UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

REPLY COMMENTS OF AMERICAN MANUFACTURERS AND LARGE INSTITUTIONAL CUSTOMERS

PJM Industrial Customer Coalition; Coalition of MISO Transmission Customers; American Chemistry Council; Industrial Energy Consumers of America; Industrial Energy Consumers of Pennsylvania; Industrial Energy Users – Ohio; Illinois Industrial Energy Consumers; New Jersey Large Energy Users Coalition; Ohio Energy Group; West Virginia Energy Users Group; Massachusetts Chemistry & Technology Alliance; Utah Association of Energy Users; Chemical Industry Council of Illinois; Heat Treating Services Corporation of America; Michigan Chemistry Council; Corn Refiners Association; American Feed Industry Association; Chemistry Council of New Jersey; Carolina Utility Customers Association; Glass Manufacturing Industry Council; American Foundry Society; Glass Packaging Institute; Association of Businesses Advocating Tariff Equity; Industrial Energy Consumer Group; Pennsylvania Chemical Industry Council; New York State Chemistry Council; Wisconsin Industrial Energy Group, Inc.; Minnesota Large Industrial Group; American Iron and Steel Institute; National Industrial Sand Association; Industrial Minerals Association-North America; Ohio Chemistry Technology Council; Pennsylvania Manufacturers' Association; American Forest & Paper Association; Iron Mining Association of Minnesota; Steel Manufacturers' Association; Wisconsin Paper Council; and Indiana Industrial Energy Consumers, Inc.

Robert A. Weishaar, Jr.
McNees Wallace & Nurick LLC
1200 G Street, NW, Suite 800
Washington, D.C. 20005
Phone: (202) 898-5700
Fax: (717) 260-1765
E-mail: bweishaar@mcneeslaw.com

Frank Darr
McNees Wallace & Nurick LLC
21 East State Street, 17th Floor
Columbus, OH 43215
Phone: (614) 469-8000
Fax: (614) 469-4653
E-mail: fdarr@mwncmh.com

Susan E. Bruce
Vasiliki Karandrikas
Kenneth R. Stark
McNees Wallace & Nurick LLC
100 Pine Street
Harrisburg, PA 17101
Phone: (717) 232-8000
Fax: (717) 237-5300
E-mail: sbruce@mcneeslaw.com
vkarandrikas@mcneeslaw.com
kstark@mcneeslaw.com

Counsel to the PJM Industrial Customer Coalition and
the Coalition of MISO Transmission Customers, and on behalf
of American Manufacturers and Large Institutional Customers

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Pursuant to the Federal Energy Regulatory Commission's ("Commission" or "FERC") Notice Inviting Comments dated October 2, 2017, the PJM Industrial Customer Coalition ("PJMICC"); the Coalition of MISO Transmission Customers ("CMTC"); American Chemistry Council; Industrial Energy Consumers of America ("IECA"); Industrial Energy Consumers of Pennsylvania ("IECPA"); Industrial Energy Users – Ohio ("IEU-Ohio"); Illinois Industrial Energy Consumers ("IIEC"); New Jersey Large Energy Users Coalition ("NJLEUC"); Ohio Energy Group ("OEG"), West Virginia Energy Users Group ("WVEUG"); Massachusetts Chemistry & Technology Alliance; Utah Association of Energy Users ("UAE"); Chemical Industry Council of Illinois ("CICI"); Heat Treating Services Corporation of America ("HTSMI"); Michigan Chemistry Council ("MCC"); Corn Refiners Association ("CRA"); American Feed Industry Association ("AFIA"); Chemistry Council of New Jersey ("CCNJ"); Carolina Utility Customers Association ("CUCA"); Glass Manufacturing Industry Council ("GMIC"); American Foundry Society ("AFS"); Glass Packaging Institute ("GPI"); Association of Businesses Advocating Tariff Equity ("ABATE"); Industrial Energy Consumer Group ("IECG"); Pennsylvania Chemical Industry Council ("PCIC"); New York State Chemistry Council; Wisconsin Industrial Energy Group, Inc. ("WIEG"); Minnesota Large Industrial Group ("MLIG"); American Iron and Steel Institute ("AISI"); National Industrial Sand Association ("NISI"); Industrial Minerals Association-

North America ("IMA-NA"); Ohio Chemistry Technology Council; Pennsylvania Manufacturers' Association ("PMA"); American Forest & Paper Association ("AF&PA"); Iron Mining Association of Minnesota ("IMA"); Steel Manufacturers' Association ("SMA"); Indiana Industrial Energy Consumers, Inc. ("INDIEC"); and Wisconsin Paper Council (together, "American Manufacturers") hereby file these Reply Comments in the above-captioned proceeding.

As the Commission is well aware, more than 300 Initial Comments were filed on October 23, 2017, in response to the Secretary of Energy's ("Secretary") proposed rule pursuant to the Department of Energy Organization Act ("DOE Act") (referred to as "the Grid Reliability and Resilience Pricing Rule" or "Proposed Rule" or "NOPR"). Due to the sheer number of Initial Comments that were submitted in response to the Proposed Rule and the limited time for filing Reply Comments, American Manufacturers cannot respond to each and every argument made in favor of the Proposed Rule. As a result, American Manufacturers' Reply Comments focus on responding to those arguments that are among the most antithetical to the concepts of wholesale market competition and just and reasonable rates.[1] American Manufacturers' decision not to respond to other arguments that are similarly offensive to fundamental wholesale market principles

[1] American Manufactures' Reply Comments focus on the arguments made and positions taken by the following entities: Comments of FirstEnergy Service Company *et al*. in Support of the Grid Reliability and Resilience Pricing Notice of Proposed Rulemaking, *Grid Reliability and Resilience Pricing*, Docket No. RM18-1-000 (Oct. 23, 2017) ("FE Comments"); Rulemaking Comments of the Nuclear Energy Institute, *Grid Reliability and Resilience Pricing*, Docket No. RM18-1-000 (Oct. 23, 2017) ("NEI Comments"); Comments of Murray Energy Corporation in Support of Proposed Rule, *Grid Reliability and Resilience Pricing*, Docket No. RM18-1-000 (Oct. 23, 2017) ("Murray Energy Comments"); Comments of the PSEG Companies, *Grid Reliability and Resilience Pricing*, Docket No. RM18-1-000 (Oct. 23, 2017) ("PSEG Comments"); Comments of the American Coalition for Clean Coal Electricity and National Mining Association in Support of the Department of Energy's Grid Reliability and Resilience Pricing Proposed Rule, *Grid Reliability and Resilience Pricing*, Docket No. RM18-1-000 (Oct. 23, 2017) ("Coal and Mining Comments"); Comments of Exelon Corporation, *Grid Reliability and Resilience Pricing*, Docket No. RM18-1-000 (Oct. 23, 2017) ("Exelon Comments"); and Motion to Intervene and Comments of the AES Companies, *Grid Reliability and Resilience Pricing*, Docket No. RM18-1-000 (Oct. 23, 2017) ("AES Comments"). The Reply Comments also address arguments in favor of addressing price formation on an accelerated basis in lieu of the Commission adopting the Proposed Rule.

and inconsistent with American Manufacturers' Initial Comments and these Reply Comments should not be construed as support for, or agreement with, such arguments.

For the reasons discussed below and in their Initial Comments, American Manufacturers respectfully reiterate their request that the Commission summarily *reject* the Proposed Rule.

I. INTRODUCTION AND PROCEDURAL BACKGROUND

On September 28, 2017, pursuant to section 403 of the DOE Act,[2] the Secretary proposed a rule for final action by the Commission within 60 days from publication in the *Federal Register*.[3]

On October 2, 2017, the Commission issued a notice of proposed rulemaking, establishing October 23, 2017, and November 7, 2017, as the deadlines for submitting initial and reply comments, respectively.[4]

On October 4, 2017, FERC Staff issued a *Request for Information Regarding Section 403 of the Department of Energy Organization Act's Proposed Rule for Final Action*.[5] FERC Staff's Information Request presented more than 50 questions on approximately eight issues and sub-issues for public comment as part of the proposed rulemaking process.

By Notice issued October 11, 2017, the Commission reiterated that any initial comments must be filed no later than October 23, 2017, and any reply comments must be filed no later than November 7, 2017 ("Notice").

On October 23, 2017, American Manufacturers submitted Initial Comments on the Commission's Proposed Rule, including responses to the Staff questions set forth in the Initial

[2] 42 U.S.C. § 7173 (2012).

[3] Grid Reliability and Resiliency Pricing Rule, 82 Fed. Reg. 46940 (2017) (to be codified at 18 C.F.R. pt. 35).

[4] Notice Inviting Comments, *Grid Reliability and Resilience Pricing*, Docket No. RM18-1-000 (Oct. 2, 2017).

[5] Request for Information, *Grid Reliability and Resilience Pricing*, Docket No. RM18-1-000 (Oct. 4, 2017) ("Information Request").

Request. In addition to American Manufacturers, over 300 other parties filed Initial Comments on the Proposed Rule.

Pursuant to the Commission's Notice, American Manufacturers hereby submit these Reply Comments. Supporting materials are included as Appendix A.

II. EXECUTIVE SUMMARY

The Comments that have been submitted thus far overwhelmingly favor continuation of the fundamental pro-competitive principles that the Commission has embraced for wholesale electricity markets for more than two decades. The Comments further support a conclusion that no problem exists and, even if a problem were to exist, the Proposed Rule is not a lawful or prudent solution. Finally, the Comments support a conclusion that the public interest and consumers' interest are not advanced by the Proposed Rule. Therefore, the Commission should bring a swift end to this threat to the continued operation of wholesale electricity markets. The Proposed Rule should be rejected. Calls for accelerated modifications to price formation, in lieu of or even in addition to the Proposed Rule, to benefit certain inflexible generation types should be similarly rejected.

III. REPLY COMMENTS

A. With the exception of Initial Comments from companies that would benefit from out-of-market subsidies and their related trade associations, the majority of Comments filed urge the Commission to reject the Proposed Rule.

Commercial and industrial consumers account for more than sixty percent of the nation's electricity consumption. Comments from all of these groups, including the American Manufacturers, requested that the Commission reject the Proposed Rule for a multitude of reasons. The common thread throughout the Comments is that this Proposed Rule will result in massive cost increases for consumers, who have already shouldered the burden of high prices during the various high points in market pricing. The Proposed Rule, as stated in Comments from the Rocky

Mountain Institute, is "In language urgent without evidence, alarmist without cause and peremptory without authority."[6] The Proposed Rule and the Comments supporting it do not make a significant case as to why certain types of generation should receive a bail-out nor why consumers should face the potential of significant additional costs. As commercial and industrial consumers look to the Commission to review Comments and apply sound principles for judgement, American Manufacturers note this is not a ballot taken by a show of hands, nor by the number of Comments received. The Commission has a responsibility to engage the Comments.[7] Through active engagement, the Commission should come to the unsurprising conclusion that no material problem exists and that, even if one did exist, the Proposed Rule is not the solution.

B. The nation is not facing *premature* retirements of coal and nuclear generating facilities; rather, these generating units are retiring due to correct economic signals.

Proponents of the Proposed Rule argue the nation is facing premature retirements of coal and nuclear generating facilities and argue immediate Commission action is necessary to avert a crisis. FirstEnergy argues that time is of the essence and urges the Commission to adopt a final rule no later than December 11, 2017.[8] Murray Energy likewise urges the Commission to take immediate action.[9] PSEG also argues that immediate Commission action is required.[10] The

[6] Comments by Amory B. Lovins, Cofounder and Chief Scientist, Rocky Mountain Institute at 1, *Grid Reliability and Resilience Pricing,* Docket No. RM18-1-000 (Oct. 23, 2017).

[7] In the more than 300 Comments received by the Commission, there are dozens of submissions that read almost identical to one another. Dozens of "form comments" were filed by organizations and individuals, apparently at the request of FirstEnergy. While each of these form comments is not listed here, American Manufacturers' Reply Comments do adequately address each and every point raised in the form comments.

[8] FE Comments at 4.

[9] It is imperative that FERC act now given the continued retirement of coal and nuclear power plants. Murray Energy Comments at 28.

[10] The Commission should act immediately to address the current gap between public policies and market operation in PJM and develop a mechanism that ascribes value to resiliency attributes. PSEG Comments at 7.

Nuclear Energy Institute shares the view that immediate action is warranted.[11] Exelon is a bit more restrained, and recommends further study before the Commission takes action.[12]

These Armageddon-themed claims stand in stark contrast to reality. Reserve margins are ample in all regions of the country, particularly so in the regions that would be subject to the Proposed Rule. Retirement decisions have been based upon fundamental economic dynamics, involving many generation facilities that have reached the end of their normal lives. These retirements cannot be accurately characterized as *premature*. Nuclear units that have retired have done so based upon multiple factors, including equipment repairs that became unfeasible. Further, the minimal use of reliability must run agreements demonstrates that the organized market regions are, by no means, facing the loss of critical generation facilities.

1. **Ample capacity reserve margins, particularly in PJM Interconnection, L.L.C. ("PJM"), and other Regional Transmission Organizations ("RTOs"), demonstrate that retirements have not been premature.**

In PJM, the most recent capacity auction for the 2020/2021 delivery year cleared reserves of 23.3 percent or 6.7 percent higher than the targeted minimum required reserve level of 16.6 percent.[13] The fact that 165,109.2 megawatts ("MW") of unforced capacity producing reserves of 23.3 percent in PJM cleared in the base residual auction does not tell the whole story.[14] The amount of capacity in PJM greatly exceeds the amount of cleared resources with a total of 189,917.8 MW of capacity offered into the 2020/2021 base residual auction. Resources that were eligible to

[11] NEI Comments at 7.

[12] Exelon Comments at 7. Exelon does request the Commission take immediate action regarding specific market rule changes in PJM. *Id.* at 11-23.

[13] American Manufacturers Comments at 32, n. 67. *See also* American Manufacturers Comments at Appendix A-28.

[14] *Id.*, Appendix A-28 at 1.

participate in the auction exceeded this amount, and totaled 212,995.6 MW.[15] By any measure, PJM does not face a capacity shortfall.

The New York Independent System Operator ("ISO") also reports healthy levels of reserves, notwithstanding the retirement of several older generating facilities.[16] Similarly, the Midwest Transmission System Operator ("MISO") projects actual reserve levels above required reserve levels.[17] In fact, in its most recent summer assessment, the North American Electric Reliability Corporation ("NERC") concluded that all regions of the country other than NPCC-New England had adequate reserves.[18] NPCC-New England fell slightly below its target with reserves of 14.88 percent versus a target of 15.10 percent. However, this was due to the delayed startup of 700 MW of new resources, which are anticipated to increase reserves to 20.32 percent when they enter service.[19]

Interconnection queues for new generation facilities are also quite robust. For example, based upon a recent report, there are over 60,000 MW of new generation resources in various stages of PJM's interconnection queue.[20] Although the vast majority of this new generation is planned as renewable or gas-fired resources, that fact simply reflects the current economics of

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[15] *Id.*

[16] "[A]vailable power resources remain above the projected peak demand of 33,178 MW plus the reserve requirement, a combined total of 39,150 MW." New York Independent System Operator, *Power Trends, New York's Evolving Electric Grid* at 24 (2017), *available at* http://www.nyiso.com/public/webdocs/media_room/publications_presentations/Power_Trends/Power_Trends/2017_Power_Trends.pdf. A copy of this document is attached as Appendix A-1.

[17] American Manufacturers Comments at 32, n. 67.

[18] North American Electric Reliability Corporation, *2017 Summer Reliability Assessment* at 6 (2017), *available at* http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2017%20Summer%20Assessment.pdf. A copy of this document is attached as Appendix A-2.

[19] *Id.* at 7.

[20] PJM Interconnection, L.L.C., *PJM Interconnection Queue Status & Statistics Update Database Snapshot on 04/24/2017* at 16 (May 4, 2017), *available at* http://www.pjm.com/-/media/committees-groups/committees/pc/20170504/20170504-item-12-pjm-queue-status-update.ashx. A copy of this document is attached as Appendix A-3.

constructing new generation facilities. Clearly, recent attempts to construct new coal-fired and nuclear facilities have not proved to be great success stories.[21] Under these circumstances, and given continued and projected low natural gas prices, it is simply the logical conclusion that interconnection queues are dominated by renewable and gas-fired generation facilities. While not all planned generation facilities in the queue will ultimately be placed in service, many of them will be.

Clearly there is no current or imminent shortage of generation resources that warrants any action, much less the type of action contemplated in the Proposed Rule. The fact that some existing coal-fired and nuclear generating facilities have recently retired, or plan in the near future to retire, is simply a function of market economics, a fact conceded by at least one proponent of the Proposed Rule.[22]

2. Business decisions not to invest in plant upgrades necessary to comply with the U.S. Environmental Protection Agency's ("EPA") Mercury and Air Toxins ("MATS") rule are responsible for many recent retirements of coal-fired generating facilities.

A May 2015 analysis by SNL predicted that 12,300 MW of coal-fired generation would shut down in 2015 rather than invest in environmental controls to comply with the EPA's MATS

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[21] *See* The Post and Courier, *Two identical nuclear projects, one in Georgia and one in South Carolina. Only one survived* (Oct. 29, 2017), *available at* http://www.postandcourier.com/news/two-identical-nuclear-projects-one-in-georgia-and-one-in/article_4954353a-b8f6-11e7-be85-f341791366a7.html (last accessed Oct. 31, 2017). A copy of this document is attached as Appendix A-4. *See also* Mississippi Public Service Commission, *Mississippi Power Company to Suspend Lignite Coal Gasification at Kemper Co. Power Plant* (June 28, 2017), *available at* http://www.psc.state.ms.us/mpsc/press%20releases/2017/Mississippi%20Power%20Company%20to%20Suspend%20Lignite%20Coal%20Gasification%20at%20Kemper%20Co.%20Power%20Plant.pdf. A copy of this document is attached as Appendix A-5.

[22] Given the current market disincentives, this process makes intuitive sense. With lower wholesale prices of electricity due to falling natural gas prices and increasing low marginal cost renewables, coal and nuclear plants make less money and become increasingly financially distressed. Eventually, dismal revenue projections and falling profits lead to a management decision to shed unprofitable assets. While other issues – including increasing environmental burdens for coal and rising operating costs for nuclear – were contributing factors, **the core issue boils down to economics**. If wholesale electricity prices were higher, for example, it would be profitable for a coal plant to install new emission scrubbers and the magnitude of coal and nuclear retirements would be lower. Murray Energy Comments at 19 (emphasis added).

rule.[23] That same analysis predicted an additional 7,300 MW of coal-fired generating facilities would close in 2016, and that between 2012 and 2022 approximately 46,000 MW of coal-fired generating facilities would close. After-the-fact reporting by the U.S. Energy Information Agency ("EIA") confirmed that these predictions were, if anything, underestimates. According to EIA, by the end of 2015, over 18 gigawatts of coal-fired capacity retired.[24]

Business decisions not to invest in environmental controls are responsible for the vast majority of recent coal-fired power plant retirements.[25] Following the MATS compliance

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[23] *See* SNL, Data Dispatch, *With MATS in effect, coal unit retirements to hit peak in 2015* (May 12, 2015), *available at* https://www.snl.com/InteractiveX/Article.aspx?cdid=A-32607383-10040&mkt_tok=3RkMMJWWfF9wsRoju6TAe%2B%2FhmjTEU5z17OwpUKSylMI%2F0ER3fOvrPUfGjI4CT8diNK%2BTFAwTG5toziV8R7DNLM1wy8YQWhPh (last accessed Oct. 31, 2017). A copy of this document is attached as Appendix A-6.

[24] *See* U.S. Energy Information Administration, *Coal made up more than 80% of retired electricity generation capacity in 2015* (Mar. 8, 2016), *available at* https://www.eia.gov/todayinenergy/detail.php?id=25272 ("*EIA Mar. 8, 2016 Electric Generator Inventory*"). A copy of this document is attached as Appendix A-7.

[25] For example, in its 2014 second quarter final report submitted to the Securities and Exchange Commission ("SEC"), American Electric Power Corporation ("AEP") described its expected costs to bring its coal fired generating facilities into compliance with various environmental regulations:

> As of June 30, 2014, the AEP System had a total generating capacity of 37,600 MWs, of which 23,700 MWs are coal-fired. We continue to refine the cost estimates of complying with these rules and other impacts of the environmental proposals on our generating facilities. Based upon our estimates, investment to meet these requirements ranges from approximately $3 billion to $3.5 billion through 2020. Several proposed regulations issued during 2014, including CO2 and Clean Water Act, are currently under review and we cannot currently predict the impact these programs may have on future resource plans or our existing generating fleet; however, the costs may be substantial. These amounts include investments to convert some of our coal generation to natural gas. If natural gas conversion is not completed, the units could be retired sooner than planned.
>
> The cost estimates will change depending on the timing of implementation and whether the Federal EPA provides flexibility in the final rules. The cost estimates will also change based on: (a) the states' implementation of these regulatory programs, including the potential for state implementation plans (SIPs) or federal implementation plans (FIPs) that impose more stringent standards, (b) additional rulemaking activities in response to court decisions, (c) the actual performance of the pollution control technologies installed on our units, (d) changes in costs for new pollution controls, (e) new generating technology developments, (f) total MWs of capacity retired and replaced, including the type and amount of such replacement capacity and (g) other factors. In addition, we are continuing to evaluate the economic feasibility of environmental investments on nonregulated plants.

American Electric Power Company, Inc., et al., *Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934* at 6 (10-Q) (July 25, 2014), *available at* https://www.sec.gov/Archives/edgar/data/4904/000000490414000090/q214aep10q.htm. A copy of this document is attached as Appendix A-8. AEP identified 11 coal-fired generating facilities totaling 6,533 MW of capacity that it planned to retire before or during 2016 rather than investing in controls to comply with environmental regulations.

deadline, electric utilities have continued to make business decisions to retire existing coal-fired generation facilities rather than invest in environmental controls, again based upon fundamental economics.[26] These retirements are not being driven by perceived shortcomings in RTO market rules.

3. <u>Many coal-fired generation facilities have reached the end of their remaining useful life, triggering retirement.</u>

The coal units that were retired in 2015 were mainly built between 1950 and 1970, and the average age of those retired units was 54 years. The rest of the coal fleet that continues to operate is relatively younger, with an average age of 38 years.[27] The coal units retired in 2015 also tended to be smaller than the rest of the coal fleet. The net summer capacity of the average retired coal unit was 133 MW, compared with 278 MW for the rest of the coal units still operating.[28] Coal plants in these vintages have a typical design life of between 30 to 40 years.[29] Thus, the coal-fired power plants that have recently retired are beyond their design life[30] and their smaller size makes them generally less economic to run.

[26] *In the Matter of the Application of The Empire District Electric Company for Approval of Its Customer Savings Plan,* Missouri Public Service Commission File No. E0-2018-0092, October 31, 2017. The Empire District Electric Company is a member of the Southwest Power Pool.

[27] *See EIA Mar. 8, 2016 Electric Generator Inventory.*

[28] *Id.*

[29] *See* American Public Power Association, *Michigan's Lansing BWL to close coal-fired power plant by end of 2025* (Aug. 25, 2017), *available at* https://www.publicpower.org/periodical/article/michigans-lansing-bwl-close-coal-fired-power-plant-end-2025 (last accessed Oct. 31, 2017). A copy of this document is attached as Appendix A-9.

[30] *See* Power, *America's Aging Generation Fleet* (Jan. 28, 2013), *available at* http://www.powermag.com/americas-aging-generation-fleet/?printmode=1 (last accessed Oct. 31, 2017). A copy of this document is attached as Appendix A-10.

4. **Nuclear plant retirements have been driven by economics, local politics, and equipment failures.**

An examination of recent nuclear plant retirements supports the conclusion that the retirements have been driven by economics and equipment failures that proved too costly to repair, or resulted from negotiations with state or local officials who were concerned over continued operation of the facilities.

In January of 2017, Entergy announced that it had reached an agreement with the State of New York to shut down the Indian Point nuclear station by 2021 rather than continuing to fight legal battles over renewal of licenses.[31] Entergy also cited economic factors as contributing to the decision to shut down the facility.

Dominion Energy elected to close the Kewaunee Power Station in Wisconsin in 2013 after failing to find a buyer.[32] Dominion said the decision was based purely upon economics, as the plant lacked economies of scale and falling natural gas prices had lowered wholesale power prices.

Owners of the San Onofre nuclear power plant made the decision to close the facility in 2013, after a project to replace steam generators went poorly.[33]

Duke Energy announced in 2013 that it would close the Crystal River nuclear facility in Florida after construction workers cracked the wall of the containment building during a project to replace steam generators.[34]

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[31] *See* Entergy, *Entergy, NY Officials Agree on Indian Point Closure in 2020-2021* (Jan. 9, 2017), *available at* http://www.entergynewsroom.com/latest-news/entergy-ny-officials-agree-indian-point-closure-2020-2021/ (last accessed Oct. 31, 2017). A copy of this document is attached as Appendix A-11.

[32] *See* USA Today, *Kewaunee County ready to move on after nuclear plant closing* (July 12, 2017), *available at* https://www.usatoday.com/story/news/investigations/2017/07/12/kewaunee-nuclear-plant-closing/103598506/ (last accessed Oct. 31, 2017). A copy of this document is attached as Appendix A-12.

[33] *See* The Orange County Register, *San Onofre nuclear plant to shut permanently, Edison says* (June 8, 2013), *available at* http://www.ocregister.com/2013/06/08/san-onofre-nuclear-plant-to-shut-permanently-edison-says/ (last accessed Oct. 31, 2017). A copy of this document is attached as Appendix- A-13.

[34] *See* Tampa Bay Times, *Duke Energy announces closing of Crystal River nuclear power plant* (updated Feb. 11, 2014), *available at* http://www.tampabay.com/news/business/energy/duke-energy-announces-closing-of-crystal-

Pacific Gas & Electric Co. announced in June 2016 that it would shut down its Diablo Canyon nuclear reactors when their operating licenses expire in 2024 and 2025. However, the decision to shut down the reactors was the result of a negotiated settlement with environmental organizations.[35]

Exelon Corporation agreed to cease electric generation operations at the Oyster Creek Generating Station by December 31, 2019. The agreement was part of a negotiated settlement with the State of New Jersey intended to ensure that water withdrawals from Barnegat Bay for cooling purposes and discharges from the plant did not damage the ecological health of the Bay.[36]

Vermont Yankee Nuclear Power Station closed in December 2014. Entergy's decision to shut down the facility resulted from negotiations with state officials who objected to continued operation of the facility.[37]

Entergy announced in December 2016 that it planned to close the Palisades nuclear generating facility in Michigan on October 1, 2018. On September 28, 2017, Entergy announced it was reversing its decision and would operate the facility at least until the spring of 2022.[38]

Finally, on October 31, 2017, Connecticut Governor Dannel P. Malloy announced he had signed Senate Bill 1501, "*An Act Concerning Zero Carbon Procurement*," which was approved

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river-nuclear-power-plant/1273794 (last accessed Oct. 31, 2017). A copy of this document is attached as Appendix-A-14.

[35] ***See*** Los Angeles Times, *PG&E to close Diablo Canyon, California's last nuclear power plant* (June 21, 2016), ***available at*** http://www.latimes.com/business/la-fi-diablo-canyon-nuclear-20160621-snap-story.html (last accessed Oct. 31, 2017). A copy of this document is attached as Appendix A-15.

[36] ***See*** State of New Jersey Department of Environmental Protection, *Comprehensive Plan of Action Item #1 Close Oyster Creek Nuclear Power Plant* (last updated June 16, 2016), *available at* http://www.nj.gov/dep/barnegatbay/plan-oystercreek.htm. A copy of this document is attached as Appendix A-16.

[37] ***See*** State of Vermont Public Service Department, *Brief History of Vermont Nuclear Power* (2017), *available at* http://publicservice.vermont.gov/content/nuclear_decommissioning_citizens_advisory_panel_ndcap/history. A copy of this document is attached as Appendix A-17.

[38] ***See*** Entergy, *Entergy to Continue Operating Palisades Power Plant Until Spring 2022* (Sept. 28, 2017), *available at* http://www.palisadespower.com/entergy-to-continue-operating-palisades-power-plant-until-spring-2022/ (last accessed Oct. 31, 2017). A copy of this document is attached as Appendix A-18.

last week by the Connecticut General Assembly. The legislation could provide financial support for the Millstone nuclear power facility. However, simultaneously with his approval of the legislation, the Governor released a letter from Commissioners of the Connecticut Department of Energy and Environmental Protection and the Public Utilities Regulatory Authority summarizing a study that concludes the Millstone nuclear generation facility is likely to be profitable and not require state subsidies.[39]

As these decisions to operate or close existing reactors illustrate, nuclear plant retirements are not being driven by RTO power market rules. In some cases, local politics and equipment failures have led to decisions to retire or to continue to operate nuclear generating facilities. In fact, three of these closures (Kewaunee, San Onofre, and Crystal River) are not even located in regions of the country that would be subject to the Proposed Rule. Thus, the claim that RTO market rules are driving *premature* nuclear plant retirements does not withstand scrutiny.

5. The use of reliability must run ("RMR") and system support resource ("SSR") agreements has been infrequent.

As discussed extensively in the American Manufacturers' Comments, there has been infrequent and very limited use of RMR and SMR agreements, which further confirms that generation needed for reliability or "resilience" is not retiring and certainly not retiring prematurely.[40]

[39] *See* State of Connecticut Department of Energy and Environmental Protection, *Gov. Malloy Signs Millstone Bill and Encourages Dominion's Participation* (Oct. 31, 2017), *available at* http://www.ct.gov/pura/cwp/view.asp?A=4144&Q=597410. A copy of this document is attached as Appendix A-19. *See also* State of Connecticut Department of Energy and Environmental Protection, *Executive Order 59 Preliminary Progress Report* (Oct. 31, 2017), *available at* http://portal.ct.gov/-/media/Office-of-the-Governor/Press-Room/20171031-Commr-Letter-to-Gov-re-EO-59.pdf?la=en. A copy of this document is attached as Appendix A-20.

[40] American Manufacturers Comments at 34-39.

The nation is not facing *premature* retirements of coal and nuclear generating facilities; rather, these generating units are retiring due to correct economic signals or for reasons completely unrelated to RTO market rules. All of these factors demonstrate why it is not necessary or appropriate for the Commission to adopt the Proposed Rule.

C. There has been no demonstration that existing RTO rates are unjust and unreasonable.

The wholesale compensation mechanisms of the RTOs and Independent System Operators ("ISOs") that would be affected by the Proposed Rule are established through FERC-approved tariffs that the Commission must find are just and reasonable.[41] To alter those tariffs, the Commission must find that the current tariffs are not just and reasonable before it may determine a just and reasonable replacement rate.[42] Under section 206 of the Federal Power Act ("FPA"), the burden of proof to show that any rate, charge, classification, rule, regulation, practice, or contract is unjust, unreasonable, unduly discriminatory, or preferential is on the proponent of the new rate.[43] Although existing rates previously found to be just and reasonable may become unjust and unreasonable by intervening shifts in circumstances,[44] it is not enough, as many proponents of the Proposed Rule assert, to claim that the rates are unreasonable because unit owners may be required to close uneconomic generation units. Providing economic signals to unit owners is the very point of market-based compensation and the just and reasonable market rules that are in place to determine market-based compensation.[45] Accordingly, the closing of units does not

[41] 16 U.S.C. § 824d.

[42] *Id*. § 824e.

[43] *Id*. § 824e(b); *FirstEnergy Serv. Corp. v. FERC*, 758 F.3d 346, 354 (D.C. Cir. 2014).

[44] *FirstEnergy Serv. Corp. v. FERC*, 758 F.3d 346, 356 (D.C. Cir. 2014).

[45] Murray Energy Comments at 19 ("While other issues—including increasing environmental burdens for coal and rising operating costs for nuclear—were contributing factors, the core issue boils down to economics. If wholesale prices were higher, for example, it would be profitable for a coal plant to install new emission scrubbers and the magnitude of coal and nuclear retirements would be significantly lower.").

demonstrate that rates that have been found to be just and reasonable have suddenly become unjust and unreasonable.

The question raised by the industry proponents of the Proposed Rule revolves around the closure of nuclear and coal-fired units that they own or operate. Their complaint is that the market-based rates under the existing RTO tariffs do not generate sufficient revenue for their generating units to cover sunk fixed costs; thus, units will be closed and the owners will be forced to absorb the sunk costs (to the extent that those sunk costs were not already compensated by the billions of dollars of retail or wholesale stranded cost payments).[46] In effect, owners of uneconomic generation units equate the poor economics of their units with unreasonable rates.[47] A guarantee of positive annual revenue in a competitive market, however, is not required by the U.S. Constitution or the FPA.[48]

To avoid claims that they are seeking a bailout for their nuclear and coal units, the owners wrap their claims that current rates are unreasonable in the further assertion that resilience of the system is at risk if their units are retired,[49] but the claims that reliability or resilience is at risk are undemonstrated. As the DOE staff report, the PJM Independent Market Monitor,[50] the RTOs and ISOs[51] that will be adversely affected by the Proposed Rule, and the prior section of these Reply

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[46] Notably absent from the Secretary's proposal or the comments of the rule's proponents is any mention that retail consumers in Ohio, Pennsylvania, and other states have already paid for stranded costs of these uneconomic units.

[47] *See, e.g.*, Exelon Comments at 9. There is also a substantial inconsistency in the claims the parties are making as to the failures inherent in the market-based approaches of the RTOs and ISOs. For example, the Nuclear Energy Institute complains about the effect of short term prices while simultaneously pointing out that other social goals are embedded in retail and wholesale pricing. NEI Comments at 3-4.

[48] *Market Street Railway Co. v. California Railroad Comm'n*, 323 U.S. 548 (1945); *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944) (regulation under the parallel provisions of the Natural Gas Act does not insure that the business will produce net revenue).

[49] *See, e.g.*, FE Comments at 32.

[50] Comments of the Independent Market Monitor for PJM at 14, *Grid Reliability and Resilience Pricing,* Docket No. RM18-1-000 (Oct. 23, 2017) ("IMM Comments").

[51] Initial Comments of PJM Interconnection, L.L.C. of the United States Department of Energy Proposed Rule at 5-17, *Grid Reliability and Resilience Pricing,* Docket No. RM18-1-000 (Oct. 23, 2017) ("PJM Comments"); Comments

Comments all amply demonstrate, the current market-based approach has produced an electric grid that is both reliable and resilient.

If any further demonstration is needed that current rates are not unjust or unreasonable, several of the Proposed Rule's proponents do not even claim that the rule should be based on the need to compensate for supposed resilience or reliability "benefits" of their generation units. FirstEnergy, for example, supports the Proposed Rule but recommends modifications that would remove a requirement for "reliability."[52] A more ridiculous outcome in a proceeding based on the purported need to foster grid resilience is difficult to conceive.

D. Requests to initiate a new section 206 proceeding to provide subsidies under the guise of changes to "energy price formation" are similarly unfounded and should be rejected.

1. Proponents of price formation initiatives have not identified a problem.

Several commenters urge the Commission to use this platform as means to address energy price formation, with most of the attention directed to the PJM footprint.[53] PJM asks the Commission to direct each RTO/ISO to identify whether changes in the resource mix has created issues that are currently "not addressed" in the market and, if so, to prioritize the issues within a Commission-specified deadline that "is in the near term."[54] Exelon and PJM Providers Group go further and ask the Commission to direct PJM file under section 206 its proposal for allowing inflexible units to set locational marginal price ("LMP").[55] Others, including PSEG and NRG,

of the Midcontinent Independent System Operator, Inc., at 5-11, *Grid Reliability and Resilience Pricing,* Docket No. RM18-1-000 (Oct. 23, 2017) ("MISO Comments").

[52] FE Comments at 40.

[53] *See, e.g.,* Exelon Comments at 9-22; PSEG Comments at 11-22; PJM Comments at 36-49.

[54] PJM Comments at 48.

[55] *See* Exelon Comments at 9; PJM Power Providers Comments at 14.

implicitly request a similar result.[56] No imminent reliability problem exists and certainly not one of such magnitude that warrants the press by certain commenters for nearly emergency action on price formation.

First, as discussed in American Manufacturers' Comments, it should be recalled that abundant excess capacity exists in PJM.[57] Moreover, among PJM's own findings in its study *PJM's Evolving Resource Mix and System Reliability,* which was just released in March of this year, is that "[t]he expected near-term resource portfolio is among the highest-performing portfolios and is well equipped to provide the generator reliability attributes" based on the requirements of the PJM Open Access Transmission Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement and applicable NERC reliability standards.[58] Even as the potential future resource mix moves in the direction of less coal and nuclear generation, the PJM Evolving Resource Mix Study found generator reliability attributes of frequency response, reactive capability and fuel assurance may decrease, but flexibility and ramping attributes increase.[59] As recently as six months ago when the study was released, PJM did not express the sense of urgency that is being displayed by certain market participants. To be clear, PJM's study identified areas of future attention, but the study did not suggest a reliability problem of such a magnitude that it needed to be addressed within the next six months or even within the next year.

[56] PSEG Comments at 25 (requesting "that the Commission direct that PJM submit proposed tariff revisions concerning their proposal to expand the eligibility of all units required to supply energy on the system to set price so that it can be fully evaluated by the Commission"); NRG Comments at 15 ("urg[ing] the Commission to direct each ISO and RTO to immediately lay out a timetable to ensure that all resources, dispatched as part of the least-cost reliability operation of the system, are allowed to set real-time energy prices").

[57] *See* American Manufacturers' Comments at 31-32 and n. 67.

[58] PJM Interconnection, L.L.C., *PJM's Evolving Resource Mix and System Reliability*, at 4 (Mar. 30, 2017) (internal footnote omitted) ("*PJM Evolving Resource Mix Study*"), *available at* http://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx.

[59] *PJM Evolving Resource Mix Study* at 5.

Some commenters claim that "resilient firm-fuel resources in PJM are providing generation needed to serve customers, yet they are not paid for their cost of doing so."[60] Such a characterization implies that certain inflexible resources are being required to operate at a loss. That is simply not the case. Stating the interest of certain generation owners a bit differently, inflexible coal or nuclear units serving load may operate at a loss during a particular hour, but PJM makes a unit that is dispatched whole over an entire day period – losses in some hours are netted with profits in other hours. Allowing inflexible units to set LMP during the times suggested by certain generation owners would reduce or eliminate the individual hours those units may operate at a loss under current market conditions, which would increase the amount paid to such generators and increase the overall *profit* the unit would earn over the entire day period. The higher LMP would also be paid to all other resources, magnifying the cost impact on customers. For units that are not dispatched but self scheduled (such as a nuclear unit), such units do not receive uplift. Allowing such inflexible units to set price would increase LMPs and increase payments to such self-scheduled units as well. [61]

In a nutshell, if the generation units were flexible, the units would be backed down or shut down when they became uneconomic to run. An approach that allows these inflexible resources to set prices does not comport with economic logic or the fundamentals of LMP. Simply put, inflexible units may operate and serve load, but, if the inflexible units were to retire, other presumably flexible units would replace them. Such is the reality of using markets to discipline market entry and exit. The complaints around price formation by owners of inflexible resource

[60] Exelon Comments at 5.

[61] IMM Comments at 38

owners alleged in this docket do not amount to evidence supporting a section 206 finding that the longstanding approach to LMP and price formation is unjust and unreasonable.

Negative LMPs were also cited as a "problem" requiring price formation changes.[62] Similarly, no apparent compelling case has been made that negative LMPs are a pervasive problem. For example, PSEG Comments argue that negative bidding resources present a "source of distortion"; however, no empirical evidence was presented that supports a finding that such negative bidding presents a source of distortion.[63] Similarly, PSEG broadly, but not specifically, alleges that potential impacts on reliability and national security provide "ample justification" for change.[64]

The need to reduce uplift has also been cited as a reason for allowing inflexible resources to set LMP. The facts, however, suggest otherwise. Uplift itself is at historical low levels. According to the IMM, since 2015, all uplift, not just the generator make-whole payment, represents an average of less than 0.5 percent of the total PJM price. And some of the price formation concepts being floated in this docket would still produce a type of uplift for flexible generators that are required to back down for the inflexible resources.

As noted in the IMM Comments, PJM's Whitepaper on Energy Price Formation and Valuing Flexibility ("Price Formation Whitepaper") suggests a bias exists in the market, claiming that baseload, nuclear and coal generation is undervalued in the market, implying negative energy market offers unfairly hasten the retirement of baseload generation and citing increased reliance on capacity market revenues rather than energy market revenues.[65] As the PJM Internal Market

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[62] *See, e.g.*, Exelon Comments at 5 & 10; PSEG Comments at 25.

[63] *See* PSEG Comments.

[64] PSEG Comments at 29.

[65] IMM Comments at 34.

Monitor correctly notes, however, neither the PJM Price Formation Whitepaper nor the PJM Comments at this docket provide concrete evidence that supports a finding of a "problem."[66] More than the scant, unsubstantiated record before the Commission is required to support a Commission finding that a problem exists and that a fundamental change in LMP price formation mechanics is warranted – least of all a fast-track change.

2. <u>Energy prices are currently reflecting lower fuel prices.</u>

A fundamental characteristic of LMP is that it drives short-term market outcomes toward pricing for all energy on the basis of the least efficient and most expensive fuel source. In 2008-2009, when natural gas prices were high, customers shouldered the burden with respect to higher energy prices. During that time of record high LMPs, customers raised repeated concern, if not objection, that LMP drove short-term market outcomes toward pricing for all energy on the basis of high-priced natural gas.[67] The response then to customer concerns was effectively that "the market was the market," with high prices being only a function of gas prices and nothing can or should be done to ameliorate high LMPs. With the shale gas revolution and abundant natural gas and low fuel prices, LMPs have reached historic lows.

At least in PJM, the Independent Market Monitor has recognized that LMPs are low but that LMPs are not too low.[68] As noted in the PJM IMM Comments, PJM energy prices track closely with fuel prices and indicate an efficiently functioning market.[69] Energy markets and capacity markets work together to allow resources an opportunity to recover their costs. In a time

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[66] *Id.*

[67] *Id.* at 15 ("The majority of short run marginal costs for power production are fuel costs.").

[68] Testimony of Joseph Bowring Before the House Committee on Energy & Commerce, Subcommittee on Energy, State of Electricity Markets at 4 (Oct. 5, 2017), *available at* http://docs.house.gov/meetings/IF/IF03/20171005/106470/HHRG-115-IF03-Wstate-BowringJ-20171005-U3.pdf. This document is attached as Appendix A-21.

[69] IMM Comments at 15.

of low energy prices, it should not be surprising that the capacity market needs to do more "heavy lifting" to support ISOs/RTOs resource adequacy and reliability imperatives and return the "missing money" that was often cited as the initial need for capacity markets. Even with low energy prices, the PJM Independent Market Monitor has found that at least 50 percent of all nuclear units recovered avoidable costs from all markets, including the capacity markets.[70] Based on the twelve months ending June 2017, at least 75 percent of all nuclear units recovered avoidable costs from all markets.

It also warrants noting that several other initiatives have been implemented recently that may have impacts on LMP in PJM, such as the Capacity Performance requirements, increasing the PJM energy offer price cap, allowing the triggering of transient shortages, and adding new steps to the operating reserve demand curve for shortage pricing. These changes should be given an opportunity to address any perceived concerns that may still linger. For example, on September 21, 2017, as reserve margins reduced and began to approach reserve requirements, PJM real-time LMP and reserve prices rose significantly due to the recently implemented changes to the shortage pricing operating reserve demand curves. On this day, between 2:00 p.m. and 5:00 p.m., more than half of the pricing for this period was impacted by a market change that triggers shortage pricing as reserves *approach* a reserve requirement rather than trigger shortage pricing only after reserve requirements have been violated.[71] This change to shortage pricing was implemented only a few months ago on July 12, 2017.

Confidence in markets is tested when changes to energy market price formation can be viewed as a thinly veiled effort to provide price support for certain classes of resources or certain

[70] *Id.* at 18.

[71] *See* PJM Interconnection, L.L.C., *Real-time Market Results* at 6 (Sept. 21, 2017), *available at* http://www.pjm.com/-/media/committees-groups/committees/oc/20171010/20171010-item-19-real-time-market-results.ashx. A copy of this document is attached as Appendix A-22.

market participants. Industrials advocated for restructuring over twenty years ago to allow the market to discipline such market entry and exit; it is a fine line between adjusting market rules and engineering preferred pricing outcomes. Coal-fired units with an average age of 49 years old comprise the majority of capacity that is at risk of retirement.[72] It is reasonable to query how long these assets should reasonably be expected to be operational? Without substantial evidence of reliability problems with the current time-tested approach to energy price formation, the "Energy Price Reform" initiative can reasonably be viewed as a reckless attempt to engineer preferred pricing outcomes to support certain legacy units.

Low natural gas prices may have an adverse impact on certain PJM market participants but, as a general matter, the shale gas revolution should be viewed as a remarkably beneficial opportunity for this region to establish a competitive advantage for businesses. Modifying energy price formation to benefit certain legacy units will increase, to some unknown degree, near-term, if not long-term, costs to customers, including businesses that evaluate energy costs as a component of whether to site or expand business in a particular region. Low energy prices send a signal that resources may be uneconomic and should retire – that is an efficient market result.

3. Unit inflexibility should not be used as an excuse to inflate energy prices.

PJM's Comments set forth its position that price formation changes are required to address non-convex conditions under LMP that may exist with inflexible resources.[73] According to PJM, inflexible generators may incur losses if the price is set at marginal cost and, as such, to the extent these resources are required to serve load, they require additional payment or uplift payment.[74]

[72] IMM Comments at 19-20.
[73] PJM Comments at 43-44.
[74] *See id.*

Exelon, PSEG, and NRG support PJM's initiative.[75] To be clear, the inflexible resources that produce the non-convex conditions are, generally speaking, legacy units that were operational from the time that LMP was implemented in PJM.

PJM's Comments reference that it is actively exploring a transition to an extended LMP method under which inflexible units needed to meet demand for five-minute increments would be treated like a flexible unit and allowed to set price.[76] At a high level, this does not appear to be consistent with the notion of valuing flexibility, which was an objective of the Capacity Performance changes that PJM implemented.[77] Rather, this approach would seem to establish inflexible units as the default. For the reasons explained by the Independent Market Monitor, no economic theory supports allowing inflexible, baseload units to set price.

Not only does PJM's approach run afoul of marginal cost theory, it should be recognized that allowing such units to set price would appear to have significant cost consequences for load. PJM has pointed to MISO's implementation of the extended LMP method; however, PJM seeks to go beyond what MISO has implemented. While PJM Members have not been afforded any PJM simulation results, a recent Exelon Corp. earnings call since PJM filed its Comments at this docket suggests that the price impacts could be between $2 per megawatt-hour ("MWh") and $5 per MWh.[78] Such impacts will be significant for energy-intensive businesses that are vital to our nation's economic growth.

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[75] *See* Exelon Comments at 11; PSEG Comments at 11; NRG Comments at 13-16.

[76] PJM Comments at 45.

[77] *See* IMM Comments at 39.

[78] *See* Seeking Alpha, *Exelon's (EXC) CEO Chris Crane on Q3 2017 Results – Earnings Call Transcript* at 8 (Nov. 2, 2017), *available at* https://seekingalpha.com/article/4119801-exelons-exc-ceo-chris-crane-q3-2017-results-earnings-call-transcript. This document is attached as Appendix A-23.

Exacerbating the cost consequences is the potential that allowing inflexible resources to set LMP would necessitate the development a new ancillary service product to encourage the flexibility that already is baked in the current construct. As Exelon's Comments note, "PJM has discussed proposing an additional product that would compensate the flexible resource for turning down in response to the dispatch signal."[79] This additional product would further add to customer costs.

To the extent price formation is an issue that warrants attention, many fundamental issues must be considered before the bedrock of PJM's energy markets is upset. For example, during this time where PJM has tremendous excess supply, *does increasing LMP prices send an inefficient signal to incent more resources, further exacerbating the supply-demand imbalance?* PSEG claims that "getting energy prices right is critical to ensuring that the correct price signals are sent to incent efficient investment and market exit."[80] Is increasing LMPs sending an efficient signal that resources may not be needed and should retire? Why would these higher prices not encourage more gas-fired generation to come online, which would defeat an implicit purpose of allowing inflexible resources to set LMP?

Similarly, *does treating "inflexible resources" akin to "flexible resources" undercut PJM's efforts in the Capacity Performance realm to encourage more flexibility among resources*? During the 2014 Polar Vortex, compensating gas-fired generators for operations during long run times to honor gas commitments was viewed negatively, prompting PJM to propose Capacity Performance modifications. Would an inefficient coal unit with, for example, a 5-day minimum run time, be allowed to set prices for all five days, even if not required to serve load during that period of time?

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[79] Exelon Comments at 22.

[80] PSEG Comments at 24.

If not, how would PJM distinguish between those resources that could set price and those that cannot? To be clear, if a generator is required to serve load and LMP compensation is inadequate to cover the generator's entire cost, uplift provides the required funding such that at no time does a PJM scheduled unit not recover its full offer cost.

Another unanswered question is *how would PJM's approach protect against strategic bidding by asset owners with a portfolio of resources, including some with inflexible operating parameters*? The IMM Comments raise substantial questions about the adverse economic behavioral incentives PJM's conceptual proposal would engender.[81] If the LMP construct is stretched to send additional revenue streams to inflexible generators, strong consumer protections would be necessary.

Based on PJM efforts around demand resources over the past several years, where demand resources that were less flexible were paid less, PJM's concept appears to turn that model upside down for generators. Under PJM's proposed approach, it would appear that an inflexible unit would become the default and more flexible units would get paid more.

In short, the price formation concept offered by PJM should not gain theoretical acceptance without understanding the market and operational ramifications as well as cost consequences to customers. PJM itself concedes its proposal is only "conceptual."[82] When MISO implemented extended LMP, the concept was considered by stakeholders by at least five years before implementation. The extended MISO experience is offered by way of example to avoid a risk to judgment, particularly when PJM stakeholders, as discussed below, have had only the barest opportunity to consider the concept.

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[81] IMM Comments at 40-41.

[82] PJM Comments at 41.

4. <u>Adoption of changes to energy pricing rules would severely disrupt contracting for retail supply.</u>

Given the heavily regulated nature of RTO/ISO energy markets, a common feature of industry-standard agreements for wholesale transactions and for service to retail customers is a "change in law" provision or "regulatory change" clause.[83] Such provisions authorize suppliers, many of which are affiliated with firms seeking a change in the LMP methodology at this docket, to pass along additional costs caused by a change in law or regulatory change to their customers currently under contract. As the Commission considers PJM's and market participants' calls for the Commission to direct PJM, under section 206 or as a compliance directive, to modify the fundamentals of LMP, the Commission should be cognizant of the ripple effects of such an action on contracts across the industry, including potentially default service agreements and retail agreements.

While ISO/RTO markets have experienced numerous rule changes, the LMP price-setting fundamentals in PJM have been virtually unchanged. Where LMP mechanics have changed in other markets, such changes have occurred after significant stakeholder processes that included market simulations that previewed the resulting pricing under the new regime. For example, MISO began its discussions of extended LMP, which PJM referenced in its Comments, in at least 2010, if not before. MISO submitted proposed tariff revisions to implement extended LMP (Initial ELMP Filing) in December 22, 2011 in Docket No. ER12-668-000, which were conditionally approved on July 20, 2012. Extended LMP was not implemented until March 1, 2015,[84] which

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[83] *See* Energy Research Council, *Are fixed-price electricity supply contracts really fixed?* (2013), *available at* http://energyresearchcouncil.com/Are-fixed-price-electricity-supply-contracts-really-fixed.html ("Many supplier contracts have "pass-through" or "change-in-law" provisions, which can affect a customer's electricity bill.") (website sponsored by, among others, Constellation, an affiliate of Exelon). A copy of this document is attached as Appendix A-24.

[84] A status report was filed in ER12-668 on August 29, 2016.

gave ample time for operational analysis to be performed and market participants to understand the implications of the change.

In contrast, PJM has called for energy pricing changes that "go beyond" that pursued in other RTO/ISO markets – hence the concern by American Manufacturers. Initial reports from the PJM Independent Market Monitor are that PJM's contemplated energy pricing modifications would increase LMPs by 10 to 15 percent. Some market participants are urging the price formation changes in PJM be acted upon by the Commission now,[85] even though the price formation changes are "conceptual" by PJM's own admission. Such a significant change, especially without appropriate time to understand the potential market implications, adds to uncertainty and may lead some market participants to re-open existing contracts using the industry-standard "change in law" or "regulatory change" provisions.

In this context, some suppliers may argue that the higher LMPs produced by the change in law or regulatory change are costs that should be shifted to their counterparties. For retail energy contracts and default service agreements, quantifying the impact of a change in law or regulatory change of this magnitude and complexity would be speculative and costly. Customers would have little information or leverage to dispute the amount of additional costs their suppliers will require them to pay to avoid default.

Significant changes in the regulatory rules can and have been accommodated in retail contracts. With the PJM capacity market, for example, the three-year forward nature enables many of the changes in law to be anticipated in contracts. In the case of modifying LMP price-setting methodology, certain market participants are advocating for, based on only broad sketches of purported evidence, a fundamental change in the foundations of energy markets regulated by this

[85] Exelon Comments at 6; PSEG Comments at 25.

Commission. Before such a change is directed, a substantial record evidence should exist that the existing rules are unjust and unreasonable and, to the extent there is a need to address energy price formation, ample time for stakeholder consideration of approaches that would minimize the impacts of triggering a change in law or regulatory change clause relative to the established platform for ISO/RTO energy markets.

5. <u>This proceeding should not be used to short-circuit or circumvent any stakeholder processes that are just now getting underway to consider any need for price formation changes.</u>

As discussed above, many commenters on the NOPR request, with varying levels of urgency, that the Commission to utilize the NOPR platform to take action on price formation. Yet, despite these calls from numerous parties, very little stakeholder discussion relative to energy price formation has occurred to date, at least in the PJM stakeholder process. In fact, no Problem Statement has been introduced for such a PJM stakeholder effort by any of the commenters seeking prompt Commission action.[86] The absence of a PJM stakeholder process on the PJM Price Formation Whitepaper is curious given representations by certain market participants that they would be advocating for PJM to propose its pricing reforms to the Commission in early 2018 with implementation by summer 2018.[87] This history is relevant because it reflects the complete lack of stakeholder engagement that has occurred to date on understanding the perceived problem

[86] While a version of the problem statement initiating the Capacity Construct and Public Policy Senior Task Force included examining energy market effects of Zero Emission Credit programs, stakeholders ultimately declined to adopt that version. And no version focused specifically on LMP price setting has been otherwise introduced by PJM or any of the other PJM Members that have raised price formation concerns here. The PJM stakeholder process around problem statements may be found in PJM's Manual 34. *See* PJM Interconnection, L.L.C., *PJM Manual 34: PJM Stakeholder Process* at 31 (May 19, 2016), *available at* http://pjm.com/-/media/documents/manuals/m34.ashx. A copy of this document is attached as Appendix A-25.

[87] *See* IMM Comments at 35 (citing Exelon Q2 2017 Results – Earnings Call Transcript, Seeking Alpha (August 2, 2017), https://seekingalpha.com/article/4093911-exelon-exc-q2-2017-results-earnings-call-transcript).

around price formation, at least in PJM. By way of contrast, MISO stakeholders considered Extended LMP for at least five years before it was implemented in March 2015.[88]

The fact that energy price formation is likely to be controversial in and of itself should not be viewed as a limiting factor for stakeholder discussions. PJM Members regularly take up difficult and divisive issues, such as capacity markets and energy market offer caps. While PJM Members may not always reach consensus, any resulting rule changes are improved by multi-party stakeholder consideration.

Prior to the NOPR's issuance, it appeared that PJM stakeholders may have been on the precipice of being asked to take up the mantle on price formation. PJM had issued its Whitepaper on Energy Price Formation on June 15, 2017.[89] No dedicated PJM stakeholder meetings, however, have been held to review the details of the Whitepaper itself yet.[90] At the August PJM Markets and Reliability Committee ("MRC") meeting, PJM offered a brief presentation on the status of its Energy Price Formation analysis. In terms of next steps on the initiative, the presentation merely referenced that no simulations had been completed yet, simulation results would be available in the next few months, and that PJM Members should monitor regulatory activity.[91] During that

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[88] *See* Midcontinent Independent System Operator, Inc., *ELMP Parallel Operational Analysis* (June 2014), *available at* https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/MSC/2014/20140603/20140603%20MSC%20Item%2005e%20ELMP%20Parallel%20Operation%20Analysis.pdf. A copy of this document is attached as Appendix A-26.

[89] *See* PJM Interconnection, L.L.C., *Energy Price Formation and Valuing Flexibility* (June 15, 2017), *available at* http://www.pjm.com/~/media/library/reports-notices/special-reports/20170615-energy-market-price-formation.ashx. A copy of this document is attached as Appendix A-27.

[90] Price Formation has been a topic at the PJM Liaison Committee. The substance of the Liaison Committee meetings are confidential between PJM, its Board and PJM Members. These discussions are designed to be high level, strategic discussions, not reviewing the details of proposals. *See* PJM Liaison Committee Charter (last updated Jan. 28, 2016), *available at* http://pjm.com/-/media/committees-groups/committees/lc/postings/20160205-lc-charter-revision-4.ashx?la=en. A copy of this document is attached as Appendix A-28.

[91] *See* PJM Interconnection, L.L.C., *Price Formation Working Paper* (Aug. 24, 2017), *available at* http://pjm.com/-/media/committees-groups/committees/mrc/20170824/20170824-item-10-energy-market-price-formation.ashx. A copy of this document is attached as Appendix A-29.

meeting, PJM Members questioned the timeline for PJM action, noting that certain PJM Members had indicated a timeline for energy price formation that did not line up with the absence of any PJM stakeholder process.

In short, the Commission should not presume that extensive discussions have occurred within the PJM stakeholder process on energy price formation when, in fact, the opposite is true. Very little stakeholder vetting of the issues around price formation has occurred in PJM. PJM's Price Formation Whitepaper may have been a meaningful first step to considering issues around the longstanding LMP price-setting logic, but that should only be viewed as the starting point. American Manufacturers urge that PJM be allowed to complete a meaningful stakeholder process "to explore ideas, to discuss options, and to allow all PJM stakeholders an opportunity to represent their interests."[92]

In addition to the options identified by PJM in its Price Formation Whitepaper, other options for addressing measurable and verifiable reliability or resilience concerns exist. For example, the PJM Independent Market Monitor has identified a number of efficient changes to the PJM energy market design that would improve price formation. The Commission must not constrain the PJM stakeholder process to only consider one option, the option PJM identified in its Price Formation Whitepaper, which has been supported in Comments filed at this docket by generators with inflexible resources in their portfolio that would apparently stand to benefit. PJM's proposal has not undergone rigorous stakeholder vetting to test questions such as:

- Does increasing LMP prices send an inefficient signal that incents the development of more natural gas-fired resources, further complicating our supply-demand imbalance and depressing energy prices?
- How can allowing inflexible units to set price be reconciled with PJM's efforts in the Capacity Performance realm to encourage more flexibility among resources?

[92] IMM Comments at 35.

- How do we protect against strategic bidding by asset owners with a portfolio of resources, including some with inflexible operating parameters?

The Commission must provide adequate latitude and discretion to the stakeholder process to allow all reasonable options to be considered, including those options offered in the Independent Market Monitor's Comments at this docket.[93]

This NOPR proceeding, initiated by the DOE Secretary and a thinly veiled effort driven by certain political interests, should not become a vehicle for this independent Commission to short-circuit stakeholder processes to consider the need for price formation changes. Certainly, the record does not support a finding that existing price formation is unjust and unreasonable. The FPA requires more before significant costs are put upon customers, including American Manufacturers, to the benefit of the owners of nuclear and coal-fired generation.[94]

E. RTO markets have already adopted changes in response to the 2014 Polar vortex; no further changes are appropriate or required at this time.

Supporters of the Proposed Rule argue that the 2014 Polar Vortex demonstrates that the Commission needs to take steps to secure the continued operation of existing generation facilities with on-site fuel supply.[95] These arguments fail to recognize the many market rule changes and generation performance enhancements that have already been implemented and have demonstrated improved system performance.

1. The 2015 Polar Vortex demonstrates that lessons learned have been successful.

As noted in the initial comments of the ISO/RTO Council, the two regions most directly impacted by the 2014 Polar Vortex have already undertaken detailed reviews and have

[93] *Id.* at 42-45.

[94] *Id.* at 35.

[95] FE Comments at 32-24; Murray Energy Comments at 22-24; PSEG Comments at 9-10; Exelon Comments at 23-27.

implemented market rule changes to forestall a repeat performance of the operational issues that challenged grid performance in 2014.[96] PJM has implemented numerous changes to its market rules that include its Capacity Performance construct and changing the timing of its day-ahead scheduling deadlines to provide gas-fired generators a better ability to submit timely pipeline nominations.[97] ISO New England has also implemented market rule changes that include its forward capacity market pay-for-performance rules.[98] Even regions not directly stressed by the 2014 Polar Vortex have used it as a "lessons learned" experience and have taken steps to improve market functionality. These include changes by the New York ISO to its shortage pricing rules and improved operational monitoring on fuel availability.[99] MISO has implemented over 20 specific steps to reduce risks associated with grid operation during extreme weather events.[100]

Even though not all of the market rule changes have been implemented, the changes put in place prior to the winter of 2015 have already demonstrated a marked improvement in system performance. The winter of 2015 was remarkably similar to weather in 2014 as described by PJM:

> The winter of 2015 was marked by cold temperatures similar to the winter of 2014 – with the coldest temperatures experienced during February 2015 throughout the entire PJM footprint. Numerous cities across PJM hit their daily low-temperature records during February 2015. Due to the low temperatures and associated high

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[96] The 2014 Polar Vortex and earlier severe winter weather conditions did, however, highlight operational issues that contributed to the forced outages and poor performance, and compelled examination of the underlying causes and remedies. The regions most affected—PJM and ISO-NE—undertook detailed reviews to rectify those issues. PJM and ISO-NE each found that most, if not all, of the operational issues could be addressed if generation suppliers made investments in weatherization or increased operating budgets and commitments for future fuel deliveries. Both regions proposed (and the Commission generally accepted) market solutions that: (1) pay generation resources for better performance and allow recovery of investment in operational reliability of the resource, including forward fuel costs; and (2) impose a strong monetary penalty for poor performance—with limited to no exceptions. Comments of the ISO/RTO Council at 21, *Grid Reliability and Resilience Pricing,* Docket No. RM18-1-000 (Oct. 23, 2017) ("ISO/RTO Council Comments").

[97] PJM Comments, Appendix A at 3-7.

[98] Comments of ISO New England Inc. at 11, *Grid Reliability and Resilience Pricing,* Docket No. RM18-1-000 (Oct. 23, 2017) ("ISO-NE Comments").

[99] Comments of the New York Independent System Operator, Inc., Attachment at 5, *Grid Reliability and Resilience Pricing,* Docket No. RM18-1-000 (Oct. 23, 2017) ("NYISO Comments").

[100] MISO Comments, Attachment A at 20.

electricity demand for heating needs, PJM set a new wintertime peak demand record of 143,086 megawatts the morning of Feb. 20 (hour ending 0800). The new peak record surpassed the previous all-time winter peak of 142,863 MW set Jan. 7, 2014. Some of the individual transmission zones within the PJM footprint also set all-time record winter peaks.

> In addition to the extremely cold temperatures, PJM also reviewed effective temperatures or wind chill data, for select cities throughout the footprint for both 2014 and 2015. This analysis indicated January 2014 actually felt colder just about everywhere when compared to 2015, especially in Columbus, Cleveland and Chicago, where effective temperatures were between 14 and 16 degrees warmer in 2015. The significant wind chill experienced during 2014 could have contributed to the higher amount of generator forced outages encountered in 2014. By comparison, the less severe warmer effective temperature, wind chill, in 2015 may have contributed to improved generator performance.[101]

PJM reported improved system performance in 2015 notwithstanding the fact that certain market rule changes, such as its Capacity Performance rules, had not been implemented:

> Generator performance in February 2015 showed improvement, with forced outage rates better than in January 2014. For the morning of Feb. 20, 2015, when PJM reached a new all-time winter peak, the forced outage rate was 13.4 percent, representing 24,805 MW of generation forced out of service. Although the 2015 winter peak forced outage rates represent an improvement over the 22 percent forced outage rate during the Jan. 7, 2014, peak, the 2015 rates were still above historical "normal" winter peak outage rate of between 7 and 10 percent. The performance improvements of winter 2015 over 2014 are attributed to steps PJM and generation owners initiated after the winter of 2014 experience: pre-winter operational testing for dual-fuel and infrequently run units, a winter-preparation checklist program, better communication of fuel status and increased coordination with natural gas pipelines.
>
> A total of 168 units (9,919 MW) participated in the pre-winter operational testing. Units that participated in the pre-winter operational testing had a lower rate of forced outages compared to those that did not test.[102]

Other RTOs have also reported improved operational performance due to market rule changes that were implemented following the 2014 Polar Vortex.[103] Given these facts, there is

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[101] PJM Interconnection, L.L.C., *2015 Winter Report* at 5 (May 13, 2015), *available at* http://www.pjm.com/-/media/library/reports-notices/weather-related/20150513-2015-winter-report.ashx?la=en.

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

[103] ISO/RTO Council Comments at 21-22.

simply no justification to now rely upon the 2014 Polar Vortex as the basis for out-of-market subsidies to prop up the continued operation of existing coal-fired and nuclear generating facilities.

2. **Analysis submitted by Rhodium Group demonstrates that on-site fuel supply is not a significant contribution to reliability and resilience.**

The fundamental premise underlying the Proposed Rule, the assumption that a significant on-site fuel supply contributes to grid reliability and resilience, is contradicted by factual history. Comments submitted by The Rhodium Group, LLC ("Rhodium") supports this conclusion. Relying upon data submitted to the EIA on Form OE-417 reports since the beginning of 2012, Rhodium found that:

> [b]etween 2012 and 2016, utilities reported roughly 3.4 billion customer-hours impacted by major electricity disruptions. 96% of those lost service hours were due to severe weather (Figure 2). Fuel emergencies or deficiencies at power plants resulted in 2,382 customer hours of lost service or 0.00007% of the total. **2,333 of those customer hours were due to one event in Northern Minnesota in 2014 involving a coal-fired power plant.**[104]

Rhodium found that the vast majority of customer outages were the result of damaged distribution facilities.[105] Thus, on-site fuel supply contributes little, if anything, to actual reliability and resilience. Further, the relatively short duration of most disruptive events completely undermines any basis for the 90-day requirement specified in the Proposed Rule.[106]

F. **The NOPR would mark an abrupt and unjustified shift in Commission policy.**

1. **Shifting away from competition as the primary means of ensuring just and reasonable rates is not consistent with the evidence and would constitute arbitrary and capricious decision-making.**

The Commission is obligated to explain shifts in Commission policy and departures from existing precedent. The Proposed Rule, if adopted, would impermissibly depart from well-

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[104] Rhodium Comments at 3, *Grid Reliability and Resilience Pricing,* Docket No. RM18-1-000 (Oct. 23, 2017) (emphasis added) ("Rhodium Comments").

[105] *Id.* at 2.

[106] ISO/RTO Council Comments at 18-19.

established Commission policy and precedent without providing a reasoned explanation for this departure. The Proposed Rule's failure "to come to terms with [the Commission's] own precedent reflects the absence of a reasoned decision making process."[107] Without a reasoned basis for altering the current rules applicable to RTOs and ISOs and the tariffs the Commission has approved under those rules, the Commission may not lawfully adopt the Secretary's Proposed Rule.[108]

2. The NOPR would place the Commission in the untenable role of being a central planner.

Proponents of the Proposed Rule argue that existing RTO market rules are not selecting or producing the correct set of generation resources.[109] They argue the generation fleet is becoming increasingly less resilient (an undefined term under the Proposed Rule) and putting the nation's consumers at risk.[110] They suggest the Commission take on the role of being an "uber-utility" and dictate by command and control the appropriate mix of generation resources in the Eastern RTOs in order to prevent nuclear and coal-fired generating facilities from retiring.[111] Such actions would place the Commission in the untenable role of being a central planner for the Eastern RTOs. The ISO/RTO markets have proven themselves adequately capable of ensuring the regions they serve

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[107] *PSE&G Gas Transmission v. FERC*, 315 F.3d 383, 390 (D.C. Cir. 2003) (vacating FERC orders); *see also North Carolina Utils. Comm'n v. FERC*, 42 F.3d 659, 666 (D.C. Cir. 1994) (rejecting a FERC order because the Commission did not "sufficiently explain[] its departure from its prior cases"); *Hatch v. FERC*, 654 F.2d 825, 834 (D.C. Cir. 1981) ("[A]n agency must provide a reasoned explanation for any failure to adhere to its own precedents."); *Greater Boston Television Corp. v. FCC*, 444 F.2d 841, 852 (D.C. Cir. 1970) ("[A]n agency changing its course must supply a reasoned analysis indicating that prior policies and standards are being deliberately changed, not casually ignored.").

[108] *Wisconsin Gas Co. v. FERC*, 770 F.2d 1144 (D.C. Cir. 1985) (Commission may not rely solely on unsupported or abstract allegations). The Commission's rulemaking is governed by the Administrative Procedures Act. Under the Act, Section 553 of Title 5 concerning rulemaking, an agency must provide a sufficiently clear, cogent and reasoned explanation for its decision to alter an existing rule. *American Petroleum Institute v. Johnson*, 541 F. Supp. 2d 165 (D.D.C. 2008).

[109] FE Comments at 22-30; Murray Energy Comments at 7; PSEG Comments at 3; Exelon Comments at 3.

[110] Fuel-secure, resilient generators are retiring as a result of RTO/ISO markets failing. FE Comments at 3. Current market designs fail to value the generator attributes that contribute to the strength and reliability of the grid. PSEG Comments at 2. Market rules undervalue the resilience benefits that nuclear units provide to customers. Exelon Comments at 5.

[111] It is worth observing that some comments suggest the Commission become the central planner for the entire United States.

have an adequate and diverse mix of generation resources.[112] Time and time again, markets have demonstrated they produce superior outcomes when benchmarked against regulators on picking market winners and losers, a reality the Commission has wisely recognized and respected with its efforts to encourage competition in the electricity market over the last 20 years.

A brief historical perspective may be useful. In response to the oil embargo of the 1970s, Congress passed a series of laws altering the nation's energy laws and uses. This included the Power Plant and Industrial Fuel Use Act of 1978. The law prohibited the use of natural gas or petroleum as an energy source in any new electric power plant and prohibited the construction of any new electric power plant without the capability to use coal or an alternate fuel as a primary energy source.[113] The law also placed restrictions on the use of natural gas, including limitations on industrial customers using natural gas as a boiler fuel. The main goal of the 1978 law has been characterized as shifting the nation's electric power generation from petroleum to coal. The nation's utilities did burn more coal as the amount of electricity generated from gas and oil dropped from 30.3 percent in 1978 to 15.9 percent in 1985.

However, other factors were also in play. The Natural Gas Policy Act of 1978 phased in natural gas wellhead price controls and drilling flourished. By the later part of the 1980s, natural gas was plentiful, causing prices to fall. The lower price made natural gas competitive with coal for "baseload" generating plants. The central planning choice to force power plants to use coal in

[112] Regarding the impact of the retirements of coal and nuclear resources on reliability in RTOs/ISOs, the markets "are currently functioning as designed—to ensure reliability and minimize the short-term cost of wholesale electricity." Indeed, such retirements have not negatively impacted resource adequacy. Figure 4.2 of the DOE Staff Report shows that each RTO/ISO's region has maintained a five-year average reserve margin of between fifteen and thirty percent, sometimes well in excess of their respective targets, even in the face of significant changes in the resource mix. ISO/RTO Council Comments at 23-24 (footnotes omitted).

[113] The Secretary of Energy was authorized to grant exemptions in certain circumstances.

the 1970s turned out, within a few years, not to be such a wise decision.[114] The Power Plant and Industrial Fuel Use Act of 1978 was repealed in 1987 and natural gas plants begin displacing coal-fired power plants. The Commission wisely did not step in to rescue coal-fired power plants displaced by natural gas in the 1980s and 1990s and should avoid doing so now.

G. Consideration of the NOPR does not satisfy the Administrative Procedures Act.

Proponents of the Proposed Rule recommend that the Commission adhere to the Secretary's recommendation for a rapid approval and implementation of the Proposed Rule.[115] Because the impacts of the Proposed Rule are so great and rest on such unsupported claims, a rapid adoption of the ill-considered and poorly noticed NOPR would result in a violation of the Administrative Procedures Act.

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[114] Other forays into central planning has proven equally unsuccessful. In the Soviet Union, under *Gosplan,* the basic economic task of allocating scarce resources to competing objectives was accomplished primarily through centrally directed planning rather than through the interplay of market forces. During the decades following the Bolshevik Revolution and especially under Stalin, a complex system of planning and control had developed, in which the state attempted to manage all production activity.

Economic planning was a feature of socialism under Soviet governance for decades. Soviet economic theorists held the view that planning was based on a profound knowledge and application of objective socialist economic laws and that it was independent of the personal will and desires of individuals. The basic law of socialism defined the aim of economic production as the fullest satisfaction of the constantly rising material and cultural requirements of the population, using advanced technology to achieve continued growth and improvement of production. Centralized planning was presented by its proponents as the conscious application of economic laws to benefit the people through effective use of all natural resources and productive forces.

The regime established production targets and prices and allocated resources, codifying these decisions in a comprehensive plan or set of plans. These five year plans dictated targets for the supply of materials, equipment, labor, and finances to the producing sector; for the procurement of agricultural products by the government; and for the distribution of food and manufactured products to the population. Traditionally, the plans were specific to the level of the individual economic enterprise, where they were reflected in a set of output goals and performance indicators that management was expected to maintain. *See* USSR: Role of the State Planning Committee (Gosplan) (Apr. 23, 1975), *available at* https://www.cia.gov/library/readingroom/docs/DOC_0000308042.pdf. A copy of this document is attached as Appendix A-30.

In the mid- and late 1980s, however, economic reforms sponsored by General Secretary (later Chairman and President) Mikhail Gorbachev were introduced that shifted away from centralized planning. *See* Director of Central Intelligence, *Gorbachev's Economic Programs: The Challenges Ahead* (Dec. 20, 1988), *available at* https://www.cia.gov/library/center-for-the-study-of-intelligence/csi-publications/books-and-monographs/at-cold-wars-end-us-intelligence-on-the-soviet-union-and-eastern-europe-1989-1991/16526pdffiles/NIE11-23-88.pdf. A copy of this document is attached as Appendix A-31.

[115] *See, e.g.*, FE Comments at 16 ("Time is of the essence.").

Section 553 of Title 5 governs the informal rulemaking process of the Commission. That section requires the Commission to provide adequate notice of the Proposed Rule that includes reference to the legal authority under which the rule is proposed and either the terms or substance of the Proposed Rule or a description of the subjects and issues involved.[116] Under section 553, "the interested public must have an opportunity to respond to the substance of pivotal Agency actions. Notice of generalities alone will not suffice."[117]

The initial comments demonstrate in detail that the Secretary's poorly drafted Proposed Rule and unsupported general assertions of the need for the dramatic reversal of Commission policy fail to meet even the most basic requirements of reasoned rulemaking.[118] The Secretary provided no clear evidence that the retirement of uneconomic resources has had or will have any adverse effect on the reliability or "resilience" of the electrical grid.[119] Additionally, the "resilience" claims by the rule's proponents are based on questionable, if not false, allegations.[120] Based on this lack of evidence to support the Proposed Rule, there is no reasoned basis for the departure from the Commission's own precedent.[121]

The truncated schedule in this proceeding compounds the violation of the notice requirement of Section 553. In effect, the Secretary is asking the Commission to disregard over 20 years of efforts to a market-based structure for the nation's wholesale electric markets in favor

[116] 5 U.S.C. § 553(b)(1) & (2).

[117] *National Association of Psychiatric Treatment Centers for Children v. Weinberger*, 658 F. Supp. 48, 55 (D. Colo. 1987).

[118] 5 U.S.C. § 553(b).

[119] *See* American Manufacturers' Comments at 23.

[120] *See* discussion in Sections III.A-C, *supra*.

[121] American Manufacturers Comments at 16-17.

of an ill-defined mishmash of competitive and "cost-based"[122] pricing rules in 120 days.[123] While the typical problem is agency inaction,[124] the Commission's decision making nonetheless is governed by a rule of reason. A rush to adopt the Secretary's Proposed Rule based on the unsupported claims would fail to meet the usually forgiving standards of section 553.

H. <u>The timeline and estimated cost for compliance with the Proposed Rule is not realistic or achievable.</u>

Proponents of the Proposed Rule urge the Commission to adopt a final rule quickly and require compliance based upon an unrealistic timeline.[125] Other commenters that express general support for issues raised by the Proposed Rule urge the Commission to take steps more incrementally.[126]

In their initial comments, the ISOs/RTOs provide a reality check on both the unrealistic timelines and cost estimates reflected in the Proposed Rule. The collective ISO/RTO Council concludes the proposed timeline is unrealistic and contrary to past Commission practice.[127] Their

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[122] As there is no agreement as to the causes of the so-called problem, likewise there is a wide range of definitions of what constitutes "cost-based" compensation. The definitions of what may be recovered vary substantially among the rule's proponents; the rule itself offers almost no guidance.

[123] Comments of American Municipal Power, Inc. on Notice of Proposed Rulemaking at 6-8, *Grid Reliability and Resilience Pricing,* Docket No. RM18-1-000 (Oct. 23, 2017) ("AMP Comments").

[124] *MCI Telecomm. Corp. v. FCC,* 627 F.2d 322, 340-342 (D.C. Cir. 1980).

[125] *See, e.g.,* FE Comments at 61; PSEG Comments at 1; Murray Energy Comments at 36.

[126] [B]efore adopting a final rule in this proceeding, the Commission should require the RTOs covered by the NOPR to submit detailed information that can be used to develop a richer understanding of where our grid's vulnerabilities lie; how those vulnerabilities match up against the intelligence community's threat assessments; and what steps must be taken to ensure a sufficient degree of resiliency to protect the nation from known and credible national security threats. With that design basis threat analysis in hand, the Commission can then identify which solutions will address the identified deficiencies in the most cost-effective manner. Exelon Comments at 7.

[127] The proposed requirement that RTOs and ISOs submit their compliance filings a mere fifteen days after the effective date of the final rule (and thus only forty-five days after the rule is published) is unreasonable and contrary both to Commission policy and past practices. ISO/RTO Council Comments at 30.

views on the estimated compliance costs are equally instructive, and concludes that a compliance cost of $291,042 bears no resemblance to reality.[128]

These views are reflected by each of the ISOs and RTOs as well. MISO states that it would be highly unlikely to achieve modifications to its tariff within 15 days.[129] MISO also concludes the cost of legal fees alone would likely exceed one million dollars and the costs to complete software changes would increase this multifold.[130]

ISO New England projects that compliance will likely take years rather than months.[131] It also projects compliance costs will measure in the millions.[132]

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[128] The estimated cost burden is unrealistically low. To implement the NOPR, each RTO must incur expenses related to, for example, market design changes, stakeholder meetings, tariff drafting efforts, software changes, and costs and fees associated with litigating regulatory proceedings. If experience is any guide, such efforts will be in **millions of dollars** for each RTO. The NOPR's estimate is unrepresentative of the total cost of complying with a rule of this magnitude. ISO/RTO Council Comments at 32 (emphasis added).

[129] MISO would unlikely be able to adjust its Tariff in 15 days without the final rule providing very clear direction. Even then, it is highly unlikely that any such Tariff changes could be implemented without substantial changes to supporting systems (i.e., software and settlements) within such a timeframe. In addition, such a compressed timeframe would not allow market participants any meaningful opportunity to participate in the process. MISO Comments Attachment A at 26.

[130] Without the benefit of any additional time to consider this question, MISO believes that this estimate is unreasonably low. Costs to be considered should include costs associated with the failure to have an extensive stakeholder process. Stakeholder processes are designed to allow for thoughtful development of creative solutions to complex problems. It is inherent in the way ISO/RTOs operate. The Proposal's extremely abbreviated timeline will mean the stakeholder process plays out through regulatory (and later court) litigation. Legal fees (including fees for an extensive Section 205 filing process, rehearing, appeal, complaints, and potential state and federal court activity) could amount to hundreds of thousands of dollars if not millions of dollars per RTO/ISO. Then, considerations such as, staff time, computer hardware and software costs, and extensive post-implementation stakeholder process will have to be addressed. Even small changes to markets can involve thousands of hours of staff time and millions of dollars in technology expenditures. This is no small change. While it is impossible to determine the burden with certainty, the Proposal's estimate is unrealistically low. *Id.* at 28-29.

[131] The NOPR proposes a wholesale re-write of each region's market rules within fifteen days after the effective date of the final rule. This is unreasonable, given the complexity of the Tariff in each region, as well as the impossibility of consulting with stakeholders pursuant to existing processes. Moreover, as indicated above, there are significant open questions about many important details regarding the NOPR. The NOPR also proposes implementation within fifteen days, which is markedly inadequate given the need to adjust procedures and software. Projects of this magnitude often require years to retain vendors, develop design documents, complete programming, test the changes, and fulfill cyber security requirements. ISO-NE Comments at 19.

[132] These steps will also require expenditures for vendors or internal development time, software, legal costs, and stakeholder meetings. Such efforts will be in the millions of dollars for each RTO. *Id.* at 19-20 (footnotes omitted).

The New York ISO estimates at least two years would be required to implement any final rule, given market rule changes already under way and the need to avoid conflicts with current software.[133] It also pegs the cost of compliance in excess of a million dollars.[134]

PJM agrees with the estimates submitted by the ISO/RTO Council.[135]

In short, none of the organizations that would be responsible for implementing a final rule (should one be adopted) view the 15-day compliance deadline and the estimated implementation cost of less than $300,000 as having any linkage to reality. American Manufacturers agree with these assessments. The Commission should come to this conclusion as well. If the Commission decides to adopt a final rule (which American Manufacturers do not support), the Commission must be realistic regarding the timeline and cost that will be required to comply with any final rule.

I. **The Commission should exercise its authority under DOE Act Section 403(b) and reject the Proposed Rule.**

As explained in their Initial Comments, under section 403(b) of the DOE Act, the Commission may reject or amend the Secretary's Proposed Rule. Given the ill-advised nature of the rule that the Secretary has proposed, the Commission should exercise its authority under section 403 to reject the Proposed Rule.

Title IV of the DOE Act provides for the creation of the Commission as an "independent regulatory commission."[136] Under section 402 of the DOE Act, the Commission is vested with the

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[133] NYISO estimates requiring six months or more, after the Commission issues any Final Rule, to develop the market rules for its compliance filing and approximately a year-and-a-half to develop and implement software, assuming the Commission accepts the NYISO's initial compliance filing. NYISO Comments, Attachment at 19.

[134] The estimated burden to develop and implement new market rules in response to the proposed rule should be increased to at least $1.5M. The NYISO estimates a cost of approximately $300,000 to develop market rules and to prepare its compliance filing. Assuming the Commission accepts NYISO's compliance filing, the NYISO's estimated burden for developing functional requirements and software is approximately $1M. *Id.*

[135] PJM Comments, Appendix A at 17.

[136] 42 U.S.C. § 7171(a). As an independent regulatory commission, "the members, employees, or other personnel of the Commission shall not be responsible to or subject to the supervision or direction of any officer, employee, or agent of any other part of the Department [of Energy]." *Id*. § 7171(d).

authority to enforce Part II of the FPA. The Commission's jurisdiction is exclusive.[137] Section 401(f) provides that the Commission is authorized to establish such procedural and administrative rules as are necessary to exercise its functions. Additionally, section 403(c) provides that "[a]ny function described in section 402 of this Act which relates to the establishment of rates and charges under the Federal Power Act…may be conducted by rulemaking procedures."[138]

Although the Secretary has some limited authority to present recommendations to the Commission for the adoption of rules, that authority does *not* include dictating the results of the rulemaking, as the Secretary attempts to do here. Section 403(a) of the DOE Act provides the Secretary is "authorized to propose rules, regulations, and statements of policy of general applicability with respect to any function within the jurisdiction of the Commission under section 402 of this Act."[139] The Commission, however, has "exclusive jurisdiction with respect to any proposal made" by the Secretary under subsection (a).[140] The DOE Act explicitly states, "[t]he decision of the Commission involving any function within its jurisdiction…*shall not* be subject to further review by the Secretary."[141] As the DOE Act's legislative history underscores, the Secretary may "participate" in the rulemaking proceeding, but jurisdiction over the subject matter remains with the Commission.[142] As in the case of a proceeding under section 404, the Conference Committee Report further states, "[The] Commission may either concur in the Secretary's proposal, concur with an amendment, or recommend against adopting the rule."[143]

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[137] *Id*. § 7172(g).

[138] 42 U.S.C. § 7173(c).

[139] *Id*. § 7173(a).

[140] *Id*. § 7173(b).

[141] *Id*. § 7172(g) (emphasis added).

[142] House Conf. Rep. 95-539, 95th Cong., 1st Sess. at 76 (1977).

[143] *Id*. at 80.

Thus, the Commission possesses the authority to amend or reject the Secretary's Proposed Rule under section 403(b). As discussed in their Initial Comments and these Reply Comments, there is ample reason for the Commission to reject the Proposed Rule in this proceeding.

J. If the Commission does proceed with a final rule, any out-of-market compensation should be approved for so-called baseload generating facilities only on a temporary basis until such time as the Commission accepts market-based approaches to address the alleged problem.

In response generally to the various Comments that advocate cost-based compensation to certain types of generation, American Manufacturers reiterate that, if the Commission proceeds down this path, it should do so on a very limited and temporary basis until such time as the Commission accepts market-based approaches to address a clearly identified problem. American Manufacturers, in their Comments, proposed a number of guidelines and requirements that should apply to any such cost-based compensation.[144]

K. If the Commission does proceed with a final rule, any compensation should be allocated on a demand basis, not on an energy basis as some commenters suggest.

In response generally to the various Comments that acknowledge that the Proposed Rule does not address cost allocation for any cost-based compensation, American Manufacturers reiterate that, if the Commission adopts the Proposed Rule, costs should be allocated and recovered on the same basis that capacity costs are allocated and recovered.[145] Alternatively, such costs could be recovered on the same basis that RMR and SSR costs are recovered. In all circumstances, because the costs are for standby purposes ("resilience") and consistent with cost-causation principles, the costs should be recovered on a demand (MW) basis, rather than an energy (MWh), basis.

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[144] *See* American Manufacturers Comments at 46-50.

[145] *See* American Manufacturers Comments at 50.

IV. CONCLUSION

WHEREFORE, American Manufacturers and Large Institutional Customers respectfully requests that the Commission reject the Proposed Rule.

Respectfully submitted,

/s/ Robert A. Weishaar, Jr.
By: ______________________________
Robert A. Weishaar, Jr.
McNees Wallace & Nurick LLC
1200 G Street, NW, Suite 800
Washington, D.C. 20005
Phone: (202) 898-5700
Fax: (717) 260-1765
E-mail: bweishaar@mcneeslaw.com

Susan E. Bruce
Vasiliki Karandrikas
Kenneth R. Stark
100 Pine Street
Harrisburg, PA 17101
Phone: (717) 232-8000
Fax: (717) 237-5300
E-mail: sbruce@mcneeslaw.com
vkarandrikas@mcneeslaw.com
kstark@mcneeslaw.com

/s/ Frank Darr
By: ______________________________
Frank Darr
McNees Wallace & Nurick LLC
21 East State Street, 17th Floor
Columbus, OH 43215
Phone: (614) 469-8000
Fax: (614) 469-4653
E-mail: fdarr@mwncmh.com

Counsel to the PJM Industrial Customer Coalition and the Coalition of MISO Transmission Customers, and on behalf of American Manufacturers

Dated: November 7, 2017

APPENDIX A

Supporting Materials

Item No.	DESCRIPTION	LINK
A-1	New York Independent System Operator, *Power Trends, New York's Evolving Electric Grid* at 24 (2017), *available at* http://www.nyiso.com/public/webdocs/media_room/publications_presentations/Power_Trends/Power_Trends/2017_Power_Trends.pdf.	http://www.nyiso.com/public/webdocs/media_room/publications_presentations/Power_Trends/Power_Trends/2017_Power_Trends.pdf.
A-2	North American Electric Reliability Corporation, *2017 Summer Reliability Assessment* at 6 (2017), *available at* http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2017%20Summer%20Assessment.pdf.	http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2017%20Summer%20Assessment.pdf.
A-3	PJM Interconnection, L.L.C., *PJM Interconnection Queue Status & Statistics Update Database Snapshot on 04/24/2017* at 16 (May 4, 2017), *available at* http://www.pjm.com/-/media/committees-groups/committees/pc/20170504/20170504-item-12-pjm-queue-status-update.ashx.	http://www.pjm.com/-/media/committees-groups/committees/pc/20170504/20170504-item-12-pjm-queue-status-update.ashx.
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Hard copies of the supporting documents, as referenced in the footnotes herein, are included in Appendix A to ensure completeness of the record.

Hard copies to follow.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served, via first-class mail, electronic transmission, or hand-delivery, the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 7th day of November, 2017.

/s/ Robert A. Weishaar, Jr.

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Robert A. Weishaar, Jr.
McNees Wallace & Nurick LLC
1200 G Street, NW, Suite 800
Washington, D.C. 20005
Phone: (202) 898-5700
Fax: (717) 260-1765
E-mail: bweishaar@mcneeslaw.com