As an example, the National Academy of Sciences recently summarized the threat scenarios in two types: those that relate to human actions and those that relate to natural causes. Its report lists and discusses the following *Causes of Most Electricity System Outages*:[13]

- Cyber attacks
- Major operations errors
- Hurricanes
- Space weather and other electromagnetic threats
- Drought and water shortage
- Ice storms
- Tsunamis
- Earthquakes
- Volcanic events
- Floods and storm surge
- Physical attacks
- Wildfires
- Regional storms and tornadoes

None of the various industry studies that have analyzed grid resilience, however, have established an *operational* definition of resilience that would involve metrics or a method of quantification or measurement. Such metrics and methods would: (1) enable some assessment of grid resilience separately from ordinary reliability metrics; (2) form the basis for standards or rules that could improve or maintain resilience; and (3) permit the examination of economic

[13] *Enhancing the Resilience of the Nation's Electricity System*, National Academy of Sciences, Engineering, and Medicine, Washington, DC: The National Academies Press, 2017, p. 2. Available at: https://www.nap.edu/download/24836

tradeoffs of such adjustments in a cost-benefit study.[14] The NOPR similarly does not describe an operational definition of "resilience" or a resilience standard that might form a basis for action.

C. THE VALUE OF 90 DAYS ONSITE FUEL

Despite the progress made conceptualizing resilience, no clear consensus has formed around the value of fuel-supply assurance and how it might relate to overall grid resilience. The NOPR states that recent retirements of coal and nuclear plants, coupled with increased reliance on natural gas fuel and variable energy resources, have left certain regions vulnerable to interruptions in natural gas deliveries during extreme weather events or other disasters, impairing the resilience of the U.S. electric system. But neither the NOPR nor other studies of which we are aware have evaluated the key steps in this argument: the extent to which days, weeks, or months of on-site fuel stocks actually contribute to resilience under different conditions, how the relationship between fuel inventories and grid resilience might be measured and valued, and how the recent retirements might have affected grid resilience in particular regions. We examine those topics after taking a closer look at the Polar Vortex event.

1. The Polar Vortex Event

The NOPR cites the Polar Vortex as emblematic of emerging resilience risk, citing the DOE Staff report account of that event and the role that-soon-to-be-retired coal plants played.[15] However, the NOPR account did not mention other generation issues observed during the Polar Vortex such as outages at coal plants. (Also absent were the material changes that have been put in place following these events, as we discuss in the following section.) Analyses of the event by PJM and NERC, on the other hand, examined a much broader set of impacts as well as a range of mitigation strategies used to maintain customer service during the event.

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[14] For example, researchers at Sandia National Labs developed a risk-based framework in a 2015 report called the "Resilience Analysis Process," by which such an operational definition of resilience along these lines could emerge. We provide more details on this process in the Appendix A.

[15] 82 FR 46,942, citing DOE Staff Report at page 98. For the DOE Staff Reporte: *Staff Report to the Secretary on Electricity Markets and Reliability*, U.S. Department of Energy, August 2017. Available at: https://energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf

The Polar Vortex encompassed colder than normal temperatures in the Eastern U.S. during January and February of 2014. According to the event analysis conducted by NERC, the challenges to the electricity system centered on a four-day period of extreme cold, January 5-8 that began in the upper Midwest and moved south and east with a (roughly) two day period of severe cold conditions in most localities.[16] The NERC event study looked at generator outages across the entire Eastern Interconnection and the Electric Reliability Council of Texas ("ERCOT") and found that, out of the almost 90,000 MW of outages from all causes recorded during the height of the polar vortex weather conditions, extreme cold weather and issues of fuel supply accounted for about 35,000 MW of the total outages.[17] Approximately 19,500 MW of capacity was lost due to cold weather conditions, with over 17,700 MW due to frozen equipment conditions that affected both coal and natural gas-fired plants, implying over 15,000 MW lost due to fuel curtailments during the peak national impact.[18] Nuclear plants generally performed well, but both natural gas and coal plants faced higher outages: natural gas plants, which comprised about 40% of installed capacity, accounted for over 55% of the reported forced outages; and coal plants, about 31% of the installed capacity, accounted for about 26% of forced outages.[19] The effects varied across the NERC regions, with fuel-supply-related outages most prominent in the Northeast, ERCOT, and Reliability First (roughly identical to PJM) regions, and with equipment failures due to cold temperatures more prominent in the Florida, Midwest Reliability Organization (MRO, roughly MISO North), Southeast, and Southwest Power Pool regions.

PJM similarly conducted a review of the Polar Vortex event, which they defined as the three-day period January 6–8. During that time, PJM experienced a record wintertime peak demand, much higher than normal plant forced outages (40,200 MW or 22% forced outage rate) and very tight

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16 *Polar Vortex Review*, NERC, September 2014. Available at: http://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf

17 *Id.*, p. 4.

18 *Id.*, pp. 4-5. Examination of Figure 5 (p. 4) suggests that fuel-related outages may have grown to nearly 20,000 MW later in during the event.

19 *Id.*, p. 13.

reserves, but no loss of load.[20] Equipment issues involving both coal and gas-fired generation caused most of the forced outages, while natural gas fuel supply interruptions comprised almost 24% (9,300 MW) of the total forced outages. Notably, this was less than equipment-related outages during the peak hour at both coal plants (13,700 MW) and natural gas plants (9,700 MW).

Having managed through the Polar Vortex event in early January, PJM and market participants were prepared for a late January period of very cold weather combined with a winter storm (January 17–29).[21] Compared with the initial Polar Vortex event, during late January equipment failures were much less prevalent and additional gas deliveries were procured (although at high prices) and demand response helped maintain reserves and continuous reliability.

2. Subsequent Reforms and Studies to Address Fuel Assurance

In response to the Polar Vortex experience, the RTOs/ISOs, and the FERC have improved market designs to improve fuel assurance and reliability during challenging conditions. PJM implemented reforms to ensure that generators can offer energy at prices that fully include their costs of fuel even when the price of fuel spikes in extreme cold-weather conditions. Even more importantly, PJM and ISO-NE instituted "Capacity Performance" reforms to provide strong financial incentives for generators to take whatever measures are needed to make themselves able to perform when needed, included through securing fuel supplies. The FERC accepted these reforms and emphasized that such evolution is a part of improving the performance of generators, particularly when the system is under stress:

> The Commission approves PJM's proposed reforms, as modified herein, because we find that these reforms are a significant step toward addressing a confluence of changes in the PJM markets, including both recent performance issues that PJM has demonstrated are impacted by inadequate incentives and penalties for resource performance under its current construct, and ongoing changes in PJM's resource mix that are projected to accelerate… The Commission has been actively involved in the review of capacity markets and larger trends regarding resource

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[20] *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events*, PJM Interconnection, May 8, 2014, p. 24. Available at: 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] *Id.*, p. 31.

> adequacy and fuel assurance. In particular, we note that the Commission recently recognized the need to address resource performance issues in ISO New England Inc. (ISO-NE), and in a generic proceeding in which the Commission: (i) directed regional transmission organizations (RTOs) and independent system operators (ISOs) to file reports on the status of their efforts to address fuel assurance issues; and (ii) provided guidance to assist RTOs and ISOs in these efforts. PJM states that its proposed reforms were prepared in the context of these related policy initiatives, and are designed to ensure that resources committed as capacity to meet PJM's reliability needs will deliver the promised energy and reserves when called upon in emergencies, and thus will provide the reliability that the region expects and requires.[22]

As a result, the reliability and resilience of the regions affected by the Polar Vortex has arguably improved, not declined, even as the generating fleet continues to change. In March 2017, PJM issued a report that examined the reliability value of fuel diversity determined that a broad range of potential future fleet compositions (including the current diverse fleet) would operate reliability.[23] The study assessed fuel adequacy against a future with further coal and nuclear plant retirements and much more reliance on gas, by simulating fuel delivery and electricity production during severe cold weather events such as the Polar Vortex. The key takeaway from this analysis is that reliability in PJM has not declined due to retirements that have recently occurred, and PJM is not confronting any immediate reliability issues as generation fleet changes continue in the near term. In fact, "the expected near-term resource portfolio is among the highest-performing portfolios and is well equipped to provide the generator reliability attributes."[24]

Over longer time horizons, simulations showed that generation portfolios of up to 86% natural gas-fired capacity (more than twice the 33% share expected for 2021) could perform reliably under expected winter and summer weather conditions; and portfolios with up to 66% natural

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[22] See 151 FERC ¶ 61,208 Docket Nos. ER15-623-000, EL15-29-000, ER15-623-001, EL15-41-000 Order on Proposed Tariff Revisions, June 9, 2015, p. 7.

[23] *PJM's Evolving Resource Mix and System Reliability*, PJM Interconnection, March 30, 2017. Available at: http://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx

[24] *Id.*, p. 4.

gas-fired generation could perform reliably even under Polar Vortex scenarios.[25] While the study did not directly address fuel security and resilience, the analysis did explore how different generating fleets would provide reliability attributes to the system, and how shifts away from coal and nuclear generation would reduce some attributes (*e.g.*, fuel assurance, frequency response, reactive power) but increase others (*e.g.*, flexibility and ramping). These findings are relevant over much longer-term horizons, within which there is sufficient time to analyze the potential reliability and resilience issues that might arise as the generation fleet evolves.

Despite the substantial reforms that arose from the experience of the Polar Vortex and the studies showing robust preparedness for future weather-related challenges, the NOPR states that "the fundamental challenge of maintaining a resilient electric grid has not been sufficiently addressed by the Commission or the ISOs and RTOs."[26] Perhaps there are some threat scenarios that the RTOs/ISOs have not studied or planned for—a possibility that should be explored, as we discuss in Section II.D.1 below. However, DOE has neither identified nor analyzed such threats. Nor has it identified whether or how the current construct and market improvements developed by the RTOs/ISOs and approved by FERC fall short of meeting any particular resilience-related needs.

3. Resilience Value of 90 Days of On-Site Fuel

The DOE NOPR does not explain why 90 days of on-site fuel inventory is necessary or even valuable for maintaining resilience. For example, many natural gas-fired generators have on-site oil storage sufficient for several days of operations, which ensures performance and contributes to system resilience during temporary interruptions in natural gas delivery. The 90-day requirement appears to be based on the DOE Staff Report description of nuclear units and the recent average of bituminous coal fuel on-site.[27] It is not obvious, however, why 90-days inventory would enhance resilience in any meaningful way, or why it would be necessary for the

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[25] PJM did not model other HILF events (such as cyber attacks or other risks) that one might consider when analyzing overall resilience. See *Appendix to PJM's Evolving Resource Mix and System Reliability*, PJM Interconnection, March 30, 2017, p. 41.

[26] 82 FR 46,945

[27] See DOE Staff Report p. 95 for nuclear plants nearing a refueling outage: "However, even if there is a delay in the arrival of new fuel, the reactor could continue to operate for an additional three months before reaching 70 percent capacity". For bituminous coal stocks, see Figure 4.19 on p. 96 showing recent bituminous coal stocks hovering near 90 days of fuel.

RTOs/ISOs to compensate generating plants that can achieve this requirement (or why, for that matter, a 60-day fuel inventory does not sufficiently enhance resilience). As described earlier, the Polar Vortex event highlighted outage risks to the electricity system that lasted three to four days.[28] In 2011, a cold weather event that led to generator outages and some load shedding occurred in the Southwest lasted five days (February 1–5). As in the Polar Vortex, some of those cold weather events caused outages at various types of generating plants, including coal plants that presumably had weeks of fuel on site but were nevertheless unable to generate when needed.[29] Thus, it is not clear whether or why a 90-day fuel supply would be valuable under the circumstances referenced in the NOPR.

Reliability studies have always focused on random generator outages; some recent studies also address multiple, simultaneous generator outages due to common-mode or single-point-of-failure-disruptions such as curtailed fuel availability or severe weather. However, the purpose of maintaining adequate reserve margins is so that multiple simultaneous outages can be sustained without having a disruption in customer electricity service.

Recently, The Rhodium Group analyzed the data on major system disturbances that utilities around the country report to DOE. Analyzing the data, The Rhodium Group concluded: "Between 2012 and 2016, there were roughly 3.4 billion customer-hours impacted by major electricity disruptions. Of that, 2,382 hours, or 0.00007% of the total, was due to fuel supply problems." And of these 2,382 hours of customer service disruption, 2,333 hours occurred in 2014 due to a single event in Northern Minnesota involving a coal-fired power plant.[30]

Consistent with the Rhodium Group's analysis, Brattle Group analyses have found that 99% of customers' loss of power in typical utility service territories is due to distribution system disruptions. Only about 1% is associated with outages at generation stations and the transmission

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[28] *Polar Vortex Review*, NERC, September 2014. Available at: http://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf

[29] *Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011: Causes and Recommendations*, prepared by the Staffs of Federal Energy Regulatory Commission and the North American Electric Reliability Corporation, August 2011.

[30] "The Real Electricity Reliability Crisis," Trevor Houser, John Larson and Peter Marsters, October 3, 2017. Available at: http://rhg.com/notes/the-real-electricity-reliability-crisis. Notably, this study period included the January 2014 Polar Vortex.

system.[31] Distribution systems are especially vulnerable to damage from extreme storms. For example, in our analyses for ERCOT we documented that less than 1 minute of customer outages per year would be expected from supply inadequacy, while distribution-related events accounted for 100–200 customer outage minutes per year without major storms and up to 10,000 customer outage minutes in years with major storms.[32] During these severe events, substantial fuel inventories at generating plants provide no resilience value since the problems do not involve a lack of fuel for generation but the inability to deliver the generated power to customers.

In the National Academy of Sciences, Engineering and Medicine's recent report on *Enhancing the Resilience of the Nation's Electricity System,* the authors explain the risks associated with many potential hazards to the electricity system from human actions and from natural causes.[33] The authors provided ideas about improvements in planning and preparations for facing those hazards, including many ideas about protecting the critical electricity infrastructure such as using advanced technologies and protection systems, designing the system to reduce the criticality of individual components, investing in spare parts sharing programs, and conducting restoration drills and exercises. Although the report noted the importance of fuel diversity, dual-fuel capability, and assuring the availability of adequate natural gas resources, the report did not conclude that maintaining many weeks' worth of on-site fuel at certain generation facilities would improve grid resilience.

Other reports on high-impact, low-frequency events consider much longer periods of disruption that go well beyond 90 days. For example, NERC considered events, such as coordinated

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[31] "Finding the Balance Between Reliability and Cost: How Much Risk Should Consumers Bear?," William Zarakas and Johannes Pfeifenberger, presented at Western Conference of Public Service Commissioners, June 3, 2013. Available at: http://www.brattle.com/system/publications/pdfs/000/004/417/original/Finding_the_Balance_Between_Reliability_and_Cost_Zarakas_Pfeifenberger_WCPSC_June_3_2013.pdf?1378772104

[32] *ERCOT Investment Incentives and Resource Adequacy*, Samuel Newell, et al., June 1, 2012, pp. 101-02. Available at: http://www.brattle.com/system/publications/pdfs/000/004/820/original/ERCOT_Investment_Incentives_and_Resource_Adequacy_Newell_Spees_Pfeifenberger_Mudge_ERCOT_June_2_2012.pdf?1378772132.

[33] *Enhancing the Resilience of the Nation's Electricity System*, National Academies of Sciences, Engineering, and Medicine, Washington, DC: The National Academies Press, 2017. Available at: https://doi.org/10.17226/24836

physical attacks, coordinated cyber-attacks, and geomagnetic disturbances that could require six months to a year to fully restore the system to prior operation.[34] The role of several months' of fuel supply on shortening or even effecting the restoration time under these catastrophic scenarios has not been explored.

D. Analysis Needed to Support FERC Action

The DOE NOPR does not appear to include or reference any formal analysis that normally would accompany a major action by FERC. The NOPR does not offer a measurement or metric that could quantify resilience risk in the RTO/ISO markets or attempt to estimate the severity or magnitude of that risk.[35] The NOPR does not explore alternative strategies, and does not estimate how the proposed rule might mitigate such risks, or assess the value of such mitigation. Furthermore, the NOPR does not provide any indication of the likely range of the costs of implementing the proposed rule or compare such costs against potential. The NOPR instead implies that the IHS Markit Report's estimate of the replacement cost of all coal and nuclear generation provides a valid benefit figure for the proposed rule (which we discuss in Section III.E). The lack of analysis or evidence contrasts sharply with the urgent tone of the NOPR, which directs FERC to institute major changes in RTO pricing within 60 days to support solid-fuel generation.

The NOPR does raise important questions about reliability and resilience, including how to prepare for threats that are extreme and outside of historic experience. Prior to taking action on such issues, however, RTOs/ISOs and FERC would need an understanding of the plausible threats to each region, as well as the potential improvements that system planners, operators, and markets could provide. Like many other challenges that FERC has faced in the past, these

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[34] *Severe Impact Resilience: Considerations and Recommendations*, NERC Severe Impact Resilience Task Force, accepted by the Board of Trustees on May 9, 2012. Available at: http://www.nerc.com/comm/OC/SIRTF%20Related%20Files%20DL/SIRTF_Final_May_9_2012-Board_Accepted.pdf

[35] See *Measuring the Resilience of Energy Distribution Systems*, Henry H. Willis and Kathleen Loa, The Rand Corporation, 2015 (part of the DOE Quadrennial Energy Review). Available at: https://energy.gov/sites/prod/files/2015/07/f24/QER%20Analysis%20-%20Measuring%20the%20Resilience%20of%20Energy%20Distribution%20Systems.pdf
A total of 105 potential resilience metrics were identified in an extensive table, with only 3 concerning energy inputs: energy feedstock, energy not supplied, and energy storage. Neither fuel assurance nor on-site fuel inventory was cited directly.

questions can be analyzed methodically. Below we outline the basic analytical steps that would be appropriate for a considered evaluation of grid resilience issues.

1. Assessing Relevant Threat Scenarios

The DOE NOPR cites the Polar Vortex specifically as the type of event that could cause severe disruption to electricity service. As an initial matter, we recommend defining the *range* of potential threats or contingencies that might occur, based in part on historic experience (*e.g.*, the Polar Vortex) and in part on plausible but unprecedented scenarios (*e.g.*, debilitating cyber or physical attacks on major elements of the natural gas delivery system, multiple and severe weather damage scenarios for bulk transmission system, *etc.*). Some of the resilience analyses cited above envision such extreme events or disruptions, and they provide useful ingredients for scenarios to evaluate potential strategies to avoid damages or to quickly restore systems to normal operation.

In addition to considering multiple potential causes of system disturbances that would challenge resilience, an appropriate assessment of threat scenarios would examine the likelihood of such occurrences (to the extent that probabilities could be developed) and develop variations on the threat scenarios to explore specific vulnerabilities that might be amenable to policies or investments to mitigate risks or effects. For example, some threat scenarios to natural gas deliverability could also involve risks to coal plants, *e.g.*, wet or frozen coal piles that force out coal generation.

2. Establishing Metrics to Measure Resilience Risks and Outcomes

Beyond a general goal of enhancing resilience, the NOPR does not articulate specifically what measurable change in resilience might occur as the result of the proposal, what metric or metrics would be useful in that regard, or how those metrics might differ from the traditional reliability metrics such as loss-of-load-expectation. Appropriate metrics help inform the desired design features of a policy as well as enable analysis of alternatives and assessments of effectiveness.

The National Academy of Sciences recognizes metric development as a key step in the process of developing cost-effective policy:

> Development of resilience metrics and methods to defining resilience goals, as well as comparison of alternative strategies for increasing resilience, remains an active area of research, and the committee believes more research and demonstration is required before the electricity sector can reach consensus on a

set of appropriate metrics. Metrics often drive decision making. Establishing and building consensus around metrics is an important prerequisite for comparing resilience enhancement strategies and for evaluating their costs and benefits. **Many of the technologies and strategies for increasing the resilience of the electricity system described in the following chapters are expensive, particularly when implemented on a large scale. Without consistent resilience metrics, large amounts of money could be spent with little understanding of actual resilience benefits and with much of this cost passed on to ratepayers.**[36]

3. Evaluating Alternative Resilience Strategies

The next stage of analysis would compare the effects of alternative resilience strategies on avoiding or minimizing potential impact on customers across various types of incidents. Such analyses, even using less rigorous approaches that reflect the lack of reliable data, can produce useful estimates of and the costs and potential effects of various policy approaches under extreme events. For example, major widespread damage to the bulk transmission network could cause widespread, long and costly outages, but fuel assurance at large stationary generating plants would not likely have any effect on the restoration time. In contrast, developing microgrids, adding battery storage, maintaining sufficient black start capability, and providing flexible generating capabilities at certain locations may be effective under such situations. Market-based approaches should also be considered, such as the Pay-for-Performance and Capacity Performance programs that PJM and ISO-NE already developed, evaluated, and implemented.

This is important because analyses might determine that certain policies or approaches are likely to reduce adverse customer impact under a broad range of extreme events, perhaps including events such as repeat of the Polar Vortex, while others might only mitigate risk for certain types of events. Such policies may or may not involve several months of on-site fuel, but those options should be analyzed and compared with other approaches before committing to potentially expensive or ineffective policies. In this regard, analyses that underlie the establishment of specific system needs (such as black start or rapid-start capability that would help reduce system restoration times in a wide-scale loss-of-service event) would be helpful.

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[36] *Enhancing the Resilience of the Nation's Electricity System*, National Academies of Sciences, Engineering, and Medicine, Washington, DC: The National Academies Press, 2017, p. 33. Emphasis added.

4. The Importance of Regional Considerations

While certain extreme events could occur in all regions (such as cyberattacks), other types of events may be very region-specific. For example, cold weather events in New England will produce different impacts and require different strategies than hurricanes in Florida. This differentiation suggests that the regional reliability entities should conduct the analysis and tailor mitigation strategies to the high-impact incidents that are most relevant to a particular location or system. In addition, the regional entities are best situated to account for the specific characteristics of their resource mix, transmission grid, loads, and system operations.

The DOE NOPR cites the DOE Staff Report in pointing out significant retirements of "fuel-secure" generation between 2002 and 2016, including roughly 59,000 MW of coal-fired capacity and 4,700 MW of nuclear capacity.[37] The underlying premise of the NOPR appears to be that coal and nuclear generating plants disproportionately contribute to regional resilience, which makes relevant the geographic pattern of historic retirements and the associated changes in resource mix. In this regard, most of the coal and nuclear retirements have taken place in PJM, the Southeast and MISO, while most of the oil and gas retirements have occurred in ERCOT and California (referred to in the DOE report as "CAISO+"). These data shown in the DOE Staff Report (Appendix A) are depicted in Figure 1 below.[38]

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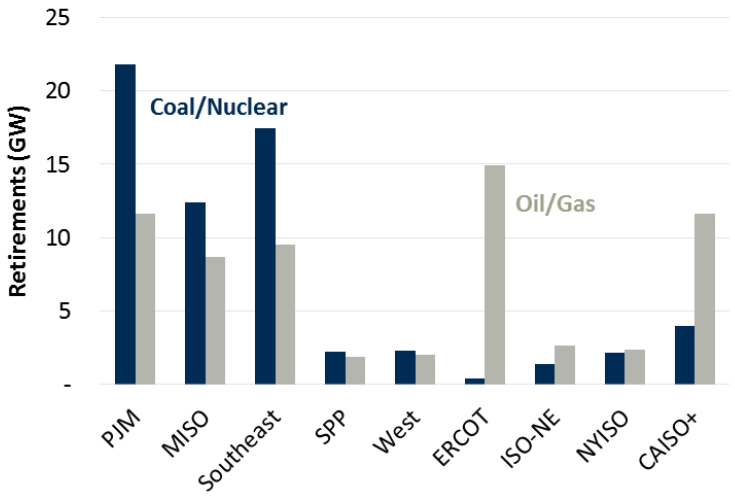
[37] 82 FR 46,942. According to the DOE Staff Report, however, more oil and natural gas capacity retired over the same period, namely 65.6 GW of oil and gas compared to 64.0 GW of coal and nuclear. See DOE Staff Report Appendix A, U.S. National Profile.

[38] In this section we use the RTO/ISO names associated with each region, as defined on page 4 of the DOE Staff Report. DOE defines the "CAISO+" region to include CAISO and small balancing areas in California.

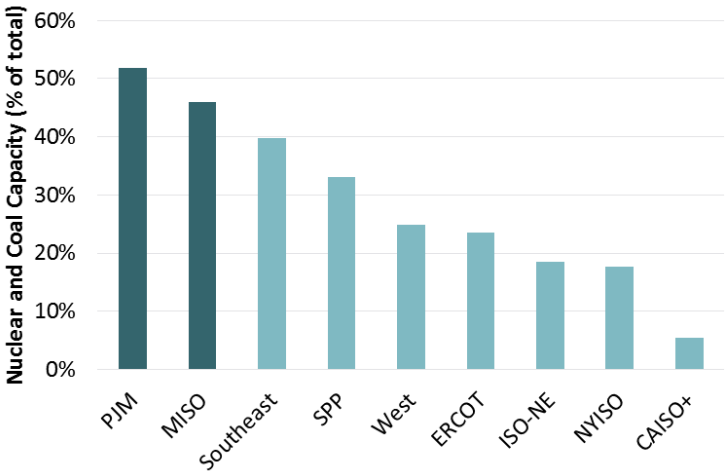
Figure 1
Generating Plant Retirements 2002–2016



Source: Brattle Group analysis of data in DOE Staff Report (Appendix A). We use the RTO/ISO names for each region based on the definitions on p. 4 of the DOE Staff Report.

While PJM and MISO have experienced the greatest amount of retirements in megawatt terms, consistent with the prevalence of coal and nuclear generation there, *they continue to have the highest proportion of coal and nuclear generating capacity in their fleets*, as shown in Figure 2 below.

Figure 2
Regional Percent of Coal and Nuclear Capacity in Fleet 2016



Source: Brattle Group analysis of data in DOE Staff Report (Appendix A). We use the RTO/ISO names for each region based on the definitions on p. 4 of the DOE Staff Report.

To the extent, therefore, that resilience depends on coal and nuclear generating capacity, PJM and MISO would already appear to be the most resilient regions, with no particularly urgent need to provide financial support for fuel-secure baseload generation there. Yet DOE's proposed

rule that focuses on preserving coal and nuclear capacity in PJM and MISO would target precisely the regions that already have the highest proportion of fuel-secure baseload capacity in their generation mix. Conversely, the NOPR would have very little impact in California, New England, New York and no impact in ERCOT (Texas)—regions that currently have the lowest proportion of coal and nuclear generation and that, under the logic of the NOPR, would exhibit the highest resilience concerns. While NERC has recently focused its attention on resilience risk in these regions with relatively little coal and nuclear generation, the NOPR has the greatest impact on regions that already enjoy much higher levels of fuel-secure coal and nuclear capacity.[39]

[39] *Short Term Special Assessment: Operational Risk Assessment with High Penetration of Natural Gas-Fired Generation*, NERC, May 2016, which analyzed the gas dependence risk in ISO-NE, NYISO, ERCOT and CAISO.

III. The Estimated Cost of the Proposed Rule

The proposed rule requires payments to eligible resources to recover their "fully allocated costs and a fair return on equity," where compensable costs "…shall include, but not limited to, operating and fuel expenses, costs of capital and debt, and a fair return on equity and investment."[40] In this section, we estimate the potential range of out-of-market payments that would have to be made to eligible generators under the proposed rule. Our estimate is indicative, focusing on the payments eligible generators would have received in 2016, had the rule been in place in then.

To develop an estimate, we first assume that the FERC would implement the equivalent of traditional cost-of-service rate regulation for generating plants that are currently operating as merchant resources in organized wholesale electricity markets. By assuming that these resources would be paid under traditional cost-of-service terms, each of the eligible generation plants would have a "ratebase" on which the owner earns a regulated rate of return and receives revenues to cover the generation plant's fixed and variable operating costs. Second, we assume that the regulated revenue requirements would be offset by revenues received from selling energy and capacity in the wholesale markets. Third, we assume that the compensation would not affect how the plants are bid into the wholesale energy markets or capacity markets relative to how they are currently bid.

Our approach to estimating the hypothetical 2016 payments under the proposed rule includes the following steps:

1. Identify the plants that are potentially eligible;
2. Estimate the total cost-of-service for the eligible plants (i.e., before subtracting market revenues), including a return on and of pre-2016 capital expenditures plus operating costs;
3. Estimate market revenues from energy and capacity markets by those plants in 2016; and
4. Estimate the out-of-market payments under the proposed rule as the gross cost-of-service minus the market revenues.

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[40] 82 FR 46,948.

In this analysis, we develop an indicative range of possible costs reflecting different assumptions regarding plant depreciation and by using various data sources for the original plants' capital costs. The resulting range of possible costs of the proposed payments for the first year of implementation is between $3.7 billion and $11.2 billion (see Table 2 later in this section). The low end of this estimate is based on a low estimate for plants' operating costs and short depreciation life for past capital expenditures, and the high end of the estimate is based on higher operating cost estimates and long depreciation life for past capital expenditures.

Our analysis and associated cost estimates provide an indicator of the additional costs of the proposed rule. The actual payments can be estimated only after FERC issues a rule that contains the specific criteria for eligible resources, eligible costs to include in the cost-of-service calculations, the final rules to be issued by RTOs/ISOs (and approved by FERC), and the actual performance of the eligible plants in the wholesale markets. One would expect that each potentially eligible plant would need to submit cost data to FERC to compute a cost-of-service tariff for that plant. The level of effort required for FERC staff to determine plant-specific rates would be significant because we anticipate that more than 300 generating units would likely be eligible to receive the proposed payments under the NOPR. At minimum, the calculation of the invested capital would need to be plant-specific and would likely to be complex. There currently is no public cost data for merchant plant and each eligible plant has a unique history of ownership and expenditures that would require extensive FERC staff review to ensure that costs included are reasonable and are specifically allowed under the proposed rule.

The rest of this section describes our approach to estimate total costs, offsetting market revenues, and the subsidies for the potentially eligible generation plants and Appendix B contains the details of the calculations.

A. Potentially Eligible Resources

The proposed rule would support electric generation resources that are:

- Physically located within the Commission-approved RTO/ISO regions with energy and capacity markets;
- Able to provide energy and ancillary services;
- With a 90-day fuel supply on site;

- Compliant with all applicable environmental regulations; and
- Not subject to cost-of-service rate regulation by any state or local regulatory authority.[41]

These conditions imply that the potentially eligible generation plants under the proposed rule are generators that would otherwise operate as merchant generators inside RTO/ISO regions, presumably with centralized energy and capacity markets subject to FERC jurisdiction, such as PJM, MISO, New York ISO ("NYISO"), and ISO-NE, with at least 90-day fuel supply on site. These requirements could be satisfied with coal, nuclear and (possibly) some hydro generation plants with pondage. While the amount of on-site fuel supply for coal plants on average has been less than 90-days of coal burn,[42] we assume in this analysis that the plants with less than 90-day fuel supply on site would increase their on-site coal inventory to be eligible for the payments under the proposed rule.[43]

The proposed rule does not specify whether the eligible resources need to be currently operating or also include new plants and recently retired or mothballed resources that could be brought back to service. The proposed rule also does not specify whether the generation plants that have entered into long-term power purchase agreements (PPAs) with certain customers (e.g., load-serving entities) would be eligible for the payments under the proposed rule.

For the purpose of estimating total costs, we assume that the eligible resources only include those that are currently operating as merchant coal and nuclear generators in the wholesale markets of PJM, MISO, NYISO, and ISO-NE regions. We do not exclude any plants that might have entered into long-term PPAs.[44] We do not include any of the recently retired or any of the planned new generation in our estimates of eligible resources. We do, however, include plants that have

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41 82 FR 46,948.

42 According to the most recent EIA analysis (September 2017), the U.S. coal fleet burning bituminous coal had on average 76 days of fuel supply on site (and 72 days for subbituminous coal) during July 2017. See https://www.eia.gov/electricity/monthly/update/fossil_fuel_stocks.php#tabs_stocks2-2.

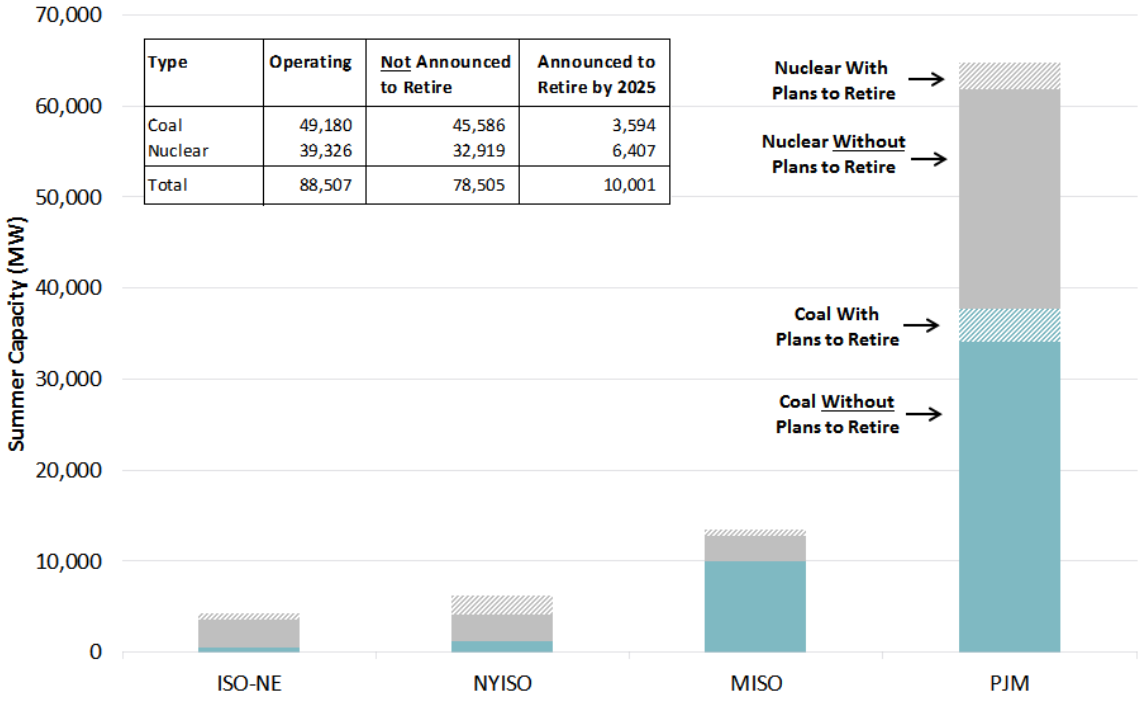
43 Regarding the prospects for meeting this requirement, Dynegy CEO Robert Flexon said "if somebody's going to pay us cost of service with a return if we have 90 days of inventory, we'll find ways to get 90 days of inventory." *Disappointment and hope in Perry's Texas*, E&E News, October 4, 2017. Alternatively, we assume that the 90-day supply would be defined so that all coal units would qualify.

44 We excluded SPP and CAISO units because all of the states in the SPP footprint are regulated states and the only nuclear plant left in the CAISO footprint is also under regulated cost of service. Further, neither RTO operates a centralized capacity market.

announced their intentions to retire, assuming these plants would be able to reconsider those retirement decisions if the proposed rule were implemented.

Figure 3 below shows the composition of the potentially eligible generation plants by type and RTO/ISO region. We estimate that approximately 88,500 MW (89 GW) operating plants would be eligible under the proposed rule. Of these 89 GW, about 50 GW are coal-fired plants and 39 GW are nuclear plants. As shown in the figure, a majority of the potentially eligible plants (approximately 65 GW) are located in PJM, followed by MISO, NYISO, and ISO-NE. Of this range of potentially eligible generating plants, a small share, about 10 GW (11%) is currently planned to be retired by 2025. Of these 10 GW of proposed retirements, about 3.6 GW are coal-fired generating plants.[45]

Figure 3
Eligible Generation Capacity by RTO/ISO



Type	Operating	Not Announced to Retire	Announced to Retire by 2025
Coal	49,180	45,586	3,594
Nuclear	39,326	32,919	6,407
Total	88,507	78,505	10,001

Source: Summarized using GUC data from ABB, Inc. Velocity Suite (2017). Limited to operating coal and nuclear plants that are unregulated private investor-owned.

[45] In contrast, about 8 GW of the non-merchant (i.e., units subject to state cost of service rate regulation) coal and nuclear capacity in these RTO regions is scheduled to retire by 2025. These regulated retiring units are not eligible for the financial support under the proposed rule, unless sold to merchant entities.

B. TOTAL COST OF SERVICE

As indicated earlier, the proposed rule requires recovery of costs including "operating and fuel expenses, costs of capital and debt, and a fair return on equity and investment" for eligible generation plants. We will refer to the combination of these costs as the total cost of service. As we estimate these costs on an annual basis, they include two main components: annual operating and fuel expenses, and annual return on and of capital expenditures. Specifically, annual operating and fuel expenses include the cost incurred for fuel used for generation and for materials, equipment and labor used in that year to operate, maintain, and repair the generation plant. For determining the annual return on and of capital expenditures for each eligible plant, we needed to estimate an approximate "ratebase" that includes the undepreciated portion of past capital expenditures. In addition to the initial plant capital costs or acquisition cost, the owners of these merchant generating plants would have made capital investments for major repairs and improvements to their generation facilities over time. Thus, we expect that those capital expenditures (CapEx) enter into the ratebase in the year they are incurred. For a regulated cost-of-service calculation, the owner would earn a rate of return on the undepreciated amount of these capital expenditures over time. Thus, even when a plant itself is fully depreciated based on its original investment cost, there could still be a remaining ratebase made up of historical capital expenditures.

The proposed rule does not specify how FERC would establish the magnitude of the ratebase for each merchant plant. Unlike regulated utilities, merchant generators are not required to report their operating and capital costs. Thus, FERC would need the owners of these generating plants to provide the costs of acquiring those plants (or, in the case of original ownership, the original plants' capital costs), a process that would require time to validate and verify data.

Once FERC determined the ratebase, FERC would need a methodology to estimate the annual cost recovery profile to provide for full recovery of the ratebase and a return on that ratebase over time. One possible approach is the depreciated original cost (DOC) methodology typically implemented by state regulatory agencies for generating plants subject to cost-of-service regulation. Under this approach (for a plant that was built as a regulated plant), the initial ratebase would include plant's development and construction costs, and the total ratebase would

typically include interest incurred during the construction period.[46] If a plant was acquired from a third party, the initial ratebase would be approximated by the acquisition price.

In the initial year of operations, the owner of a particular generating facility would receive a payment for depreciation on its investment (book depreciation, which is usually straight-line for 30 or more years) and would earn a regulated rate of return on the capital cost of the facility. In the second year the utility would receive another increment of payment for depreciation on its original investment and earn a regulated rate of return on the remaining book value at the beginning of the year. The net effect of this is that the utility's annual cost recovery declines over time until at the end of the period over which it is depreciated.

Another approach that FERC could adopt is to levelize the annual cost recovery over the remaining life of the facilities such that the annual charges for the capital cost remain constant over time such that the owner of the generating facilities would be paid a fixed annual payment.

Since we are estimating the cost had the proposed rule been implemented in 2016, we estimate the gross cost of service for potentially eligible generation plants for 2016. To do so, we estimate three components of the costs:

- **Annual operating and fuel costs**—fuel costs, variable operation and maintenance (VOM) costs, fixed O&M (FOM) costs, and ongoing capital expenditures (CapEx) in 2016;
- **Annualized capital costs of environmental retrofits** installed on coal plants since 2008; and
- **Annualized capital costs of the original** generation facilities.

First, to estimate annual operating and fuel costs, we relied on various public data sources to develop an estimated cost range in 2016 for potentially-eligible coal and nuclear plants. Depending on the source of cost estimates (some of which provide unit-specific cost estimates), the annual operating and fuel costs range from $38 to $50/MWh for the potentially-eligible fleet of coal plants and from $27 to $38/MWh for the potentially-eligible fleet of nuclear plants.

[46] This analysis excludes interest during the construction period, which can be a considerable portion of the initial ratebase.

Next, to estimate the capital costs of retrofits recently installed on coal plants, we relied on EPA's estimates of the installed capital cost for each type of retrofit equipment (such as wet scrubbers and baghouses). We estimate the total capital costs for installed retrofits at coal plants since 2008 to be approximately $18.9 billion (in 2001 dollars). Most of these costs are associated with the installation of wet scrubbers and Selective Catalytic Reduction (SCR) systems. Assuming a 15-year depreciation period for these capital expenditures, we estimate the first-year charge for the return on and of these retrofit capital expenditures made for the potentially-eligible coal plants to range from $1.7 billion to $2.2 billion.

For the original capital costs of coal generation facilities (before retrofits), we rely on public estimates of capital costs as of the initial online year of the plants and estimate the remaining book value of these investments as of 2016. For the nuclear generating plants, we use the reported sales prices (and our own estimates) for those plants when their ownerships transitioned to the current merchant owners of the plants. We assume that the new owner of the nuclear plants would depreciate the initial plants' cost from the date of acquisition to 2016 using a straight-line depreciation over a period equal to the difference between the end of the plant's NRC licensed life and the date of acquisition. Depending on the assumed depreciation life and the approach for determining the annual recovery profile of the capital costs, we estimate the first-year charge for the return on and of the initial capital expenditures for the fleet of potentially-eligible coal and nuclear plants to range from $1.9 billion to $4.4 billion.

Appendix B provides a more detailed description of our approach and data sources use to estimate each of these cost components.

C. Offsetting Market Revenues

The potentially eligible generating plants have to operate in RTOs with centralized energy and capacity markets. Thus, we assume that market-based revenues for these merchant generating plants are limited to the sale of energy (at day-ahead energy prices at each plant's location) and the sale of capacity (in regional capacity auctions).[47]

[47] These estimates do not account for Zero Emission Credit (ZEC) programs for nuclear plants in some states since they were not implemented in our 2016 test year. Future payments under the proposed rule would presumably be offset by ZEC payments if not reduce the ZEC payments.

As shown in Table 1 below, we estimate the 2016 market revenues for the full fleet of potentially-eligible generating plants from energy and capacity markets to be approximately $17 billion across the four regional markets with eligible plants. The first set of rows in Table 1 summarizes the estimated market revenues, aggregated for coal plants and for nuclear plants in 2016 by RTO region. The second set of rows in the table shows the average revenues normalized to $/kW-year for coal and nuclear plants across the markets. And the next two sets of rows show the estimated unit-specific minimum and maximum $/kW-year revenues received in 2016. Appendix B provides further details on this derivation of market revenues.

Table 1
Summary of Total Market Revenues (and Ranges Across Units) by RTO/ISO Region

	MISO	PJM	ISO-NE	NYISO
Total ($ Millions)				
Coal	1,315	6,105	26	61
Nuclear	814	6,638	1,052	1,149
Average ($/kW-yr)				
Coal	132	162	68	54
Nuclear	234	246	277	227
Min ($/kW-yr)				
Coal	65	61	68	36
Nuclear	188	187	261	165
Max ($/kW-yr)				
Coal	210	252	68	107
Nuclear	257	341	291	321

D. Estimated Net Out-Of-Market Payments

We estimate the net cost of annual out-of-market payments under the proposed rule to the fleet of potentially-eligible plants to range from $3.7 billion to $11.2 billion annually. Table 2 below shows the components of these estimates. As discussed in Appendix B, variation in several parameters account for the overall range of estimates: variances in data sources used to estimate going-forward cost, different approaches to annualize the past capital costs, and different depreciation schedules used to compute capital charges in the first year of implementation.

Table 2
Estimated Annual Out-of-Market Payments under the Proposed Rule

	Low	High
Gross Cost of Service ($ Billions)	**19.8**	**28.3**
Operating and Fuel Costs	16.1	21.7
CapEx from Past Retrofits	1.7	2.2
CapEx from Original Cost	1.9	4.4
Market Revenues ($ Billions)	**17.2**	**17.2**
Energy	13.2	13.2
Capacity	3.9	3.9
Total Capacity Receiving Out-of-Market Payments (GW)	**57.0**	**88.4**
Coal	38.5	49.2
Nuclear	18.5	39.2
Average Cost of Out-of-Market Payments ($/kW-yr)		
Coal	81.4	152.6
Nuclear	30.4	93.3
Total Cost of Out-of-Market Payments ($ Billions)	**3.7**	**11.2**
Coal	3.1	7.5
Nuclear	0.6	3.7

At the low end of the estimate (the left-hand column in the table), the estimated total (gross) cost of service for all eligible plants is $19.8 billion annually, which is largely driven by $16.1 billion of operating and fuel costs. The total annual revenues from energy and capacity markets for all eligible plants are $17.2 billion, largely from energy market revenues. If we were to combine the earnings for all of the potentially eligible plants, we would include those generating plants that would have earned more in the market than what is estimated to be needed to cover their gross cost of service. Instead, out of the 89 GW of plants potentially eligible for the proposed payments, only an estimated 57 GW earns market revenues less than their total cost of service. The plants that already earn revenues in excess of their costs are coal plants that did not recently make major capital investments on retrofits or nuclear plants located in areas with relatively high market prices. For those 57 GW of plants with revenues below total costs (38.5 GW of coal and 18.5 GW of nuclear), the estimated out-of-market payments is $3.7 billion annually (which is not

the simple difference between $19.8 and $17.2 billion as discussed above). The $3.7 billion/year translates to an average payment of $81.4/kW-year for the potentially-eligible coal plants, and to $30.4/kW-year for the potentially-eligible nuclear plants.

At the high end of the estimate (the right-hand column in the table), the estimated total (gross) cost of service for all eligible plants is $28.3 billion annually. The total revenue from energy and capacity market is the same as in the low case: $17.2 billion. Under this high-end estimate, about 88 GW of eligible plants (most of the 89 GW of eligible plants) are estimated to receive market revenues that are less than their total cost of service. In this case, we estimate the net cost of the out-of-market payment to be approximately $11.2 billion annually. This translates into $152.6/kW-year on average for the affected coal plants, and $93.3/kW-year for the affected nuclear plants.

E. Comparison with the Cost Estimate Referenced in the NOPR

In contrast to our cost analysis, the NOPR suggests that the proposed rule might save money:

> The IHS Markit study also concludes that preservation of generation diversity provided by fuel-secure resources benefits consumers: "The current diversified US electric supply portfolio lowers the cost of electricity production by about $114 billion per year and lowers the average retail price of electricity by 27%" compared with a "less efficient diversity case" involving "no meaningful contributions from coal or nuclear resources."[48]

However, these estimates contained in the IHS Markit report cited in the NOPR are not applicable to the proposed rule. The IHS study simply compared the costs of producing electricity from the current generation mix to the generating costs without *any* nuclear or coal-fired generation. This is not a relevant "but-for" scenario (*i.e.*, absent the proposed rule) upon which the NOPR could base its assessment. While some plants will naturally retire over time due to their advanced age and their inability to compete with newer, more efficient power plants, many other coal and nuclear plants would continue to operate. In a competitive market, plant owners will only retire their plants if they expect to lose money on a going-forward basis. As some plants retire, the wholesale electricity prices likely will increase, which will help those remaining to earn more and continue operating.

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[48] 82 FR 46,943.

If the proposed rule were implemented, it would also preserve the least cost-effective coal and nuclear plants that would otherwise retire, at a significant net cost. But the proposed rule would not change the operating status of the more cost-effective plants and cannot take "credit" for preserving them (even if it would provide them extra money as a return on past investment costs). Finally, the IHS Markit study does not relate its cost analysis to the value of increased resilience. While the IHS Report claims that the retirement of current traditional thermal generating plants is eroding system reliability and resilience, the IHS report's assertion is not supported by any evidence or analysis.

IV. Compatibility with Competitive Wholesale Markets

As discussed above, there is not a clearly articulated objective, nor is there currently any demonstrated need or analysis supporting the proposed rule. But even if the costs of such action might be justified by the mitigation of some latent risk, the particular solution DOE proposes would have broad market impacts beyond simply preserving solid fuel generating capacity. By re-regulating and subsidizing a large portion of the generation fleet, the proposed rule would undermine the core principles and diminish some of the most important advantages of competitive wholesale power markets. In addition, implementing the proposed rule would involve many controversial decisions, with potential unintended consequences that would be difficult to address satisfactorily, given the lack of guiding principles and the limited amount of time allowed.

The current regional wholesale power markets operated by the RTOs/ISOs provide a platform for customers and system operators to procure well-defined products and grid services in a competitive manner, where resources can compete based on their costs and the value they bring to the market. In that context, suppliers take the risks of making their investment and are guided by market prices to operate their resources in the most efficient manner possible. The plant owners decide when to enter, when to continue operating (and incur the associated ongoing costs and capital expenditures), and when to retire resources that are no longer competitive.

The wholesale electricity markets are designed to efficiently meet customer-driven demand while also meeting the needs of the system operator to ensure resource adequacy and comply with system reliability criteria defined by NERC. The RTOs/ISOs satisfy these needs through the products and services they purchase on behalf of customers, allowing the price to adjust to attract, retain, and operate competitive resources sufficient to meet the specified needs. Resource adequacy requirements are competitively met through capacity markets, and operating reserve requirements are competitively met through ancillary services markets. Together they help ensure system reliability. Some other generation-related services, such as system black start, voltage control and reactive power, are paid through transmission tariff charges. Resources providing such services receive (usually modest) compensation for these services without any guarantee that their total revenues are sufficient to cover the facilities' entire cost-of-service. Nothing resembling cost-of-service compensation is used—except very sparingly in special, temporary situations where a retiring plant is critically needed for local reliability needs. There, reliability-must-run (RMR) contracts are used temporarily to retain the plant by covering its to-

go costs (not its full investment costs) until a transmission solution or market-based resource meets the need.

The rules of the centralized wholesale markets have been established, debated, challenged, and improved by the RTOs/ISOs, their stakeholders, and the FERC over the past fifteen-plus years. The common element of all of these efforts is to define products and services to meet well-defined customer needs and system needs, and to set the quantities needed based on rigorous analysis. If new reliability or resilience requirements were established, they could be incorporated into this wholesale market framework. A well-structured market-based approach would entail the following steps: (a) clearly state the objectives that the system needs to achieve; (b) clearly define the attributes that the system needs to operate; (c) analyze the quantity of the need given the unique features of each ISO (and sub-regions within each system); and (d) set up the market to reward the desired attribute in a resource-neutral manner, with every provider being paid the same price for providing the same unit of service. This framework would continue to support the competitive nature of the wholesale electricity market by retaining the broadest-possible competition from resources that meet the specified objectives.

In contrast, DOE's proposed approach skips over these important steps of defining a market-based process to meet any particular system need. Instead, it goes straight to imposing a non-market solution—providing certain generating resources cost-of-service payments to deter retirement regardless of the economic viability of the plant or its measured contribution to resilience. DOE's proposed approach (a) has not set out the objectives for the industry (e.g., what types of plausible disruptions should the fleet be resilient against, and what is the nature of such disruptions and recovery); (b) has not identified a range of attributes that may help meet well-defined objectives, nor does it analyze the types and quantities of certain attributes needed to meet those objectives (which would vary by ISO); and (c) does not translate such attributes into services that are competitively procured in the market, along with the suite of other services already in the mix. Thus, overall, the proposed rule is not compatible with the process that RTO/ISOs use to reform competitive wholesale markets to meet evolving system needs in a cost-effective manner.

Aside from skipping important steps during the process of introducing the proposed rule, a rule that affects the compensation of a significant portion of the fleet will reverberate through markets in ways that would distort price signals and reduce efficiency. For instance, if coal and nuclear plants received the proposed cost-of-service payments, this could significantly reduce

wholesale prices—particularly because some of the uneconomic resources would otherwise retire—and could even force more competitive resources into retirement. Such a displacement would be economically inefficient, assuming the subsidized resources did not actually provide value commensurate with their special compensation. Furthermore, if some coal and nuclear plants that would have stayed in the market economically are selected to receive cost of service compensation that includes a full return on investment (which may not be available through market revenues), then the additional compensation would represent a transfer of wealth from customers to the respective generators without having any effect on system reliability.

FERC aims to develop market rules that treat all resources equitably and ensure that the maximum amount of competition is at play to help reduce costs for customers. Placing a substantial portion of the fleet on cost-of-service compensation would challenge the regional system operators to design a tariff to make such cost-of-service payments in a way that does not adversely affect market pricing for all other resources, does not adversely interfere with the concept of economic dispatch in the energy and ancillary services markets, and does not adversely affect the least-cost procurement of capacity in the capacity markets. Adhering to market design principles might further require additional rules to ensure that market participants that have equivalent fuel supply capabilities and deliver the same energy as those receiving the cost-of-service payments would receive comparable treatment.

Even if the proposed cost-based rule were justified, too many challenging details would need to resolved in a very short timeframe (and without a clearly-defined objective to guide decisions) to avoid potentially large and costly unintended consequences. FERC staff has already raised many complex questions that would require significant time to analyze in order to address all of the complex design specifications. Just as importantly, wholesale electricity market participants and customers would need time to analyze and understand that potential implications so that investors can adjust their investment decisions and customers can adapt their usage in response to such a significant regulatory change. Implementing cost-based compensation as proposed by DOE would be an exceptionally challenging undertaking for FERC and the regional system operators, with significant risk to the continued integrity of the competitive wholesale electricity markets.

Overall, the proposed rule would be costly and would conflict with the principles of competitive markets without providing any assured or measurable contribution to the electricity grid's reliability or resilience. While power system resilience is an important and multi-faceted area

that the industry still needs to analyze and address, multiple industry studies and all available evidence shows that no emergency or urgency currently exists that would require immediate action, particularly not action focused on merchant generating plants with 90-days of on-site fuel storage. This requires sufficient time to analyze resilience needs in a systematic fashion. If grid resilience needs are subsequently identified, then stakeholders could consider market-based mechanisms that would provide strong incentives to address the identified need cost-effectively. Such approaches would not only be more compatible with existing wholesale power markets, they would also result in lower-cost outcomes than DOE's proposal.

Appendix A: Review of Resilience Studies

Over the past ten years, several organizations have conducted studies on the topic of electric power system resilience. These include the U.S. Department of Energy (DOE), the DOE National Laboratories, the National Academy of Sciences, the North American Electric Reliability Corporation (NERC), and the National Infrastructure Advisory Council (NIAC). This appendix provides a brief summary of the following studies on resilience of critical infrastructure and the electric power sector:

- *Critical Infrastructure Resilience*, National Infrastructure Advisory Council, Final Report and Recommendations, September 8, 2009.
- *High-Impact, Low-Frequency Event Risk to the North American Bulk Power System*, A Jointly-Commissioned Summary Report of the North American Electric Reliability Corporation and the U.S. Department of Energy's November 2009 Workshop, June 2010.
- *A Framework for Establishing Critical Infrastructure Resilience Goals*, National Infrastructure Advisory Council, Final Report and Recommendations by the Council, October 19, 2010.
- *Severe Impact Resilience: Considerations and Recommendations*, NERC Severe Impact Resilience Task Force, accepted by the Board of Trustees on May 9, 2012.
- *Measuring the Resilience of Energy Distribution Systems*, Henry H. Willis and Kathleen Loa, Rand Corporation, 2015.
- *Conceptual Framework for Developing Resilience Metrics for the Electricity, Oil, and Gas Sectors in the United States*, Jean-Paul Watson, *et al.*, SAND2014-18019, September, 2015.
- *Resilience of the U.S. Electricity System: A Multi-Hazard Perspective*, Benjamin L. Preston, *et al.*, August 18, 2016.
- *Transforming the Nation's Electricity System: The Second Installment of the QER*, Chapter IV: Ensuring Electricity System Reliability, Security, and Resilience, U.S. Department of Energy, January 2017.
- *Enhancing the Resilience of the Nation's Electricity System*, National Academy of Sciences, Engineering, and Medicine, Washington, DC: The National Academies Press, 2017.

We summarize the major findings from these papers relevant to the current Resiliency Pricing NOPR, focusing on the following aspects of these reports:

A. Definitions of resilience

B. The role of generation in electric power sector resilience

C. Metrics for measuring resilience

D. Approaches to manage electric power system resilience

A. Definitions of Resilience

In its 2009 study, *Critical Infrastructure Resilience*, the National Infrastructure Advisory Council (NIAC) defined resilience as:

> Infrastructure resilience is the ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event.[49]

In its follow up 2010 report, *A Framework for Establishing Critical Infrastructure Resilience Goals*, NIAC continued to use the same definition and further developed the "resilience construct," which includes the following components:[50]

- Robustness: the ability to absorb shocks and continue operating;
- Resourcefulness: the ability to skillfully manage a crisis as it unfolds;
- Rapid Recovery: the ability to get services back as quickly as possible; and
- Adaptability: the ability to incorporate lessons learned from past events to improve resilience.

The report includes the following graphic to illustrate how these features are interconnected and sequenced within the NIAC-defined resilience construct.

Figure 4: The Sequence of the NIAC Resilience Construct

[49] *Critical Infrastructure Resilience*, National Infrastructure Advisory Council, Final Report and Recommendations, September 8, 2009, p. 8.

[50] *A Framework for Establishing Critical Infrastructure Resilience Goals*, National Infrastructure Advisory Council, Final Report and Recommendations by the Council, October 19, 2010, p. 5.

Source: *A Framework for Establishing Critical Infrastructure Resilience Goals*, National Infrastructure Advisory Council, Final Report and Recommendations by the Council, October 19, 2010, p. 17.

A 2012 report by the NERC Severe Impact Reliability Task Force defined "resilience" and "infrastructure resilience" in the following ways:[51]

> Resilience is the ability of an organization to resist being affected by an event or the ability to return to an acceptable level of performance in an acceptable period of time after being affected by an event.
>
> Infrastructure resilience is the ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event.
>
> A severe impact event is an event during which "complete restoration is not possible and the [bulk power system] is operated at a reduced state of reliability and supply for an extended period of time, for months or possibly years – a New Normal.

As a part of the *2014 Quadrennial Energy Review*, a 2015 Rand Corporation study[52] reviewed the most recent progress in measuring electric power system resilience based on existing literature and reviewed definitions of resilience, including the following published by the White House in 2013:

> The term "resilience" means the ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions. Resilience includes the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents.[53]

In doing so, the Rand Corporation report identified four aspects of the system addressed in the definitions:[54]

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51 *Severe Impact Resilience: Considerations and Recommendations*, NERC Severe Impact Resilience Task Force, accepted by the Board of Trustees on May 9, 2012, pp 10 – 12.

52 *Measuring the Resilience of Energy Distribution Systems*, Henry H. Willis and Kathleen Loa, Rand Corporation, 2015.

53 *Presidential policy directive 21: Critical infrastructure security and resilience*, The White House, February 12, 2013.

54 *Measuring the Resilience of Energy Distribution Systems*, Henry H. Willis and Kathleen Loa, Rand Corporation, 2015, pp. 3-4.

> First, resilience describes the state of service being provided by a system in response to a disruption.... Resilience describes the degree of disruption across multiple dimensions, which could include type, quality, time, and geography of service provision.
>
> Second, the state of a system depends on how it was designed and how it is operated. These choices influence whether and how service is degraded during a disruption, how quickly it recovers, and how completely it recovers.
>
> Third, different responses will lead to different resilience at different costs.
>
> Finally, resilience of a system also depends on the timescale. If recovery of a grid places equipment where it was and as it was designed, over a period of years, the system may experience repeated disruptions if climate change leads to greater frequency of flooding.

They also noted that the term "resilience" is not used consistently:

> Our review of definitions finds additional concepts that are sometimes included in definitions of resilience. Some of these are redundant; others distinguish important system characteristics. Examples are reliability, robustness, recoverability, sustainability, hardness, vulnerability, fault tolerance, and redundancy. While relevant, these additional terms are not used consistently. Reconciling the competing definitions of resilience in the literature is a difficult and not terribly productive task. Instead, when attempting to define metrics of resilience in the context of the Quadrennial Energy Review, it is more important to capture the relevant aspects of service delivery, system design, system operations, disruptions, costs, and timescale.[55]

A 2016 DOE National Laboratories report finds the following definitions characterize resilience:[56]

> *Resourcefulness*: in practice this could be applied to the power transmission and distribution system by implementing a constant monitoring and optimized dispatching and/or load shedding to respond to anomalies. For example, if a critical transmission line is lost, power might still be delivered by temporarily overloading parallel/alternative routes and monitoring conductor temperature and time of overload conditions.

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55 *Id.*, p. 6.

56 *Resilience of the U.S. Electricity System: A Multi-Hazard Perspective*, Benjamin L. Preston, *et al.*, August 18, 2016, p. 8.

> *Redundancy*: over-engineering critical systems to be able to function, at least at a reduced level, in critical conditions.
>
> *Restoration:* coordination and integration among stakeholders of restoration efforts, plans optimized for a variety of scenarios to avoid the need of improvising a solution during critical conditions. Sharing best practices among different organizations (from local to global, nation-wide) and practicing simulated emergencies should be mandated and coordinated at the national level. This sharing should include mutual assistance

The second installment of the *Quadrennial Energy Review* used the following definitions:[57]

> Reliability is the ability of the system or its components to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components.
>
> Security refers specifically to the ability of a system or its components to withstand attacks including physical and cyber incidents) on its integrity and operations.
>
> Resilience is the ability of a system or its components to adapt to changing conditions and withstand and rapidly recover from disruptions.

The 2017 National Academy of Science study, *Enhancing the Resilience of the Nation's Electricity System*, defines resilience as follows:

> Resilience is not just about lessening the likelihood that these outages will occur. It is also about limiting the scope and impact of outages when they do occur, restoring power rapidly afterwards, and learning from these experiences to better deal with events in the future.[58]

The study comes to the following conclusion for differentiating between reliability and resilience:

> Resilience is not the same as reliability. While minimizing the likelihood of large-area, long-duration outages is important, a resilient system is one that acknowledges that such outages can occur, prepares to deal with them, minimizes

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[57] *Transforming the Nation's Electricity System: The Second Installment of the QER*, Chapter IV: Ensuring Electricity System Reliability, Security, and Resilience, U.S. Department of Energy, January 2017, p. 4-4.

[58] *Enhancing the Resilience of the Nation's Electricity System*, National Academy of Sciences, Engineering, and Medicine, Washington, DC: The National Academies Press, 2017, p. 1.

their impact when they occur, is able to restore service quickly, and draws lessons from the experience to improve performance in the future.[59]

These studies and reports demonstrate that there is not a single consistent definition of "resilience" and that there is a need to define the difference from "reliability." One consistent thread is that the resilience of the system is associated with its ability to withstand and recover from a disruptive event. The types of events considered range widely from extreme weather events to coordinated physical or cyber attacks on the electric power system to crippling events beyond the electric power system such as a pandemic. Due to the wide range of events, the impacts of each type of event and the system that need to be in place to respond to these events fall across the electric power system. As the Preston, et al. paper notes, "[i]nfrastructure resilience is a whole-of-community issue."[60]

B. GENERATION RESILIENCE

Most of the studies included a wide range of processes that would be useful to increase the resilience of the electric power systems. In our review of the studies, we focus on whether and how assurance of fuel supply would support the resilience of the electric power system. While fuel supply at electric power generators is an element to keeping generators, we did not find any studies that directly linked retaining certain types of generating facilities with a specific amount of on-site fuel with system resilience. Out of the nine studies, four specifically referred to the importance of on-site fuel.

The 2012 NERC report provides the following recommendations for three types of generation:[61]

Recommendations – Coal

- Operators should ascertain and maintain cognizance of on-hand fuel supplies and storage capacity at coal fired generators.
- Operators should understand the coal transport routes in their area, consider possible supply disruption points, and explore alternate routes or transport modes.

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59 *Id.*, p. 10.

60 *Resilience of the U.S. Electricity System: A Multi-Hazard Perspective*, Benjamin L. Preston, *et al.*, August 18, 2016, p. 41.

61 *Severe Impact Resilience: Considerations and Recommendations*, NERC Severe Impact Resilience Task Force, accepted by the Board of Trustees on May 9, 2012, pp. 63-64.

- Operators should develop contingency plans around "out of fuel" scenarios in the coal fleet. What would New Normal operation look like in a short coal supply scenario?

Recommendations – Natural Gas

- Entities should understand the gas pipeline networks and arrangements in place to supply gas-fired generators in their footprint (e.g., gas-fired generators and pipelines that supply them, operator communications protocols during normal operations and emergencies).
- System operators should know which pipeline compressor facilities are gas versus electric powered and what gas pressure drops might be in the event of a sustained BPS outage. System operators will need to work with gas counterparts to understand power outage impacts on gas supply, and vice versa, and identify which are priority loads.
- In the event of a physical or cyber attack on gas infrastructure (including gas SCADA systems), system operators should consider the impact on gas-fired generation, and encourage their gas counterparts to share their plans to respond and restore operation.
- System operators should coordinate with gas operations personnel concerning their load shedding priorities.

Recommendations – Oil

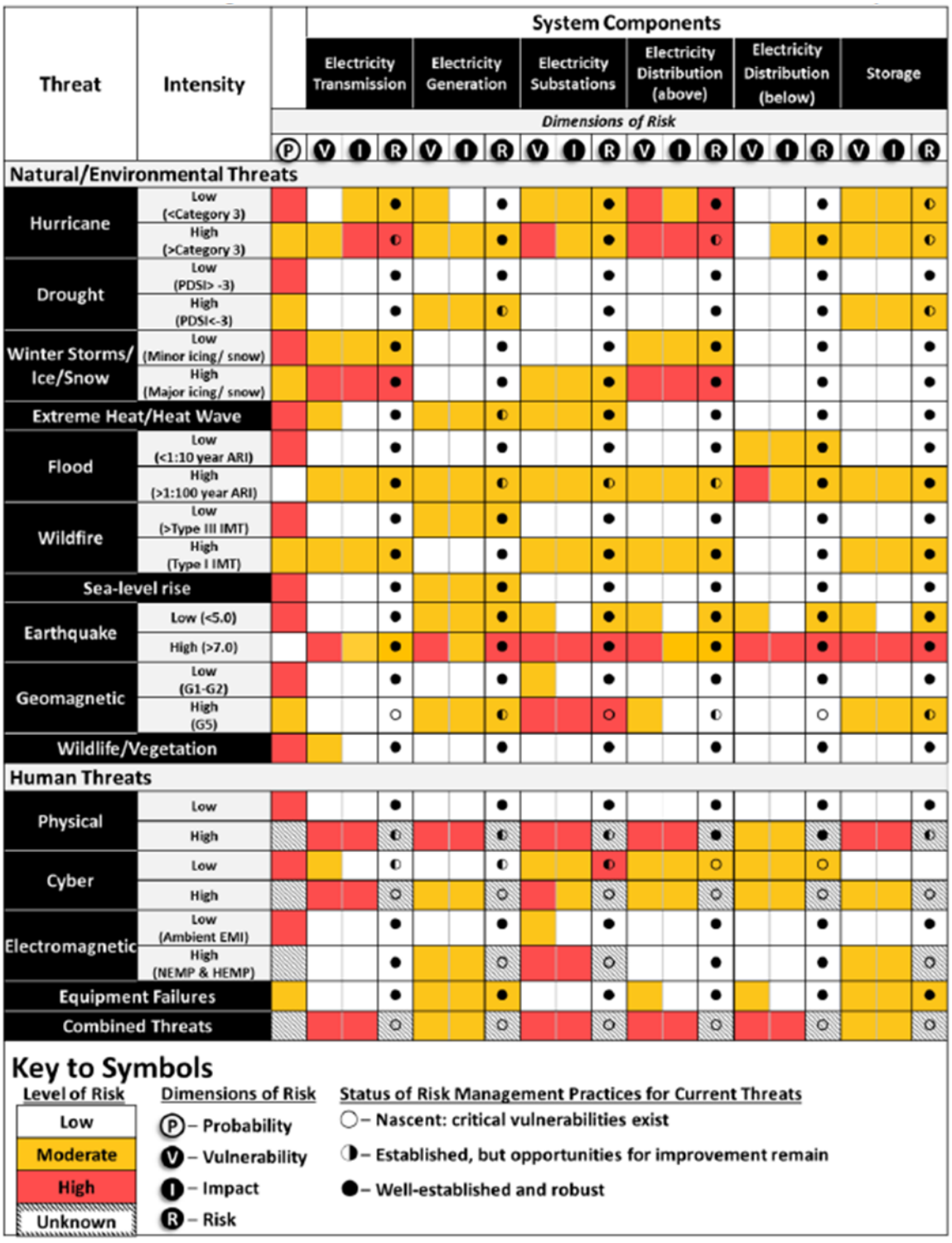
- Oil is a relatively minor fuel source for the bulk power system (BPS), however, system operators should assume these units will be unavailable due to unprecedented demand for diesel and gasoline fuel for standby and backup generators.
- Diesel fuel is needed for emergency standby generators at all critical BPS facilities that are without a reliable supply of power from the BPS during restoration. Entities should review contractual arrangements and establish priorities with fuel suppliers.
- Diesel and gasoline fuel is needed for transportation purposes. Regional Entities may wish to consider establishing regional fuel reserves for use in severe emergencies when normal fuel delivery channels may not be available for extended periods or when competing fuel demands (e.g., National Defense) take precedence for available supplies.

While on-site fuel for coal plants is listed above, it is just one of several recommendations that are necessary for maintaining operations of generation during disruptions. The report does not discuss the role of several months' fuel supply on the resilience of the system.

The second installment of the *Quadrennial Energy Review* summarizes how different components of the electricity system would need to respond to different types of threats to the electric power system.[62] That QER report summarized 15 types of threats, categorized into those related to natural or environmental threats and those associated with human actions, based on the table in the Preston, et al. paper shown in Figure 5. Of the type of incidents that would affect generation facilities, physical attacks are expected to have a high impact. Generators are expected to be vulnerable to hurricanes, drought, extreme heat, flood, sea level rise, earth quakes, geomagnetic, cyber attacks and electromagnetic pulses, and equipment failures as shown in the figure below. Despite the vulnerabilities, many of these risks are already managed in a robust fashion. None of them would be directly resolved by having a 90-day fuel supply on site.

[62] *Transforming the Nation's Electricity System: The Second Installment of the QER*, Chapter IV: Ensuring Electricity System Reliability, Security, and Resilience, U.S. Department of Energy, January 2017, pp. 4-26 – 4-27.

Figure 5
Detailed Integrated Assessment of Risk and Resilience to the Electricity Sector

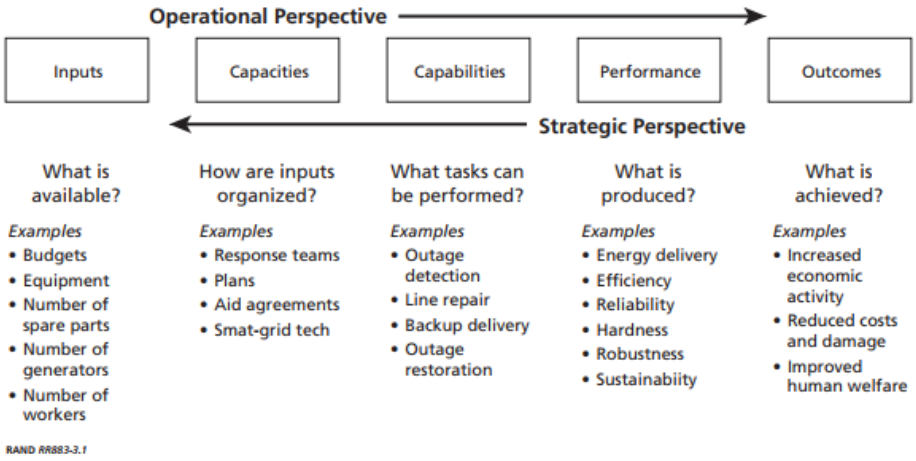


Source: *Resilience of the U.S. Electricity System: A Multi-Hazard Perspective*, Benjamin L. Preston, et al., August 18, 2016, p. 45.

C. RESILIENCE METRICS

As shown in Figure 6 from the 2015 Rand Corporation report, the metrics that are used to measure resilience fall into several categories: inputs, capacities, capabilities, performance, and outcomes.[63] Metrics at the facility/system level tend to be focused on inputs, capabilities, and performance, while metrics at the regional/national level tend to focus on performance and outcomes. Of the 105 metrics specific to the power system, we identified three that appear to relate to fuel supply generally: energy feedstock, energy not supplied, and energy storage.[64] However, solid fuel inventories, such as on-site coal and nuclear fuel, are not explicitly mentioned.

Figure 6
RAND Summary of Resilience Metrics



Source: *Measuring the Resilience of Energy Distribution Systems*, Henry H. Willis and Kathleen Loa, Rand Corporation, 2015, p. 8.

The National Academy of Science explains that "unlike reliability, there are no generally agreed upon resilience metrics that are used widely today. This is in part because there is not a long history of large-area, long-duration outages that can be analyzed to guide future investments."[65] The study concludes the following on resilience metrics:

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63 *Measuring the Resilience of Energy Distribution Systems*, Henry H. Willis and Kathleen Loa, Rand Corporation, 2015, p. 8.

64 *Id.*, p. 14.

65 *Enhancing the Resilience of the Nation's Electricity System*, National Academy of Sciences, Engineering, and Medicine, Washington, DC: The National Academies Press, 2017, p. 32.

> Development of resilience metrics and methods to defining resilience goals, as well as comparison of alternative strategies for increasing resilience, remains an active area of research, and the committee believes more research and demonstration is required before the electricity sector can reach consensus on a set of appropriate metrics. Metrics often drive decision making. Establishing and building consensus around metrics is an important prerequisite for comparing resilience enhancement strategies and for evaluating their costs and benefits. Many of the technologies and strategies for increasing the resilience of the electricity system described in the following chapters are expensive, particularly when implemented on a large scale. *Without consistent resilience metrics, large amounts of money could be spent with little understanding of actual resilience benefits and with much of this cost passed on to ratepayers*.[66]

D. Approaches to Manage Resilience

The 2010 NIAC report found that there is a "rich and diverse array of practices use by electric and nuclear companies to manage a variety of risks within both regulated and competitive business environments" and practicing resilience is "already a core operating principle and an integral part of their commitment to customers, shareholders, and communities."[67] The report includes the following list of current activities for maintaining reliability and resilience:

> The electricity and nuclear sectors make extensive use of emergency and continuity planning, risk modeling, disaster drills, tabletop exercises, operator training, safety features, redundant and backup systems, advanced technologies, innovative organizational structures, mutual assistance, supply chain management, and other methods to manage a variety of everyday and uncommon risks. These practices are woven into the business functions, operations, and culture of both sectors.[68]

The report identifies a framework for establishing resilience goals based on its study of the electricity sector, shown below in Figure 7.

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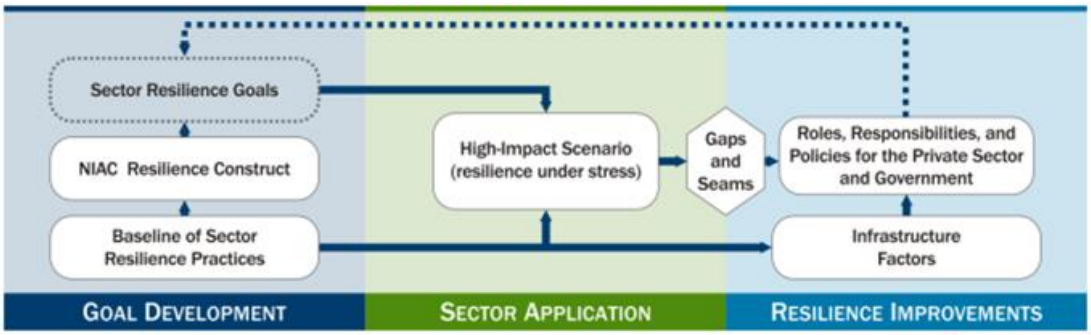
66 *Id.*, p. 33, emphasis added.

67 *A Framework for Establishing Critical Infrastructure Resilience Goals*, National Infrastructure Advisory Council, Final Report and Recommendations by the Council, October 19, 2010, p. 5.

68 *Ibid.*

Figure 7
NIAC Framework for Establishing Resilience Goals



Source: *A Framework for Establishing Critical Infrastructure Resilience Goals*, National Infrastructure Advisory Council, Final Report and Recommendations by the Council, October 19, 2010, p. 18.

The joint DOE/NERC report on high impact, low frequency event risk notes that "a successful risk management approach will begin by identifying the threat environment and protection goals for the system, balancing expected outcomes against the costs associated with proposed mitigations."[69] And, "determining appropriate cost ceilings and recovery mechanisms for protections related to [high impact, low frequency] risks will be critical to ensuring a viable approach to addressing them."[70]

Similarly, the 2016 study by researchers at DOE National Labs notes that "[e]ach type of risk is associated with different risk management interventions to maintain or enhance various elements of resilience in the face of different types of threats."[71] For improving electric power sector resilience, the report recommends the following:

> Future efforts toward building resilience should focus on risk assessment and planning for multiple and emerging contingencies, particularly for potentially catastrophic threats. Continuing to invest in new generation technologies and grid modernization while enhancing the capacity for launching coordinated responses across multiple actors will generate significant benefits in terms of maintaining

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69 *High-Impact, Low-Frequency Event Risk to the North American Bulk Power System*, A Jointly-Commissioned Summary Report of the North American Electric Reliability Corporation and the U.S. Department of Energy's November 2009 Workshop, June 2010, p. 9.

70 *Ibid.*

71 *Resilience of the U.S. Electricity System: A Multi-Hazard Perspective*, Benjamin L. Preston, et al., August 18, 2016, p. 8.

> reliability. Such investments will also help enable the system to keep pace with the rapidly changing nature of the U.S. energy sector and emerging threats.[72]

Researchers at Sandia National Laboratories developed a risk-based framework in their 2015 report for defining resilience metrics and identifying how those metrics should be applied, known as the Resiliency Analysis Process ("RAP").

Despite the various frameworks proposed to help manage resilience, the NOPR does not point to any that might support the proposition that a 90-day on-site fuel supply would help manage the resilience of the power system. The Sandia report recommends a process to identify metrics that: (1) are useful; (2) provide a mechanism for comparison; (3) are useable in operations and planning contexts; (4) exhibit extensibility; (5) are quantitative; (6) reflect uncertainty; (7) support a risk-based approach; and (8) consider recovery time.[73] The report notes that deploying resilience metrics in this way requires a fundamental change in approach for defining energy system resilience and highlights that there has been "little work that quantitatively expresses values of resilience."[74]

Sandia researchers recommend that a deliberate and quantitative process should be followed, including these seven steps shown in Table 3. The DOE NOPR did not follow such a process, except perhaps for adopting what could be considered a resilience metric, *i.e.*, 90-days of on-site fuel, without first defining the resilience goals. There was no characterization of threats, no estimation of the level of disruption, no application of system models to calculate consequences, and no evaluation of resilience improvements as outlined in the Resilience Analysis Process.

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[72] *Id.*, p. iv.

[73] *Conceptual Framework for Developing Resilience Metrics for the Electricity, Oil, and Gas Sectors in the United States*, Jean-Paul Watson, et al., SAND2014-18019, September, 2015, pp. 12-13.

[74] *Id.*, p. 13.

Table 3
Seven Steps of the Resilience Analysis Process

Step	Description	Purpose
1	**Define resilience goals**	Before determining the scope of the system relevant for analyzing and selecting appropriate metrics, it is essential to define high-level resilience goals. The goal set during this first RAP step lays the foundation for all following steps.
2	**Define system and resilience metrics**	The system under consideration and the resilience metric definitions determine the analysis' scope. This could include identifying a larger system's geographic boundaries, relevant time periods, and/or relevant components.
3	**Characterize threats**	Threat characterization is critical to understanding how capable the system must be to absorb and adapt to different types of attacks or natural events. When evaluating resilience against multiple hazards, information about (1) the likelihood of each possible threat scenario and (2) the capabilities or strength of the threat are extremely important. In risk analysis, threat and consequence are used to understand which vulnerabilities are most important to address to reduce the consequences associated with the threat.
4	**Determine level of disruption**	Once an understanding of the relevant threats has been solidified, the attributes of each threat are used to determine the amount of damage to the system (infrastructure, equipment, etc.) that is likely to result from that set of threats. This is the RAP step where expectations about structural damage or other system impacts that could affect performance are defined.
5	**Define and apply system models**	The damage states outlined in Step 4 can then be used as input to system models—tying damage to system output levels. For example, anticipated physical damage (or a range of damage outcomes incorporating uncertainty) to an electric grid from an earthquake can be used as input to a system model that ties those outages due to damage to load not served within the system over time. Multiple system models may be required to capture all of the relevant aspects of the complete system. Furthermore, dependencies may exist between models.
6	**Calculate consequence**	When evaluating resilience, direct impacts to system output as a result of damage are only part of the story. Most energy systems provide energy some larger social purpose (e.g., transportation, health care, manufacturing, economic gain). During this step, outputs from system models are converted to the resilience metrics that were defined during Step 2. When uncertainty is included in the RAP, probability distributions will characterize the resilience-metric values
7	**Evaluate resilience improvements**	Unless the RAP is being undertaken purely for assessment purposes, it is likely that some decision or decisions must be made about how to modify operational decisions or plan investments to improve resilience. After completing a baseline RAP through the preceding steps, it is possible and desirable to populate the metrics for a system configuration that is in some way different from the baseline in order to compare which configuration would provide better resilience.

Source: *Conceptual Framework for Developing Resilience Metrics for the Electricity, Oil, and Gas Sectors in the United States*, Jean-Paul Watson, et al., SAND2014-18019, September, 2015, p. 14.

Appendix B: Estimated Cost of Proposed Rule

This appendix provides the details supporting the estimation of the costs of the proposed rule, in the form of out-of-market payments. Below in three sections, we describe the details of our assumptions and calculations of the ranges of the cost estimates. The three sections include the estimations of (i) Total Cost of Service, (ii) Offsetting Market Revenues from the energy and capacity markets, and (iii) the overall Out-of-Market Payments to the potentially eligible generating units.

A. Total Cost of Service for the Potentially Eligible Resources

The proposed rule would include paying for the costs associated with "operating and fuel expenses, costs of capital and debt, and a fair return on equity and investment" for eligible generation units. We refer to the combination of these costs as the "gross cost of service." We separate these costs into three components, as described below:

- Annual operating and fuel costs—fuel costs, variable operation and maintenance (VOM) costs, fixed O&M (FOM) costs, and ongoing capital expenditures (CapEx) in 2016;
- Annualized capital costs of environmental retrofits installed on coal units since 2008; and
- Annualized capital costs of the original generation facilities.

Below we discuss our approach and the data sources used to estimate each of these cost components.

1. Annual Operating and Fuel Costs

The sources for estimating the annual fuel costs, variable operating and maintenance (VOM) costs, fixed operating and maintenance (FOM) costs and ongoing capital expenditures (CapEx) are described in this subsection.[75] Since there is no single complete database that provides unit-

[75] Note that the ongoing capital expenditures are typically added to the ratebase to earn a return on that investment over time in addition to recovering the investment cost. However, due to lack of data for historical annual capital expenditures by merchant units, we treated these annual investments as expense, i.e., identical to FOM. This approach to treat them as expense would understate the annual cost recovery as it ignores the return on those investments.

specific cost data for all of these components, we reviewed several sources of information to develop a range of estimates for unit-specific annual operating and fuel costs.

- **ABB, Inc.**: contains estimated unit-specific information on fuel costs, VOM costs and FOM costs in 2016.[76] The ABB, Inc. dataset does not include estimates for ongoing CapEx.
- **U.S. Environmental Protection Agency (EPA):** contains unit-specific estimates of VOM and FOM costs for nuclear units, and estimated VOM and FOM costs for coal units based on age, size, and installed emissions control equipment. These estimates have been developed by the EPA as part of their economic analysis of the Clean Power Plan (CPP).[77] The EPA data does not include estimates for fuel costs and ongoing CapEx.
- **U.S. Energy Information Administration (EIA):** contains estimated ongoing CapEx for a typical coal unit and a typical nuclear unit.[78]
- **Nuclear Energy Institute (NEI):** contains average costs of fuel, operating and ongoing CapEx in 2016 for the nuclear fleet.
- **Idaho National Laboratory (INL)**: contains estimated costs of fuel, operating and ongoing CapEx for 24 nuclear units.[79]

To estimate the payments that potentially eligible generating units would have received in 2016, we estimate the operating and fuel costs in 2016 for each unit under the following four scenarios. These scenarios differ by the sources of data for various cost estimates:

- **Scenario 1:** ABB, Inc. fuel and O&M costs, and EIA ongoing CapEx
- **Scenario 2:** ABB, Inc. fuel, EPA O&M and EIA ongoing CapEx

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[76] ABB, Inc. Velocity Suite (2017).

[77] *Documentation for EPA Base Case v.5.13 Using the Integrated Planning Model*, EPA, November 2013, Tables 4-8, 4-9, and 4-34. Available at: https://www.epa.gov/sites/production/files/2015-07/documents/documentation_for_epa_base_case_v.5.13_using_the_integrated_planning_model.pdf.

[78] *Assumptions to the Annual Energy Outlook 2017*, EIA, July 2017, p. 113. Available at: https://www.eia.gov/outlooks/aeo/assumptions/pdf/0554(2017).pdf

[79] *Economic and Market Challenges Facing the U.S. Nuclear Commercial Fleet*, INL, September 2016, Tables A-1 through A-5. Available at: https://gain.inl.gov/Shared_Documents/Economics-Nuclear-Fleet.pdf

- **Scenario 3:** For nuclear units, NEI data for operating costs and ongoing CapEx; for coal units, ABB, Inc. fuel costs, EPA O&M and EIA CapEx
- **Scenario 4:** For nuclear units, Idaho Lab and NEI data on operating costs and ongoing CapEx; for coal units, ABB, Inc. fuel, EPA O&M and EIA CapEx

Table 4 below summarizes the estimated average operating and fuel costs for coal nuclear units by component under each scenario. For both coal and nuclear units, Scenario 1 has the lowest estimate for the average operating and fuel costs at $38/MWh and $27/MWh, respectively. Scenario 2 has the highest cost estimate for nuclear units at $38/MWh, and Scenarios 2 through 4 has the highest cost estimate for coal units at $50/MWh. The largest component of the operating and fuel costs on a per MWh basis is the fuel costs for coal units and fixed O&M (FOM) costs for nuclear units. The table also shows a wide range of estimated costs for coal plants based on unit-specific information provided by various data sources. The range of the $/MWh cost is depicted by the minimum and maximum numbers in the table. Because some coal units operate at very low capacity factors, when calculated in terms of $/MWh, they would show very high costs, up to about $400/MWh in 2016. These costs are significantly higher than the average for all eligible coal units due to those units' high fixed operating costs divided by the small amount of generation output.

Table 4
Operating and Fuel Costs for Eligible Coal and Nuclear Units
Four Scenarios/Data Sources

	Scenarios			
	1	**2**	**3**	**4**
Coal Average Operating and Fuel Costs ($/MWh)				
Fuel Costs	22.51	22.51	22.51	22.51
VOM	1.68	5.54	5.54	5.54
FOM	8.21	15.69	15.69	15.69
Ongoing CapEx	5.82	5.82	5.82	5.82
Total	**38.21**	**49.54**	**49.54**	**49.54**
Min	25.44	32.76	32.76	32.76
Max	260.18	397.57	397.57	397.57
Nuclear Average Operating and Fuel Costs ($/MWh)				
Fuel Costs	4.70	4.70	6.76	6.76
VOM	3.46	0.24	0.00	0.00
FOM	13.55	27.42	20.43	21.50
Ongoing CapEx	5.73	5.73	6.74	6.74
Total	**27.44**	**38.10**	**33.93**	**35.00**
Min	22.49	32.40	33.93	33.61
Max	34.27	52.96	33.93	50.90

2. Annualized Capital Costs of Environmental Retrofits at Coal Units

The proposed rule requires payments to eligible generators for the recovery of and a fair return on capital investments, which would include the capital cost of emission control equipment retrofitted onto existing coal units. Some state and federal environmental regulations required large capital expenditures; for example the recent Mercury and Air Toxics rule (MATS) mandated emissions rates that required one or more retrofit controls such as flue gas desulfurization (wet scrubber), dry sorbent injection, baghouse, and activated carbon injection (ACI).

As a conservative estimate of the retrofit costs already incurred, we identified the actual retrofits installed since 2008. To the extent that retrofits installed prior to 2008 are not yet fully depreciated, the estimated return on and of the retrofit capital expenditures would understate those costs that could be subject to cost recovery under the proposed rule.

To estimate the original capital costs for the retrofits installed since 2008, we rely on EPA's generic cost estimates by equipment and by size of the coal unit. Table 5 below shows the assumed capital costs ($/kW) for each equipment type we included in our cost estimate. We

estimate the resulting total installed capital costs for retrofits on the potentially eligible coal units since 2008 to be approximately $18.9 billion (in 2001 dollars), mostly from investments in wet scrubbers and SCRs.

Table 5
Retrofit Pollution Controls Overnight Capital Costs

Retrofit Equipment	Unit Size (MW)						Total Retrofit Capital Cost ($M)
	0 - 50	50 - 100	100 - 300	300 - 500	500 - 700	700 - 1000	
Wet Scrubber		859	629	544	451	447	12,245
Dry Scrubber	857		537	465	442		2,046
SCR			287	266	255		2,293
SNCR	56	56	30	23	19		156
ACI	34	34	13	9	6		221
DSI			65	45	36		311
Baghouse	281	281	225	203	190		1,583
							18,856

The proposed rule does not specify how the past investment costs (and a fair return on that investment) would be recovered in annual payments to eligible units going forward. As a reasonable indicator of such costs, we assume that any undepreciated portion of those original retrofit capital costs by 2016 would be recovered through annual capital recovery payments similar to the regulatory treatment of capital costs in ratebase for generating units subject to cost-of-service regulation.

Assuming a straight-line depreciation over 15 years[80] for the capital costs associated with the retrofits, we estimate approximately $10 billion in undepreciated retrofit capital costs associated with the potentially eligible coal generating units. These costs are akin to the remaining book value of the retrofit costs as of the beginning of 2016 (since we are estimating the likely annualized costs of the environmental retrofits for the year 2016).

[80] The assumed 15-year depreciation life for the environmental retrofits is consistent with EPA's assumption in its economic analysis of the retrofit equipment costs (see https://www.epa.gov/sites/production/files/2015-07/documents/documentation_for_epa_base_case_v.5.13_using_the_integrated_planning_model.pdf page 8-14).

We estimate the annual capital recovery charges for the past retrofit costs by assuming an illustrative cost of capital (ATWACC) of 6.75% for a regulated generation unit,[81] and considering two potential approaches that FERC might adopt to determine the recovery of capital costs in the first year of implementing the proposed rule. The first potential approach would be a depreciated original cost (DOC) approach typically implemented by state regulatory agencies to determine the revenue requirements for generating units subject to cost-of-service regulation. The second approach is to estimate the annual return on and of the invested capital based on a level-nominal estimation approach that is a constant nominal dollar amount every year over the remaining life of the capital investments.

Using the depreciated original cost approach, we estimate that the first-year's return on and of the past retrofit capital expenditures would be $2.2 billion. Using the level-nominal approach, we estimate that the annual cost (which would be the same value in each year going forward) would be about $1.7 billion.

3. Annualized Capital Costs of the Original Generation Facilities

Most of the potentially eligible generating units were originally built and owned by regulated utilities before deregulation of the industry in the late 1990s. Subsequent to deregulation, many of them were sold to merchant generating companies or spun off into merchant subsidiaries of the original owning utilities. A relatively small number of these units were originally developed and built as merchant units. For most of the potentially eligible nuclear generating units, we are able to identify the current owner's purchase price or the implied price paid for the assets when transferred to an unregulated subsidiary. In cases where we have the purchase price information for a fleet of nuclear units, we assume that each unit was sold for the same dollar per kilowatt on average. We then assume that such purchase prices set the initial ratebase on which cost recovery calculation would be based. In a few instances that we cannot determine the purchase price from publicly available data, we estimate the likely sales price for the unit based on prices associated with other transactions.

After we estimate the capital costs of the potentially eligible units, we assume that the owner would have depreciated the cost of the plant from the date of acquisition (or in-service dates) to

[81] Based on the following assumptions: 50:50 debt/ equity capital structure, debt cost of 5% and allowed return on equity of 10.5%.

2016 using straight-line depreciation over a time period equal to the difference between the end of the unit's Nuclear Regulatory Commission approved license life and the date of acquisition.

For the coal plants, very limited data on the transaction prices are available. We were able to obtain data for only 14 of the 283 affected coal units. The data that we collected indicate a wide range of purchase prices, from $141/kW to $720/kW in PJM, and $209/kW to $638/kW in MISO for transactions completed between 2013 at 2016. Given such data limitation, we decided to estimate their net book value, instead of purchase values. To estimate the net book values, we estimate the initial capital cost of the coal generating units in the year they came online. Then we depreciated those values using a straight-line depreciation for either 30 or 50 years as two sensitivities to establish a remaining book value at the beginning of 2016.

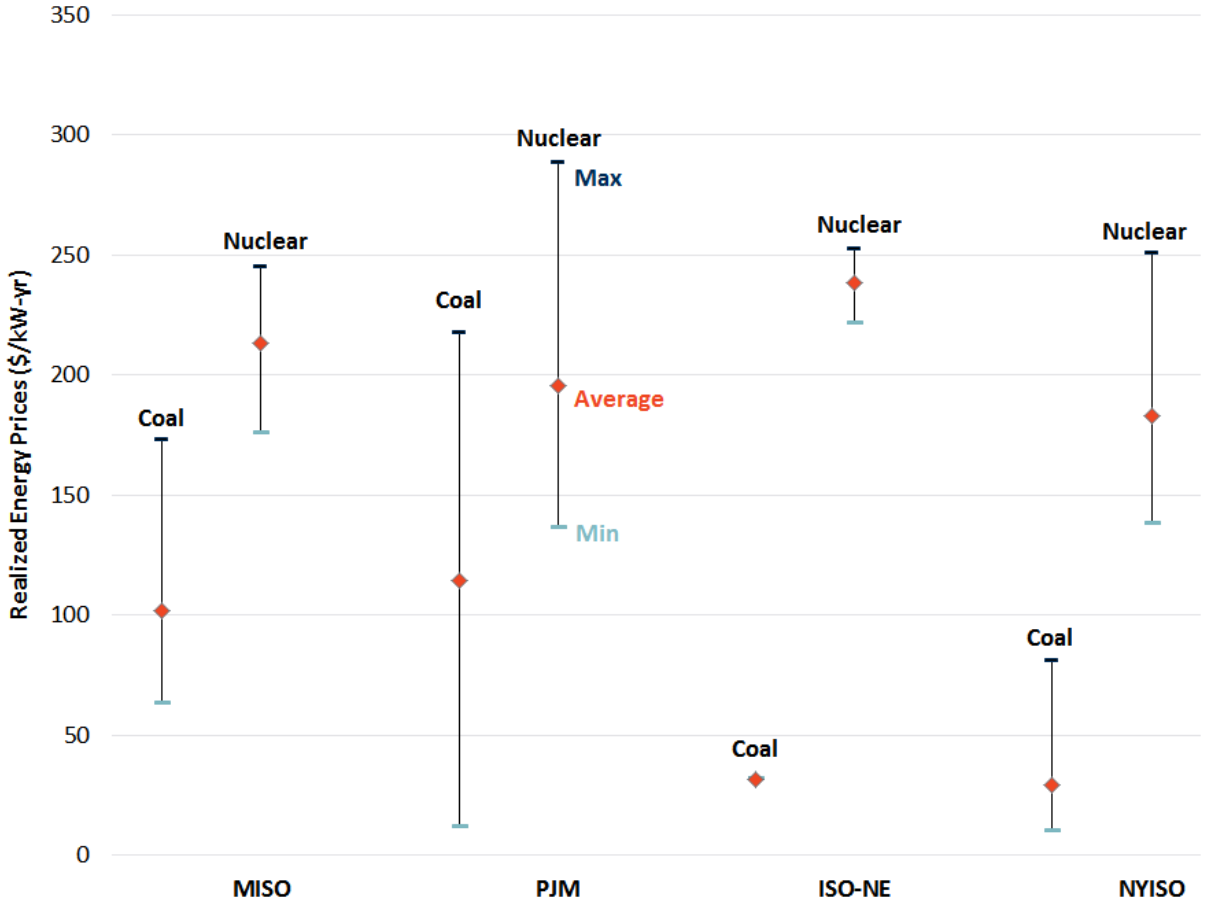
We relied on Energy Information Agency Annual Energy Outlook estimates for coal unit capital costs back to 1996. We also relied on the 1993 Electric Power Research Institute (EPRI) Technical Assistance Guide (TAG) for a 1993 estimate, and a report done by Black and Veatch for the Michigan Electricity Option Study in 1986 for a then-contemporaneous estimate of the cost of building a coal plant. We interpolated between years to fill in the entire series.

For both nuclear and coal units, we estimate the capital recovery charges for the capital costs incurred using the same methodologies and the same cost of capital (6.75% ATWACC) as the one that we use to estimate capital recovery charges for the environmental retrofit costs incurred. Using the DOC approach, we estimate the first-year costs associated with the return on and of the plant capital expenditures to be between $2.8 and $4.4 billion depending on the depreciation schedule used. Using the level-nominal approach, we estimate the 2016 annual costs that reflect the return on and of the plant capital expenditures to be between $1.9 and $3.3 billion.

B. Offsetting Market Revenues

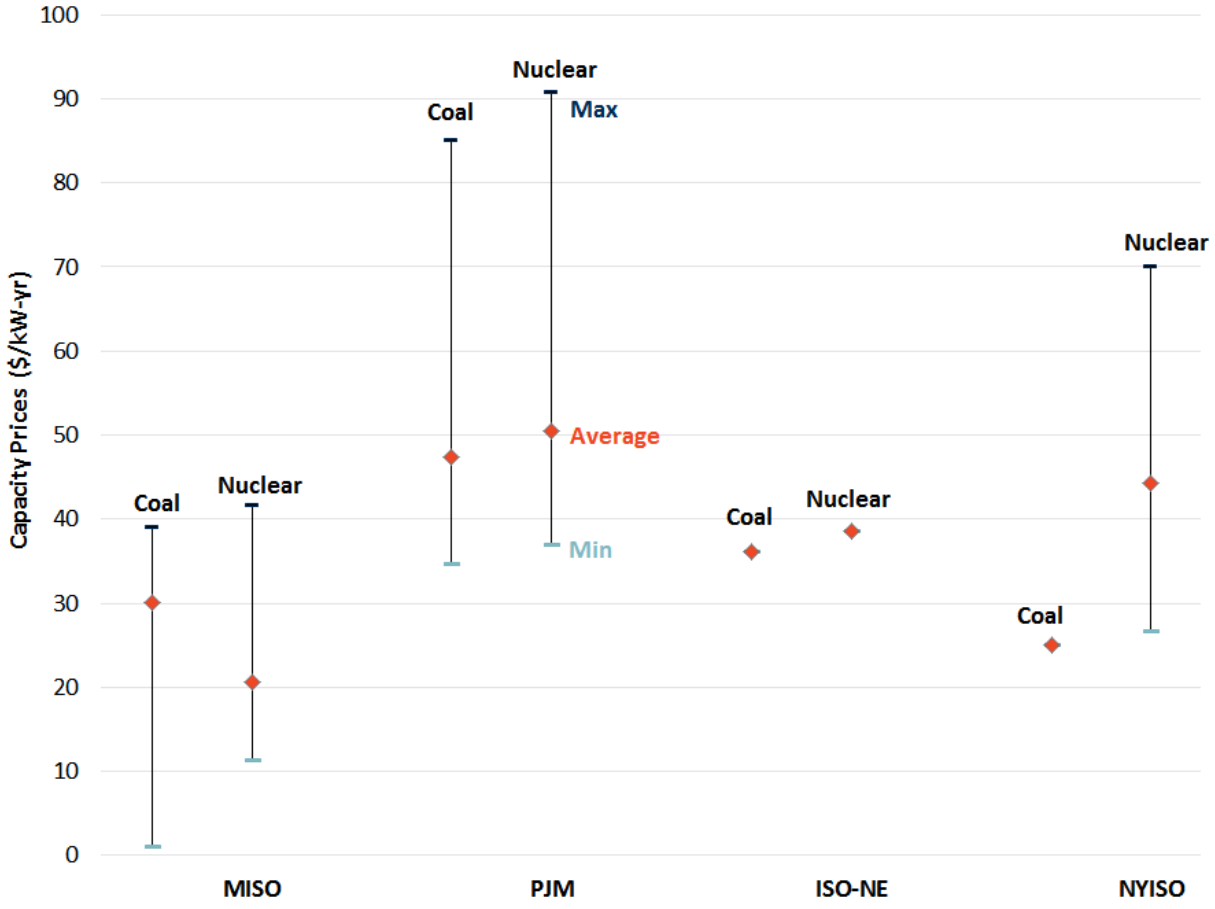
We estimate the energy market revenues for each generating unit in the RTO energy markets in 2016 based on the unit-specific information compiled by ABB, Inc. for the day-ahead market revenues. Figure 8 below summarizes the annual average realized energy price for the merchant coal and nuclear units by RTO region. The average realized energy revenues (in $/kW-year) for coal units were lower than nuclear units in all regions due to higher capacity factors of the nuclear units. On average, nuclear units earned $180-$240/kW-year in energy revenues. Coal units' energy revenues varied more widely among the RTO regions (higher in PJM and MISO, lower in ISO-NE and NYISO).

Figure 8
Annual Average Realized Energy Price
for the Merchant Coal and Nuclear Units by RTO Region



While historical market-clearing prices for the RTO capacity market auctions are publicly available, historical capacity revenues for merchant generating units are not. Some of the existing generating capacities did not clear in all past capacity auctions. As an estimate that err on the side of higher market-based capacity payments, we assume that all of the potentially eligible units would have cleared in the capacity market for 2016 and would have received the full capacity revenues based on the market-clearing prices in the zone they are located. Figure 9 below summarizes the estimated capacity prices received by merchant coal and nuclear units by RTO region. The PJM and NYISO regions provided the highest realized capacity prices on average for the potentially eligible units at $45-50/kW-year, and the units in the MISO region had the lowest realized capacity prices at $20-30/kW-year. Within each RTO, the realized capacity prices varied substantially among the individual units due to zonal differences in capacity prices in 2016.

Figure 9
Estimated Capacity Prices Received in 2016
by Merchant Coal and Nuclear Units by RTO Region



Overall, we estimate that the market revenues for the potentially eligible generating units from energy and capacity markets in 2016 to be approximately $17 billion.[82] On a per kW-year basis, the average combined revenues from energy and capacity markets were lower for coal units (especially in ISO-NE and NYISO where the) than nuclear units. Table 6Table 1 below summarizes the total market revenues (and ranges across units) by RTO region.

[82] These estimates do not account for Zero Emission Credit (ZEC) programs for nuclear plants in some states since they were not implemented in our 2016 test year. Future payments under the proposed rule would presumably be offset by ZEC payments if not reduce the ZEC payments.

Table 6
Summary of Total Market Revenues by RTO Region in 2016
(including ranges across units)

	MISO	PJM	ISO-NE	NYISO
Total ($ Millions)				
Coal	1,315	6,105	26	61
Nuclear	814	6,638	1,052	1,149
Average ($/kW-yr)				
Coal	132	162	68	54
Nuclear	234	246	277	227
Min ($/kW-yr)				
Coal	65	61	68	36
Nuclear	188	187	261	165
Max ($/kW-yr)				
Coal	210	252	68	107
Nuclear	257	341	291	321

C. Estimated Out-of-Market Payments To Potentially Eligible Resources

We estimate the annual payments required to cover the to-go cost of potentially eligible units to be in the range of $0.8 to $4.7 billion. Adding the return of and return on past capital expenditures on original capital costs of the coal units and the estimated payments by the current owners for purchasing the nuclear units plus the capital charges from recent retrofit investments at coal plants brings the total annual payments to a range of $3.7 to $11.2 billion. Table 7 below shows the components of these estimates. Variation in several parameters account for the overall range of estimates: data sources used to estimate going-forward cost and different depreciation schedules used to compute annual capital charges.

Table 7
Summary of Estimated Cost of the Proposed Rule

	Operating Costs Only		Operating Costs, Past Retrofits, and Original Cost	
	Low	High	Low	High
Gross Cost of Service ($ Billions)	**16.1**	**21.7**	**19.8**	**28.3**
Operating and Fuel Costs	16.1	21.7	16.1	21.7
CapEx from Past Retrofits	0.0	0.0	1.7	2.2
CapEx from Original Cost	0.0	0.0	1.9	4.4
Market Revenues ($ Billions)	**17.2**	**17.2**	**17.2**	**17.2**
Energy	13.2	13.2	13.2	13.2
Capacity	3.9	3.9	3.9	3.9
Total Capacity Receiving Out-of-Market Payments (GW)	**37.0**	**80.2**	**57.0**	**88.4**
Coal	23.4	44.0	38.5	49.2
Nuclear	13.6	36.2	18.5	39.2
Average Cost of Out-of-Market Payments ($/kW-yr)				
Coal	19.0	47.9	81.4	152.6
Nuclear	24.2	71.2	30.4	93.3
Total Cost of Out-of-Market Payments ($ Billions)	**0.8**	**4.7**	**3.7**	**11.2**
Coal	0.4	2.1	3.1	7.5
Nuclear	0.3	2.6	0.6	3.7

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