STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

I/M/O THE IMPLEMENTATION OF L. 2018, c. 16 REGARDING THE ESTABLISHMENT OF A ZERO EMISSION CERTIFICATE PROGRAM FOR NUCLEAR POWER PLANTS	BPU Docket No. EO18080899

Comments of the PJM Power Providers Group

"There has been a lot of discussion about -- that this is an automatic hand-out to the utility. That is not true. This Bill creates a process for the BPU to review the finances of the utility to make sure that it can function and stay operational .... And with that, we drafted a Bill that doesn't guarantee anything but a review."[1]

Senator Stephen Sweeney, December 20, 2017

The Legislature gave the Board of Public Utilities ("BPU" or the "Board") a tall task that basically boils down to a single question – will the nuclear units in Salem County cease operations within three years absent a material financial change? Common sense, practical logical and publicly available information, all lead to the answer to this question as an unqualified "no."

The BPU was not instructed by the Legislature to award a subsidy - the Legislature could have easily ordered the BPU to do so if that was the intent. The BPU was directed to conduct a process and nothing more. The BPU should have never been put in the position of

[1] https://www.njleg.state.nj.us/legislativepub/pubhear/senatu12202017.pdf Committee Meeting at pages 2 and 3.

conducting this process in the first place. The PJM Power Providers Group ("P3")[2] and many other parties pointed to the fact that unprecedently low energy prices in 2016 made for a challenging year for all PJM generators. Since 2016, energy prices have improved and many generators that lost money in 2016 made up for those loses in 2018. This information was available, but not well understood, when L. 2018, c. 16, (N.J.S.A. 48:3-87.3, et seq.) was approved by the Legislature.

PSEG relied on half-truths and misrepresentations to convince the Legislature to believe that the nuclear units in Salem County were teetering on the edge of fully shutting down in the near term. As these representations were being made, the Salem County nuclear plants were fully committed to providing capacity in PJM until May 31, 2021 and additional commitments until May 31, 2022 were secured in PJM's May 2018 capacity auction. All publicly available data offered by the PJM market monitor and others portrayed these plants as operating profitably for the foreseeable future. Given these questions surrounding the veracity of PSEG's assertions of the financial distress for these units, the Legislature did not directly award the subsidy (like it did with the renewable portfolio standard) but instead created a process, whereby plants are to only receive a subsidy if it is shown they are unprofitable and deserving of financial assistance from ratepayers.

While P3 has concerns about how the process was conducted, the BPU can fulfill its duty and reject a subsidy that is not necessary and would serve nothing more than to pad the

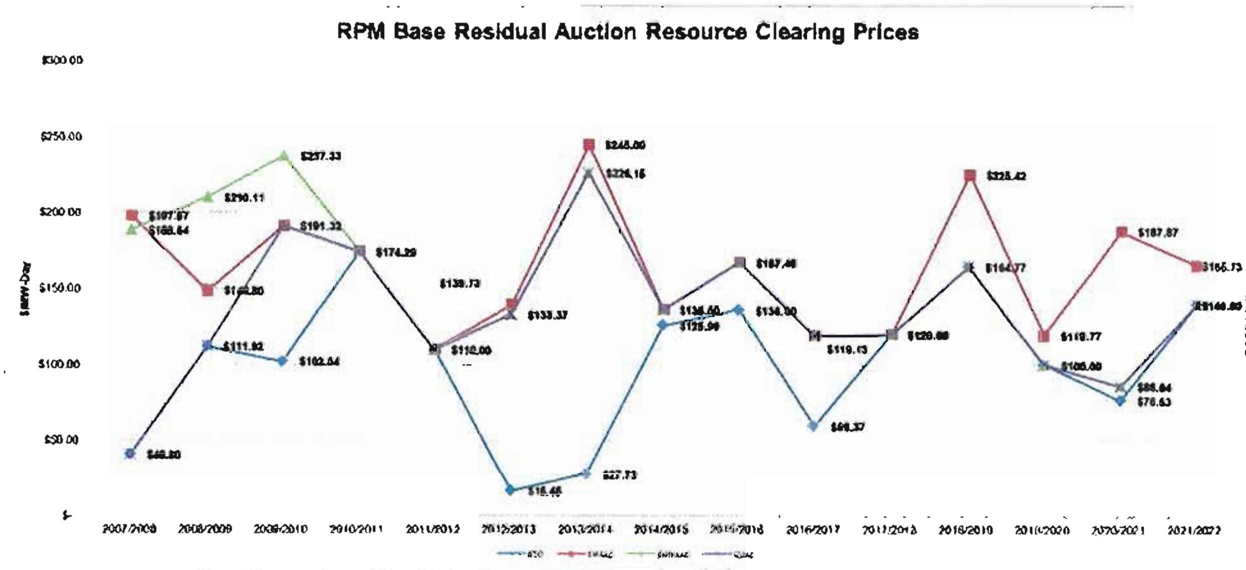
[2] P3 is a non-profit organization dedicated to advancing federal, state and regional policies that promote properly designed and well-functioning electricity markets in the PJM Interconnection, L.L.C. ("PJM") region. Combined, P3 members own over 84,000 MWs of generation assets, produce enough power to supply over 20 million homes and employ over 40,000 people in the PJM region covering 13 states and the District of Columbia. The comments contained in this filing represent the position of P3 as an organization, but not necessarily the views of any particular member with respect to any issue.

coffers of the plant owners and their shareholders. Based on information available to P3, the economic profile of these plants has not changed since the bill passed and efforts underway at PJM could lead to additional compensation for these units. The BPU does not have a duty to be complicit in a fleecing of New Jersey consumers that awards additional revenues to profitable plants. The BPU should just say "no."

I. New Jersey Nuclear Plants are Profitable and Do Not Need ZECs.

P3 has been frustrated by the inability to respond to information deemed confidential that goes to the question of whether these units are truly in the financial distress they purport to be in. While P3 respects that information could be deemed commercially sensitive, P3 believes that PSEG has taken an inappropriately expansive view of what should be confidential information and as a result limited the ability of parties like P3 to help develop a record. However, there is certainly a bevy of publicly available information and data that lead to a nearly irrefutable conclusion that the plants in Salem County are solidly profitable and extremely unlikely to close in the next four years – even in the absence of a Zero Emission Certificates ("ZEC") payment. Consider the following evidence.

First, the Salem nuclear plants are committed to the PJM market until May of 2022 having cleared the PJM BRA Auctions. The New Jersey nuclear units are located in the EMAAC LDA which encompasses all of New Jersey, far eastern Pennsylvania, and the Delmarva Peninsula. According to former PJM Chief Economist Dr. Paul Sotkiewicz, "Historically the EMAAC LDA has cleared at capacity price above the wider RTO price due to having higher peak loads relative to generation resources and historically limited transmission import capability into the region."[3] The chart below[4] (with EMACC depicted in red) shows how capacity prices in New Jersey are consistently higher than the rest of the PJM footprint.



As units that are committed to provide capacity in PJM, the Salem County nuclear units must be available to deliver energy through May 31, 2022 at their cleared capacity commitment or face significant financial penalties. Both Salem and Hope Creek cleared the most recent Base Residual Auction ("BRA") in May of 2018 indicating that the clearing prices for those units were sufficient to cover their going forward costs through May of 2022 and they did so without a ZEC. Regardless of any testimony offered by PSEG in this proceeding, this commitment to PJM to deliver capacity through May of 2022 is firm and provides the Board a

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[3] In the Matter of the Implementation of L. 2018, c. 16 Regarding The Establishment Of A Zero Emission Certificate Program For Eligible Nuclear Power Plants, Prepared Comments of Paul M. Sotkiewicz, PH.D., BPU Docket No. EO18080899, See Attachment A ("Dr. Sotkiewicz Comments"), at P. 54.

[4] https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx at 16.

reasonable degree of confidence that the units will remain in operation lest PSEG suffer the severe consequences of defaulting on its obligation. To date, no nuclear unit in PJM with a capacity obligation has ceased operations and defaulted on a capacity commitment.

Beyond the capacity commitment, the New Jersey nuclear units are making money and have no incentive to retire because they are profitable. Dr. Sotkiewicz illustrates that projected New Jersey nuclear unit revenues "exceed their going forward/avoidable costs and that they will not shut down under any circumstances .... There are projected to be significant contributions to returns and there is no incentive for the New Jersey nuclear units to retire. Based on publicly available data and reasonable assumptions about the market, the New Jersey nuclear units are highly profitable through 2023 and face no imminent threat of retirement."[5] Dr. Joseph Bowring, the Independent Market Monitor for PJM concurs, finding that "[t]he PSEG units are economic and expected to be economic in the foreseeable future based on market data."[6]

To illustrate the net margins for the Salem County nuclear units, the below chart illustrates the significant total profits of these units. The chart illustrates that revenues are well above costs. Note that Dr. Sotkiewicz projects, the New Jersey nuclear plants will make profits of between $338 to $477 million dollars every year for the next ten years.

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[5] Dr. Sotkiewicz Comments at P 57.

[6] *See* https://www.njspotlight.com/stories/18/10/23/critics-say-three-nj-nuclear-plants-are-making-money-dont-need-subsidies/

Projected Profitability of New Jersey's Nuclear Units[7]

	Energy Price ($/MWh)	Capacity Price	Total Revenue ($/MWh)	Fuel plus Avoidable Cost ($/MWh)	Contribution to Returns ($/MWh)	Total Profits for All Capacity($/year) for 3518 MW of Capacity
2019	$34.68	$7.51	$42.18	$26.70	$15.48	$477,155,951
2020	$32.61	$7.33	$39.95	$26.70	$13.25	$408,308,301
2021	$30.76	$8.03	$38.80	$26.70	$12.10	$372,798,511
2022	$29.83	$7.85	$37.68	$26.70	$10.98	$338,322,458
2023	$29.71	$8.02	$37.74	$26.70	$11.04	$340,107,827
2024	$29.94	$8.02	$37.96	$26.70	$11.26	$347,041,805
2025	$30.55	$8.02	$38.57	$26.70	$11.87	$365,789,227
2026	$31.26	$8.02	$39.28	$26.70	$12.58	$387,811,028
2027	$32.01	$8.02	$40.03	$26.70	$13.33	$410,795,881
2028	$33.44	$8.02	$41.47	$26.70	$14.77	$455,096,296

Similarly, analysis from the PJM Independent Market Monitor ("IMM") also shows robust revenue flows for nuclear generating units and profitability of the Salem County nuclear plants through 2021. As part of the IMM's review of market performance, the IMM analyzed the nuclear net revenues in PJM. The analysis of nuclear plants includes annual avoidable costs and incremental capital expenditures from the Nuclear Energy Institute based on its calculations of average costs for all U.S. nuclear plants.[8] The IMM notes that results for nuclear plants are sensitive to small changes in PJM energy and capacity prices and that energy prices in the first nine months of 2018 were significantly higher than in the first nine months of 2017 and forward prices are higher now than earlier in 2018. "The result is that nuclear

[7] Source: Adapted from comments of PAUL M. SOTKIEWICZ, PH.D., filed before the NJ Board of Public Utilities - Docket No. EO18080899, Attachment A.

[8] State of the Market Report for PJM January through September, Monitoring Analytics, LLC, Independent Market Monitor for PJM, 11.8. 2018. See http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018q3-som-pjm.pdf ("IMM Quarterly State of the Market Report 2018") at p. 327.

plant net revenues have continued to increase during 2018 and for the three year forward period."[9] The IMM reports that certain nuclear plants did not clear the capacity auctions, however, the New Jersey nuclear plants were not on this list.[10] Furthermore, the IMM reports that "Based on forward prices for energy, known forward prices for capacity, and public data on costs, there are three nuclear plants in PJM at risk of not covering their annual avoidable costs on average over the next three year (2019 through 2021). The three plants are Davis Besse, Perry, and Three Mile Island."[11] Importantly, note that the IMM did find the Salem County nuclear plants were recovering their annual avoidable costs on average over the next three years (2019 through 2021).[12] The IMM further reports the surplus or shortfall in $/MWh for the nineteen nuclear plants in PJM from 2008 through 2017 – with the Salem and Hope Creek plants showing a surplus in all years except 2016.[13]

II. There are Additional Market Reforms Under Discussion that Could Lead to Additional Revenue for New Jersey Nuclear Units.

There are additional reforms that PJM is currently working on that could lead to additional revenue in the next three years to the Salem County nuclear plants. PJM is currently evaluating the importance of "fuel secure" resources such as nuclear power to determine if additional market products are necessary to ensure a sufficient level of fuel secure resources. PJM has made it clear

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[9] IMM Quarterly State of the Market Report 2018 at p. 327.

[10] IMM Quarterly State of the Market Report 2018 at p. 329.

[11] IMM Quarterly State of the Market Report 2018 at p. 313. Note that Davis Bess and Perry are in Ohio and Three Mile Island is in Pennsylvania.

[12] IMM Quarterly Sate of the Market Report 2018 at p. 331.

[13] IMM Quarterly State of the Market Report 2018 at pp. 329 and 330.

that, "… the PJM system is reliable today and will remain reliable into the future"[14]; however, PJM has also indicated that it is "exploring proactive measures to value fuel security attributes."[15] PJM intends to discuss the issue with stakeholders over the next several months and make a FERC filing at the end of the year. If enacted, this initiative could lead to additional revenues for the Salem County nuclear units in 2020.

Additionally, PJM is focused on reforms to energy pricing that will likely lead to additional revenues for nuclear units throughout the PJM footprint. The PJM Board has made it clear that it is not satisfied that PJM's current energy market rules are appropriately pricing energy and reserves and has called upon stakeholders to develop a proposal that addresses the following elements:

- Consolidation of Tier 1 and Tier 2 Synchronized Reserve products;
- Improved utilization of existing capability for locational reserve needs;
- Alignment of market-based reserve products in Day-ahead and Real-time Energy Markets;
- Operating Reserve Demand Curves (ORDC) for all reserve products;
- Increased penalty factors to ORDCs to ensure utilization of all supply prior to a reserve shortage;

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[14] https://www.pjm.com/-/media/library/reports-notices/fuel-security/2018-fuel-security-analysis.ashx?la=en at 1.

[15] *Id.*

- Transitional mechanism to the RPM Energy and Ancillary Services (E&AS) Revenue Offset to reflect expected changes in revenues in the determination of the Net Cost of New Entry.[16]

If stakeholders are unable to reach consensus on these matters by January 31, 2019, the PJM Board will make a 206 filing at FERC. Early projections from PJM indicate that these reforms could lead to additional $2 billion in energy market revenues to PJM generators starting in 2020 – of which the Salem County Nuclear Plants would gain a share.

Additionally, New Jersey just announced in December 2018, that it will rejoin the Regional Greenhouse Gas Initiative ("RGGI"). If New Jersey does join RGGI, generation units in the state that emit carbon will be subject to additional costs for those carbon emissions. These additional costs are, in turn, included in the generators' offer prices, which results in higher market prices for power. While the increase in power prices as a result of RGGI costs varies by region, conservative estimates indicate the power price uplift is equal to 20% to 25% of the RGGI price (i.e. a $5/ton to $10/ton RGGI price will result in a $1/MWh to $2.50/MWh increase in power prices). Due to the substantial amount of generation from these nuclear units, even a modest increase in power prices represents a significant increase in annual revenue. For the New Jersey nuclear units, this means an additional $30 to $70 million a year in additional profits.[17]

Moreover, the Salem County nuclear units annually participate in PJM's Base Residual Capacity Auction. Each year, these units have the opportunity to offer their capacity at their going

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[16] https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20181205-pjm-board-letter-re-price-formation.ashx?la=en

[17] Salem and Hope Creek list their capacity at 3,462 MW and there are 8,760 hours in a year, which means that the plants produce approximately 30,327,000 MW-hours of generation per year (8,760*3,462). Assuming a 95% capacity factor, $1/MW-hour of RGGI revenues, this equates to slightly less than $30 million. At $2.50/MW-hour, it equates to roughly $70 million.

forward costs and clear or not clear depending on the market dynamics that year. To date, the Salem County nuclear units have cleared every BRA and as result were compensated as capacity resources in exchange for a commitment to deliver energy when called upon by PJM. Every year, the clearing price fluctuates and, as a result, so do PSEG's revenues – however, the clearing price can safely be assumed to be above the unit's going forward costs meaning any ZEC payment would be over and above a unit's going forward costs. Until such time as the Salem County nuclear units do not clear the BRA, the BPU can be confident that the units are receiving sufficient revenues to maintain operations.

Lastly, FERC policy has yet to be set regarding the treatment of out of market subsidy payments. The New Jersey nuclear units could be subject to the Minimum Offer Price rule, if the ZEC's are approved. As Dr. Paul pointed out, "If FERC decides on a remedy similar to a 'clean MOPR' or a 'CASPR-like solution' it is possible that if the resources that were awarded ZECs would be subject to the MOPR, but were able to show their actual costs were low enough to still clear in the capacity market absent the ZECs, it would show that the ZECS were not needed to keep the resources in service and would simply result in extra costs to New Jersey customers that did not need to be incurred. Alternatively, if it turns out that the nuclear resources are awarded ZECs were uneconomic without them, and a 'clean MOPR' or 'CASPR-like' approach were to be adopted by FERC, then the BPU runs the risk of effectively paying twice for capacity. And the Commission has already indicated that it is comfortable as a matter of policy for states to pay twice for capacity. In such a scenario, the most cost-effective course of action for the BPU would be to not award ZECs to avoid this outcome."[18]

[18] Dr. Sotkiewicz Comments at PP 24 -25.

III. New Jersey Electricity Rates Are Already Highest in the Region and Forcing New Jersey Ratepayers to Fund an Unnecessary ZEC Program would Compound the Problem.

New Jersey electricity rates are already extremely high in the region – and abandoning the competitive market, and awarding unnecessary ZECs will make them even higher. Utilizing information from the U.S. Energy Information Administration reveals that New Jersey ranks highest among other states in the region regarding electricity rates and ranks 41st out of 49 states.[19] Comparing annual average electricity price by state in 2017, New Jersey's average electricity rate for all sectors was 13.38 cents per kilowatt-hour compared to 10.16 in Pennsylvania, 10.99 in Delaware and 12.00 in Maryland.[20] Furthermore, when comparing the average price of electricity to ultimate customers for all sectors in all states, New Jersey's rates were not only higher than surrounding states, but also significantly increased in 2018 from 2017. Specifically, in October of 2017 New Jersey's electricity rate was 12.27 cents per kilowatt-hour and in October of 2018 this increased to 12.64. Alternatively, in Pennsylvania rates were lower than New Jersey and decreased in 2018 with the rate in October 2017 at 9.98 and decreased to 9.85 in October 2018. Delaware's rates were 11.03 in October 2017 and 11.08 in October 2018, and Maryland's rates were 11.88 in October 2017 and dropped to 11.80 in October 2018.[21]

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[19] See Annual Average Electricity Price Comparison by State at http://www.neo.ne.gov/statshtml/204.htm

[20] *Id.*

[21] U.S. Energy Information Administration, Electric Power Monthly, With Data for October 2018, issued December 2018, Table 5.6.A Average Price of Electricity to Ultimate Customers by End-Use Sector, by State, October 2018 and 2017, at page 138 , See https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a

New Jersey can ill-afford to hoist extra hundreds of millions in costs on its ratepayers to fund a ZEC program that is not necessary. If New Jersey is to remain competitive as a place to live or locate a business, electricity rates must remain competitive with neighboring states. With the exception of New York, no neighboring state has a ZEC program and, if approved, New Jersey citizens would be shouldering a burden that consumers in neighboring states do not. The dramatic gap that exists between New Jersey and Pennsylvania, Delaware and Maryland would grow even further making it even harder to pursue initiatives of importance to the Governor such as off shore wind.

IV. The BPU Has Wide Discretion to Make The Correct Decision

Importantly, L. 2018, c. 16, (N.J.S.A. 48:3-87.3, et seq.), vests the Board with wide discretion to determine whether a nuclear facility has satisfied the objectives of the Act, and if it does not, the Board is under no obligation to certify such nuclear plant as eligible, c. 16, Sec. 3(d) ("If the board determines, in its discretion, that no nuclear plant that applies pursuant to subsection c. of this section satisfies the objectives of this act, then the board shall be under no obligation to certify any nuclear power plant as an eligible nuclear power plant.") (emphasis supplied). Indeed, Governor Murphy who, during the signing ceremony for the ZEC Act, responded to criticisms that the law did not authorize sufficient oversight of the BPU proceedings, leaving ratepayers vulnerable and under-represented stated:

> "The ratepayer will be well represented, and I think there are a lot of safeguards in this bill that will prevent some of the sort of general swirling around, 'the money's going to go out of state, the ratepayer won't have representation, they'll get the subsidy even if they don't need it'. None of that is true."[22]

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[12] https://www.njtvonline.org/news/video/murphy-signs-nuclear-subsidy-and-renewable-energy-bills/

Accordingly, the Board has wide latitude to ensure that the intent of the statute met: that no financial award would be made where it was not supported by the substantial and credible evidence in the record, in order to protect the ratepayer and the competitive interests of P3 and its members. The Act vests the Board with discretion and there is nothing in the publicly available data to suggest that the plants are not profitable. With respect to the private data, the BPU must carefully scrutinize and determine why there exists a discrepancy between the publicly available data and the private data.

V. Conclusion

As PSEG CEO Ralph Izzo told the New Jersey Senate, "I am heartened by the fact that Stefanie [Brand] has repeatedly said she doesn't want the plants to go away. I am heartened by the fact that she wants proof that they are at financial risk. That's what this Bill allows you to do thoughtfully."[23] P3 agrees with Mr. Izzo on this point. The BPU has before it an opportunity to make a thoughtful decision on this important issue by exercising independent judgment based on the record before it. P3 has seen nothing to indicate that this should be a difficult decision and there is only one appropriate conclusion to this process: the applications should be rejected in their entirety.

Dated: January 31, 2019

[23] https://www.njleg.state.nj.us/legislativepub/pubhear/senatu12202017.pdf at Committee Meeting pp. 32 - 33.

ATTACHMENT A

Prepared Comments of Paul M. Sotkiewicz, PH.D.

In the Matter of the Implementation of L. 2018, c. 16 Regarding The Establishment Of A Zero Emission Certificate Program For Eligible Nuclear Power Plants, BPU Docket No. EO18080899

STATE OF NEW JERSEY
BEFORE THE
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE IMPLEMENTATION OF L. 2018, c. 16 REGARDING THE ESTABLISHMENT OF A ZERO EMISSION CERTIFICATE PROGRAM FOR ELIGIBLE NUCLEAR POWER PLANTS	))))))))	**BPU Docket No. EO18080899**

PREPARED COMMENTS OF PAUL M. SOTKIEWICZ, PH.D.

I. QUALIFICATIONS

1. My name is Dr. Paul M. Sotkiewicz. I am the President and Founder of E-Cubed Policy Associates, LLC ("E-Cubed") and formerly served as the Chief Economist in the Market Service Division of PJM Interconnection, L.L.C. ("PJM"). I have been asked by the PJM Power Providers Group ("P3") to submit these comments that respond to the questions posed by the New Jersey Board of Public Utilities ("NJ BPU" or "BPU") in its September 11, 2018 Notice in BPU Docket No. EO18080899.[1][2]

2. Prior to founding E-Cubed, I worked as a contractor and directly for PJM Interconnection, L.L.C. ("PJM") in Audubon, Pennsylvania from February 2008 until October 2016. In my time at PJM I first served as a Senior Economist until March 2010

[1] State of New Jersey, Board of Public Utilities, *Notice to All New Jersey Electric Distribution Customers, Electricity Suppliers, Electric Distribution Companies, Electric Generators, and other Stakeholders in the Matter of the Implementation of L. 2018 c. 16 Regarding the Establishment of Zero Emission Certificate Program for Eligible Nuclear Power Plants,* BPU Docket No. EO18080899, September 11, 2018. ("Notice")

[2] While I have been asked to provide these comments by the PJM Power Providers Group and compensated for doing so, the views expressed herein are my own and do not necessarily reflect the views of P3 or any P3 member with respect to any issues. For more information on P3 see www.P3powergroup.com

and subsequently as the Chief Economist in the Market Service Division until June 2015. From July 2015 until October 2016, I worked as a contractor for PJM under the Title of Senior Economic Policy Advisor. Prior to joining PJM, I served as the Director of Energy Studies at the Public Utility Research Center ("PURC"), University of Florida from August 2000 until February 2008 and I was an Economist at the Federal Energy Regulatory Commission ("FERC") from September 1998 until August 2000. I have a B.A. in History and Economics from the University of Florida (1991), and an M.A. (1995) and Ph.D. (2003) in Economics from the University of Minnesota.

3. I have over 20 years of experience on matters at the intersection of utility regulatory policy, power system economics, and environmental economics. In my current role, I advise private- and public-sector clients on a range of economic issues related to electricity market design and performance, power generation economics, utility regulatory policy, and the economic impacts of state and federal environmental policies. At PJM I provided expert analysis, advice, and support for PJM initiatives related to market design changes in, and performance of, PJM's energy, ancillary service, and capacity markets.

While the Director of Energy Studies at PURC, I provided executive education and expert advice to regulatory staff and utility professionals from around the world in matters such as electric power regulation, market design, incentive regulation, and cost-of-service rate cases and rate design.

As an economist at FERC, I worked on market design issues and filings related to the newly formed ISO/RTO markets concentrating primarily on the New York ISO and the

California ISO markets. The entirety of my experience and work history can be found in my CV attached as Attachment C.

A. Specific Experience with Respect to the Impact of Environmental Policies, Generation Costs, and Effects on PJM's Markets.

4. I started my work in the power industry by examining the impact of state public utility commission regulations on the cost effectiveness of the Title IV Sulfur Dioxide Trading Program under the 1990 Clean Air Act Amendments ("CAAA") which became my doctoral dissertation as noted in my CV. This work was recognized by the Transportation and Public Utility Group of the American Economic Association as most outstanding doctoral dissertation in this area. I have also served as a consultant to the Florida Department of Environmental Protection providing economic cost modeling assistance and litigation support for the proposed State Implementation Plan ("SIP") for the Clean Air Interstate Rule ("CAIR").[3] As a result, I am intimately familiar with the public policies necessary to advance environmental goals within a competitive power market.

5. As Chief Economist and later Senior Economic Advisor at PJM, I was one of the lead authors of the analysis of the effects of the Mercury and Air Toxics Standards ("MATS") on PJM's markets that examined what coal-fired resources would be at risk of retirement.[4] More recently prior to leaving PJM, I was one of the lead authors of the series of papers outlining how the Clean Power Plan ("CPP") might affect the PJM

[3] CAIR was later overturned and remanded back to the US EPA and later became the Cross State Air Pollution Rule ("CSAPR").

[4] PJM Interconnection, LLC, *Coal Capacity at Risk for Retirement in PJM: Potential Impacts of the Finalized EPA Cross State Air Pollution Rule and Proposed National Emission Standards for Hazardous Air Pollutants* August 26, 2011. ("PJM MATS Analysis")

market under various policy and economic scenarios.[5] I also served as part of peer review team examining ICF's Integrated Planning Model ("IPM") used by the Environmental Protection Agency ("EPA") used to model various EPA policies.[6]

6. While at PJM I was deeply involved in helping PJM develop various iterations of the Minimum Offer Pricing Rule ("MOPR") as filed at, and approved by, the Commission. Additionally, I was responsible for the administration of the unit specific MOPR exemption process at PJM, and I also oversaw the application of the Competitive Entry and Self-Supply Exemptions in the previous version of the MOPR that was later vacated in *NRG*.[7] I also worked with PJM staff to update the Avoidable Cost Rate (ACR) default values used in the mitigation of offers into the PJM RPM Capacity Market.[8] I was also deeply involved in the 2011 and 2014 RPM CONE and Demand Curve reviews.[9] As a

[5] PJM Interconnection, LLC, *EPA's Final Clean Power Plan Compliance Pathways Economic and Reliability Analysis, September 1, 2016* ("PJM Clean Power Plan Study") available online at https://pjm.com/-/media/library/reports-notices/clean-power-plan/20160901-cpp-compliance-assessment.ashx?la=en.

[6] United States Environmental Protection Agency ("US EPA"), Clean Air Markets Division, *Response to the Peer Review Report EPA Base Case Version 5.13 Using IPM,* and Anthony Paul, Chair; Meghan McGuinness; Walter Short; Paul Sotkiewicz; John Weyant through RTI International, *Integrated Planning Model (IPM) Base Case Version 5.13 Peer Review, Peer Review Report* October 2014, available as a single file at https://www.epa.gov/sites/production/files/2018-05/documents/response_and_peer_review_120516.pdf

[7] For the MOPR in place for the 2011 and 2012 BRA, *see PJM Interconnection, L.L.C.*, 153 FERC ¶ 61,022 (2011) ("April 2011 MOPR Order). For the MOPR in place from 2013 to 2017 until vacatur *see PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,090, (2013) ("May 2013 MOPR Order"), *reh'g denied*, 153 FERC ¶ 61,066 (2015) ("October 2015 MOPR Order"), *vacated & remanded sub nom. NRG Power Mktg., LLC v. FERC*, 862 F.3d 108 (D.C. Cir. 2017), *reh'g denied*, 2017 U.S. App LEXIS 18218 (D.C. Cir. Sept. 20, 2017).

[8] *See* PJM Interconnection, LLC, Docket No. ER13-529, December 7, 2012, Attachment A, *2012 Avoidable Cost Rate Triennial Review.*

[9] *See* PJM Interconnection, LLC, Docket No. ER12-513, December 1, 2011 ("2011 Triennial Review") and PJM Interconnection, LLC, Docket No. ER14-2490, September 25, 2014 ("2014 Quadrennial Review").

consequence of this experience along with my environmental policy experience, I have a deep knowledge of generation cost structures across various technologies.

II. EXECUTIVE SUMMARY: KEY FINDINGS AND CONCLUSIONS

7. The questions asked by the BPU in its September 11 Notice require thoughtful consideration and some detailed responses that can aid the BPU in the process of considering whether or not ZECs should be awarded, and then the process surrounding how to best proceed to serve the interests of New Jersey's electricity customers. In that spirit, this executive summary is a guide to the more detailed responses and analysis provided herein.

A. Publicly Available Data and Forecasts Indicate that Nuclear Facilities in New Jersey Can Easily Cover their Going Forward/Avoidable Costs into the Foreseeable Future.

8. Publicly available fuel and going forward/avoidable cost data indicate costs that equate to between \$26-\$27/MWh for the Salem and Hope Creek nuclear facilities in New Jersey.[10] Currently published forward curves for power at the PJM Eastern Hub show

[10] For going forward costs see, Unites States Environmental Protection Agency ("US EPA"), *Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model*, May 2018. Available online at https://www.epa.gov/sites/production/files/2018-08/documents/epa_platform_v6_documentation_-_all_chapters_august_23_2018_updated_table_6-2.pdf. Chapter 4, Generation Resources, Table 4-47 Characteristics of Existing Nuclear Units, available as a spreadsheet at https://www.epa.gov/sites/production/files/2018-05/table_4-47_characteristics_of_existing_nuclear_units_in_epa_platform_v6.xlsx. ("IPM v6 Table 4-47"). For Fuel costs *See also* Sargent & Lundy, *IPM Model – Nuclear Power Plant Costs, Nuclear Power Plant Life Extension Cost Development Methodology-Final*, at 4-6 to 4-7. Available at https://www.epa.gov/sites/production/files/2018-05/documents/attachment_4-1_nuclear_power_plant_life_extension_cost_development_methodology_1.pdf. To derive the cost per MWh, the average capacity factor using output from EIA 923 data from 2014-2017 was used and shows an average 88% capacity factor. EIA-923 data can be found at https://www.eia.gov/electricity/data/eia923/.

average annual prices for energy alone above \$29/MWh through 2026.[11] This means that in the energy market alone, the Salem and Hope Creek nuclear facilities ("New Jersey nuclear resources") can more than cover their going forward/avoidable costs and earn money to offset sunk capital costs and contribute toward returns.

9. Furthermore, given the recent PJM RPM Capacity Market clearing price for the EMAAC LDA have averaged \$174/MW-day over the last four Base Residual Auctions ("BRAs").[12] This translates to an additional \$8.02/MWh of revenue that all goes to covering sunk costs and returns on investment. If these prices remain as they have in EMAAC, this leaves more than \$10/MWh for nuclear units in New Jersey to recover any sunk costs and returns on investment for the foreseeable future.

10. The bottom line is that since the Salam and Hope Creek facilities look to more than recover going forward/avoidable costs plus recover sunk costs and returns on investment, it makes no sense for these units to retire, because these units are making money. Moreover, retiring these units would not be in the interest of shareholders as retiring these resources when they can recover sunk costs plus some return on investment would amount to fiduciary malpractice. So long as a generation resource can cover its going

[11] Intercontinental Exchange ("ICE"), Futures Daily Market Report, October 12, 2018, Futures for PJM Eastern Hub Day-ahead Peak ("PEB") and Off-peak ("PED) and PJM Western Hub Day-ahead Peak ("PJC") and Off-peak ("PJD"). These reports are available at https://www.theice.com/marketdata/reports/142. Average annual prices were determined by first taking the simple average of the peak and off-peak prices for the month recognizing that the number of peak and off-peak hours are about equal. Then these average monthly numbers were averaged over each calendar year. PJM Eastern Hub Price only are quoted through December 2023. To derive prices through 2028, the basis differential between PJM Western Hub and PJM Eastern Hub for 2023 were used and assumed to carry over through 2028.

[12] PJM Interconnection, LLC, *2021/2022 Base Residual Auction Report*, Figure 2 at 16. Available at https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx?la=en.

forward/avoidable costs, plus cover some portion of sunk costs and return on investment, it is never optimal for the resource to retire.

B. Even if Zero Emissions Credits were Needed to Prevent New Jersey Nuclear Resources from Retiring, it is Not a Cost-Effective Means to Avoid or Reduce Carbon Dioxide Emissions.

11. The charge to load for Zero Emissions Credits ("ZECs") is set at \$0.004/kWh or \$4/MWh. Given the load in New Jersey, and the load forecasts from PJM this amounts to approximately \$300 million per year in subsidies in the form of ZECs.[13] Assuming that the New Jersey nuclear facilities would actually retire, notwithstanding that the publicly available data show New Jersey nuclear resources are profitable going forward, this amounts to an extra payment of \$10.82/MWh for these resources. These payments are additional to the \$11-\$15/MWh of net profits for each MWh projected to be earned by the New Jersey nuclear resources for a total operating profit up to nearly \$26/MWh.

12. From an environmental cost-effectiveness perspective, ZECs do not make any sense. First, there is no credible threat from the publicly available data that indicates the New Jersey nuclear resources would shut down and permanently retire. This means the cost of the ZECs do not lead to any addition emissions avoidance. But even if it were assumed that the New Jersey nuclear resources would shut down absent the ZECs, each MWh of nuclear output only displaces, at the margin, about two-thirds (2/3) of a ton of carbon dioxide.[14] This implies a marginal cost of abatement of \$15.74/ton related only to the

[13] PJM Interconnection, LLC, *2018 Load Forecast Report, Data*, available at https://pjm.com/-/media/library/reports-notices/load-forecast/2018-load-forecast-report-data.ashx?la=en. ("PJM 2018 Load Forecast Report Data"). The forecast total energy for all New Jersey Zones were summed up to get the total energy forecast and then multiplied by the rate to be charged to New Jersey customers of \$4/MWh.

[14] PJM Interconnection, LLC, *2013-2017 CO2, SO2 and NOX Emission Rates*, Figure 3 at 4. The peak CO_2 marginal emissions rate is 1,376 lbs/MWh while the off-peak marginal emissions rate is 1,372 lbs/MWh.

cost of ZECs alone under the assumption that the New Jersey nuclear resources would retire.

13. In contrast, new and highly efficient combined cycle gas resources are entering the market without the benefit of out-of-market support due to the fuel efficiency and lower costs. Because of their efficiency and burning a fuel with lower carbon content overall, new entry combined cycle gas resources are ***more cost-effective at the margin*** because their new entry would reduce carbon dioxide emissions by displacing output from more expensive, higher emitting resources ***without any additional costs*** because these resources will enter the market regardless of any price or value placed on carbon dioxide emissions. In effect, the marginal cost of abatement is zero which is a far better deal than paying $15.74/ton through ZECs.

14. But given the publicly available data that indicates nuclear resources in New Jersey would not rationally retire, paying them ZECs would do nothing to reduce carbon dioxide emissions overall and will only lead to higher costs for New Jersey electricity customers.

C. Since it is Not Economically Rational for New Jersey Nuclear Facilities to Retire, the Awarding of ZECs Would Wipe Out the Cost Savings from Participating in PJM's Markets.

15. According to PJM, its markets save consumers in the PJM footprint about $2.3 billion annually. This translates to a savings of approximately $2.85/MWh with a PJM administrative cost of $0.32/MWh, for a cost benefit ratio of about 8.9-to-1 in 2018.[15]

On average this is 1,374 lbs/MWh or 0.687 tons/MWh. Available at https://pjm.com/~/media/library/reports-notices/special-reports/20180315-2017-emissions-report.ashx.

[15] PJM Interconnection, LLC, *The Value of Markets*, at 2. Available at https://www.pjm.com/-/media/about-pjm/newsroom/fact-sheets/the-value-of-pjm-markets.ashx. PJM states it saves $2.3 billion per year due to its operations. With projected PJM total energy of 806,725 GWh as shown in the PJM 2018 Load Forecast Report Data, this comes out to $2.85/MWh. PJM's administrative cost can be found in the monthly Markets Report presented to the Members Committee. The most recent report can be found at https://pjm.com/-

But the $4/MWh charge to load for ZECs would more than offset these benefits to New Jersey customers. These are just additional costs that need not be incurred since the public data indicate that these costs would simply be additional to New Jersey customers without any corresponding benefit given these nuclear resources would not rationally retire.

D. There is No Need for Additional Consideration of Market and Operational Risks as These are Embedded in the Current Cost of Capital and these Risks are No Different than Those Faced by Competitive Generation Resources. If Anything, ZECs Reduce These Risk and Result in a Lower Cost of Capital.

16. All competitive, merchant generators face operational and market risks. Operational risks are unit specific and are related to performance of the resources over time, and with capacity performance in PJM, performance during system emergencies. Operational risks can be minimized through following prudent maintenance practices to minimize the probability of unforeseen outages. Market risks are more systemic and are related to overall economic conditions such as load growth, fuel prices, technological changes, and overall supply-demand balance. While all generation resources face these risks, they affect each resource differently.

17. Given these risks, the cost of capital for each merchant generation resource should already account for such risks and will be reflected in the cost of debt and cost of equity faced by each resource. There is no need to consider these risks additionally as rational markets should have already accounted for these issues. Considering these risks beyond what they have already been would amount to double counting and, in essence, require consumers to pay twice for the same things.

/media/committees-groups/committees/mc/20181022-webinar/20181022-item-07a-markets-report.ashx?la=en.

18. The presence of an additional revenue stream outside the market in the form of ZECs should have the effect of reducing the effect of these risks and should result in a lower cost of capital rather than a higher cost of capital. The availability of such out of market payments that are otherwise not available to other resources insulates the nuclear resources in New Jersey against such risks.

E. Applicants for ZECs Should be Required to Submit Detailed Financial Information and Cost Data, Compare their Data with Publicly Available Data and Explain Why There are Differences. The Data and Financial Information Should be Presented in an Open, Transparent Process.

19. There an old adage, "Sunshine is the best disinfectant." The BPU must require that any applicants for ZECs present a full, open, ***and public*** showing of their resource's financial condition going forward. This includes all cost data, forecasts of fuel price, power prices, load forecasts, expected capital investments, actual cost of debt and equity. The financial status of the parent company, and parent company guarantees for debt of the nuclear resources, and terms and conditions for other subsidies received for resources that are similarly situated. Also, costs that cannot be avoided associated with decommissioning and the status of the resources' decommissioning accounts.

20. Furthermore, there is ample publicly available data, by which to compare or benchmark company submitted data. Publicly available cost data comes from FERC Form 1, EPA, and EIA databases. There are many publicly available forecasts for power prices, fuel prices, and load growth. Costs can be compared to other operating nuclear resources that are not seeking subsidies. Applicants for ZECs should be required to rigorously compare their submitted data and financial information and forecasts and be prepared to explain why their data and information is more representative of their current circumstance that the publicly available data. Much of the publicly available data has been submitted by

the companies themselves and should match up with their data and information submissions to the BPU.

F. The BPU Should Not Entertain any Other Policy Considerations Outside Verifying the Financial Condition of Applicants and Minimizing Costs of the Policy and the Overall Goal

21. The BPU's primary charge is to ensure that applicants for ZECs meet the financial criteria for receiving ZECs and to the extent possible to minimize costs to consumers. The legislation does allow the BPU to reduce the charge to customers or order rebates back to customers if there is excess money remaining from the ZECs. And given the publicly available data showing that nuclear resources in New Jersey can easily cover their going forward costs plus cover sunk costs plus some kind of return, the most cost-effective decision already appears to be to not award ZECs to the New Jersey nuclear resources.

22. Still, there are other considerations that are alluded to such as jobs, tax base, and local economic development within the legislation. While these are admirable policy considerations, they should not be considered in the context of minimizing costs or finding the most efficient solution within the power sector sphere. There are other means to ensure tax base and local economic development through taxing and spending policies directly under the control of the New Jersey Assembly that can accomplish the same goals without undoing the benefits of participating in PJM's markets, cross-subsidizing consumption in the rest of PJM outside of New Jersey, and distorting PJM's energy and capacity markets.

G. The Award of ZECs in the Context of the PJM Capacity Market will lead to Inefficient Outcomes, Higher Overall Costs, and Prices that do not Reflect True Costs. Or in the Alternative, Simply Increase Costs for New Jersey Customers

23. The BPU has requested feedback upon how the recent FERC Orders on PJM's Capacity Market affects the BPU's consideration of ZECs. As has been shown by multiple

intervenors, subsidizing resources that are otherwise not economic leads to the following: 1) An inefficient resource mix where lower cost resources are pushed out of the market; 2) Prices that do not match the actual costs of resources being committed; 3) Prices that are artificially below the competitive level; 4) Inappropriate cost and benefit shifting between market participants; and 5) Potential exercise of buyer-side market power which likely draws extra scrutiny from FERC. The affidavits of Dr. Paul M. Sotkiewicz on behalf of EPSA and Dr. Roy Shanker on behalf of P3 are attached to this testimony that go into detail on these issues as Attachments A and B, respectively.

24. But even more important is the risk the BPU is taking with the awarding of ZECs to nuclear resources that do not need them. If FERC decides on a remedy similar to a "clean MOPR" or a "CASPR-like solution" it is possible that if the resources that were awarded ZECs would be subject to the MOPR, but were able to show their actual costs were low enough to still clear in the capacity market absent the ZECs, it would show that the ZECs were not needed to keep the resources in service and would simply result in extra costs to New Jersey customers that did not need to be incurred.

25. Alternatively, if it turns out the nuclear resources that are awarded ZECs were uneconomic without them, and a "clean MOPR" or "CASPR-like" approach were to be adopted by FERC, then the BPU runs the risk of effectively paying twice for capacity. And the Commission has already indicated that it is comfortable as a matter of policy for states to pay twice for capacity.[16] In such a scenario, the most cost-effective course of action for the BPU would be to not award ZECs to avoid this outcome.

H. Key Takeaways: There is No Need to Award any ZECs at this Time. Publicly Available Data Show New Jersey Nuclear Resources Do Not Need the ZECs to

[16] 163 FERC ¶ 61,236, June 29, 2018 P 69.

Remain in Commercial Operation and the Adverse Risks of Awarding the ZECs Outweigh Any Possible Benefit.

26. Overall, the key takeaway is that it appears nuclear resources in New Jersey are not in need of ZEC payments to remain in commercial operation as shown by publicly available data. Given the known costs and the forward curves for energy and recent capacity market outcomes, nuclear resources easily cover their going forward/avoidable costs and can cover sunk costs plus contributions to returns. On this basis alone, ZEC's need not be awarded.

27. The adverse risks of awarding ZECs exceed any possible benefits. First, if ZECs are not needed to keep the nuclear resources in operation, then the ZECs only raise costs to New Jersey customers and, in doing so, wipe out the benefits of being in the PJM market. And under various scenarios of outcomes in the PJM capacity market proceeding in front of FERC, it could be the case that the nuclear resources receiving ZECs could clear the market even as they are subject to MOPR revealing the lack of need for ZECs in the first place which would be a politically embarrassing outcome. The board should seriously consider making failure to clear a capacity auction a condition precedent to the award of a ZEC. Why would the board provide additional dollars to resources that are already committed to serving the market and cleared the market at economic prices? Taking on a capacity obligation is a sign there is no credible threat of a unit retiring due to economic distress.

28. In order to prevent such an outcome, a full, open, public, and transparent process is necessary to ensure that submitted information from ZEC applicants is subject to the most rigorous scrutiny and challenge to ensure that resources being awarded ZECs actually need the ZECs remain in commercial operation.

29. However, this brings its own set of challenges. If ZECs are awarded and FERC opts for solutions to the PJM Capacity Market issue in front of it that enforces a strong MOPR or a CASPR-like solution, New Jersey runs the risk of paying twice for capacity when it did not need to do so.

30. Finally, as a solution to carbon dioxide emissions, ZECs are at best a higher cost solution than allowing the PJM markets to work to encourage lower emitting combined cycle gas resources or lower cost renewable resources to enter the market on their own to displace higher emitting resources. At worst, ZECs would be awarded to resources that would not retire anyway and would only increase costs without any resulting emissions avoidance or reduction benefits.

III. PURPOSE AND ORGANIZATION OF THESE PREPARED COMMENTS

31. One over-arching purpose of these prepared comments is to highlight that there is no need to award ZECs to nuclear resources as they do not need them to remain in commercial operation and that awarding any ZECs entails far greater risks than there are benefits. In order for the BPU to verify these assertions, there should be an open, public, transparent, and rigorous vetting of all information provided by ZEC applicants to show that ZECs are not necessary to keep these resources in commercial operation. Finally, these comments provide answers to the specific questions posed by the BPU in its September 11, 2018 Notice, albeit the questions are grouped by theme and not answered in the order they appear in the Notice.

32. Section IV of this testimony provides the publicly available evidence to show that nuclear resources in New Jersey do not require ZECs to remain in commercial operation as they can easily cover their going forward/avoidable costs plus cover a portion of sunk cost and/or return on investment. Section IV also responds to the BPU's threshold question

regarding the criteria the BPU should consider for a nuclear resource to be eligible for ZECs.

33. Section V addresses the relative cost of carbon dioxide emissions reduction or avoidance related to awarding ZECs to nuclear resources versus non-intervention in the wholesale power market and allowing the entry of new, efficient combined cycle gas resources and low cost renewable resources to reduce emissions at no additional costs to New Jersey electricity customers. This section also addresses the metric by which a nuclear resource should be eligible to be awarded ZECs.

34. Section VI discusses the scope of resources eligible to receive ZECs and the criteria by which they should be evaluated. This section responds to BPU Questions 13 and 14 in the Notice.

35. Section VII discusses the cost of capital questions (BPU Questions 3 and 4) posed by the BPU and explains that risks are already accounted for in the cost of capital. Moreover, this section also points out that the ability of a nuclear resource to be awarded ZECs effectively reduces the downside risks faced by the nuclear resource and should call for a lower cost of capital consideration in any case.

36. Section VIII responds to BPU questions regarding information submissions and what types of information should be submitted to the BPU for consideration of the award of ZECs (BPU Questions 4, 8, 9, 11, and 12). Additionally, the response to these questions delves into how such information should be evaluated and the manner in which it is evaluated by the BPU, and the openness with which such information should be available to the general public.

37. Section IX address BPU questions regarding other policy issues that are non-standard for state commissions to address such as other public policy goals unrelated to utilities and accounting for other environmental considerations and compensation beyond ZECs. This section responds to BPU Questions 5, 6, 7, 10, 15, and 16 in the Notice.

38. Section X addresses the BPU question regarding the interactions between the current PJM capacity market proceeding in front of FERC and the awarding of ZECs (BPU Question 17). This section outlines the impact ZECs can have on wholesale markets, but also enumerates the risks of awarding ZECs in the context of uncertainty surrounding the outcome of the current PJM proceeding in front of FERC and the additional costs this could entail for New Jersey electricity customers.

IV. NUCLEAR RESOURCES IN NEW JERSEY CAN COVER THEIR GOING FORWARD/AVOIDABLE COSTS PLUS COVER PART OF SUNK COSTS AND RETURNS ON INVESTMENT

A. What specific metrics should the Board utilize to determine if a nuclear power Unit ("Unit") should be deemed eligible for ZEC credits? (BPU Question 1)

39. This is the first question poised by the BPU in its September 11 Notice and ***it is the absolute threshold question*** before the BPU. The only metric that can reasonably be measured is whether or not a nuclear facility will be able to cover its avoidable or going forward costs. Level of profits over and above this are not relevant as the units would remain in commercial operation so long as they can cover their going forward/avoidable costs. Any revenues above and beyond going forward/avoidable costs contributes to covering sunk costs and return on investment. If the resource is able to cover its going forward/avoidable costs and contribute revenues toward sunk cost recovery and return on investment, then is the economically rational choice to continue to keep the unit in service, and it should not be eligible to receive ZECs.

40. Going forward or avoidable costs include items such as fixed operating and maintenance costs ("fixed O&M") and various other expenses that do not change with unit output such as labor costs, consumable materials, administrative costs, property taxes and insurance, and other such similar costs that must be incurred in order to keep a generating facility in commercial operation, but can be avoided if the facility shuts down. Some capital expenditures that have not yet been incurred, but would need to be spent in the future to stay in commercial operation, can also be considered going forward or avoidable costs.

41. Capital or investment costs, once they are incurred, become sunk costs. These costs are considered sunk since they can no longer be avoided...the money has already been spent. Another example of a sunk cost is debt service. Regardless of whether a generation resource remains in commercial operation, the debt service needs to be maintained (unless the resource files for bankruptcy).

42. In a competitive market environment, the optimal offer in the capacity market is offering at the net going forward/avoidable costs. These costs include items such as fixed O&M, certain administrative overhead costs, property taxes and insurance, and plant labor costs.

43. A simple example shows why all an existing resource must do is cover its net going forward/avoidable costs. Suppose the generation facility in question has net going forward/avoidable costs of $100/MW-day after accounting for net energy market revenue. If the capacity price is $174/MW-day, as it has been on average in the EMAAC LDA over the last four auctions,[17] the generation resource covers its net going forward/avoidable cost and earns $74/MW-day to cover any sunk capital costs, cost of debt financing, and a possible return on investment. In such a case it pays the generation

[17] *See Supra* note 12.

resource to remain in commercial operation even if it is not earning the returns it would like to receive. What would happen if the generation resource shuts down? It could avoid all of its going forward/avoidable costs, but then it would also lose the opportunity to earn $74/MW-day to cover its sunk costs plus any return.

44. For the sake of example, suppose the sunk costs plus a return that the resource wishes to recover each year is $120/MW-day. If the unit remains in operation it covers nearly 62% of its sunk costs plus return, but if it shuts down, it covers nothing. The economically rational course of action is to remain in commercial operation even if the resource is not earning the returns it wants. Any threat to shut down under conditions such as those in this example is simply not credible because the resource owner would not be carrying out its fiduciary responsibility to its shareholders and would be saddling shareholders with losses they would otherwise not have to bear.

B. Costs and Performance of New Jersey Nuclear

45. In New Jersey there are three nuclear units: Salem 1 and 2 and Hope Creek 1, with a total nameplate capacity of 3518 MW. On average across these three units, they have going forward/avoidable costs of $155.27/kW-year.[18] Translating this into units used by PJM, this translates into $425.40/MW-day of installed capacity ("ICAP"). Applying a class average forced outage rate for nuclear in PJM of approximately three percent converts the going forward/avoidable costs into unforced capacity ("UCAP") terms of $438.55/MW-day UCAP.[19]

[18] *See supra* note 10.

[19] Monitoring Analytics, LLC, *2017 State of the Market Report for PJM, Volume 2: Detailed Analysis*, March 8, 2018, Chapter 5, Table 5-33 at 280. Available at http://monitoringanalytics.com/reports/PJM_State_of_the_Market/2017/2017-som-pjm-sec5.pdf. The

46. The nuclear industry often translates their costs into a dollars per megawatt-hour value. Over the past four calendar years (2014-2017) the New Jersey nuclear units combined to operate at an 88 percent capacity factor on average that includes refueling outages every two years.[20] At this average capacity factor, the New Jersey nuclear units the going forward/avoidable costs translate to $20.14/MWh.[21]

47. According the Nuclear Energy Institute, fuel costs for nuclear units in the United States averaged $6.76/MWh in 2016.[22] According to work done by Sargent & Lundy for the EPA as an input to the IPM to model EPA policy outcome, this figure was stated as a historic average of $49/kw-year.[23] Taking the Sargent & Lundy figure, and converting it into $/MWh at the New Jersey nuclear capacity factor translates to $6.36/MWh. The simple average of these two reported figures is $6.56/MWh and that is the figure that will be used going forward.

48. Overall, the costs that need to be covered are the going forward/avoided costs and the fuel costs. Together, assuming the New Jersey nuclear units continue performing as they have at an 88 percent capacity factor on average, the costs of these units is $26.70/MWh. Given the nuclear industry has been trimming costs over time and the cost of nuclear fuel have come down in recent years, no inflation of these cost is assumed in the near future.[24]

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most recent forced outage rate was just below 1 percent, but historically this figure has been around 3 percent.

[20] *See supra* note 10 regarding EIA 923 data from which the capacity factor was determined.

[21] If the average capacity factor were to increase to 90 percent, then this value would be $19.69/MWh.

[22] Nuclear Energy Institute, *Nuclear Costs in Context 2017*, August 2017, at 3. Available at https://www.nei.org/CorporateSite/media/filefolder/resources/reports-and-briefs/nuclear-costs-in-context-2017.pdf.

[23] *See supra* note 10 regarding Sargent & Lundy study for the US EPA.

[24] *See supra* note 22.

C. Projected Energy Market Revenues for 2019 and Beyond

49. Generating resources operating in PJM earn revenues through a combination of energy market and capacity market participation. What matters for resources to continue in commercial operation is for projected revenues to exceed going forward/avoidable costs to contribute at least to the recovery of sunk costs and contribution toward returns on investment.

50. Projected energy prices that can be earned by the New Jersey nuclear units can be estimated from the forward curves for power in PJM as published by the Intercontinental Exchange ("ICE").[25] ICE supports futures trading at a variety of locations within the PJM footprint, with the most liquid of these points being the PJM Western Hub that aggregates points in Maryland and east central Pennsylvania.[26] It also quotes prices for Eastern Hub which had points in New Jersey, eastern Pennsylvania, and the Delmarva peninsula.[27]

51. From these forward curves, the projected average yearly energy prices for the Eastern Hub, as shown in Table 1, are no lower than $29.71/MWh through 2023 and continue to rise back above $30/MWh after 2025.[28]

Table 1: Projected Average Annual Prices at PJM Easter Hub from ICE Forward Curve

	Average Prices
2019	$34.68
2020	$32.61
2021	$30.76

[25] *See supra* note 11.

[26] *See* http://pjm.com/~/media/markets-ops/energy/lmp-model-info/lmp-hub-definitions.ashx.

[27] *Id.*

[28] *See supra* note 11. I have not addressed the basis differential between Eastern Hub and Salem and Hope Creek as there are no forward price curves or trading at specific busses. And as the forward curves are showing, even the basis differential is changing in the future such that past basis may not be relevant to looking at forward curves with new transmission and gas pipelines going into service.

2022	$29.83
2023	$29.71
2024	$29.94
2025	$30.55
2026	$31.26
2027	$32.01
2028	$33.44

52. Given projected going forward/avoidable cost of the New Jersey nuclear units, they will already cover all of their going forward/avoidable costs in the energy market alone if the units continue operating at their average annual capacity factor of 88 percent, and have money remaining to contribute to returns and covering sunk costs.

D. Projected Capacity Market Revenues

53. The PJM Capacity Market is a three year forward market for capacity to be delivered for a year beginning June 1 and ending May 31 of the following year ("Delivery Year"). PJM has already run Base Residual Auctions ("BRA") for Delivery Years out through 2021/2022 with the next scheduled BRA for 2022/2023 slated now for August 2019.[29]

54. The New Jersey nuclear units are located in the EMAAC LDA which encompasses all of New Jersey, far eastern Pennsylvania, and the Delmarva Peninsula. Historically, the EMAAC LDA has cleared at capacity price above the wider RTO price due to having higher peak loads relative to generation resources and historically limited transmission import capability into the region. Over the last 4 years the price has fluctuated but the average price over the past four BRAs has been $174.70/MW-day UCAP.[30] In ICAP terms for New Jersey nuclear units this is $169.46/MW-day ICAP to cover any remaining

[29] 164 FERC ¶ 61,153, August 30, 2018.

[30] See supra note 12.

going forward/avoidable costs and to contribute toward the recovery of sunk costs and return on investment.

55. Table 2 shows the last four years of capacity price in EMAAC. A reasonable projection of capacity market revenues beyond the 2021/2022 Delivery Year would be the average price over the past four BRAs absent any other information.

Table 2: Capacity Prices in EMAAC Over the Past Four BRAs with a Translation to $/MWh

Delivery Year	Price ($/MW-day UCAP)
2018/2019	$225.42
2019/2020	$119.77
2020/2021	$187.87
2021/2022	$165.73
Average	$174.70

56. Again, as the nuclear industry had done, converting this capacity price to a $/MWh revenue figure is straightforward by first converting the capacity price to an annual value of capacity since capacity prices span two different calendar years, then to an ICAP value, then applying the capacity factor and converting to $/MWh of energy produced. This exercise is summarized in Table 3 below.

Table 3: Capacity Revenues Converted to $/MWh for a Calendar Year

	UCAP ($/MW-day)	ICAP ($/MW-day)	$/MWh
2019	$163.48	$158.57	$7.51
2020	$159.70	$154.91	$7.33
2021	$174.89	$169.64	$8.03
2022	$170.99	$165.86	$7.85
2023 and beyond	$174.70	$169.46	$8.02

E. Net Margins for New Jersey Nuclear Units Show Revenues Well Above Costs and Large Contributions toward Sunk Costs and Returns

57. Putting the information about costs and revenues as shown in Table 1 through 3 together shows that projected New Jersey nuclear unit revenues exceed their going forward/avoidable costs and that they will not shut down under any circumstance. All of

this is summarized in Table 4. In short , the last column in Table 4 is the punchline. There are projected to be significant contributions to returns and there is no incentive for the New Jersey nuclear units to retire. Based on publicly available data and reasonable assumptions about the market, the New Jersey nuclear units are highly profitable through 2023 and face no imminent threat of retirement.

Table 4: Projected Revenues vs. Costs on a $/MWh basis and Contribution to Returns

	Energy Price ($/MWh)	Capacity Price ($/MWh)	Total Revenue ($/MWh)	Fuel plus Avoidable Cost ($/MWh)	Contribution to Returns ($/MWh)
2019	$34.68	$7.51	$42.18	$26.70	$15.48
2020	$32.61	$7.33	$39.95	$26.70	$13.25
2021	$30.76	$8.03	$38.80	$26.70	$12.10
2022	$29.83	$7.85	$37.68	$26.70	$10.98
2023	$29.71	$8.02	$37.74	$26.70	$11.04
2024	$29.94	$8.02	$37.96	$26.70	$11.26
2025	$30.55	$8.02	$38.57	$26.70	$11.87
2026	$31.26	$8.02	$39.28	$26.70	$12.58
2027	$32.01	$8.02	$40.03	$26.70	$13.33
2028	$33.44	$8.02	$41.47	$26.70	$14.77

V. CARBON DIOXIDE EMISSIONS CAN BE AVOIDED OR REDUCED AT A LOWER COST THROUGH ECONOMIC NEW ENTRY OF COMBINED CYCLE AND RENEWABLE RESOURCES THAN PROVIDING ZECS TO NUCLEAR RESOURCES

58. Ostensibly, the reason for wishing to subsidize the New Jersey nuclear resources through the award of ZECs is that they will retire absent the ZECs and that New Jersey values the avoidance or reduction in carbon dioxide ("CO_2") emissions to combat climate change. The policy goal of avoiding or reducing CO_2 emissions is a reasonable and rational policy, but New Jersey should ensure that it avoids or reduces emissions in as cost-effective a manner as possible. As shown above, the New Jersey nuclear units are projected to easily cover their going forward/avoidable costs and earn revenues to

contribute toward suck cost recovery and return on investment. So, the prospect of avoiding an increase in CO_2 emissions due to the retention of the New Jersey nuclear units seems assured since they can cover going forward/avoidable costs absent ZECs.

A. If the New Jersey Nuclear Units Remain in Operation as Indicated, the Cost of ZECs Will Not Result in Further Avoidance or Reduction in CO_2 Emissions and the Money will Raise Rates for New Jersey Customer and Profits to Nuclear Owners without Environmental Benefit (Related to BPU Question 1)

59. The level of the subsidy laid out in the legislation is $0.004/kWh or $4/MWh of energy. For a household that uses 1000 kWh per month, their bill would increase by $48/year. Over all the load projected in New Jersey according to PJM, the subsidy will amount to just over $300 million per year in the first five years of the program.

60. If the New Jersey nuclear units continue to perform as they have at an 88 percent capacity factor, these units would produce just over 27.1 million MWh or energy per year so that each ZEC would be worth $11.06/MWh. And these dollars would just flow directly to the owners of the nuclear units that are already earning sufficient revenues to cover going forward/avoidable costs. New Jersey's nuclear plants are making money - - consumers should not be forced to make them more money.

61. Since the value of the ZECs would not result in any changed behavior, as the retirement threat is not credible give the above analysis, there would be no added environmental benefit to show for the $300 million increase to New Jersey electricity customers.

B. Even Assuming New Jersey Nuclear Units Would Retire Absent ZEC Payments, It is More Cost Effective to Simply Let the PJM Market Work to Bring in New Efficient Combined Cycle and Renewable Resources to Reduce Emissions.

62. It is no secret that new, highly efficient combined cycle natural gas and increasingly cost competitive renewable resources have been entering the PJM market over the last decade due to a combination of factors. These include: 1) technological innovation in natural gas

production in the Marcellus and Utica shale basins that have resulted in extremely low natural gas prices; 2) technological innovation that has increased the heat rate efficiency of combined cycle units that reduce their running costs and emissions profiles; 3) economies of scale in combined cycle and renewable technologies that allow larger, higher capacity machines to be built at the same overall cost and reducing the cost/kW of capacity; and 4) increased experience in bringing these new resources on line reducing installation costs.

63. These new combined cycle gas units have heat rates as low as 6200 Btu/kWh (6.2 mmBtu/MWh) which implies a CO_2 emissions rate of .363 tons of CO_2/MWh or about two-thirds lower than a typical coal unit. And these new resources are being built regardless of CO_2 policy or price and consequently emissions reductions from new gas units displacing higher emitting resources happens at no additional cost. In the language of environmental economics or markets, the marginal, cost of abatement is zero.

64. In reality, the marginal CO_2 emissions rate in PJM for 2017 was reported by PJM as being 1,374/MWh (0.687 tons/MWh). The new, efficient combined cycle units are nearly half that rate so that one MWh of new combined cycle gas would displace 0.324 tons of CO_2 at no additional cost.

65. In contrast, if ZEC payments were required to keep the New Jersey nuclear units in service, which they are not, the implied marginal cost of CO_2 abatement would be $16.10/ton attributable to ZEC payments alone.[31] Clearly this is not as cost-effective as new combined cycle gas at the margin.

[31] This is calculated at $300 million, divided by New Jersey annual nuclear output of 27.1 million MWh and divided by the marginal PJM CO_2 emissions rate.

66. But taking this hypothetical even further, if the New Jersey nuclear units would ***retire but for*** the ZEC policy designed to avoid CO_2 emissions, not only could the cost of ZECs be avoided, but so could the going forward/avoidable costs not be incurred but for the policy. Accounting for these costs raises the cost of abatement to $45.42/ton. This is nearly triple the social cost of carbon as determined several years ago and used in the Illinois ZEC legislation.[32]

67. Moreover, the PJM load forecast for New Jersey zones shows annual total energy consumption declining by 2.16 million MWh between 2018 and 2023 which further reduces emission at lower costs, assuming this is driven by non-policy trends, than through ZEC payments.

68. Going back to the threshold question asked by the BPU, "What specific metrics should the Board utilize to determine if a nuclear power Unit ("Unit") should be deemed eligible for ZEC credits?" A secondary metric is the cost effectiveness of CO_2 emissions reduction and whether more cost-effective means of carbon abatement are available whether through new cost-effective renewables or combined cycle gas resources.

VI. THE BPU SHOULD CHOOSE THE MOST COST EFFECTIVE RESOURCES TO MINIMIZE THE COST OF EMISSIONS REDUCTION OR AVOIDANCE FROM NUCLEAR RESOURCE FROM WITHIN THE PJM FOOTPRINT

A. Assuming that any Unit is deemed eligible to receive ZECs by the Board, in ranking eligible Units (N.J.S.A. 48:3-87.5(d) through (g)), how should the Board factor each Unit's potential to maximize benefits to New Jersey and to minimize the

[32] Illinois General Assembly, Public Act 99-0906 ("Future Energy Jobs Act" or "FEJA"), November 30, 2016, available online at http://www.ilga.gov/legislation/publicacts/99/PDF/099-0906.pdf. The FEJA was signed into law by Governor Bruce Rauner on December 7, 2016. This value is set at $16.50/ton.

rate impact on the ratepayers of New Jersey's electric distribution companies? (BPU Question 13)

69. The evaluation of ZECs should be over three simple dimensions: 1) Are the nuclear resources going to retire but for the ZEC payments and thus the ZECs payments result in emissions avoidance? 2) Are there any other avenues of emissions avoidance or reductions that could be undertaken at zero cost, thus avoiding the needs for ZECs altogether? and 3) What would be the lowest cost set of nuclear resources to provide ZECs to minimize the cost to New Jersey electricity customers?

70. The rankings take on a variety of steps. Nuclear resources that can cover their going forward/avoidable costs would not be eligible for ZECs as they will not retire and thus do not need ZECs to continue avoid CO_2 emissions.

71. The second step is an examination of other zero cost emissions reduction strategies because they would happen anyway without any ZEC support. Two steps mentioned above is the entrance of new combined cycle gas and cost-effective renewable resources. Other state RPS policies and Federal tax policies are driving new renewables beyond the question of nuclear plant retirements. There may be other means by which to reduce emissions at zero cost.

72. The last step is, conditional on there not being enough zero cost emissions reductions or avoidance, how much avoidance is needed, and the award of the lowest cost ZECs to nuclear resources that would retire, but for the ZECs.

B. Assuming that any nuclear power plant is deemed eligible to receive ZECs by the Board, in ranking eligible Units (N.J.S.A. 48:3-87.5(d) through (g)), how should the Board factor the Unit's physical location (in-state, out-of-state, and specific venue) within PJM? (BPU Question 14)

73. The question from the BPU regarding the unit's physical location is a good one. New Jersey is in the PJM market, so all eligible resources interconnected within PJM should

be able to participate in the BPU process and receive ZECs. There are two main reasons for this: 1) electric interconnection, and 2) CO_2 as a non-localized pollutant.

74. Electrically, all generation resources interconnected on the PJM system are by definition deliverable to the PJM load. Generators pay for interconnection and upgrade costs to ensure deliverability when they interconnect to the system. So, any facility in PJM can in theory deliver energy to PJM load in New Jersey.

75. From an emissions perspective, avoided CO_2 emissions at any location go toward reducing or avoiding the impacts of climate change. This is true if emissions were to be avoided in New Jersey, or in Ohio or Illinois or Pennsylvania since climate change is a global phenomenon.

76. Moreover, from the perspective of particulate matter ("PM"), sulfur dioxide ("SO_2") and nitrogen oxides ("NO_x") the location does matter to some extent. If anything, avoiding CO_2 emissions upwind from New Jersey, may actually have better environmental outcomes for New Jersey air quality due to the air transport of emissions other than CO_2 avoidance directly in New Jersey. Plus, there are already nuclear resources with announced retirements upwind from New Jersey that could possibly meet the criteria outlined in the legislation requiring a showing of financial distress.[33]

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[33] Nuclear resources that have announced retirements already in PJM include Three Mile Island and Beaver Valley in Pennsylvania and the Davis Besse and Perry stations on Lake Erie in Ohio.

VII. ANSWERS TO BPU COST OF CAPITAL QUESTIONS

A. Referencing N.J.S.A. 48:3-87.5(a) and (e)(3), how should the risk-adjusted cost of capital for a Unit be determined? (BPU Question 3)

77. The cost of capital, including the cost of debt and the cost of equity for the owners of generation resources should already reflect the operational and market risks faced by the generation owners. If these generation owners face relatively low costs of debt and equity, then investors perceive these resources to be relatively low risk. Conversely, if the owners of these resources faced significantly higher operational or market risks, then they would be faced with higher costs of debt or equity. Information on generation owners such as credit ratings, and asset betas for publicly traded companies provide a window into the kind of risks the market perceives with these companies and their generation fleet and overall business.

78. In short, there is no reason at all to "risk adjust" the cost of capital as these risks should already be "baked into the cake" that determines costs of debt and equity faced by the generation owners. The act of "risk adjusting" the cost of capital as envisioned in the statute would be akin to allowing for the double recovery of capital costs and returns associated with these risks. I know of no regulator that would allow such double recovery of costs, and I would expect the NJ BPU to not allow such cost recovery.

79. The idea of a risk adjusted return on equity ("ROE") or cost of capital implies that the ZECs are there to ensure a certain level of profit. Such a change in philosophy would effectively convert the New Jersey nuclear resources from merchant resources that take on all the downside AND upside risks of market participation borne by the generation owners, to old-fashioned, regulated, rate-of-return facilities that shift all the down-side risk to New Jersey consumers while the shareholder keep all the upside benefits. At least

in the "old days" of rate-of-return regulation captive customers could get all the benefits of the upside risk in the form of reduced rates. Ironically, the mere presence of the subsidies in the form of ZECs provides a financial floor, effectively reduces the downside risk while leaving the merchant generation owner to capture the upside benefits of good market outcomes and superior operational performance. . It's a classic head's I win, tails you lose scenario.

80. With ZECs, New Jersey consumers only get stuck with the bill when it is bad for them. In essence, it is illogical to consider "risk adjusting" the cost of capital when ZECs reduce essentially all downside risk and keep the upside risk. Or stated another way, ***ZECs socialize the losses from downside risk*** ("Tails, you lose!") ***while privatizing the gains to upside benefits*** ("Heads, I win!"). The BPU would wisely consider that ZECs reduce risk, and this if any risk adjustment is to be considered with ZECs, it should be "risk adjusting downward" ROEs and the cost of capital.

B. Referencing N.J.S.A. 48:3-87.5(a), the Act requires the Board to consider the cost of "operational risks" and "market risks" for Units. What information should or should not be included in these two categories? (BPU Question 4)

81. Merchant generation owners, including the owners of the New Jersey nuclear resources, take on the full operational risk which includes outage risk due to poor maintenance practices, performance risk during emergency conditions under PJM's Capacity Performance construct, or simply performance risk during periods of high prices among or other operational risks. Operational risks may also include having to incur additional going forward costs to make unexpected repairs and investments to ensure energy output and meeting all mandated safety requirements. Market risks include changes in supply-demand fundamentals that include technological changes and innovations (for

themselves or competitors), changing patterns of demand, and entry or exit decisions or competitors. But operational and market risks should be borne by the merchant generation owners as they are in the best position to manage these risks. As discussed above, these risks are already included in the merchant ROE and cost of capital, and asking for consideration of them again, separately, results in double counting of the risk and over-paying on returns.

82. But at a more fundamental level, one of the main tenets behind wholesale market restructuring was to shift risk to those parties best able to manage that risk. In the old regulated world, the risk of plant performance and market risks were borne entirely by the captive customers of the regulated utility. Captive customers, being dispersed and not being expert in understanding how to operate such complex facilities had no way in which to understand the market and operational risks, let alone find ways to manage those risks. And yet, the owners of these facilities, regardless of performance, could still earn the regulated returns to capital on those assets. The result of such risks being borne by captive customers, especially with respect to nuclear plant operations was poor availability and low capacity factor performance to go along with high costs.

83. Since the advent of restructuring, with the risks of performance shifted to the owners of these nuclear assets, performance improved markedly.[34] But now, with nuclear resources going back and looking for regulated returns should risks run against them, will return New Jersey to the "bad old days" of little incentive for maintaining superior performance

[34] Davis, Lucas W. and Wolfram, Catherine, "Deregulation, Consolidation, And Efficiency: Evidence From U.S. Nuclear Power", *American Economic Journal: Applied Economics*, Vol. 4, pp. 194-225, 2012. They determine that nuclear units subject to competitive pressures have improved availability and shortened their refueling outage times leading to a 10 percent gain in operating efficiency.

for their resources. But this return to poor incentives for good performance has negative spillover effects that go beyond these resources. If the current PJM market design remains in place, or shifts to what PJM has proposed, then this has the effect of pushing out more innovative and efficient resources, thus reducing the overall incentives in the market place to bring innovative, lower cost resources to market that would benefit electricity customers. This can be seen by the displacement of otherwise economic resources from the market and through the reduced prices paid to resources in the market due to the presence of these subsidized resources.[35]

VIII. INFORMATION AND DATA SUBMISSIONS ACCOMPANYING REQUESTS FOR ZECS SHOULD BE RIGOROUS, DETAILED, AND OPEN TO PUBLIC INSPECTION WHERE POSSIBLE

A. Referencing N.J.S.A. 48:3-87.5(a) and (e)(3), what specific financial information should the Board request that Units applying for the ZEC program provide? What forecasts, projections, or estimates should be included, or disallowed, as part of a ZEC application process? What factors and expenses should the Board consider in analyzing a Unit's avoided costs if the Unit retires? (BPU Questions 4, 8, 11)

84. All unit specific information regarding costs and projected revenues and risk mitigation information and strategies for the New Jersey nuclear units should be provided not only to the BPU, but they should also all be subject to public inspection. If information is considered to be commercially sensitive, then any party in the public domain that has an interest should be permitted to view this information and respond to it under the appropriate confidentiality protections. All conditions of the New Jersey nuclear units, maintenance and forced outage history should be provided.

[35] *Initial Brief of the Electric Power Supply Association,* Affidavit of Paul M. Sotkiewicz, Ph.D. in Docket No. EL16-49, ER18-1314-000, ER18-1314-001, EL18-178, October 2, 2018. This affidavit is also included as Attachment A to these comments.

85. A full accounting must be provided of going forward costs such as fixed operations and maintenance costs (fixed O&M), labor costs, administrative costs, insurance, property taxes, consumables such as water, lubricants or other materials, avoided capital costs based on projected capital expenditures, refueling costs, or any other costs that could be considered necessary to keep the New Jersey nuclear resources in commercial operation but could otherwise be avoided if these resources retired. Categories of such costs can be found in the PJM Tariff in Attachment DD, Section 6.8. The owners of the New Jersey nuclear plants should be required to explain openly and in public why and how their submitted cost data differs from publicly available costs such as those as reported in FERC Form 1 EPA data, and the Nuclear Energy Institute ("NEI"), especially if their costs are higher than those publicly reported.

86. All revenue projections including hedges, relevant fuel price forecasts, relevant PJM forward power market curves or price forecasts being used by the nuclear unit owners to project their profitability going forward also must be provided. The unit owners should also be required to provide multiple forward curve and price forecast estimates and explain why they have chosen the forecast used to determine their need for ZECs, and why these are more reliable than relying on published forward curves upon which market participants who take actual financial positions rely upon for risk mitigation. In the showing of forecast power prices, the New Jersey nuclear owners must be required to show the underlying natural gas price forecasts, load forecasts, and forecasts of entry and exit of resources in the PJM market and explain how and why these differ from publicly available forecasts and forward curves where available.

87. Furthermore, New Jersey nuclear resource owners must be required to show publicly why their current stated cost of capital, as determined through known issuances of debt and cost of equity as determined through accepted models such as the Capital Asset Pricing Model ("CAPM") or Discounted Cash Flow ("DCF") models for capital already invested is insufficient to cover risks for sunk capital investments. As a practical matter, if investors were willing to receive compensation for sunk investments already made, there is no reason to make any adjustments on returns as risks were already accounted for in this cost of capital as discussed above in my statement.

88. For future investments going forward, the New Jersey nuclear resource owners must provide an accounting of future capital expenditures and why those prospective investments require higher returns than sunk investments, and why these returns should be higher than standard merchant investment. As part of such a showing, if nuclear owners believe they must make significant capital expenditures to keep the facilities in commercial operation, they should be required to show why these are typical levels based upon other comparable units capital spend and on models of costs spent going forward to prove these are not anomalous costs that could otherwise be avoided by shutting down.

B. What other information, confidential or not, should the Board request to fully evaluate whether or not a Unit is at risk of closure due to financial hardship? What information about parent or affiliate companies of the nuclear power plant should be requested for the Board to holistically consider the Unit's financial condition? (BPU Questions 9, 12)

89. Full financial disclosure including assets, liabilities, income, and cash flow statements going back 10 years, for the individual business units of the New Jersey nuclear resource owners with a special focus on the nuclear resources themselves should be required. Additionally, projected assets, liabilities, cash flow, and income statements for the next 10 years with and without ZEC payments should also be required. The BPU should

consider financial hardship to be a showing of multiple consecutive years of actual losses or negative cash flows that would need to be made up from the other business units of the nuclear owners historically or prospectively. Financial hardship cannot mean the resources owners are not making a "high enough return," but it must mean actual financial losses over multiple years.

90. The BPU should also require the New Jersey nuclear resource owners provide all statements made to all state and Federal regulators regarding the New Jersey nuclear resources regarding their profitability, need for capital expenditures, or safety issues. These statements would likely include but no be limited to presentations to financial analysts at major banks, the Securities and Exchange Commission ("SEC"), Nuclear Regulatory Commission ("NRC"), the Federal Energy Regulatory Commission ("FERC"), presentations to legislative bodies, presentations to industry groups, and other like material. The BPU should be looking for a pattern of consistent or inconsistent statements in the body of evidence this information can provide regarding any impending financial hardship. In addition, the BPU should review all prior capacity market bids for any units seeking to secure a ZEC. The BPU can request and the PJM must provide all prior capacity market bids. With this information, the BPU can ascertain the asset owners view of its going forward costs as reflected in the capacity market bids. As mentioned before, any units that have cleared the capacity market should not be able to receive a ZEC during any period in which that unit has a capacity commitment as those units are already receiving their going forward costs as reflected in their capacity bid.

91. New Jersey nuclear resource owners should provide the credit rating and stock quotes and industry analysis of the parent company (and all individual business units if

available) prior to announcing the New Jersey nuclear units may retire, post "stress" announcement, and post ZEC passage to gauge how this legislation was seen by the investment community across a variety of metrics. Furthermore, any similar information that may be applicable to other states such as Illinois and New York should also be provided.

92. If the New Jersey nuclear owners have ownership shares in other facilities in other states, information on the financial and physical performance of those resources relative to the New Jersey nuclear resources should be provided as a benchmark as to the wisdom of awarding ZECs in the case where these benchmark resources are better or worse performers than the New Jersey nuclear resources. If the New Jersey nuclear resources are deemed to be better performers, then this would indicate little need for additional money through ZECs. If New Jersey nuclear resources are poorer performing, it can call into question the wisdom of providing additional money through ZECs under the philosophy of, "why throw away good money after bad?"

93. Finally, New Jersey nuclear resource owners should provide analyses of other ZEC-like subsidies showing customer rate impacts, wholesale market rate impacts in both energy and capacity, and the cost of emissions avoidance relative to other means to avoid emissions. Such comparisons should highlight the key assumptions driving those results.

94. All information about hedges, conditions of the units, maintenance and forced outage history. Also, the credit rating of the parent company prior to announcing the units may retire, post "stress" announcement, and post ZEC passage. Do the parents and affiliates have other poor performing resources financially or otherwise, cost basis of other nuclear

plants in their fleet compared to the NJ units, estimated rate impacts of other subsidies in other states such as IL and NY.

IX. CONSIDERATION OF OTHER POLICY ISSUES SUCH AS RELATED ENVIRONMENTAL OUTCOMES SHOULD BE NARROWILY FOCUSSED WHILE OTHER POLICY ISSUES REALISTICALLY SHOULD NOT BE CONSIDERED AS THEY ARE BEYOND THE SCOPE OF ELIGIBILITY AND COST EFFECTIVENESS

A. Referencing N.J.S.A. 48:3-87.5(e)(2), what information should be provided to the Board to demonstrate that the Unit makes a significant and material contribution to the air quality in the state? What information should be provided to demonstrate that the Unit minimizes harmful emissions that adversely affect the citizens of the state? What information should a Unit provide to demonstrate that, if the Unit were to be retired, the retirement would significantly and negatively impact New Jersey's ability to comply with State air emissions reduction requirements? (BPU Question 5)

95. Nuclear owners should be required to provide both market simulation modeling combined with emissions air shed modeling with and without the nuclear resources to make a showing of any other significant harm. It is important to understand that in PJM if nuclear resources in New Jersey retire, air emissions may not rise in NJ since resources in other PJM states may make up the difference in generation output. With regard to carbon dioxide emissions, a one MWh reduction in nuclear output (one MWh increase in nuclear output) does not results in a one ton increase in CO_2 emissions (one ton decrease) as shown by PJM published marginal emissions data which shows that the marginal CO_2 displacement is only about two-thirds of a ton (0.687 tons). If ZECs are to represent a reduction in CO_2 emissions, then one MWh of nuclear output should earn less than one ZEC.

B. Referencing N.J.S.A. 48:3-87.5(e)(4), the Act requires that eligible Units certify that they do not receive any direct or indirect payment or credit under a law, rule, regulation, order, tariff, or other action of this State or any other state, or a federal law, rule, regulation, order, tariff, or other action, or a regional compact, despite its reasonable best efforts to obtain any such payment or credit, for its fuel diversity, resilience, air quality, or other environmental attributes that will eliminate

the need for the Unit to be retired. What should the Board interpret fuel diversity, resilience, air quality, and other environmental attributes to include? (BPU Question 6)

96. It is essential the BPU understand there are no metrics or standards regarding fuel diversity or so-called resilience. With respect to fuel diversity, the PJM footprint has become more fuel diverse over the past decade, going from a coal heavy portfolio of generation to a more evenly balanced portfolio between nuclear, coal, gas, and renewables. It has been the underlying changes in economic and market conditions that have led to this diversity with improvements in gas and renewable costs along with the shale gas revolution that has made gas the low cost fuel for power generation. As a consequence, fuel diversity is recognized implicitly within the PJM wholesale energy and capacity prices and no other recognition needs to be made.

97. The dictionary definition of resilience is the ability to recover or bounce back from a significant event. In fact, industry reliability standards are premised directly on resilience with the ability to meet changing demand, loss of a large generator or transmission line, supporting voltages to maintain transmission reliability, or meet extreme peak loading conditions during extreme weather. There are already markets for regulation and frequency response, reserves, and capacity to ensure the system can recover and ride through such events without a loss of load.

98. To the extent there are markets or FERC-approved cost-of-service payments for these services, resilience is already recognized in the market through these market and their associated revenue streams. There is no need to recognize any further needed payments beyond what are available in the market.

99. Air quality and other environmental attributes are already recognized with PJM's markets. Generation resources can reflect the costs of emissions allowances in trading

programs that can affect New Jersey for SO_2, NO_x, and CO_2 through the Regional Greenhouse Gas Initiative. And while nuclear resources do not have these specific costs, energy market prices in PJM do account for such costs that are enjoyed by nuclear resources in New Jersey. Other environmental rules such as water discharge rules and permit restrictions, to the extent they affect energy prices or capacity prices will be reflected in PJM energy or capacity prices. The same is also true for costs associated with complying with the MATS for air toxics such a mercury, other heavy metals, and hydrochloric acid emissions. There is no special need to reflect these costs additionally to the costs that are already accounted for in PJM's energy and capacity market prices.

C. Referencing N.J.S.A. 48:3-87.5(i)(3), how should the Board determine the revenue amount received by any selected nuclear power plant in an energy year for its fuel diversity, resilience, air quality, or other environmental attributes from other sources? (BPU Question 15)

100. As just discussed above, there is no need for the BPU to account for such revenues, but to understand that nuclear resources are compensated for these attributes through PJM market prices. To the extent such characteristics raise prices, then nuclear units benefit since they do not incur allowance costs for air pollutants, nor any costs associated with MATS, but market prices are higher due to these environmental policies. And nuclear power can collect money associated with resilience such as resource adequacy or voltage support payments in PJM already.

D. What information about other benefits, subsidies, or tax implications should be provided to the Board as part of a ZEC application? (BPU Question 7)

101. Benefits and costs beyond those over which the BPU has direct authority over should not be considered by the BPU. While the costs of the policy to New Jersey customers and impacts are of the utmost concern, given that the New Jersey nuclear resources are not

rate regulated by the BPU, longer-term financial viability beyond what is required to approve or not approve ZECs is also beyond the BPU's scope of authority.

102. To the extent that New Jersey nuclear owners opt to submit as part of their ZEC application such "extra benefits" such as economic development benefits related to jobs saved, property tax contribution and like metrics, they should be required to make a showing that the costs of the ZEC program do not exceed these benefits on an annual basis. Furthermore, nuclear owners should also then submit analyses showing the impacts on different customers classes and rates impacts as a percentage of income by decile in the income distribution to show the policy does not act as a regressive tax on poor customers.

103. Furthermore, the nuclear owners would then need to provide analyses showing that the rate increase will not harm other economic sectors in New Jersey and not result in a loss of jobs, and resulting tax receipts, that could be significantly greater than the job and tax receipts of keeping jobs at the New Jersey nuclear resources. Finally, the application for ZECs should provide a comparison with respect to saving jobs at the nuclear facilities through ZECs versus a simple policy of taxation and transfers that would keep property tax levels and income levels the same while closing the facilities. All of these analyses in the last two paragraphs can be avoided so long at the nuclear owners do not attempt to assert any other benefits beyond avoided emissions at the lowest cost versus other options.

104. Additionally, it is reasonable for the BPU to request nuclear owners provide evidence that ZEC payments would not result in inefficient cross-subsidies where New Jersey electricity customers are cross-subsidizing consumption in other states, or otherwise

changing the relative prices of power for New Jersey customers relative to customers in the rest of PJM. Not so much about benefits but about other costs. For example, show how much rates in NJ would rise with and without the ZEC, the price implications in other parts of the PJM footprint, the extra cost to the economy in terms of job losses due to higher rates, the cross-subsidization effect of lower rates outside of NJ come to mind.

E. What other relevant factors, such as sustainability or long-term commitment to nuclear energy production, should the Board consider and evaluate? (BPU Question 10)

105. The BPU as a utility regulator should not consider anything beyond its traditional statutory responsibilities. Issues such as environmental impacts or sustainability should be considered by the New Jersey Department of Environmental Protection ("NJ DEP") or the US EPA. Other policies issues surrounding nuclear power and energy are already assigned to the United States Department of Energy ("US DOE") and transcend state boundaries and energy policy and get into national security matters that are beyond the responsibilities and expertise of the BPU.

F. Should the application include/allow voluntary commitments as a condition of approval? (BPU Question 16)

106. The BPU should not allow the inclusion of any voluntary commitments as a condition of approval. This BPU should evaluate the information as it stands under the clear metrics of: 1) nuclear resources receiving ZECs would indeed retire as shown by the inability to cover going forward costs; and 2) cost of effectiveness of ZECs to reduce or avoid emissions relative to other emissions avoidance and reduction strategies that are available. No other metrics should be considered as a condition of approval.

X. PLEASE DISCUSS HOW THE RECENTLY ISSUED FERC ORDER REGARDING THE PJM CAPACITY MARKET, DOCKET NOS. EL16-49, ER18-1314, AND EL18-178, RELATES TO OR OTHERWISE IMPACTS THE

BOARD'S CONSIDERATION OF THE ZEC PROGRAM? (BPU QUESTION 17)

107. The BPU has requested feedback on how the recent FERC Orders on PJM's Capacity Market affects the BPU's consideration of ZECs. As has been shown by multiple intervenors, subsidizing resources that are otherwise not economic leads to the following: 1) An inefficient resources mix where lower cost resources are pushed out of the market; 2) Prices that do not match the actual costs of resources being committed; 3) Prices that are artificially below the competitive level; 4) Inappropriate cost and benefit shifting between market participants; and 5) Potential exercise of buyer-side market power. The affidavits of Dr. Paul M. Sotkiewicz on behalf of EPSA and Dr. Roy Shanker on behalf of P3 are attached to this testimony that go into detail on these issues.

108. But even more important is the risk the BPU is taking with the awarding of ZECs to nuclear resources that actually do not need them. If FERC decides on a remedy similar to a "clean MOPR" or a "CASPR-like solution" it is possible that if the resources that were awarded ZECs were subject to MOPR, but were able to show their actual costs were low enough to still clear in the capacity market absent the ZECs, it would show that the ZECs were not needed to keep the resources in service and would simply result in extra costs to New Jersey customers that did not need to be incurred.

109. Alternatively, if it turns out the nuclear resources that are awarded ZECs were uneconomic without them, and a "clean MOPR" or "CASPR-like" approach were to be adopted by FERC, then the BPU runs the risk of effectively paying twice for capacity. And the Commission has already indicated that it is comfortable as a matter of policy for states to pay twice for capacity. In such a scenario, the most cost-effective course of action for the BPU would be to not award ZECs to avoid this outcome.

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110. This concludes my prepared written testimony.

STATE OF NEW JERSEY
BEFORE THE
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE IMPLEMENTATION OF L. 2018, c. 16 REGARDING THE ESTABLISHMENT OF A ZERO EMISSION CERTIFICATE PROGRAM FOR ELIGIBLE NUCLEAR POWER PLANTS	))))))))	**BPU Docket No. EO18080899**

PREPARED COMMENTS OF PAUL M. SOTKIEWICZ, PH.D.

Paul M. Sotkiewicz, Ph.D., being duly sworn, deposes and states that the statements contained in the foregoing Affidavit of Paul M. Sotkiewicz, Ph.D. are true and correct to the best of his knowledge and belief.

Paul M. Sotkiewicz, Ph.D.

Subscribed and sworn to before me
this 22nd day of October, 2018

ALEJANDRO ELLIS
Notary Public - State of Florida
Commission # FF 940307
My Comm. Expires Dec 28, 2019
Bonded through National Notary Assn

Notary Public for
the State of Florida

State of Florida
County of Alachua

My Commission expires: 12/28/2019

Attachment A

to the

Prepared Comments

of Paul M. Sotkiewicz, Ph.D.

In Docket No. EO18080899

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Calpine Corporation **v.** **PJM Interconnection, L.L.C.**	)))))	**Docket No. EL16-49-000**
PJM Interconnection, L.L.C.	))	**Docket No. ER18-1314-000** **Docket No. ER18-1314-001**
PJM Interconnection, L.L.C.	)	**Docket No. EL18-178-000**
		(Consolidated)

AFFIDAVIT OF PAUL M. SOTKIEWICZ, PH.D.

I. QUALIFICATIONS

1. My name is Dr. Paul M. Sotkiewicz. I am the President and Founder of E-Cubed Policy Associates, LLC ("E-Cubed") and formerly served as the Chief Economist in the Market Service Division of PJM Interconnection, L.L.C. ("PJM"). I have been asked by the Electric Power Supply Association ("EPSA") to submit this affidavit in support of comments in response to the Commission initiated paper hearing on PJM's Reliability Pricing Model ("RPM") in these proceedings.[1]

2. Prior to founding E-Cubed, I worked as a contractor and directly for PJM Interconnection, L.L.C. ("PJM") in Audubon, Pennsylvania from February 2008 until October 2016. In my time at PJM I first served as a Senior Economist until March 2010 and subsequently as the Chief Economist in the Market Service Division until June 2015. From July 2015 until October 2016, I worked as a contractor for PJM under

[1] *Calpine Corp. v. PJM Interconnection, L.L.C.*, 163 FERC ¶ 61,236 (2018) ("June 29th Order").

the Title of Senior Economic Policy Advisor. Prior to joining PJM, I served as the Director of Energy Studies at the Public Utility Research Center ("PURC"), University of Florida from August 2000 until February 2008 and I was an Economist at the Federal Energy Regulatory Commission ("FERC") from September 1998 until August 2000. I have a B.A. in History and Economics from the University of Florida (1991), and an M.A. (1995) and Ph.D. (2003) in Economics from the University of Minnesota.

3. I have 20 years of experience on matters at the intersection of utility regulatory policy, power system economics, and environmental economics. In my current role, I advise private- and public-sector clients on a range of economic issues related to electricity market design and performance, power generation economics, utility regulatory policy, and the economic impacts of state and federal environmental policies. At PJM I provided expert analysis, advice, and support for PJM initiatives related to market design changes in, and performance of, PJM's energy, ancillary service, and capacity markets.

While the Director of Energy Studies at PURC, I provided executive education and expert advice to regulatory staff and utility professionals from around the world in matters such as electric power regulation, market design, incentive regulation, and cost-of-service rate cases and rate design.

As an economist at FERC, I worked on market design issues and filings related to the newly formed ISO/RTO markets concentrating primarily on the New York ISO and the California ISO markets. The entirety of my experience and work history can be found in my CV attached as Attachment A.

A. Specific Experience with Respect to RPM in PJM and other Capacity Markets

4. During my tenure at PJM, I led the PJM team working with the Brattle Group conducting the triennial review (now quadrennial) of the cost of new entry for gas-fired combustion turbines and combined cycle resources in 2011 and 2014 and provided affidavits in support of PJM filings in both cases as shown on my CV. I was also part of the team that developed and implemented the Capacity Performance construct which was heavily influenced by the ISO New England work on what is now Pay-for-Performance in the Forward Capacity Market.

5. As Chief Economist at PJM, I was involved in the helping PJM develop various iterations of the Minimum Offer Pricing Rule ("MOPR") as filed at, and approved by, the Commission. Additionally, I was responsible for the administration of the unit specific MOPR exemption process at PJM, and I also oversaw the application of the Competitive Entry and Self-Supply Exemptions in the previous version of the MOPR that was later vacated in *NRG.*[2] I also worked with PJM staff to update the Avoidable Cost Rate ("ACR") default values used in the mitigation of offers into the PJM RPM Capacity Market.[3]

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[2]For the MOPR in place for the 2011 and 2012 BRA, *see PJM Interconnection, L.L.C.*, 153 FERC ¶ 61,022 (2011) ("April 2011 MOPR Order). For the MOPR in place from 2013 to 2017 until vacatur *see PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,090, (2013) ("May 2013 MOPR Order"), *reh'g denied*, 153 FERC ¶ 61,066 (2015) ("October 2015 MOPR Order"), *vacated & remanded sub nom. NRG Power Mktg., LLC v. FERC*, 862 F.3d 108 (D.C. Cir. 2017), *reh'g denied*, 2017 U.S. App LEXIS 18218 (D.C. Cir. Sept. 20, 2017).

[3] *See* PJM Interconnection, L.L.C. *Revisions to the PJM OATT Attachment DD Avoidable Cost Rates* in Docket No. ER13-529, December 7, 2012. Attachment A to this filing was the analysis underlying the proposed changes.

6. Since Founding E-Cubed I have worked with the Alberta Electric System Operator ("AESO") on the development of their new capacity market construct providing advice on all facets of capacity market design and incentives. I have also provided capacity market advice to the New England Power Generators Association, Inc. (NEPGA) on ISO New England Forward Capacity Market (FCM) including recent changes to the Dynamic De-list Bid Threshold (DDBT) and in support of a complaint on the harm to the FCM construct by allowing resources held for reliability to be treated as price takers.

II. EXECUTIVE SUMMARY: KEY FINDINGS AND CONCLUSIONS

7. The details and facts around the Commission's determination in the June 29th Order are extremely technical in nature and require an extensive development within the body of the affidavit to reach the key conclusions. A summary of key findings and conclusions is presented along with the corresponding logic and intuition. The technical details are presented within the body of the affidavit starting with Section III.

A. The Concept that the Fixed Resources Requirement "Removes" Demand and Supply from the Market is a Myth and is Not Correct

8. One concept the comes up in the June 29th Order regarding the Fixed Resource Requirement ("FRR") as it exists in the PJM Tariff today and the FRR Alternative offered by the Commission is the idea that both supply resources and demand are simply removed from the market. This idea is a myth, it is incorrect, and is discussed in Sections V and VI below.

9. First, demand cannot be "taken out of the market". The demand for resource adequacy in PJM is determined for the entire PJM footprint and load, including load that opts into

FRR under the PJM Tariff today. When a load serving entity ("LSE") opts to use FRR under the PJM Tariff today, it is not taking its demand, or resource adequacy obligation, out of the market. The LSE is choosing to fulfill its portion of the entire PJM resource adequacy need with resources that it owns or has under contract. The FRR Alternative proposed as a remedy suffers from the fallacy.

10. Second, as a practical matter a corresponding amount of supply is "not taken out of the market". Historically, the resources used to satisfy the FRR obligations have had costs that were far above market prices in RPM. The most current price that has been reported for an FRR entity is by American Electric Power ("AEP") operating company Appalachian Power Company ("APCo") at $486/MW-day.[4] This is nearly 3.5 times the market price in RTO for the 2021/2022 Base Residual Auction ("BRA"). Going further back in history, the AEP operating companies had filed rates of $300-$400/MW-day when PJM capacity prices were below $50/MW-day.[5]

11. With the resources being used to meet the FRR load obligation above market prices, it is erroneous to say they are being removed from the market when they were never a part of the least-cost resource mix to meet the PJM resource adequacy obligation. You cannot remove supply from the market when it was not in the market. The FRR Alternative suffers from the same erroneous idea especially as the resources that would be used to meet the FRR Alternative are already assumed to "be out of the market" with costs well above the competitive price level.

[4] This information is available from PJM at https://www.pjm.com/-/media/markets-ops/settlements/frr-lse-capacity-rates/capacity-formula-rate-summary.ashx?la=en.

[5] American Electric Power Service Corporation, PJM Interconnection, LLC, Docket No. ER11-2183, November 24, 2010, Attachment B, at 1.

12. Overall, the idea behind FRR and the proposed FRR Alternative talking demand and supply out of the market is a great sound-bite that gives the illusion of protecting the market but does nothing of the kind. It actually can and does inflict even greater damage to the market.

B. The Effect of FRR and the FRR Alternative is to Artificially Reduce Prices Below Competitive Levels, Inefficient Displace Lower Cost Resources in Favor of Higher Cost Resources, Shifts Costs and Benefits between Market Participants, and Reduce overall Market Efficiency

13. It is a myth the demand for resource adequacy can be removed from the market as described above. However, what FRR does, and the FRR Alternative would do is to remove a portion of the demand from the RPM price formation process and set it aside in another price formation process to be paid by load electing the FRR or FRR Alternative. Imagine taking the demand for FRR or the FRR Alternative out of the RPM Variable Resource Requirement ("VRR") Curve, the demand curve for capacity, and setting it off to the side for a price to be determined in another way.

14. But keep in mind it is a myth to remove the supply from the market because the supply being used for FRR or the FRR Alternative is not part of the competitive, least-cost resource mix. So effectively, nothing changes the supply in the RPM price formation process.

15. The net effect of this is to reduce the demand in the RPM price formation process while leaving the effective supply unchanged. This has the immediate effect of artificially reducing prices in RPM below the competitive level.

16. The next immediate effect is to displace resources that are lower cost and would have been a part of the least-cost resources mix absent FRR or the FRR Alternative. And these resources would be replaced by the higher cost resources selected by the LSE as

part of its FRR election or FRR Alternative election in the case of the proposed remedy. Not only are we switching out low cost resources, but there is a shift in benefits from the displaced resources to the higher cost, subsidized resources.

17. There is also a shifting of market benefits from load overall, the subsidized resources that would not have been part of the competitive, least-cost solution absent the FRR or FRR Alternative. And there is a shifting of market benefits from resources remaining in the RPM price formation, to the load remaining in the RPM price formation.

18. Finally, with all the shifting of costs, there is a loss in overall benefits. The analogy to this is thinking about transferring water from one trough to another. When the transfer of water takes place, water may slosh around spill out on the ground during the transfer to the other trough or the bucket may have a small hole in it leaking water along the way. In either case, the water in the second trough will be less than what you initially started with as water spilled or leaked out in the process. The transfer of benefits between market participants due to FRR and the FRR Alternative is now different.

C. The FRR Alternative Proposed Remedy, Unlike FRR, Is Equivalent to the Mechanism used to Exercise Buyer Side Market Power and Inflicts the Same Damage as Exercises of Buyer-Side Market Power

19. The exercise of buyer-side market power requires the load carrying out the strategy to pay above-market prices to a resource that would otherwise not be a part of the competitive, least-cost resource mix because its costs are above the competitive price. The next part of the strategy is to "bring that resource into the market" by inserting the uncompetitive, high cost resource into the market as if it were a low-cost resource, in all likelihood as a price taker. An extended discussion of this is contained in Section VIII.

20. The effect of this strategy is to expand the supply of "apparently low-cost resources" while holding the demand for capacity fixed. The resulting outcome from the successful execution of this strategy is to 1) artificially suppress prices below their competitive levels; 2) displace more efficient lower cost resources from the resource commitment in favor of the higher cost, but subsidized resources; 3) reduce revenues for remaining resources; 4) shift revenues from lower cost resources to higher costs resources; 5) shift market benefits from producers to consumers; and 6) reduce the overall benefits of the market as the shifting of revenues and consumer benefits results in a loss of total benefits akin to the leaky bucket example.

21. The load executing the buyer-side market power strategy benefits by paying more for some portion of their capacity obligation while driving down the market price, so it pays less for its remaining obligation so that their overall capacity expenditures are reduced.

22. The existence of this strategy is the reason for the MOPR as a mitigation measure against buyer-side market power.

23. The proposed FRR Alternative remedy uses a mechanism that would allow a load to pay for selected resources at above market prices, just as in the execution of the buyer-side market power strategy. But rather than holding demand constant, and inserting the subsidized resources into the market as a price taker, demand is removed from the RPM price formation step and competitive supply is held constant.

24. The effects on market outcomes are identical to an exercise of buyer-side market power. The FRR Alternative would: 1) artificially suppress prices below their competitive levels; 2) displace more efficient lower cost resources from the resource

commitment in favor of the higher cost, but subsidized resources; 3) reduce revenues for remaining resources; 4) shift revenues from lower cost resources to higher costs resources; 5) shift market benefits from producers to consumers; and 6) reduce the overall benefits of the market as the shifting of revenues and consumer benefits results in a loss of total benefits akin to a leaky bucket.

25. Furthermore, the proposed FRR Alternative provides the same incentive to exercise buyer-side market power since the FRR Alternative does not require an "all or nothing" decision on electing FRR as the FRR in the PJM Tariff requires. That is, the FRR Alternative allows a LSE to choose how much load to be in the FRR Alternative while exposing the remaining load to the lower market prices. In contrast, the FRR in the PJM Tariff requires that all load for an LSE face the high cost of paying for uncompetitive resources without the opportunity to benefit from lower market prices. And while the FRR in the PJM Tariff has exactly the same effects on market outcomes, it is not an exercise of buyer-market power. The "all or nothing" requirement provides a disincentive to load to exercise that option since they bear the entire cost of their FRR election while the FRR Alternative removes this disincentive.

26. Effectively, if the Commission were to approve the FRR Alternative remedy, it would be hard-wiring the ability for LSEs to exercise buyer-side marker power into the PJM market design and would be effectively destroying competitive wholesale power market and moving wholesale market back toward re-regulation.

D. PJM's Market Simulations of Different Scenarios from the 2020/2021 BRA Provide Estimates of the Damage that Can be Inflicted on the Market Through the Proposed FRR Alternative

27. Following the conclusion of each BRA, PJM has posted simulation scenarios that add capacity to the market as price takers or capacity out of the market at the bottom of the

supply stack. The purpose of these simulation scenario is to show the effects on market prices and market quantities in each LDA.

28. For the 2020/2021 BRA, PJM ran four scenarios that added capacity to the bottom of the supply stack as price takers: 1) add 3000 MW in RTO outside of MAAC; 2) add 6000 MW in RTO outside of MAAC; 3) add 3000 MW in MAAC; and 4) add 6000 MW in MAAC.[6] Recall, adding price taking capacity that is higher cost than the competitive price leads to identical outcomes to the proposed FRR Alternative, so that these scenarios show the extent of the damage that can be inflicted upon the market.

29. **Table 1** summarizes the results from the scenario runs. More detailed results by LDA can be found in Section IX.

Table 1: Summary Results from PJM 2020/2021 BRA Simulation Scenarios

	3000 MW in RTO	6000 MW in RTO	3000 MW in MAAC	6000 MW in MAAC
Price Reductions ($/MW-Day)				
RTO	$7.21 (9.42%)	$16.53 (21.60%)	$2.03 (2.65%)	$1.53 (2.00%)
MAAC	---	---	$1.04 (1.21%)	$11.04 (12.83%)
Displaced MW				
PJM Total	2743.7 (91.46%)	5412.3 (91.21%)	2927.8 (97.59%)	5945.6 (99.09%)
MAAC	---	---	2981.5 (99.38%)	5458.5 (90.98%)
Revenue Reductions ($millions)				
PJM Total	$276.47 (4.12%)	557.02 (8.30%)	$538.95 (8.03%)	$904.59 (13.48%)
MAAC	---	---	$423.09	$778.41

[6] PJM, *Scenario Analysis for the 2020/2021 Base Residual Auction*, July 296, 2017. Available at https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2020-2021-bra-scenario-analysis.ashx?la=en.

			(14.88%)	(27.38%)
Breakeven Subsidy ($/MW-day above Price)				
RTO	$252.48	$254.35	---	---
MAAC	---	---	$386.39	$355.44

30. **Table 1** shows clearly the decline in price from inserting above-market-cost resources into the market as price takers in both RTO and MAAC locational deliverability areas ("LDAs"). The displacement of lower cost resources by higher cost resources is not quite a 1-for-1 exchange, but it is over 90 percent. For example, in MAAC, adding 3000 MW of price taking capacity displaces over 99 percent of that value. The displacement figure shows the effect of higher cost, but subsidized resources on more efficient lower cost resources that would otherwise be a part of the least-cost mix to achieve resource adequacy. Another way of viewing the displacement results is the mismatch between prices, costs and actual resource commitments the Commission found to be unjust, unreasonable, and unduly discriminatory in the June 29th Order.

31. **Table 1** also shows the decline in revenues to resources, especially in the LDAs where the price taking behavior is undertaken. So not only are lower cost resources displaced by higher cost resources, but also revenues for all remaining competitive resources are eroded far below the competitive values.

32. Finally, the last two rows of **Table 1** show the amount of the subsidy, over the market clearing price, that could be paid in a successful attempt to exercise buyer-side market power. Note that the levels of the subsidy are more than 3 times the actual price in RTO, and 4 to 4.5 times the price in MAAC that could result in a successful exercise of buyer-side market power.

E. There Does Not Exist Any Form of Accommodation of State Policies that Preserves Efficient and Competitive Outcomes and a Clean MOPR is Necessary to Protect Against Buyer-Side Market Power

33. Any accommodation of state policies requires loads in the state pushing the policy to 1) subsidize above market cost resources to make them competitive with lower cost resources; 2) insert those subsidized resources into the RPM price formation mechanisms as price takers, or the load would need to be removed from the RPM price formation step. The first is a classic execution of old-fashioned buyer-side market power. The second is the proposed FRR Alternative. Both lead to the same negative results as explained above.

34. In this case, accommodation hard-wires and accepts buyer-side market power into the PJM Market design. The only defense against this potential is a Clean MOPR which mitigates any subsidized resource to a default going forward cost, or in which a unit specific going forward costs can be determined with the IMM and PJM. Otherwise, state policies can be used as the "trojan horse" by which buyer-side market power will not just be invited into the PJM wholesale market, but openly welcomed.

III. PURPOSE AND ORGANIZATION OF THE AFFIDAVIT

35. One over-arching purpose of my affidavit is to reaffirm and support the Commission's logic that out-of-market subsidies and mismatches between prices and commitments are damaging to the PJM RPM capacity market, as articulated in its rejection of the PJM Capacity Repricing Proposal and the IMM's MOPR-Ex proposals. The second over-arching purpose of my affidavit is to show the proposed remedy of the unit-specific Fixed Resource Requirement ("FRR"), what the Commission calls the "FRR Alternative," leads to the very same damage or harm the Commission has stated it wishes to guard against in its finding the current MOPR is unjust, unreasonable, and

unduly discriminatory and the rejection of the Capacity Repricing and MOPR-Ex proposals.

36. In reaffirming the Commissions overall logic that out-of-market subsidies and mismatching pricing and commitments are damaging to the market I take a two-prong approach. The first prong is to show analytically, through the use of a graphical analysis, the efficiency of the RPM Capacity market, absent out of market subsidies, and then compare this baseline to the current FRR as defined in the PJM Tariff and Reliability Assurance Agreement ("RAA") and then show the equivalence between the unit-specific FRR remedy (the FRR Alternative) and an exercise of buyer-side market for which MOPR is designed to mitigate. Under this graphical approach, I show the changes in prices, quantities, and overall market surplus, and shifts in surplus between market participants.

37. The second prong of the approach is to provide empirical evidence through the analysis of simulations scenarios provided by PJM following the 2020/2021 Base Residual Auction ("BRA"). The analysis shows the harm the proposed FRR Alternative could do to the PJM RPM Capacity Market through changes in market prices, overall PJM RPM Capacity Market revenues, displacement of otherwise cost-effective/economic resources by subsidized resources and break-even prices across selected Locational Deliverability Areas ("LDAs") that would permit the successful exercise of buyer-side market power.

38. The affidavit is organized in the following manner. Section IV I provide a broad review of what the characteristics of an efficient PJM capacity market are without subsidies or FRR showing market clearing prices, quantities, and the maximization of market

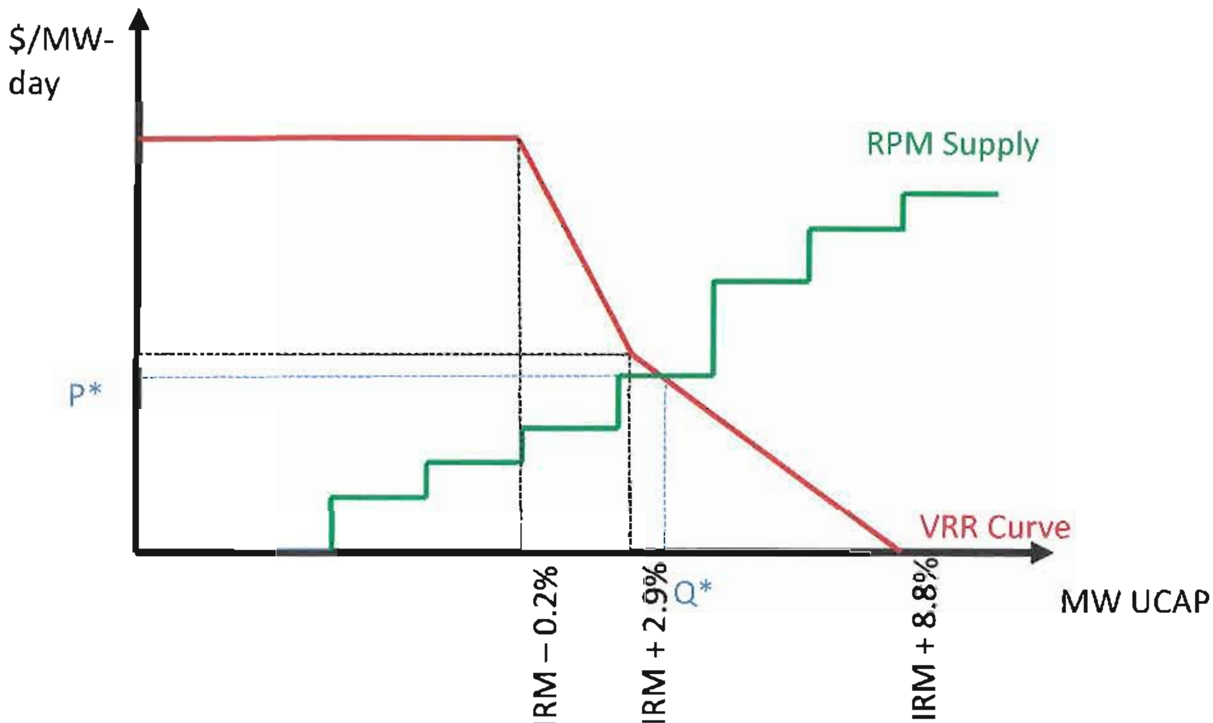
surplus. In Section V I provide a broad overview of the current FRR construct in PJM, some key history, and provide a graphical analysis of how the current FRR construct affects PJM RPM capacity Market outcomes, and the explicit incentives for opting into FRR. Section VI discusses a key myth surrounding the FRR and the incentives for load-serving entities ("LSEs") to elect the FRR. Section VII highlights the key differences between the FRR Alternative and the current PJM Tariff-defined FRR.

39. Section VIII shows the capacity market outcomes of exercise of buyer-side market power and the FRR Alternative remedy are identical and that the mechanical differences in implementing the two have one single distinction that is meaningless for market outcomes. Section IX provides the analysis of the PJM simulation scenarios reporting out the amount of 1) artificial price suppression; 2) displacement of otherwise cost-effective, economic resources by above-market-cost resources; 3) overall changes in RPM Capacity Market Revenue, and 4) breakeven prices that can be made to facilitate the successful exercise of market power disguised as unit-specific FRR in selected LDAs.

40. In light of the graphical analysis and the analysis of PJM simulations, Section X argues the only form of mitigation that can preserve the efficiency and just and reasonableness of the PJM Capacity market is a "Clean" MOPR that mitigates all subsidized resources to a default cost or their actual verified costs, and that all such subsidized resources should be subject to MOPR for as long as they are recipients of targeted subsidies. Section XI discusses the reason that there is no accommodation that exists that would preserve the efficient and just and reasonable outcome of the PJM capacity market and offers key questions for the Commission to consider.

IV. EFFICIENCY OF THE PJM RPM CAPACITY MARKET ABSENT SUBSIDIES OR FRR

Figure 1: Representation of the Supply and Demand in the Base Residual Auction Absent any Subsidies or FRR Elections



41. The reason for starting by examining the outcomes of the RPM capacity market absent subsidies, the FRR in the PJM Tariff, or the proposed FRR Alternative remedy is to show the competitive market as the baseline by which to measure changes to market outcomes resulting from subsidies, election of FRR in the PJM Tariff, or the FRR Alternative as a proposed remedy to the effects of state policy.

42. **Figure 1** provides a representation of the PJM BRA with the tariff-defined demand curve for capacity in red, and a supply curve in green reflecting the true marginal or

incremental costs of supplying capacity.[7] The demand curve is a representation of the marginal benefit of capacity as defined in the tariff. The marginal benefit of capacity is declining (demand is downward sloping) as additional amounts of capacity are procured, or as the PJM system commits additional capacity relative to its Installed Reserve Margin (IRM) target as shown in **Figure 1**. The market clearing price is denoted by P* and the market clearing quantity is denoted by Q*.

43. Efficient markets maximize surplus. Surplus is defined as the difference between what consumers are willing to pay as reflected by the demand curve, and what suppliers are willing to accept as reflected by the supply curve. So as a simple example, suppose consumers were willing to pay $450/MW-day while suppliers were willing to supply capacity at a flat price of $150/MW-day, and the demand to be satisfied were 100 MW. Then the total surplus would be ($450/MW-day - $150/MW-day) multiplied by the 100 MW or $30,000 per day.

44. The implication of efficient markets maximizing surplus is the following: 1) resources will continue to be committed so long as their marginal cost is less than the marginal benefit they provide to consumers; and 2) as a result of the cost-effective commitment of resources, market clearing prices reflect the point where the marginal (incremental) cost of supply is equal to the marginal benefit to consumers.

45. With respect to the first implication of maximizing surplus, if a resource has a marginal cost that exceeds the marginal benefit, then it is not cost-effective to commit to the

[7] With respect to capacity markets, the marginal or incremental costs are the going-forward costs of resources that include any fixed O&M costs and other fixed costs that must be incurred each year to remain in commercial operation that are not expected to be covered through net energy and ancillary service market revenues.

market and would reduce surplus. After all, it does not make sense to pay $10 for the next increment of supply when the benefit is only $7. Market clearing prices equal the marginal cost of supply and the marginal benefit of demand means that at that price, no supplier would wish to change its commitment status given the price. That is, resources with costs below the price receive a commitment and earn infra-marginal rents if their cost is less than the price. Conversely, resources that do not receive a commitment, have costs above the price and would lose money if they received a commitment.

46. The objective of the PJM RPM Capacity Market is to maximize surplus.[8] The maximum surplus, in the context of the PJM RPM Capacity Market is shown in **Figure 2**. The market clearing price in **Figure 2** is P* where the marginal cost (supply) equals the marginal benefit (demand) and the quantity of committed capacity is Q*. The total surplus has been split between the surplus accruing to consumers shown in the blue shaded area in **Figure 2** and the surplus accruing to producers as shown by the green shaded area in **Figure 2**.

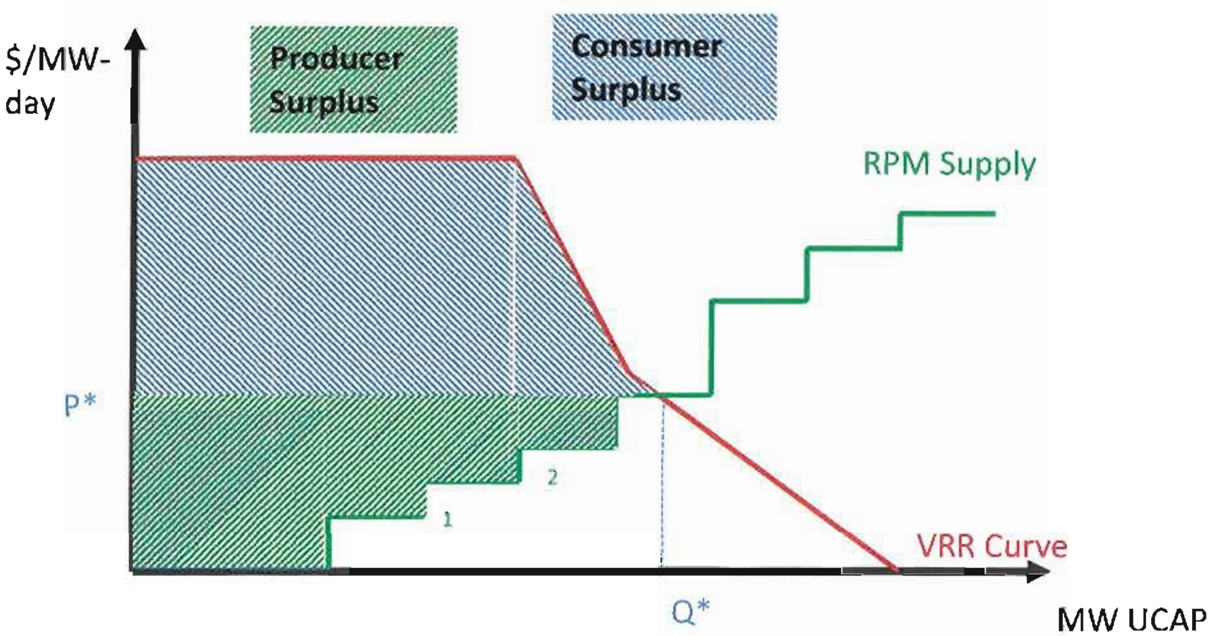
47. Consumer surplus is the difference between what they are willing to pay and the market price they pay. In **Figure 2** this is the area above the price, P*, below the demand (VRR Curve), and to the left of the cleared quantity Q*. If the price of capacity is $250/MW-day and consumers were willing to pay $450/MW-day and the cleared quantity were 100 MW, the consumer surplus would be ($450/MW-day - $250/MW-day) multiplied by 100 MW or $20,000/day. Another way of thinking about the consumer surplus is that they are getting the benefit of only paying $250/MW-day when they were willing

[8] PJM, *Base Residual Auction Optimization Formulation*, December 12, 2007. Available at https://pjm.com/-/media/markets-ops/rpm/20071212-rpm-optimization-formulation.ashx?la=en.

to pay $450/MW-day. But because of the downward sloping nature of the demand for capacity, the actual willingness to pay will vary as more capacity is committed.

48. The producer surplus is the difference between the price they are paid, and the marginal cost of supplying the capacity. In **Figure 2** this is the area above the supply curve, below the price P*, and to the left of the cleared quantity Q*. Again, and example helps to understand the benefit producers receive. As before in this section, suppose producers are willing to accept a payment of $150/MW-day to supply capacity but instead receive $250/MW-day for capacity. For the 100 MW of capacity sold the producer surplus is ($250/MW-day - $150/MW-day) multiplied by 100 MW or $10,000/day. Of course, as **Figure 1** and **Figure 2** show, producers have different willingness to accept based upon their going forward costs.

Figure 2: Maximizing Surplus in the PJM RPM Capacity Market



49. Absent any subsidies to supply resources and any FRR elections, the PJM RPM Capacity market will maximize total surplus and result in efficient market clearing

prices and resource commitments. And it is this efficient market results that serves as the baseline by which the current FRR provisions in the PJM Tariff can be assessed and compared.

V. THE CURRENT FRR PROVISIONS UNDER THE PJM TARIFF AND RELIABILITY ASSURANCE AGREEMENT

50. Since its inception, the PJM RPM Capacity Market has allowed LSEs to "opt out" of participation directly in the capacity market and allow load serving entities meet their IRM obligations through a combination of self-owned resources or contracted resources.[9] This is known as the FRR option for LSEs.

51. A discussion of the FRR option for LSEs as it currently exists in the FERC-approved PJM Tariff shows how this foreshadows market outcomes for the FRR Alternative as a proposed remedy for accommodating state policies and yet is also quite different in key ways that will be discussed in subsequent sections.

52. The FRR option has several conditions to which load serving entities must adhere. One condition is that this is an "all or nothing" option. An LSE electing the FRR option must satisfy its entire peak load obligation plus the reserve margin outside the capacity market. There is no ability to only opt to use FRR for only part of an LSE's load. Allowing an LSE to serve only part of its load under the FRR option is an invitation to exercise buyer-side market power as I discuss below in Section VIII of my affidavit. A second condition is that if the LSE has excess capacity it owns or has under contract, it faces strict limits on how much of that excess capacity can be offered into the RPM Capacity Market. Allowing unlimited excess capacity sales from an FRR entity invites

[9] PJM Interconnection, L.L.C., *Reliability Assurance Agreement Among Load Serving Entities in the PJM Region,* ("RAA") Schedule 8.1.

a form of market manipulation whereby the FRR entity uses the capacity market to offset excess costs due to oversupply to its load while artificially suppressing prices in the capacity market.

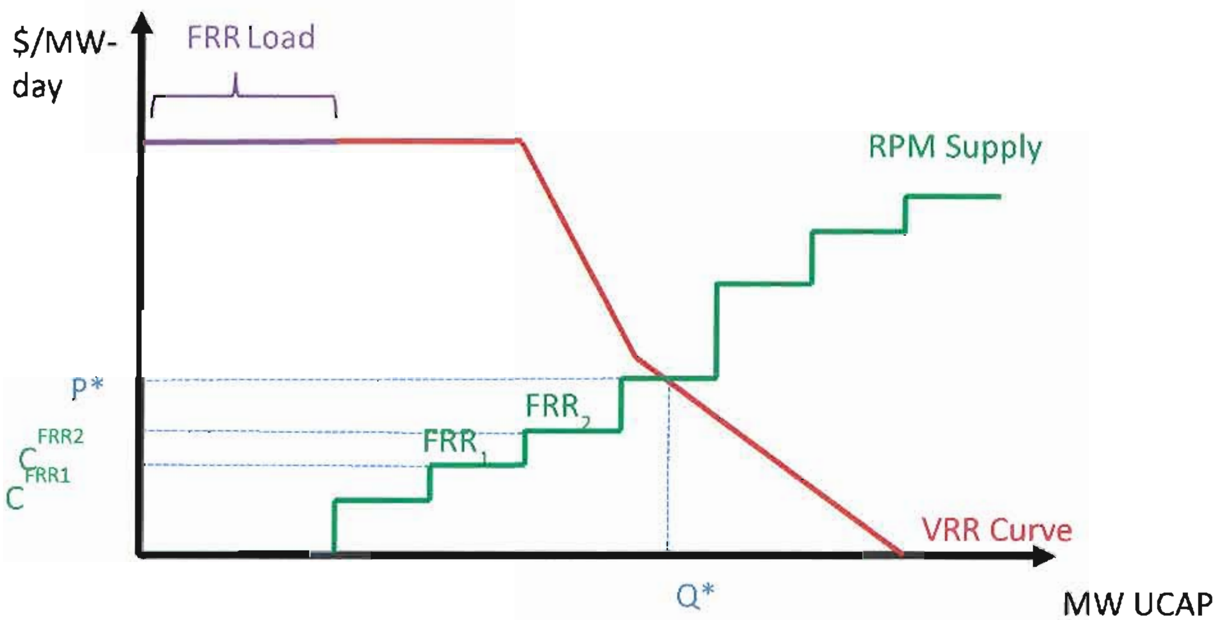
53. A third condition is that the FRR entity need only hold reserves above its peak load obligation at the IRM value set by PJM. In cases where the RPM Capacity Market clears at a reserve margin below the IRM, the results in the FRR entity holding more reserves (as a percentage of peak load) than the market. PJM has never cleared the market below its IRM target since the inception of RPM. However, with this third condition, the LSE electing the FRR option holds less reserve than the market (as a percentage) when the market clears above the IRM target set by PJM. This situation has been the case since RPM was implemented. The implication of this third condition is that the FRR load, during periods of extreme system stress such as during the polar vortex in January 2014, can essentially "free ride" on the excess capacity procured by the market if its own resources fail to perform and without needing to pay for those excess reserves procured by the market.

A. Current FRR Provisions Reduce Market Efficiency when the Cost of FRR Resources is Below the Market Price but the Efficiency Loss is Small

54. For the sake of example, suppose a LSE elects the FRR option with resources with costs below the market price of capacity. This situation is shown in **Figure 3** where there is an FRR load amount represented by the purple segment on the VRR Curve (demand curve for capacity) and two FRR resources, FRR_1 and FRR_2 with costs C^{FRR1} and C^{FRR2} respectively. **Figure 3** shows the RPM Capacity Market prior to the FRR Load and FRR Resources being removed from the capacity market. Absent the FRR

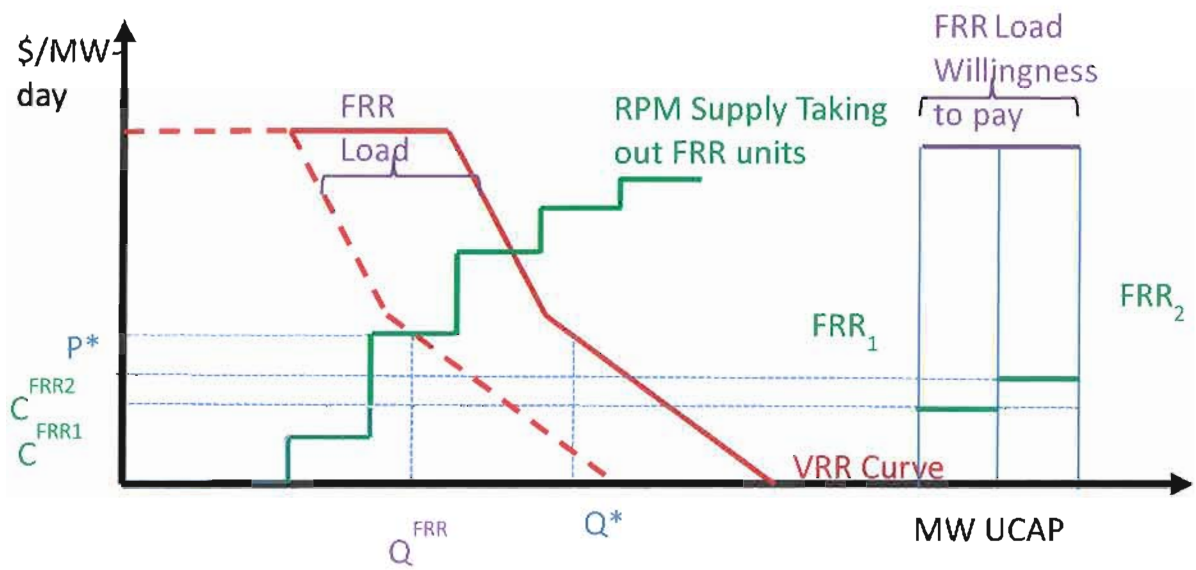
election, a market clearing price of P* and a market clearing quantity of Q* would prevail.

Figure 3: FRR Election with Resource Costs Below the Market Clearing Price



55. Removing the FRR Load from capacity market price formation shifts the VRR Curve back to the left by the amount of the FRR Load Removed as shown in **Figure 4**. The new VRR Curve is the red dashed curve. Taking out the below market price FRR resources shifts the supply curve back to the left as shown in **Figure 4**. The FRR resources and load are separated from the market and are shown off to the right in **Figure 4** with the associated costs of the FRR resources well below the willingness to pay, and with a distinct price formation function that looks like pay as bid for each resource. Despite taking the FRR load and resources out, the market clearing price remains at its efficient level of P*, but the clearing quantity in the market falls to Q^{FRR}.

Figure 4: Shifting Demand and Supply Resulting from FRR Election with Below Market Price Resources



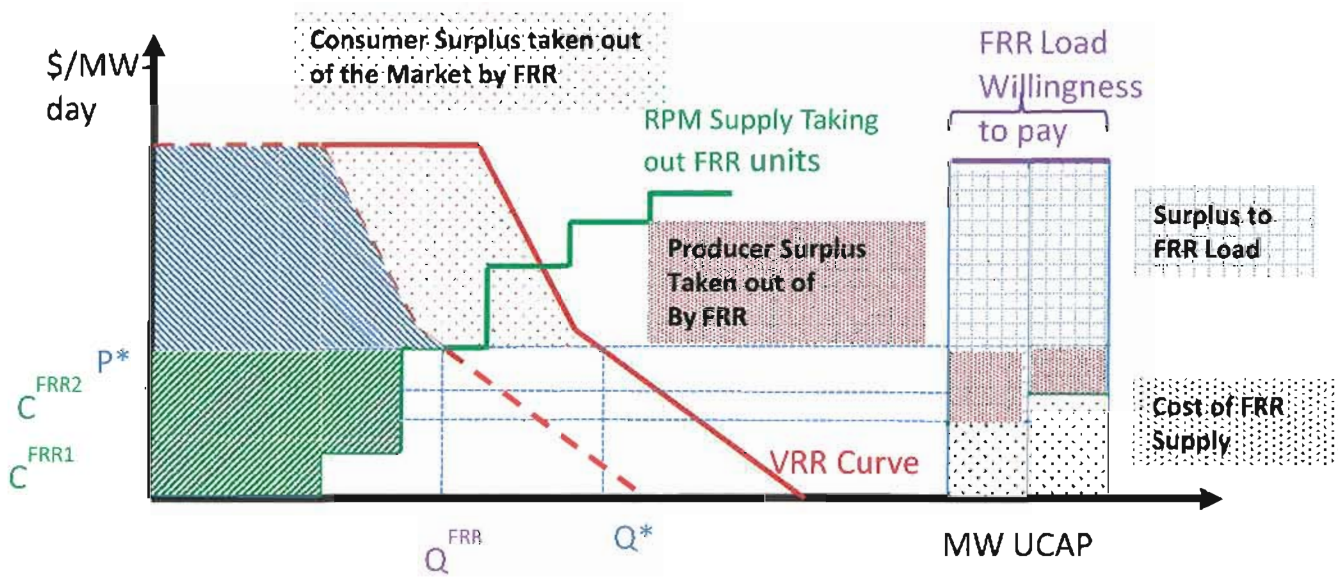
56. Though it is difficult to see graphically, given where the clearing price is being set on the VRR Curve, the overall amount of capacity cleared plus the FRR resources is below the clearing quantity Q* that would be committed in the absence of the FRR election. To provide a sense of this amount of capacity, the 2020/2021 BRA cleared at a 23.9 percent reserve margin. Had the 12,200 MW of FRR load for 2020/2021 had to hold the same reserve margin, it would have had to commit through contracts or self-owned generation an additional 831.5 MW of capacity.[10]

57. Total surplus and producer and consumer surplus get shifted around when an LSE elects the FRR option with resources that are below the market price. These changes are shown in **Figure 5**. Overall the surplus taken out of the market is largely shifted to the FRR load. Consumer surplus is represented by the blue shaded area and producer

[10] 2020/2021 BRA planning parameters and BRA auction report. Given the 6.59% forced outage rate and the 23.9% reserve margin cleared in the auction, the FRR entities would have had to hold their peak load obligation of 12,200.6 MW multiplied by (1.239)*(1-0.0659) = 14,120.4 MW of capacity or 831.5 MW greater than their FRR obligation of 13,288.9.

surplus is represented by the green shaded area in the same manner as discussed in regard to **Figure 2**. Producer surplus taken out of the market and shifted to the FRR load is shown in the red shaded area in **Figure 5**. Consumer surplus to the FRR Load is shown by the blue and white checkered area under the FRR Load and the consumer surplus taken out of the market by FRR is the red dotted area shown in **Figure 5**. Graphically, it only appears to be a shifting around of surplus, and that surplus is close to being maximized since the FRR resources are below market prices.

Figure 5: Changes in Surplus with FRR Election with Resources below Market Price



58. However, as I noted above, FRR entities need only hold a smaller percentage of reserves than has historically been cleared in RPM. And while this MW figure is small, this difference in quantities implies that there is some loss in surplus as it is shifted around. The reason some surplus is lost is analogous to the moving water from one trough to another using an old bucket. The water is the surplus that is being shifted between consumers and producers. As the water is moved from one trough to another, some water may accidently spill, or the bucket may have some small boles that allows

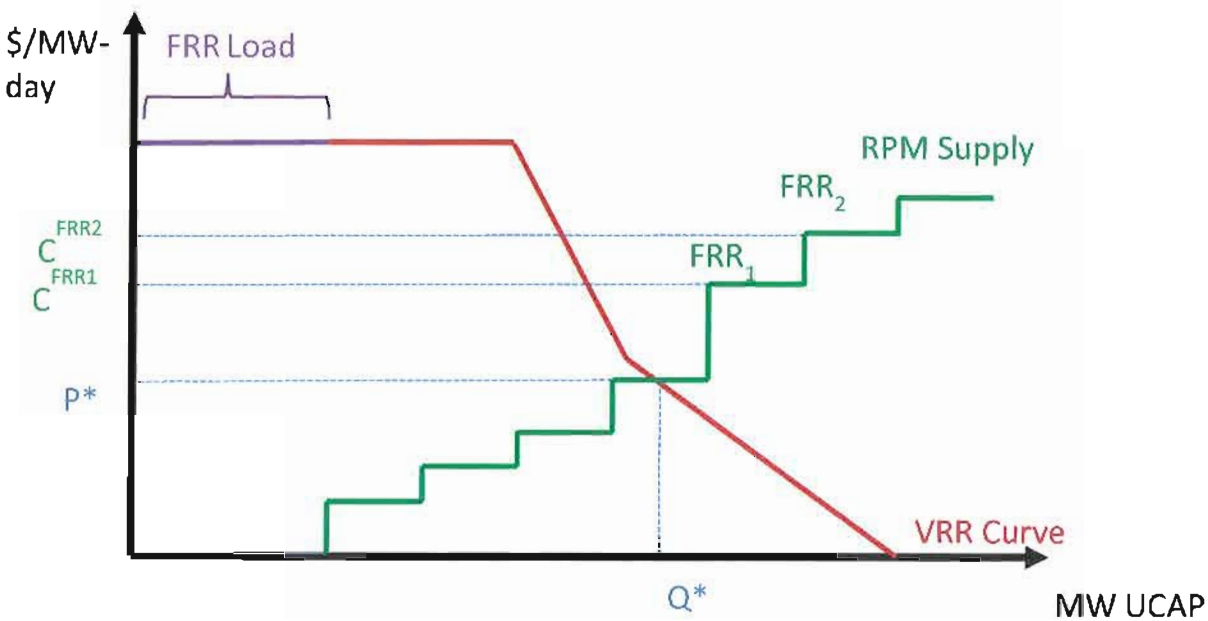
water to leak out as it is being moved. The same is true with all the surplus being moved around.

59. In **Figure 5**, given the nature of the supply curve, this loss comes from consumer surplus, albeit a small loss of surplus. So even under the best of circumstances when the cost of the FRR resources are below the market price, there is still the potential for a small loss in surplus overall, and by extension a loss in efficiency.

B. Current FRR Provisions Result in Large Losses in Market Efficiency when the Cost of FRR Resources is Above the Market Price

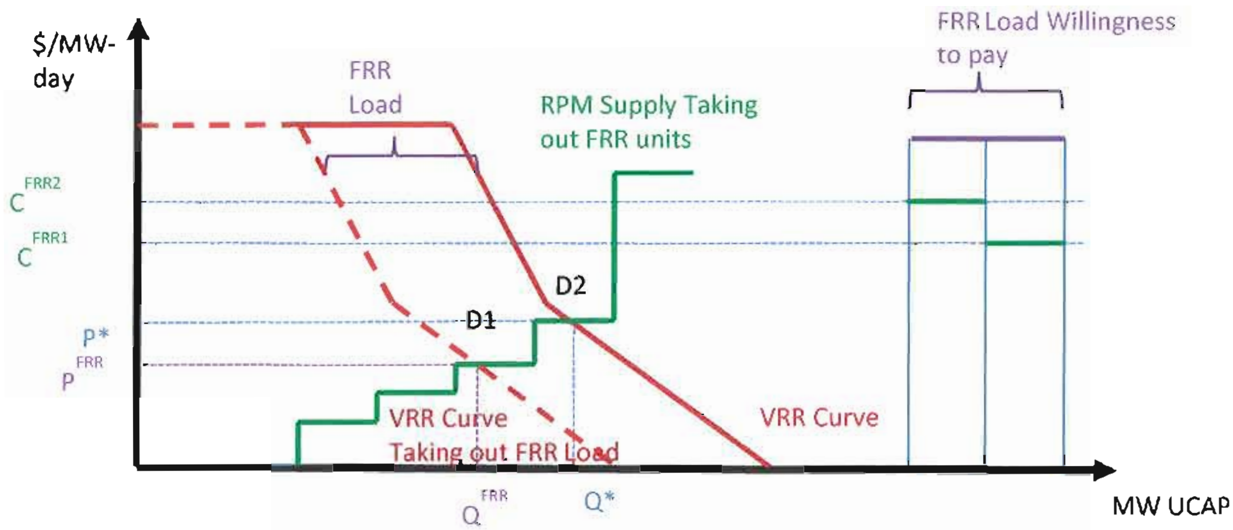
60. Following the previous example but changing the circumstances, suppose a LSE elects the FRR option with resources that have ***costs above*** the market price of capacity. This situation is shown in **Figure 6** where there is an FRR load amount represented by the purple segment on the VRR Curve (demand curve for capacity) and two FRR resources, FRR_1 and FRR_2 with costs C^{FRR1} and C^{FRR2} respectively. **Figure 6** shows the RPM Capacity Market prior to the FRR Load and FRR Resources being removed from the capacity market. Absent the FRR election, a market clearing price of P* and a market clearing quantity of Q* would prevail.

Figure 6: FRR Election with FRR Resource Costs Above the Market Price



61. Removing the FRR Load from the capacity market shifts the VRR Curve back to the left by the amount of the FRR Load Removed as shown in **Figure 7**. The new VRR Curve is the red dashed curve. Taking out the below market price FRR resources shifts the supply curve back to the left as shown in **Figure 7**. The FRR resources and load are separated from the market and are shown off to the right in **Figure 7** with the associated costs of the FRR resources well below the willingness to pay. Despite taking the FRR load and resources out, the market clearing price declines to P^{FRR} and the clearing quantity in the market falls to Q^{FRR}.

Figure 7: Shifting Demand and Supply Resulting from FRR Election with Above Market Price Resources



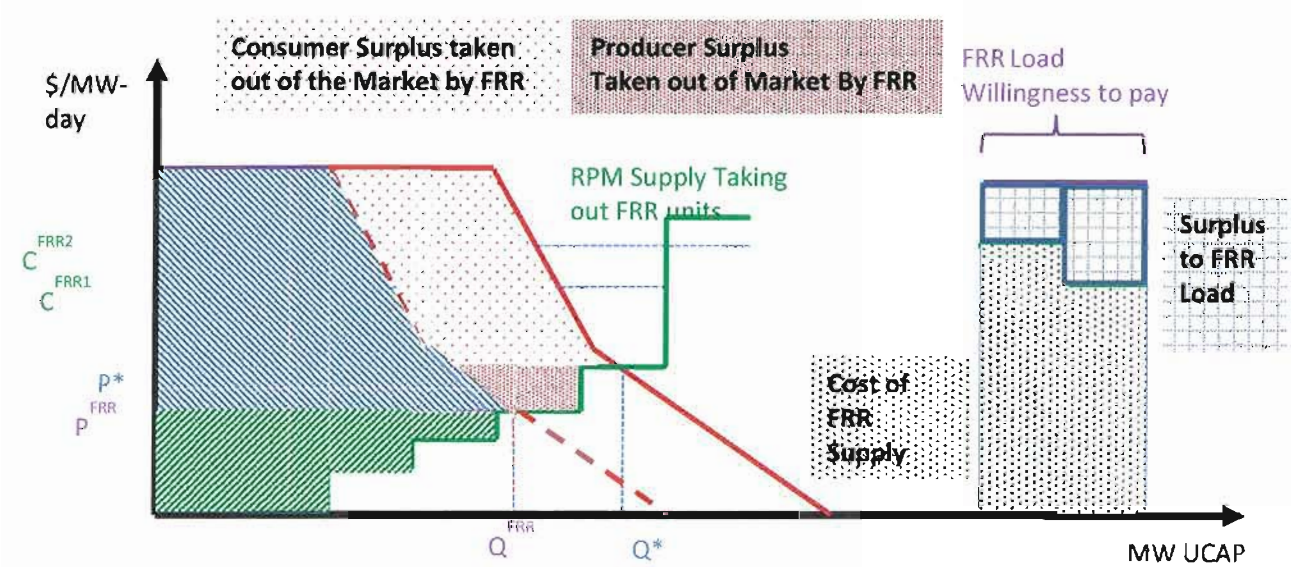
62. Unlike in the previous example where the sum of the clearing quantity in the capacity market, Q^{FRR} and the FRR Load amount will be less than the cleared quantity, the total quantity cleared could be greater than the cleared quantity, Q*, absent the FRR. To see this, note that in **Figure 7** Q^{FRR} is further down the demand curve and is associated with a lower price, P^{FRR} than was the case in the previous example in **Figure 4**. Even if the total quantities exactly matched the clearing quantity absent the FRR election, there would still be an inefficient set of resources satisfying the resource adequacy targets since some above market price resources are being committed for capacity. Notwithstanding this point, the FRR entity still does not carry the same percentage of resources cleared by the market resulting in the aforementioned "free rider" problem discussed previously in this section.

63. Furthermore, unlike the previous example, there are resources that were part of the least-cost, surplus maximizing solution absent the FRR election that have now been displaced by the use of above market price resources for the FRR Plan. These are

denoted by D1 and D2 in **Figure 7**. D1 and D2 have lower costs than the FRR resources with costs C^{FRR1} and C^{FRR2}. This result clearly shows that the FRR election has inefficiently substituted high cost resources for lower cost resources.

64. The substitution of higher cost resources for lower cost resources results in not only a shifting of surplus between market participants, but an overall loss of surplus due to the inefficient substitution of high cost resources for lower cost resources. This is shown in **Figure 8**.

Figure 8: Changes and Loss in Surplus with FRR Election with Resources Above the Market Price



65. Consumer surplus, shaded in blue, and producer surplus, shaded in green, are shown as they were in **Figure 2** and **Figure 5**. Unlike in the previous example, there is a loss in consumer surplus taken out of the market shown in the red-dotted area in **Figure 8**, and only a small portion of that is transferred to FRR Load as shown in the blue and white checkered area on the right side of the graph in **Figure 8**. That is, the FRR load is now paying more for capacity than they would have in a competitive market solution and their surplus is eroded as a consequence. The loss in consumer surplus is eroded by the

extra cost of the FRR resources as shown in the black dotted area under the FRR Load in **Figure 8**. Producer surplus is taken out of the market in the form of the red shaded area and is totally eroded by the higher cost of the FRR resources, while overall producer surplus is reduced compared to **Figure 2** where there was no FRR election. There is some producer surplus that ends up being transferred to consumers. In other words, the FRR resources are beneficiaries of the policy that takes surplus from competitive suppliers.

66. Overall, the transfer of surplus to cover the additional costs of the FRR resources results in a large loss of surplus that benefits the FRR resources at the expense of competitive resources and the load assigned to pay for the FRR resources. To place this in the context of the bucket analogy used earlier, this is equivalent to purposefully dumping several buckets of water out on the ground while moving water with the leaky bucket from one trough to another.

67. In short, an election under the existing FRR when the resources that have costs above market price leads to 1) artificially reduced capacity prices relative to prices absent FRR election; 2) The displacement of otherwise economic resources; and 3) a loss in market efficiency as evidenced by the reduction in market surplus overall. As discussed below, because the FRR Alternative would presumably only be used for uneconomic resources whose costs are above the competitive market price, it would inevitably have all of these negative consequences. However, the "all or nothing" nature of the existing FRR has desirable properties in that load faces the full cost of their FRR election and cannot cherry pick which resources and load to "take out" or "leave in" the market and thus provides a strong disincentive to choose the FRR path.

The existing FRR satisfies the Commission's intent of having the load pay for the consequences of their FRR election. In contrast the FRR Alternative eliminates this disincentive and likely encourages load and resources to elect the FRR Alternative with even greater damage to the market.

VI. MYTHS REGARDING FRR AND INCENTIVES FOR ELECTING THE FRR

A. It is a Myth to Conclude Removing FRR Load and Resources Separates Them from the Capacity Market

68. At best, the FRR Alternative only creates a minor distortion in market outcomes when the FRR resources taken out with load have costs below the market price. At worst, when FRR resources have costs above the market price, the FRR Alternative artificially reduces prices, reduces markets efficiency by reducing overall market surplus, and shifts surplus between market participants. Of course, as discussed below, the incentives to use the FRR Alternative are likely to be much stronger in the second, more troubling case.

69. It has often been suggested that because the existing FRR takes both generation and load out of the capacity market, it does not change market outcomes. This is clearly false. The preceding discussion on the current tariff-defined FRR option should dispel any notion that the FRR holds the market harmless.

70. Fundamentally, this myth breaks down because resource adequacy requirements are determined on a ***PJM system-wide basis***, which means the demand for resource adequacy is system-wide demand as represented by the VRR Curve in RPM. Consequently, taking FRR demand out of the market fundamentally changes market outcomes, all things being equal.

71. Furthermore, this demand taken out of the market is satisfied with resources that would not be a part of the efficient, least-cost solution absent targeted subsidies or the FRR option locks in the fundament change in market outcomes as shown above. In fact, to say that such an action "takes supply out of the market" is also a myth if, as will likely always be the case under the FRR Alternative, the resource used to satisfy demand in this case would never have been part of any market solution. You cannot take supply out of the market that never would have been part of the market solution. If anything, it is ***adding supply:*** high cost, inefficient supply to the market but treating that supply as if it had a zero cost.

B. Incentives for Electing the FRR Option: Reducing Load Costs through Reduced Reserve Obligations

72. If a LSE had self-owned or contracted resources that had costs below capacity market prices, what would be the incentives for electing the FRR option? Possessing such lower cost resources ultimately does not change the net costs to the LSE. Suppose the LSE's resources cost $40/MW-day and the market price was $70/MW-day. If the LSE stayed in the market, the load would pay $70/MW-day, and the resources would also receive $70/MW-day. On net, the LSE would still be paying $40/MW-day to meet its load obligations for RPM.

73. But it is also important to recognize that in the RPM Capacity Market, demand for capacity is downward sloping to reflect the idea that capacity beyond the installed reserve margin target has value, albeit at a value that is decreasing as the system adds more and more capacity beyond the reserve target. And this lower price means it is cost-effective to buy the extra capacity and results in overall lower costs to the system. Going back to the simple numerical example in the previous paragraph, suppose the

\$70/MW-day price represents a reserve margin of 20 percent, but the IRM target is only 15 percent.

74. The LSE with low cost resources can elect the FRR option to "save 5 percent" off the reserve margin it needs to keep by avoiding the additional \$70/MW-day cost it would pay for the additional 5 percent of reserve it would be responsible for purchasing if it stayed in the market.

C. Incentives for Electing the FRR Option: Protecting High Cost Generation from Competition

75. Consider an LSE with self-owned resources that has costs above the market price, but has made significant capital investments in these resources, and these resources are earning regulated rates of return at the state level so long as they can be shown to be "prudent" to keep in service or are deemed "used and useful". In a competitive market environment, such resources would fail to clear the capacity market and their higher costs would likely be called into question by their state regulators.

76. Electing the FRR option in this situation isolates these higher cost resources from the transparency of competitive market outcomes and ensures the resources remain used and useful to the FRR load they serve, and the resources can continue to earn their regulated rate of return. Unfortunately, absent a major change at the state level in the regulatory paradigm, there is little market transparency into the costs of the FRR resources unless one wishes to dig deep into state regulatory filings or FERC Form 1

data and examine the FRR plans and costs on PJM's website.[11] The most recent FFR Plan on file with PJM would charge retail competitors $435.86/MW-day.[12]

77. However, there is some insight into these incentives from one case involving the Ohio operating companies of AEP, Ohio Power and Columbus Southern Power, when Ohio transitioned to retail competition beginning in 2009. The FRR rules state clearly that the default capacity charges from an FRR LSE to competitive retail providers in its service territory would be the unconstrained RPM clearing price.[13] But notwithstanding this default value, an FRR LSE could make a Section 205 filing at FERC with a showing of higher costs unless the state had clearly articulated a policy regarding the capacity costs that could be passed through to competitive retail providers.[14]

78. In Docket No. ER11-2183, AEP filed to charge competitive retail providers $310/MW-day in Columbus Southern Power territory and $401/MW-day in the Ohio Power territory.[15] It is worth noting that at the time of this filing, capacity prices in the unconstrained portion of PJM, where AEP load is located, had cleared as low as $16/MW-day. At no time since PJM has been operating the RPM Capacity Market has the unconstrained RTO market price been above $175/MW-day, as it was for the 2010/2011 Delivery Year.[16] [17]

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[11] https://www.pjm.com/markets-and-operations/billing-settlements-and-credit/frr-lse-capacity-rates.aspx

[12] https://www.pjm.com/-/media/markets-ops/settlements/frr-lse-capacity-rates/capacity-formula-rate-summary.ashx?la=en. This is the rate charged by APCo for the 2018/2019 Delivery Year.

[13] PJM, RAA Schedule 8.1, Section D.8.

[14] *Id.*

[15] American Electric Power Service Corporation, PJM Interconnection, LLC, Docket No. ER11-2183, November 24, 2010, Attachment B, at 1.

[16] PJM, *2021/2022 RPM Base Residual Auction Results*, May 23, 2018, Table 1 at 6. Available at https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx?la=en.

79. Filing for recovery for costs in rates that were demonstrably above market prices before and since this filing certainly reflects the incentives for protecting resources with costs above market prices from competition. And as a post-script, as Ohio embarked upon retail competition and vertically integrated companies spun off their generation resources, many of the resources previously owned by Ohio Power and Columbus Southern Power eventually retired.[18]

VII. THE PROPOSED FRR ALTERNATIVE REMEDY VS. THE EXISTING FRR: KEY DIFFERENCES AND SIMILARITIES

80. In its June 29th Order, the Commission proposed to expand the MOPR and to "implement a resource-specific FRR Alternative option, under which a resource receiving out-of-market support may remain on the system, but outside the capacity market."[19] The stated intent of the FRR Alternative is to "mitigate or avoid the potential for double payment and over procurement."[20]

81. The Commission proposed that "PJM adapt its current FRR option to allow, on a resources specific basis, resources receiving out-of-market support to choose to be removed from the PJM capacity market, along with some commensurate amount of load for some time."[21] The Commission explicitly acknowledges these subsidized

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[17] Subsequently, the Public Utilities Commission of Ohio ("PUCO") articulated a policy of taking the PJM price as the price to be charged to competitive LSEs pending the outcome of a docket in front of the PUCO, and AEP subsequently filed a complaint at FERC in EL12-32 that was later withdrawn by AEP and never ruled upon by the Commission. *See American Electric Power Service Corp.*, 134 FERC ¶ 61,039 (2011) at P 10.

[18] See the PJM Deactivation page at https://pjm.com/planning/services-requests/gen-deactivations.aspx. Of these are the Muskingum River units 1-5, Conesville 3, and Picway 5.

[19] June 29th Order at P 157

[20] June 29th Order at P 160

[21] *Id.*

resources are unable to compete in the capacity market based on their costs and characterize the removal of the resource and commensurate amount of load to allow these resources to "exit the capacity market".[22]

A. The Proposed Resource Specific FRR Remedy has Notable Differences from the Current FRR Option

82. There are a number of notable differences between the proposed FRR Alternative and the existing FRR, all of which make the former materially more problematic than the latter. These differences magnify the adverse effects of the existing FRR mechanism and create new adverse effects.

83. Unlike the current FRR option, which can only be exercised by a LSE, the resource specific FRR Alternative as proposed by the Commission appears to allow resource owners to make the election. Regardless of the specific implementation details, this shifting of the election right will have serious implications for load.

84. Under the current Option, the LSE knows what costs it will bear under its FRR election given the portfolio of resources it either owns or has under contract. Under the FRR Alternative as proposed by the Commission, the resource with out-of-market support (subsidy) makes the FRR election, but there remains a question of what load is "stuck" paying for cost of the "out-of-market resource" when it has lower cost capacity available through the market? At best this is undefined as to who makes this marriage between the FRR Alternative resource and the load that must pay for it. At worst, it allows for resources to seek subsidies and then stick the bill for the rest to a specific segment of load. In either case, the state, whose policy has created this situation, is

[22] *Id.*

likely to make a determination onto which wholesale loads the additional costs of FRR resources will be placed without any regard to the implications of cost shifting or the jurisdictional question of who should be responsible for assigning these costs.

85. The current FRR option requires an LSE satisfy its entire resource adequacy obligation with its own resources. And even if this results in lower capacity market prices, as demonstrated in Section V, at least the LSE cannot benefit from any potential exercise of buyer-side market power by having some its load paying the lower market price. By definition, the FRR Alternative allows for partial exit.

86. In contrast, under the Commission proposed remedy, if there is an LSE that wanted to serve part of its load with a resource electing the resource specific FRR Alternative, the LSE could use this subsidized higher cost resource to successfully execute a buyer-side market power strategy that would result in lower overall capacity market expenditures. This ability that had been previously foreclosed would now be hardwired into the market design if it were approved by the Commission.

87. The current FRR option if elected by a LSE places tight restrictions on the amount of excess capacity that can be sold into the capacity market. This forces the LSE electing the FRR option to pay for the consequences of its actions leading to oversupply and paying directly for those extra costs rather than trying to offset those costs of excess supply through capacity market transactions leading to depressed prices and inefficient outcomes.

88. In contrast, the proposed Commission remedy under the resource specific alternative would allow a ***supplier*** receiving support for specific resources and a large portfolio of other resources to avoid bearing the cost of its high cost resources, but effectively

receive out of market support for its uneconomic resources while enjoying market pricing for its remaining portfolio without restriction, or possibly even using proceeds for the out-of-market support to engage in an economic withholding strategy to raise market prices above competitive levels.[23]

B. The Proposed FRR Alternative Appears to Be Premised on Key Myths Associated with the Current FRR Option

89. The language of the June 29th Order suggests that the Commission has erroneously accepted the myth that the FRR simply "removes" load and resources from the market under all circumstances. As discussed above, load is not removed "from the market" under any circumstances, because the overall demand is determined for the entire PJM footprint as discussed previously. The demand for resource adequacy in PJM is in fact not changing at all, but the treatment of that demand is changing.

90. As also discussed above, generation is not removed from the market where it is uneconomic and would otherwise be out of the market. As recognized in the June 29th Order, the resources to be accommodated by the FRR Alternative are uneconomic and are, therefore, already "out of the market."[24] As a result, the FRR Alternative will not take these resources "out of the market" but will instead bring these resources from outside the market and inserting them into the market at an effective cost basis of zero.

91. The FRR Alternative will thus take uneconomic supply and treating it as a price taker as a practical matter which has the same effects on prices and market efficiency as shown in Section V. Moreover, LSEs could reduce their overall obligations relative to

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[23] *Comments of American Petroleum Institute, J-POWER USA Development Co., Ltd, and Panda Power Generation Infrastructure Fund. LLC* in Docket No. ER18-1314, Affidavit of Paul M. Sotkiewicz, Ph.D., May 7, 2018.

[24] June 29th Order P 160.

the market if they are only required to hold reserves up to the IRM on the resource specific FRR resource and load as is the case today under the current FRR option.

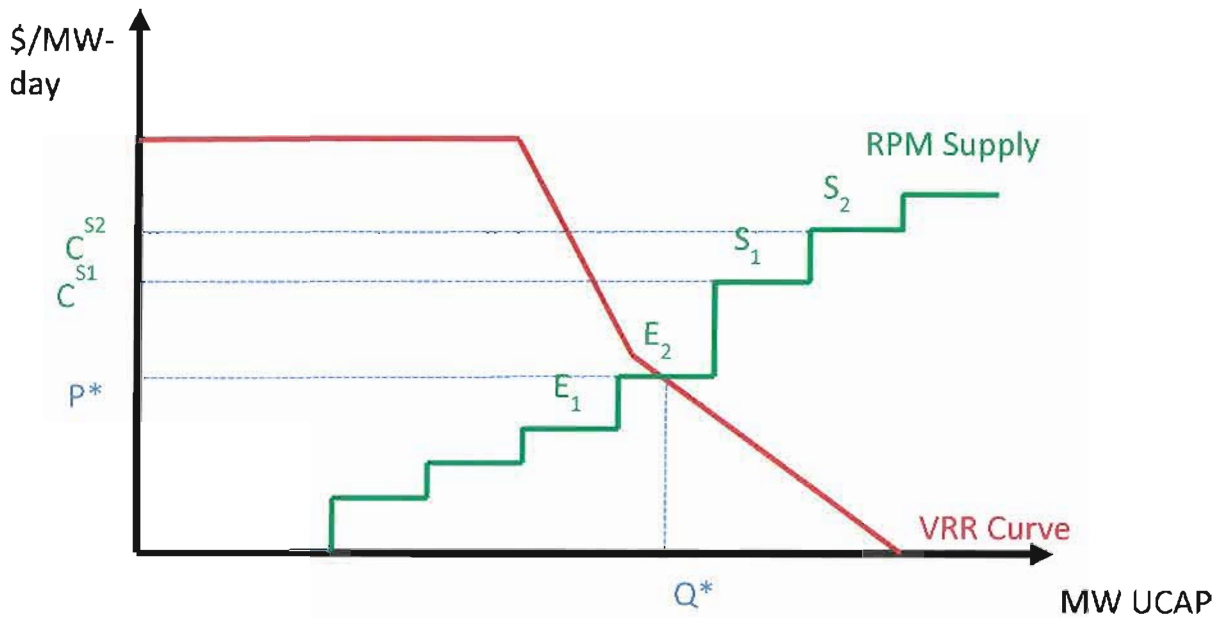
92. Furthermore, as noted in the previous section, the Commission's proposed remedy hardwires the incentives to protect resources with costs above market prices from competitive pressures. The Commission's proposed remedy also accentuates the incentives for load to potentially manipulate the proposed remedy to reduce their out-of-pocket costs for meeting its resource adequacy obligation through an exercise of buyer-side market power that will be hard-coded into the PJM market design should such a mechanism be approved.

VIII. THE OUTCOMES OF THE PROPOSED FRR ALTERNATIVE REMEDY ARE IDENTICAL TO AN EXERCISE OF BUYER-SIDE MARKET POWER

93. As alluded to in the previous Section, the FRR Alternative has the same implications for artificially reducing prices as an exercise of buyer-side market power. The objective of buyer-side market power is to pay extra money to a subset of above market price resources, insert those resources into the capacity market as price takers, and reduce the price of capacity to be paid for by the remaining load in the portfolio.

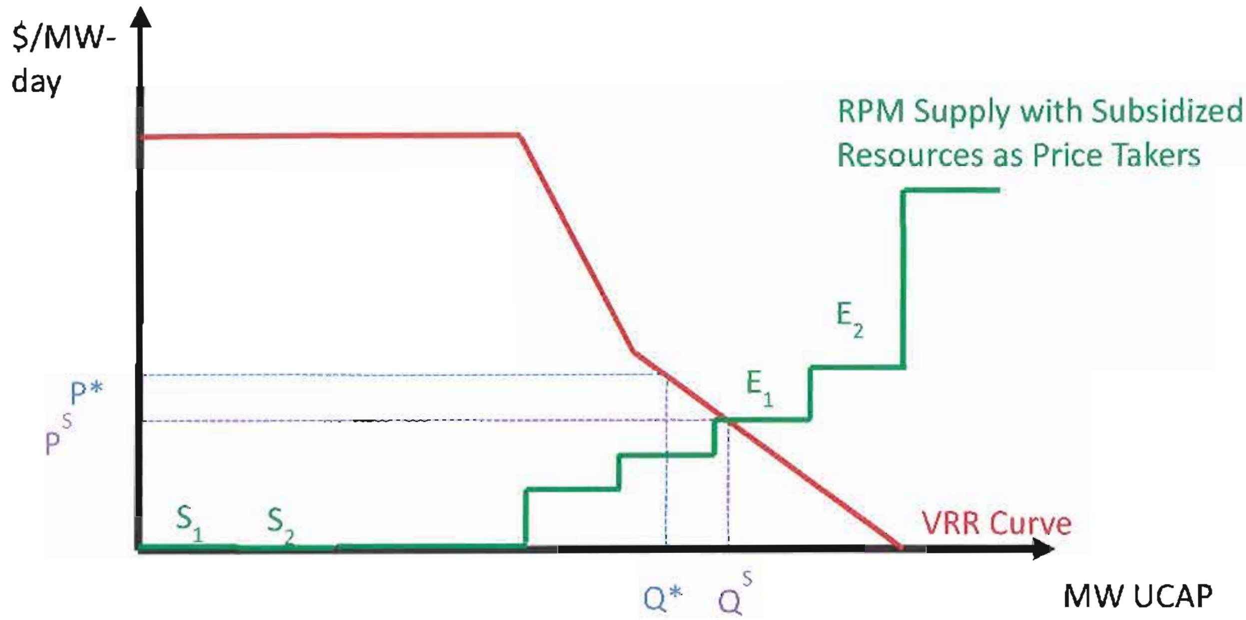
94. Consider the following simple example with two potentially subsidized resources, S_1 and S_2 as shown in **Figure 9** that have costs C^{S1} and C^{S2} respectively that are above the market price as shown in **Figure 9**. If these resources are offered at their respective costs, the market clearing price would be P* and the clearing quantity Q*. The market outcome is in fact identical to the market outcome shown in **Figure 1** in Section IV. Resource E2 is the marginal resource setting price, though only part of its capacity is committed, and resource E1 is infra-marginal with all its capacity committed.

Figure 9: Market Clearing with Potentially Subsidized Resources with Costs Above the Market Price



95. As an exercise of buyer-side market power, resources S_1 and S_2 are inserted into the capacity market as price takers as shown in **Figure 10**. The resulting price is artificially suppressed from P* to P^S. The cleared quantity of capacity increases from Q* to Q^S, though this increase in the cleared quantity of capacity is less the capacity from the subsidized resources inserted as price takers. Additionally, resources E_2 and E_1 that were originally part of the least cost solution have been displaced by the more expensive, yet subsidized resources.

Figure 10: Subsidized Resources Inserted as Price Takers as an Exercise of Buyer-Side Market Power Reduces Market Clearing Prices



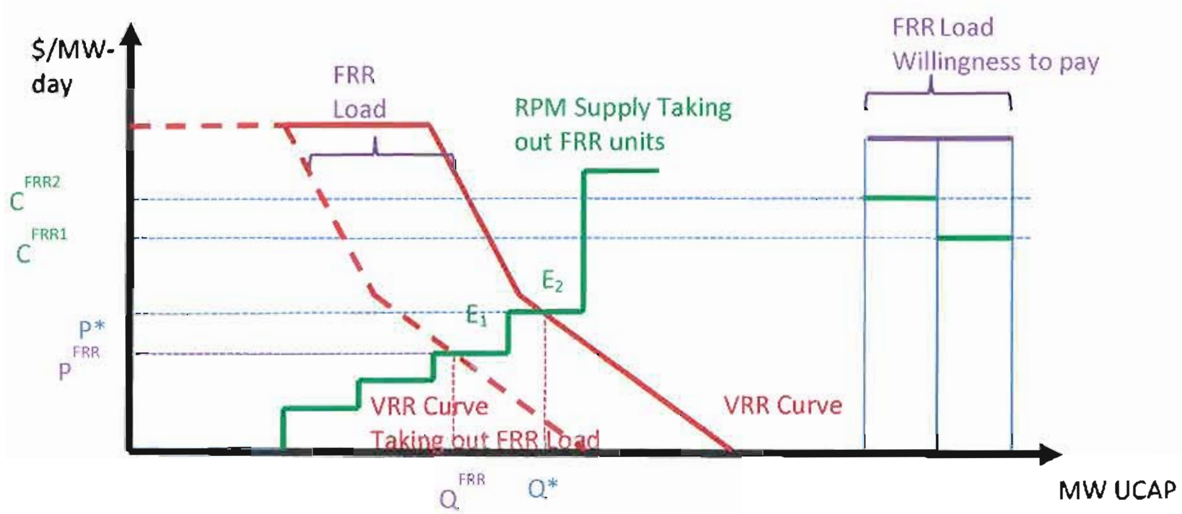
96. In terms of the effects on prices (artificially suppressed), and displacement of lower cost resources in favor of higher cost resources, the outcome of an attempted exercise of market power is no different from electing an FRR option for the same subsidized resources to brought into the market to satisfy part of the demand as was shown in **Figure 7** in Section V except now the FRR election is not for the entire load. **Figure 7** is reproduced below as **Figure 11** to make it easier to see the similar outcomes, and with the displaced resources labeled.[25]

97. The mechanisms by which these outcomes are achieved differ, but the outcomes are effectively identical. In the buyer-side market power case, the resources that were once out of market, are being brought into the market as price takers, shifting the balance

[25] The total quantity outcomes under the FRR Alternative versus buyer-side market power may differ, but only slightly and overall, and is not the main issue with regard to market distortions.

toward more "apparently" lower cost supply. In the case of the FRR Alternative, demand is being brought to the higher cost resources outside the market, again shifting the balance on net toward an "apparently" lower cost supply. The mechanisms differ, one brings in supply into price formation, and one takes out demand from price formation, but the net change is the same.

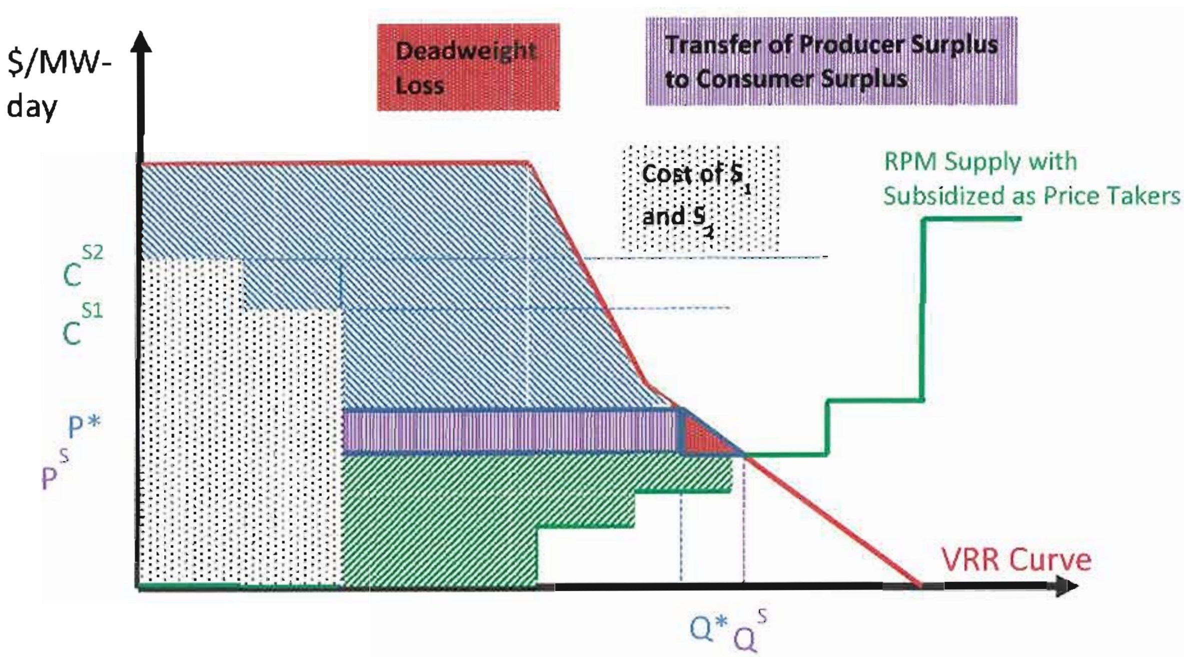
Figure 11: Reproduced Figure 7 Showing the Artificial Price Suppression and Displacement of Cost-Effective Resources



98. Given the distortions and inefficiencies caused by buyer-side market power, it should not be surprising that exercise of buyer-side market power reduces overall market surplus and by extension erode market efficiency. The loss in market surplus is attributable to the additional cost of the subsidized resources shown in the dotted area in **Figure 12**. Those costs significantly reduce producer surplus, and erode consumer surplus, though the impacts of the consumer surplus reduction are borne by the consumers subsidizing the above market price resources. As in the earlier examples, the remaining consumer surplus and producer surplus are represented in the blue and green shaded areas respectively in **Figure 12**. The additional quantity of capacity procured

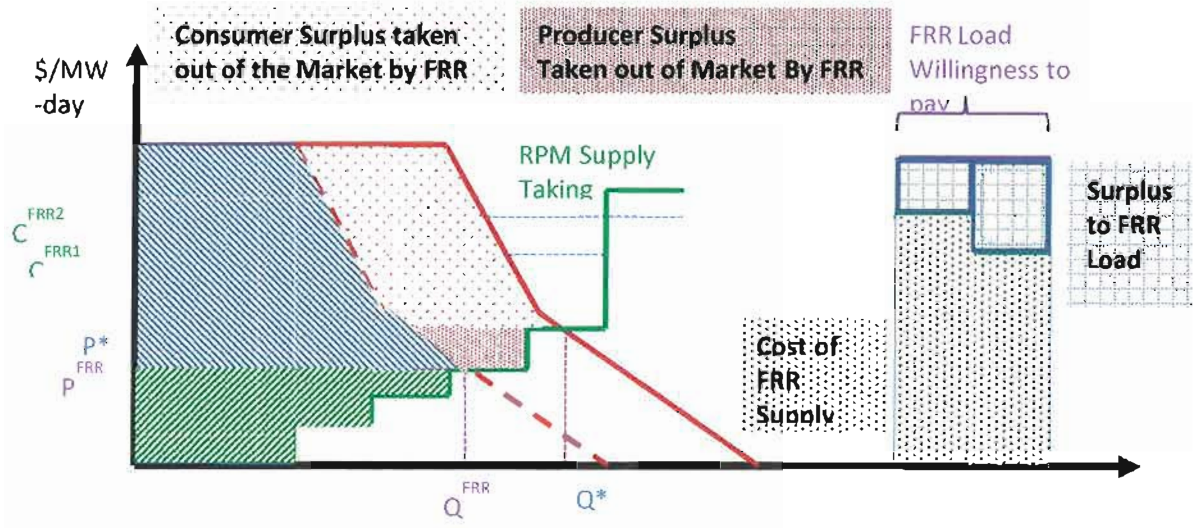
over and above the optimal quantity Q* results in the red shaded deadweight loss to overall surplus. Finally, the purple shaded area shows the transfer of surplus from producers to consumers.

Figure 12: Reduction in Market Surplus Due to an Exercise of Buyer-Side Market Power



99. This loss in overall surplus looks very similar to that shown under an FRR election with higher cost resources shown in **Figure 8** in Section V.B, and reproduced here as **Figure 13**. The remaining consumer and producer surplus match up exactly once one separates out the subsidized resources from the rest of the market in **Figure 12** as has been done in **Figure 13**. And give that in each example the demand curves for capacity are the same across both examples, and the supply curves are originally the same, before FRR or subsidized treatment, it is straightforward to see the equivalence surplus reduction and loss of efficiency between the exercise of buyer-side market power and the Alternate FRR.

Figure 13: Figure 8 Reproduced Showing the Reduction in and Transfer of Surplus from FRR Election



IX. ANALYSIS OF PJM SIMULATION SCENARIOS PROVIDE A REAL-WORLD ESTIMATE OF THE HARM DONE FROM THE USE OF A UNIT SPECIFIC FRR REMEDY

100. The graphical analysis provided in Sections IV, V, and VIII is designed to provide an intuitive understanding of the effects of the current FFR option and the equivalence between exercises of buyer-side market power and the FRR Alternative remedy in terms of market outcomes. Market simulation scenarios using real data from PJM confirms the concepts illustrated graphically and shows the magnitude of the damage to the market that can be done by the FRR Alternative. The same kind of damage has been shown in a recent analysis provided by the IMM for PJM for different levels of resources identified by the FRR Alternative.[26]

[26] Monitoring Analytics, Independent Market Monitor for PJM, *MOPR/FRR Sensitivity Analyses of the 2021/2022 RPM Base Residual Auction*, September 26, 2018. Available at http://www.monitoringanalytics.com/reports/Reports/2018/IMM_MOPR_FRR_Sensitivity_Analyses_Report_20180926.pdf.

101. Following the completion of base residual auctions, PJM performs and releases simulation scenarios to examine the price and quantity clearing effects of adding or removing capacity from large areas in the footprint. These have been RTO outside of MAAC and the MAAC region.[27] After the past two BRAs, PJM has provided scenario simulations adding 3,000 MW in RTO outside of MAAC, 6,000 MW in RTO outside of MAAC, 3,000 MW in MAAC, and 6,000 MW in MAAC.[28] In general these capacity additions were spread out over multiple locations in RTO and MAAC. **Table 2** provides the specific location and amounts of capacity added for each of the four scenarios listed.

Table 2: Location of Capacity Additions for Four Price Taking Scenarios in RTO and MAAC

LDA	3000 MW in RTO Outside of MAAC	6000 MW in RTO Outside of MAAC	3000 MW in MAAC	6000 MW in MAAC
Rest of ATSI	291	582	---	---
ASTI-Cleveland	146.3	292.7	---	---
COMED	754.8	1509.6	---	---
DAY	115.6	231.1	---	---
DEOK	156.2	312.4	---	---
Rest of RTO[29]	1536.1	302.2	---	---
Rest of MAAC[30]	---	---	302.4	64.9
Rest of EMAAC[31]	---	---	991.6	1983.2

[27] PJM, *Scenario Analysis for the 2020/2021 Base Residual Auction*, July 296, 2017. Available at https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2020-2021-bra-scenario-analysis.ashx?la=en.

[28] *Id.*

[29] This is the Rest of RTO that is not otherwise Modeled as a binding LDA. This would include the AEP, EKPC, APS, DUQ, and DOM zones.

[30] Rest of MAAC would include all LDAs that are not otherwise modeled in the analysis. These would include Penelec and MetEd zones.

Rest of PS	---	---	259.3	518.7
PS-North	---	---	258	516
DPL-South	---	---	120.1	240.1
Pepco	---	---	336.9	673.7
BGE	---	---	352.3	704.6
PPL	---	---	379.4	758.8

102. These price-taking scenarios were applied by PJM to run simulations to examine changes in market prices and cleared quantities of capacity. With additional calculations, additional information can be gleaned from these simulations such as 1) the amount of cost-effective capacity that is inefficiently displaced from the market by the price taking MW; 2) the overall changes in revenues available in the market; and 3) a first order estimate of the potential room for the exercise of buyer-side market power.

A. Changes in Locational Capacity Market Clearing Prices due to Additional MW of Price Taking Capacity in the 2020/2021 BRA

103. **Table 3** provides the actual market price from the 2020/2021 BRA along-side the reduced prices as shown by the PJM simulations in each scenario. There are three observations that I would make about **Table 3**. First, when one adds more price taking capacity, the price reductions are greater. This is not all that surprising. The second observation is that the price changes are greatest in the LDAs with the most capacity additions relative to size. This also should not be a surprise since the capacity additions in a smaller LDA should have a greater impact on the supply-demand balance. The third observation is that adding price taking capacity to otherwise constrained LDAs, such as EMAAC, has larger impacts than adding capacity in unconstrained LDAs.

[31] The Rest of EMAAC includes the RE, ACE, JCPL, PECO, and the DPL zone not included in DPL-South.

104. **Table 5** and **Table 5** provide a different look at the price changes reporting these in absolute terms and in percentage terms, respectively. Not surprisingly, adding additional capacity in the RTO does nothing to affect prices in MAAC LDAs. But capacity additions in MAAC, while primarily affecting MAAC LDAs, does have some spillover effects in the RTO zones.

Table 3: 2020/2021 BRA Prices and Price Taking Simulation Results in $/MW-day

LDA	2020/2021 BRA Results	3000 MW in RTO	6000 MW in RTO	3000 MW in MAAC	6000 MW in MAAC
RTO	$76.53	$69.32	$60.00	$74.50	$75.00
MAAC	$86.04	$86.04	$86.04	$85.00	$75.00
EMAAC	$187.87	$187.87	$187.87	$149.92	$124.70
SWMAAC	$86.04	$86.04	$86.04	$85.00	$75.00
PSEG	$187.87	$187.87	$187.87	$149.92	$124.70
PS-NORTH	$187.87	$187.87	$187.87	$149.92	$124.70
DPL-SOUTH	$187.87	$187.87	$187.87	$149.92	$124.70
PEPCO	$86.04	$86.04	$86.04	$85.00	$75.00
ATSI	$76.53	$69.32	$60.00	$74.50	$75.00
ATSI-C	$76.53	$69.32	$60.00	$74.50	$75.00
COMED	$188.12	$185.00	$174.36	$188.12	$188.12
BGE	$86.04	$86.04	$86.04	$85.00	$75.00
PPL	$86.04	$86.04	$86.04	$85.00	$75.00
DAY	$76.53	$69.32	$60.00	$74.50	$75.00
DEOK	$130.00	$122.50	$115.00	$130.00	$130.00

Table 4: Absolute Change in Capacity Prices Due to Price Taking Behavior in $/MW-day from the 2020/2021 BRA Prices

LDA	2020/2021 BRA Results	3000 MW in RTO	6000 MW in RTO	3000 MW in MAAC	6000 MW in MAAC
RTO	---	$7.21	$16.53	$2.03	$1.53
MAAC	---	---	---	$1.04	$11.04
EMAAC	---	---	---	$37.95	$63.17
SWMAAC	---	---	---	$1.04	$11.04
PSEG	---	---	---	$37.95	$63.17

PS-NORTH	---	---	---	$37.95	$63.17
DPL-SOUTH	---	---	---	$37.95	$63.17
PEPCO	---	---	---	$1.04	$11.04
ATSI	---	$7.21	$16.53	$2.03	$1.53
ATSI-C	---	$7.21	$16.53	$2.03	$1.53
COMED	---	$3.12	$13.76	---	---
BGE	---	---	---	$1.04	$11.04
PPL	---	---	---	$1.04	$11.04
DAY	---	$7.21	$16.53	$2.03	$1.53
DEOK	---	$7.50	$15.00	---	---

Table 5: Percentage Changes in Prices in Price Taking Scenarios from the 2020/2021 BRA Prices

LDA	2020/2021 BRA Results	3000 MW in RTO	6000 MW in RTO	3000 MW in MAAC	6000 MW in MAAC
RTO	---	9.42%	21.60%	2.65%	2.00%
MAAC	---	---	---	1.21%	12.83%
EMAAC	---	---	---	20.20%	33.62%
SWMAAC	---	---	---	1.21%	12.83%
PSEG	---	---	---	20.20%	33.62%
PS-NORTH	---	---	---	20.20%	33.62%
DPL-SOUTH	---	---	---	20.20%	33.62%
PEPCO	---	---	---	1.21%	12.83%
ATSI	---	9.42%	21.60%	2.65%	2.00%
ATSI-C	---	9.42%	21.60%	2.65%	2.00%
COMED	---	1.66%	7.31%	---	---
BGE	---	---	---	1.21%	12.83%
PPL	---	---	---	1.21%	12.83%
DAY	---	9.42%	21.60%	2.65%	2.00%
DEOK	---	5.77%	11.54%	---	---

105. The addition of 3,000 MW across the entire RTO is only 1.94 percent and 6,000 MW is only 3.89 percent of the reliability requirement respectively, in the 2020/22021 BRA.[32] So, another observation is that small percentages additions of price taking MW, can have an outsize percentage effect on price as shown in **Table 5**. A 3.89 percent increase in price taking MW can lead to a 21.6 percent decrease in price in the RTO. The additional 3,000 MW and 6,000 MW of price taking MW are 4.54 percent and 9.09 percent of the MAAC reliability requirement respectively.[33] Yet, the price impact in the EMAAC zones is a 20-33 percent decline in prices as shown in **Table 5**.

B. Displacement of Cost-Effective Resources by Price Taking Resources

106. In addition to artificial price suppression, another major distortion that can arise from buyer-side market power or equivalently the proposed FRR Alternative remedy, is the replacement of cost-effective resources with higher cost resources that have obtained subsidies to remain in service. **Table 6** and **Table 7** show the cost-effective capacity displaced by the 3,000 MW and 6,000 MW of price taking capacity in the RTO outside of MAAC.

Table 6: Displacement of Cost-Effective Capacity by 3000 MW of Price Taking Capacity in RTO Outside MAAC

LDA	Price Taking MW	Displacement MW	Displacement %
RTO Total	3000.0	2743.70	91.46%
Rest of RTO	1536.1	1773.00	115.42%
ATSI Total	437.3	58.10	13.29%

[32] PJM, *Planning Period Parameters for 2020/2021 Base Residual Auction*, May 23, 2017. Available at https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2020-2021-bra-planning-period-parameters.ashx?la=en. The reliability requirement is 154,355 MW after taking out FRR load.

[33] *Id.* The MAAC requirement is 66,385 MW

Rest of ATSI	291.0	39.90	13.71%
ATSI-C	146.3	18.20	12.44%
COMED	754.8	738.10	97.79%
DAY	115.6	31.10	26.90%
DEOK	156.2	143.50	91.87%

107. Overall in the RTO, the displacement ratio is over 90 percent as it also is for constrained zones in ComEd and DEOK. Dayton and ATSI already cleared with the RTO and inserting price taking capacity in those LDAs simply displaces more expensive capacity elsewhere in the RTO, such as the rest of the non-modeled RTO LDAs. This is true in both **Table 7** and **Table 7**. Effectively, for every 100 MW of higher cost, price taking capacity that comes into the market, 90 MW of lower cost capacity will get inefficiently displaced in the RTO eroding the cost-effectiveness and efficiency of the capacity market.

Table 7: Displacement of Cost-Effective Capacity by 6000 MW of Price Taking Capacity in RTO Outside MAAC

LDA	Price Taking MW	Displacement MW	Displacement %
RTO Total	6000.0	5412.30	90.21%
Rest of RTO	3072.2	2003.60	115.22%
ATSI Total	874.7	89.80	10.27%
Rest of ATSI	582.0	70.40	12.10%
ATSI-C	292.7	19.40	6.63%
COMED	1509.6	1435.80	95.11%
DAY	231.1	60.10	26.01%
DEOK	312.4	287.00	91.87%

108. As with inserting price taking MW into the RTO, inserting price taking MW into MAAC LDAs also has even higher overall displacement percentages between 97.5 and 99 percent as shown in **Table 8** and **Table 9**. As with inserting price taking capacity in the RTO, the displacement in LDAs that were not binding within MAAC, but cleared

with the MAAC LDA such as Pepco in SWMAAC and the rest of MAAC witnessed as much as 300 percent displacement relative to inserted price taking capacity because price taking capacity in the rest of MAAC displaced more expensive resources in those areas that had cleared previously. This is another example of cost shifting but in a geographic sense among producers where some zones experience greater resource displacement than others. It appears price taking capacity in EMAAC displaced a lot of capacity in the Rest of MAAC and, SWMAAC and Pepco LDAs indicating those areas had cost effective resources, but with costs closer to the market price. Additionally, there were some small spillover effects to the wider RTO from price taking capacity entering MAAC, but overall these effects were small.

Table 8: Displacement of Cost-Effective Capacity by 3000 MW of Price Taking Capacity in MAAC LDAs

LDA	Price Taking MW	Displacement MW	Displacement %
RTO	3000	2927.8	97.59%
Rest of RTO	0	-53.5	N/A
MAAC	3000	2981.5	99.38%
Rest of MAAC	302.4	772.3	255.39%
EMAAC	1629	1295.1	79.50%
Rest of EMAAC	991.6	934	94.19%
SWMAAC	689.2	1396.5	202.63%
PSEG Total	517.3	359.9	69.57%
Rest of PSEG	259.3	139.9	53.95%
PS-NORTH	258	220	85.27%
DPL-SOUTH	120.1	1.2	1.00%
PEPCO	339.9	1050.8	311.90%
ATSI	0	4.5	N/A
ATSI-C	0	3.2	N/A
COMED	0	0	N/A
BGE	352.3	345.8	98.15%
PPL	379.4	4.3	1.13%

DAY	0	1.8	N/A
DEOK	0	0	N/A

109. Overall, for every 1,000 MW of higher cost subsidized price taking capacity inserted in the market displaces between 975 and 990 MW of cost-effective capacity overall leading the same conclusion that that exercises of buyer market power, or equivalently the unit specific FRR Alternative will lead to an inefficient substitution of high cost resources, albeit subsidized, for lower cost resources.

Table 9: Displacement of Cost-Effective Capacity by 6000 MW of Price Taking Capacity in MAAC LDAs

LDA	Price Taking MW	Displacement MW	Displacement %
RTO	6000	5945.6	99.09%
Rest of RTO	0	693.1	N/A
MAAC	6000	5458.5	90.98%
Rest of MAAC	604.9	1309.7	216.53%
EMAAC	3258	2702.2	82.94%
Rest of EMAAC	1983.2	1827.9	92.17%
SWMAAC	1378.3	1675.4	121.56%
PSEG Total	1034.7	830.6	80.27%
Rest of PSEG	518.7	349.5	67.40%
PS-NORTH	516	481	93.22%
DPL-SOUTH	240.1	43.7	18.20%
PEPCO	673.7	1106.9	164.30%
ATSI	0	4.4	N/A
ATSI-C	0	3.2	N/A
COMED	0	0	N/A
BGE	704.6	492.4	69.88%
PPL	758.8	159.1	20.97%
DAY	0	1.8	N/A
DEOK	0	0	N/A

C. Revenues Reductions in the Capacity Market Due to Price Taking Behavior by Resources Receiving Out-of-Market Support.

110. **Table 11** and **Table 11** show the overall revenues collected by committed capacity resources and the absolute difference in revenues collected, respectively. Of course, as additional resources with out-of-market support enter as price takers, market prices decline as evidenced in **Table 5** and **Table 5** and so do corresponding revenues. The largest impact on revenues, as it is on prices, is due to pride taking behavior in the more constrained LDAs such as EMAAC, and to a lesser extent the binding LDAs in RTO such as ComEd and DEOK. **Table 11** shows an additional 6,000 MW of price taking resources in RTO, has about the same impact on overall revenues in PJM as 3000 MW of price taking resources in MAAC.

Table 10: Revenues from the 2020/2021 BRA and Scenarios with Price Taking Behavior of Capacity Receiving Out-of-Market Support

Area	2020/2021 BRA Results	3000 MW in Rest of RTO	6000 MW in Rest of RTO	3000 MW in MAAC	6000 MW in MAAC
RTO outside MAAC	$3,869,024,266	$3,592,557,604	$3,312,001,625	$3,753,163,285	$3,742,845,282
MAAC	$2,842,580,333	$2,842,580,333	$2,842,580,333	$2,419,485,221	$2,064,167,455
PJM Total	$6,711,604,599	$6,435,137,936	$6,154,581,958	$6,172,648,505	$5,807,012,737

Table 11: Difference in Revenues due to Price Taking Behavior of Capacity Receiving Out-of-Market Support Relative to the 2020/2021 BRA

Area	2020/2021 BRA Results	3000 MW in Rest of RTO	6000 MW in Rest of RTO	3000 MW in MAAC	6000 MW in MAAC
RTO outside MAAC	---	$276,466,663	$557,022,641	$115,860,982	$126,178,984
MAAC	---	$0	$0	$423,095,112	$778,412,878
PJM Total	---	$276,466,663	$557,022,641	$538,956,094	$904,591,862

111. **Table 12** provides the percentage change in revenues from the price taking scenarios. Again, keeping in mind that the additional MW are 1.94 and 3.89 percent of the reliability requirement in RPM across all of PJM, 4.54 and 9.09 percent of the MAAC

reliability requirement respectively. The percent changes in revenue are multiples of these values. For example, the change in revenue in the RTO outside of MAAC from a 3.89 percent increase in price taking MW from resources receiving out-of-market support results in a 14.4 percent change in revenue in the same area -- an impact 3.7 times greater than the change in price taking MW. Similarly, in MAAC, a 9.09 percent change increase in price taking MW results in a 27.38 percent decline in revenues in MAAC -- an impact 3 times greater than the change in price taking MW.

Table 12: Percentage Difference in Revenues due to Price Taking Behavior of Capacity Receiving Out-of-Market Support Relative to the 2020/2021 BRA

Area	2020/2021 BRA Results	3000 MW in Rest of RTO	6000 MW in Rest of RTO	3000 MW in MAAC	6000 MW in MAAC
RTO outside MAAC	---	7.15%	14.40%	2.99%	3.26%
MAAC	---	0.00%	0.00%	14.88%	27.38%
PJM Total	---	4.12%	8.30%	8.03%	13.48%

112. The bottom line is that relatively small changes in price taking capacity from resources receiving out-of-market support can have large impacts on capacity market revenues where the subsidies are being awarded. Such a large impact as shown in **Table 11** and **Table 12** can only rattle investor confidence in the markets with such a small percentage of FRR resources causing such a large reduction in revenues. And the Commission has already signaled its intent to maintain investor confidence in the context of state policies in ISO New England.[34] And given that the capacity market is

[34] *ISO New England Inc.*, 162 FERC ¶ 61,205 (2018) ("CASPR Order"), P 21, "A capacity market should facilitate robust competition for capacity supply obligations, provide price signals that guide the orderly entry and exit of capacity resources, result in the selection of the least-cost set of resources that possess the attributes sought by the markets, provide price transparency, shift risk as appropriate from customers to private capital, and mitigate market power. Ultimately, the purpose of basing capacity market

"financially the residual market" by which resources can cover their going forward costs, this reduction in revenues along with displacement threatens the ability of cost-effective resources to remain in commercial operation.

D. Determining the Ability to Exercise Buyer-Side Market Power, or How Much Subsidy can be Provided and Yet Reduce Overall Load Expenditures?

113. A successful exercise of buyer-side market power through the subsidization of resources that have costs above market prices will find the right level of payment, over and above the market price, that will still result in lower revenues paid out to all resources. And this is exactly the kind of behavior the proposed FRR Alternative encourages by its very design and the mechanisms through which it would be implemented. The idea is to get the high cost resource to enter the market as a price taker, effectively increasing the supply. The way to figure this out is to examine the difference in capacity revenues and simply divide by the MW of capacity receiving the subsidized support to enter the market as price takers.

114. As shown in **Table 11**, when 3,000 MW of price taking MW with subsidized support is added to RTO outside of MAAC, the difference in revenue is just over $276 million per year. Also note the price change is "only" a reduction in the market price of $7.21/MW-day as shown in **Table 4**. But divide the reduction in revenue by the 3,000 MW of capacity and then divide again by 365 to get the amount of the subsidy, over and above the market clearing price, that could be paid to all 3,000 MW of these resources. That breakeven subsidy level is $252/MW-day. Any subsidy payment below that amount can

constructs on these principles is to produce a level of investor confidence that is sufficient to ensure resource adequacy at just and reasonable rates."

result in lower overall revenues paid by load while displacing lower cost resources and reducing market revenues.

115. For the 3,000 MW of price taking MW with subsidized support is added to MAAC, the difference in revenue is just over $423 million per year in MAAC alone as shown in **Table 11**. The price change in MAAC is only $1.04/MW-day, but the big impact is in EMAAC where the capacity price falls by nearly $38/MW-day as shown in **Table 4**. Carrying out the same exercise I just described results in a breakeven subsidy level of $386/MW-day. Again, any subsidy paid below this amount will result in lower total expenditures to be paid by the load in MAAC while displacing lower cost resources and reducing market revenues.

Table 13: Level of Breakeven Subsidy Payable Over the Market Price ($/MW-day)

Area	3000 MW in Rest of RTO	6000 MW in Rest of RTO	3000 MW in MAAC	6000 MW in MAAC
RTO outside MAAC	**$252.48**	**$254.35**	---	---
MAAC	---	---	**$386.39**	**$355.44**

116. **Table 13** shows the breakeven subsidy payment in each of four price taking scenarios for revenue changes only in the identified areas overall. In MAAC, and mostly due to the binding constraints in EMAAC, the level of breakeven subsidy is much larger than it is in RTO. These numbers can easily be verified by simply taking the revenue decreases shown in **Table 11** and dividing by the price taking MW and dividing again by 365 to arrive at $/MW-day.

E. Implications for Known Subsidies in New Jersey and Illinois

117. The results shown on the breakeven subsidies are instructive for the approved subsidies for nuclear resources in New Jersey and Illinois. The New Jersey nuclear units are in

EMAAC where the biggest impact has been shown, and the affected capacity is equal to just over 3,500 MW. Moreover, New Jersey has already approved subsidies for offshore wind that would add another increment of subsidized capacity into RPM in EMAAC. [35] The kind of price suppression that could be observed is likely beyond that shown in this analysis.

118. In Illinois, approximately 1,400 MW of nuclear capacity from the Quad Cities Nuclear station has been awarded subsidies granted under the Future Energy Jobs Act.[36] Along with the Clinton Nuclear station in MISO, this amounts to the nuclear units receiving as much as \$366/MW-day in subsidies.[37] The 1,400 MW of Quad Cities that is in PJM is just about the amount of capacity added to ComEd in the simulation scenario adding 6,000 MW of price taking capacity in RTO outside of MAAC. The change in price in this scenario is \$13.76/MW-day as shown in **Table 4**. The change in revenue in ComEd alone is just over \$115 million per year, with an implied breakeven subsidy of nearly \$210/MW-day.

119. As an estimate, it appears that the subsidy in ComEd may not be a successful exercise of buyer-side market power in the sense that it has not reduced prices sufficiently to offset the cost of the subsidies. Nonetheless, it will still have the effect of distorting the market and effecting revenues for other suppliers in that LDA.

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[35] Joshua S. Hill, "New Jersey Makes Way For 1.1 Gigawatt Offshore Wind", September 21, 2018 available at https://cleantechnica.com/2018/09/21/new-jersey-makes-way-for-1-1-gigawatt-offshore-wind/

[36] Illinois General Assembly, Public Act 99-0906 ("Future Energy Jobs Act" or "FEJA"), November 30, 2016, available online at http://www.ilga.gov/legislation/publicacts/99/PDF/099-0906.pdf. The FEJA was signed into law by Governor Bruce Rauner on December 7, 2016.

[37] Combined the Quad Cities and Clinton nuclear stations in Illinois have approximately 2400-2500 MW of capacity. The maximum amount of money paid out under the Future Energy Jobs Act is about \$330 million per year. This works out to payments equal to about \$366/MW-day.

X. TO PRESERVE EFFICIENT OUTCOMES IN THE CAPACITY MARKET A "CLEAN" MOPR IS THE SIMPLEST AND MOST EFFECTIVE MITIGATION MEASURE

120. As the PJM scenario simulations and the graphical analysis illustrate, below-cost offers from subsidized resources artificially suppress clearing prices and thereby inefficiently displace otherwise cost-effective resources and reduce overall market efficiency. Given that the proposed resource specific FRR Alternative has the exact same impact on clearing prices, it would have the same effects in terms of inefficiently displacing otherwise cost-effective resources and reducing overall market efficiency.

121. The Commission already rejected the idea of a MOPR riddled with exemptions and exceptions when it rejected PJM's MOPR-Ex proposal.[38] Furthermore, the Commission has indicated a strong MOPR is absolutely necessary to protect the market from the kind of damage that can be inflicted by subsidized price taking resources. All of this leads to one clear conclusion: implement a so-called "Clean MOPR" as proposed in Docket No. EL18-169-000.

A. A Clean MOPR Only Mitigates Resources with Actionable Subsidies

122. Actionable subsidies should include subsidies that are not available to similarly situated resources. An actionable subsidy is one designed for specific generation technologies, generation fuel types, or specific generators in specific locations themselves. In this sense, actionable subsidies are inherently discriminatory with the intent of aiding one particular generation resource, or technology or in a resource at a particular location at the expense of other competitors in the market as has been shown in the graphical above. Simply stated, actionable subsidies are those explicitly designed to shift

[38] June 29th Order P 158.

revenues from more efficient, lower cost resources to higher cost, but preferred resources.

123. Furthermore, these sorts of subsidies are inherently anti-competitive in that there is generally no competition among ***all resource types*** for subsidies targeted toward specific goals such as the emissions reductions. The resource types targeted are chosen in advance regardless of the implied cost of emission abatement of the chosen technologies versus other technology types. And while the cost of pollution abatement is not within the Commission's purview, the related impacts in terms of cost shifting, price suppression, and inefficient outcomes in wholesale power markets are squarely within the Commission's bailiwick.

124. New, and now increasingly existing, resources are recipients of actionable subsidies and both new and existing resources should be subject to the Clean MOPR. Being subject to a Clean MOPR, these actionable subsidies are really impermissible in wholesale power markets.

125. There are various other subsidies that should not be actionable, consistent with those covered by PJM's proposed "Competitive Exemption." These include tax abatement for local economic development that are available to all resources types and generally other sectors of the economy as well.

B. A Clean MOPR Mitigates Resources with Impermissible Subsidies to a Measure of Net Going Forward Costs

126. Mitigation of new entrants that are recipients of actionable or impermissible subsidies can be done based on estimates for the Net Cost of New Entry ("Net CONE") as has been the case for new gas combined cycle and gas combustion turbines in PJM for

several years. The IMM has already computed Net CONE values for wind and solar resources that are potentially recipients of impermissible subsidies.

127. Mitigation of existing resources can be addressed in one of two ways. The first way is a bottom up approach by which the existing resource can submit all of its cost data and projected revenue data to come up with a unit specific mitigation value. The problem with this method is two-fold from my experience Chief Economist at PJM in charge of this unit specific mitigation process. First, the subsidized resource has an incentive to "shade" its costs on the low side to get a lower price floor to clear and verifying the cost data is a time and personnel intensive exercise. Second, the cost data presented may not be consistent with the data provided to the states to receive the subsidy.

128. The second approach to mitigating existing resources, which can also work for new resources, is to rely on the information inherent in the subsidy level and the data used in the legislation or regulatory proceeding to arrive at the subsidy level. In this sense, mitigation is using the idea of information revelation to ascertain the net going forward cost of the resource receiving the unpermitted subsidy. This eliminates the issue of conflicting information. Other information can be used to supplement the level of mitigation, but it tailors the mitigation to the level of the impermissible subsidy.

C. There are no Exemptions or Exceptions with a Clean MOPR

129. Any recipient of an actionable or impermissible subsidy should be subject to mitigation. This stands in sharp contrast to the MOPR that existed in PJM just prior to *NRG* where renewable resources and existing resources were still exempt from MOPR.

130. Resources not receiving actionable subsidies are, by definition, not subject to the Clean MOPR.

131. There should be no "carve outs" allowing for a certain amount of resources receiving unpermitted subsidies to be exempt from a Clean MOPR in any given year. As the analysis of the PJM simulations shows, even allowing such an exemption for less than two percent of the reliability requirement can lead to significant artificial price suppression, reduced revenues, displacement of otherwise economic resources, cost shifting, and reduced efficiency.

XI. NO FORM OF ACCOMMODATION EXISTS THAT WILL PRESERVE THE EFFICIENCY AND JUST AND REASONABLENESS OF PJM CAPACITY MARKET OUTCOMES

132. I understand the Commission's desire to accommodate state policies to prevent load from potential double payments for both subsidized resources and capacity resources. While this is an admirable goal, technically speaking, it is simply not possible to accommodate such polices and preserve efficient and just and reasonable outcomes in the PJM capacity market.

133. Any accommodation policy that permits resources with out-of-market support (subsidies) and costs above competitive market prices to enter the market as price takers to receive a capacity commitment can only result in harm to the market. This harm comes in the form of artificial price suppression, displacement of otherwise cost-effective resources, reductions in capacity market revenues to competitive resources, the shifting of costs and benefits among market participants, and inefficient outcomes that are characteristic of an exercise of buyer-side market power.

134. It does not matter whether this accommodation comes in the form of an exemption to a Clean MOPR or the use of the FRR Alternative. Such an accommodation opens up an avenue to explicitly permit exercises of buyer-side market power under the guise of satisfying other public policy objectives regardless of those objectives are.

135. It does not matter if the accommodation requires above market price resources to satisfy other conditions or require actions on the part of other market participants such as retirement. It is does not matter if the accommodation only allows damage to the market at some point in the future. The graphical analysis and simulation results are clear and unambiguous. Accommodation will eventually result in above-market-price resources receiving subsidies to enter the market as price takers to receive a capacity commitment leading to irreversible harm to the market. And such accommodation hard-wires buyer-side market power as part of the PJM market design.

136. This can be seen not only through the graphical analysis I have presented in this affidavit, but also through actual simulations run by PJM confirming the outcomes seen in the graphical analysis. The only question with an accommodation strategy is how much damage to competitive outcomes is "acceptable"? Or stated another way, how much in the way of "unjust, unreasonable, and unduly discriminatory" outcomes are "permissible"?

* *

137. This concludes my affidavit.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Calpine Corporation v. **PJM Interconnection, L.L.C.**	)))))	**Docket No. EL16-49-000**
PJM Interconnection, L.L.C.	))	**Docket No. ER18-1314-000** **Docket No. ER18-1314-001**
PJM Interconnection, L.L.C.	)	**Docket No. EL18-178-000**
		(Consolidated)

AFFIDAVIT OF PAUL M. SOTKIEWICZ, PH.D.

Paul M. Sotkiewicz, Ph.D., being duly sworn, deposes and states that the statements contained in the foregoing Affidavit of Paul M. Sotkiewicz, Ph.D. are true and correct to the best of his knowledge and belief.

Paul M. Sotkiewicz, Ph.D.

Subscribed and sworn to before me
this 1st day of October, 2018

Notary Public for
the State of Florida

State of Florida
County of Alachua

Notary Public State of Florida
Cesar Jose Andrade
My Commission FF 903861
Expires 07/27/2019

My Commission expires: 07/27/19

Attachment B

to the

Prepared Comments

of Paul M. Sotkiewicz, Ph.D.

In Docket No. EO18080899

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

AFFIDAVIT OF ROY J. SHANKER, Ph.D.

Docket No. EL16-49-000
Docket No. ER18-1314-000
Docket No. ER18-1314-001
Docket No. EL18-178-000

1. My name is Dr. Roy J. Shanker. My address is P.O. Box 1480, Pebble Beach, CA. 93953. I am an independent consultant. My resume, attached as Exhibit RJS-1, summarizes my experiences in numerous regulatory proceedings before state commissions and the Commission.

2. I have been asked by the PJM Power Providers Group ("P3")[1] to review the Federal Energy Regulatory Commission's ("Commission") June 29, 2018 Order in Docket Numbers EL16-49-000; ER18-1314-000; ER18-1314-001; and EL18-178-000 (Consolidated). ("Order" or "June 29 Order").

3. I am an independent consultant. I have worked on electricity issues since approximately 1973 and independently since approximately 1981. I have had consulting engagements related to PJM since approximately 1976. I have been part of the PJM ISO/RTO stakeholder process since approximately 1995. I have participated in just about every aspect of the PJM capacity market developments since the inception of the market. I was involved in the development of the RPM through stakeholder processes and related Commission dockets and participated in the Commission settlement proceedings that resulted in the initial version of RPM.

4. I have also submitted comments to the Commission regarding the above dockets and similar proceedings in other markets. Specifically, I have offered testimony on this

[1] While I have been retained by P3 to offer this statement, the views expressed herein represent my views alone and not necessarily the views of P3 or any P3 members with respect to any issue.

subject in Docket No. AD17-11 (invited speaker), and filed technical conference comments and post conference comments in Dockets No. ER13-535; No. ER11-2875; No. EL11-20; and No. EL15-64-000. I also appeared before the New Jersey General Assembly in 2011, addressing related issues in discussions of Assembly Bill 3442 and Senate Bill 2381, related to the impacts of state-directed and subsidized capacity procurement for new natural gas units. In ISO-NE, I testified in Dockets No. ER10-787-000; No. EL10-50-000; and No. EL10-57-000 addressing a similar mitigation issue. I participated in multiple stakeholder processes in PJM and NYISO that discussed these issues, including the most recent ones in PJM that evaluated the two alternatives that PJM submitted in the proceedings (Capacity Repricing and MOPR-Ex), related to this Order. I also recently submitted an affidavit in the related (and still open) Docket No. EL18-169. Finally, PJM has had an ongoing stakeholder process as it fashions its own response to the June 29 Order, and I have participated in this process on behalf of several parties.

5. I have, for over a decade, discussed in one form or another, these issues with most of the relevant PJM staff and management, as well as the Independent Market Monitor ("IMM"). I also participated in similar issues and Commission dockets in ISO-NE and NYISO.

6. I have a bachelor's degree from Swarthmore College and both a master's and doctorate degree from Carnegie-Mellon University.

Background

7. The June 29 Order determined that the current PJM tariff procedures for dealing with out-of-market subsidies is unjust and unreasonable.[2] I agree with the Commission's

[2] Order at paragraph 156, "For the foregoing reasons, we find, based on this record, that the PJM Tariff allows resources receiving out-of-market support to significantly affect capacity prices in a manner that will cause unjust and unreasonable and unduly discriminatory rates in PJM regardless of the intent motivating the support. We are compelled by the evidence presented by PJM, Calpine, and other parties to these consolidated proceedings to conclude that out-of-market payments by certain PJM states have reached a level sufficient to significantly impact the capacity market clearing prices and the integrity of the resulting price signals on which investors and consumers rely to guide the orderly entry and exit of capacity resources. We cannot rely on such a construct to harness competitive market forces and produce just and

conclusion and logic supporting this finding. It echoes similar comments I have recently made before the Commission in the related proceedings. The Commission also specifically rejected both of PJM's proposed two alternative "fixes," the so-called "Repricing" and the "MOPR-Ex" proposals. Neither alternative was found to result in a just and reasonable means to address the problem of out-of-market payments/subsidies to both new market entrants and existing facilities suppressing wholesale capacity rates rendering them unjust and unreasonable.

Conclusions Related to Commission's Order

8. While certainly not exhaustive, I have three principal conclusions. First, any action that the Commission takes in this paper hearing must satisfy the Commission's basic finding that the status quo is unjust and unreasonable because it allows price suppression from subsidized units. Said another way, any proposal that the Commission approves must be demonstrated not to cause price suppression and to remedy any existing adverse impacts. Second, consistent with my testimony in the underlying proceeding, I support a "Clean MOPR" that mitigates seller offers to a competitive level for any unit receiving a Material Subsidy (as defined by PJM in Docket No. ER18-1314). Such a MOPR would not include any special exemptions for self-supply resources, state procured resources or public power entities other than the ability to offer at its actual costs versus the default competitive level/reference price. Finally, I believe that the existing FRR construct, with certain modifications, provides a viable means for a state, on its own initiative, to procure its own capacity obligations, through means it may prefer other than an interstate centralized capacity construct. I emphasize this approach, though still price suppressive, is quite different than the partial or unit specific FRR alternative that the Commission suggested.

reasonable rates. The PJM Tariff, therefore, is unjust and unreasonable." P3's accompanying comments contain additional citations.

9. The proposed use of a unit specific FRR is fatally flawed and should be rejected. While there are a number of actions that could be taken to reduce the adverse impacts of a unit specific FRR, any reduction in system load by out-of-market subsidized generation inherently suppresses prices and therefore violates the Commission's fundamental finding regarding the unjust and unreasonable nature of any solution that artificially suppresses prices. Below I will explain this in more detail with several examples. In particular I will discuss how PJM's analysis and suggested implementation of the unit specific FRR option results in a level of price suppression that is totally undifferentiated from doing nothing at all to mitigate any subsidies.

Recommendation

10. I strongly support the Commission's call for a Clean MOPR with few or no exceptions that would be uniformly applied to all market participants receiving a Material Subsidy.[3] Such a structure would resemble the MOPR-Ex alternative which PJM filed in the underlying docket, but without the broad range of specific exemptions that undo the desired mitigation. While I appreciate the Commission's attempt to offer an alternative to states that seek to favor certain resources, a unit-specific FRR inevitably leads to market-distorting price suppression and is riddled with administrative complexities. I do not believe there are any "fixes" that can be made to the unit specific FRR to make it work in a manner that can address these concerns nor remedy the Commission's finding that price suppression under the status quo causes the PJM rates to be unjust and unreasonable. Instead, the best, indeed perhaps only, path forward for PJM to instill just and reasonable tariff provisions that address the challenges posed by subsidized resources is to support a "Clean MOPR." A "Clean MOPR" can be established while allowing states and LSEs to continue to have the option to pursue full FRR status through slightly modified existing tariff provisions. Similarly, under such an approach, the states would have the opportunity to fully evaluate the economic risks and costs of pursuing such options and the associated mitigation of market seller offers. Indeed, appropriate

[3] I adopt the definition of Material Subsidy initially offered by PJM in its initial filing, and as differentiated from the defined Actionable Subsidy. See, https://www.p3powergroup.com/siteFiles/News/EF343052C741AEA526C2FA792312F0D2.pdf at 19-20.

mitigation allows the transparent recognition and evaluation of these types of risks prior to creating the state subsidies. This is strongly contrasted with the risk/costs being imposed on existing suppliers who have relied on the Commission's historic preference for a level playing field for comparable products providing comparable service.

11. I would also note that I believe the existing FRR mechanism in PJM could be improved and I encourage the Commission to direct PJM to file a compliance filing that modifies the existing FRR mechanism in the fashion I discuss below.

Any Solution Must Address the Problem of Subsidized Units Unjustly and Unreasonably Suppressing Capacity Market Rates.

12. The starting point for any Commission review of a unit specific FRR proposal is the Commission's own determination that the status quo is unjust and unreasonable based on the existing and continued price suppression due to subsidized participation in the capacity markets. In this context, I believe that any proposal put forward to the Commission has to affirmatively demonstrate that it does not result in price suppression, nor allow the continuation of existing price suppression, or have "loop-holes" that allow circumvention of the mitigation that prevents price suppression. Alternatively, any proposal that has the property of allowing price suppression should have an affirmative obligation to quantify such suppression, and justify it in the context of the ability of the market clearing prices to accurately send entry and exit signals consistent with the pricing, costs and revenues associated with a competitive unsubsidized supplier and at the same time allow the potential for a fully compensatory payment over time to existing and new competitive suppliers. The Commission's finding squarely assigns this burden of proof to those seeking to offer subsidized supply into the market, and the Commission should dismiss any proposals that can not meet this burden.

13. Such a litmus test is a reasonable one and an empirically feasible standard for the Commission to evaluate in response to the June 29 Order.

A Clean MOPR is the Most Effective Means to Address Price Suppression in the Capacity Markets.

14. I refer the Commission to the comments and affidavits I filed in Docket No. ER 18-1314, which has been consolidated into this proceeding, and Docket No. EL18-169, which has not been consolidated into this proceeding. A clean MOPR mitigating all suppliers with a Material Subsidy to an appropriate competitive offer floor price is the best solution to mitigate the price distortion of subsidies provided to select suppliers. It is simple and all-inclusive. Parties that would otherwise have to claim a competitive exemption are exempt in this process, by definition, as they have no Material Subsidy. The only true exception would be the ability to demonstrate costs lower than a default offer cap, presumably B * Net CONE.[4]

15. The Commission suggests that exemptions might be applied to a very broad MOPR and asks whether a self-supply exemption should be considered.[5] My conclusion in regard to a self-supply exemption is very simple: the only instance in which self-supply should not be subject to mitigation is when the supply is obtained via an all source (new and existing), arms-length, competitive solicitation that is evaluated by an impartial third-party using objective criteria. Any other approach, by definition, has a potentially market-distorting out-of-market subsidy impact due to the purchase and cost assurances associated with public power or IOU ownership and is thus discriminatory. The assurance of recovery (or ability to charge/pass through) prudent costs constitutes a material subsidy which leads to price suppression. The market seller is assured full prudent cost

[4] PJM is currently considering revisions to the Market Seller Offer Cap that would result in a cap that deviates from the underlying price offer indifference properties that defined the present cap. If this is the case, I believe the specific offer cap for mitigation may have to be reviewed to determine a metric that approximates the existing cap in terms of the empirical criteria for mitigation to a competitive level if PJM should make these modifications.

[5] Order at paragraph 167: As discussed above, the proposed replacement rate would expand the MOPR to new and existing resources receiving out-of-market support with few to no exemptions. We request comment on the types of MOPR exemptions that should be included. For example, should an exemption be included for self-supplied resources used to meet loads of public power entities? Alternatively, should those resources have the option to use the resource-specific FRR Alternative? What, if any, exceptions should be added to the MOPR for existing resources in the capacity auction?"

recovery regardless of the market-clearing price and thus has an incentive to offer at zero, to assure clearing and the recovery of some funds to offset of regulatory revenues. In turn, the self-supply seller is allowed to lean on the rest of the market when convenient in order to reduce the costs of carrying surplus capacity at the expense of other load, while at the same time suppressing pricing to competitive suppliers.

16. The Commission should also be wary of justifications for such exemptions based on arguments related to "historic business models." Such models were indeed followed in the past, but they were done so for a different regulatory, business and operational model, not the current RTO market design. The "historic business model" did not have the benefits of a fully integrated and efficient operating market of approximately 150,000 MW, nor did it offer the reliability benefits of such an integrated market. It also wasn't designed to be compatible with and facilitate retail access. Parties entering into a more efficient market like the current RTO structure did so voluntarily to capture the benefits of scale, efficiency and reliability. These entities also voluntarily accepted the burdens of a competitive platform. While self-supply resources may wish to obtain discriminatory and favorable rules, appealing to historic practices and ignoring the reality and benefits of the RTO structure is not a legitimate justification.

17. A new paradigm was put in place with attendant obligations. The reality of fully participating in an unbiased design which may not accommodate all of a load serving entity's preferences leads to two options: withdrawing, or accepting the full consequences, both positive and negative (from their own perspective) of a level, non-discriminatory and competitive market platform.

18. Similarly, I believe a discussion by Robert Stoddard, sponsored by NRG, in Docket No. ER 18-1314, also offers an excellent articulation of the market impact of the current self-supply exemption and would urge the Commission to consider those comments in making its own proposal. Specifically, Mr. Stoddard observes, "In the face of massive surpluses, averaging over 7,300 MW in the past five BRAs, self-supply entities should be deferring new builds and buying any capacity shortfall at the low

market prices, rather than exacerbating the surplus and lowering prices even more. The net-short and net-long bands are providing a false sense of security, as evidenced by the fact that at least two "self-supply" providers have cleared 4,152 MWs in the five BRAs in which the exemption and bands were in effect, even though capacity prices were low and no new supply was needed."[6] Unambiguously, it would have been far more cost effective to defer these new facilities until a time when the PJM capacity markets were clearing far below the estimated net cost of new entry. But, the "traditional business model" of rate-based, full recovery of investment, provided incentives that overwhelm this benefit of competitive markets, and does so to the detriment of all other suppliers.

The Unit Specific FRR, as Proposed, Leads to the Same Price Suppression as Unmitigated, Subsidized Units Participating in the Capacity Auction.

19. The Commission's suggested alternative of a unit specific FRR is inherently price suppressive. It actually appears worse than the status quo by allowing unfettered subsidization of existing and new units, corresponding reductions in load, and the displacement of competitive units. All of this still combines to suppress prices artificially due to the subsidies compounding the very problem that the Commission seeks to address.

20. The mechanics of removing both generation and an appropriate level of load from the auction process as suggested by the Commission are slightly different for new entrants and existing units that failed to previously clear the auction without a subsidy, versus application to existing units that have cleared and received a subsidy. However, the negative impacts to the market are similar.

21. When an existing unit that failed to clear the RPM auction receives a subsidy and then clears, under a partial FRR load would be reduced comparable to the size of the subsidized unit (including reserve adjustment). However, the same supply curve that would have existed without the subsidized unit remains up to the previous higher load requirement. This unequivocally results in the same previous existing supply competing

[6] Stoddard Affidavit attached to NRG Protest, Docket No. ER 18-1314, at page 20.

for less load, and a lower clearing price due to the subsidy. This was the same conclusion I previously reached, and similarly was confirmed by the IMM in its September 26, 2018 report on auction sensitivities and impacts of a partial/unit specific FRR.[7]

22. Consider an actual example in which an existing unit failed to clear an auction, but then received a subsidy. Exelon owns approximately 1350 MWs of the Quad Cities nuclear station (Quad Cities). Quad Cities failed to clear in the 2016 and 2017 RPM auctions.[8] Failure to clear two consecutive auctions is an indication that a unit is likely no longer economic and should consider retiring. Indeed, in 2016, Exelon announced its intention to shut down Quad Cities on June 1, 2018.[9] However, in the case of Quad Cities, Illinois provided an out-of-market subsidy in the form of a Zero Emissions Credit in 2017 ("ZEC"), thus enabling Quad Cities to clear the auction in May of 2018. As Exelon made clear in a press release, "Quad Cities cleared the capacity auction as a result of Illinois legislation…."[10]

23. Had a "Clean MOPR" been applied to the materially subsidized Quad Cities unit, the Material Subsidy would have been recognized and the offer price mitigated to remove the impact of the subsidy. However, had the unit specific FRR been available (assuming Illinois found a means to provide full compensation for Exelon's capacity), the unit and the load associated with it would have been removed from PJM's capacity auction. So, for the unit specific FRR, if applied in the case of the 2018 BRA to Quad Cities, approximately 1350 MWs that would have not cleared the auction due to application of a strong MOPR, would now be considered an FRR resource and the appropriate,

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[7] *See*, http://www.monitoringanalytics.com/reports/Reports/2018/IMM_MOPR_FRR_Sensitivity_Analyses_Report_20180926.pdf. ("IMM MOPR FRR Report")

[8] http://www.exeloncorp.com/newsroom/pjm-auction-results-release-2017 and http://www.exeloncorp.com/newsroom/pjm-auction-results-2016.

[9] https://qctimes.com/news/local/exelon-begins-steps-to-shut-down-nuclear-plant-in-cordova/article_b88c247c-28be-11e6-b843-23266077cb5a.html

[10] http://www.exeloncorp.com/newsroom/Documents/Press-Release-Exelon%20Announces%20Outcome%20of%202021-2022%20PJM%20Capacity%20Auction_3784.pdf

corresponding load would have been reduced to account for the unit FRR choice (i.e. load declines and pre-subsidy auction supply curve stays the same). The same supply chasing less load results in suppressed prices due to the subsidized partial FRR.

24. For the market as a whole in the 2017 BRA, 165,109.2 MWs cleared, resulting in a 23.3% reserve margin (excluding FRR).[11] If we consider the actual 2017 BRA as our base case "without" the FRR unit exemption, we can quickly see the impact of allowing 1350 MW of uncleared capacity to "qualify" under a unit specific exemption. The "with" or unit FRR case for the market would have the exact same supply curve up to the 165,109.2 MWs, but now load would be reduced by the amount of load deemed to be associated with the 1350 MW of unit specific FRR capacity. Assuming a very conservative 25% reserve margin for the FRR capacity and 0% EFORd (for simplicity), load would be reduced by 1080 MWs (80% of 1350 resulting in the 25% reserve e.g. 1350/1080=1.25). Inherently this means that the price must decline as the supply curve has remained the same (recall the previously uncleared unit priced above the clearing quantity has left the market while the existing cleared units still remain), but in the "with" case the overall demand is reduced by approximately 0.7% (the 1080 MWs). ***This is a generic result***. Any existing unit that failed to clear and then is subsidized and associated load removed via the unit specific FRR must suppress price as cleared supply remains the same but load decreases. The same is true for any new entry claiming the exemption

25. To put this in context, PJM's IMM, Dr. Joseph Bowring, conducted an analysis of the capacity auction impacts of adding 1000 MWs of subsidized power in 2011 (in the context of the debate over Maryland and New Jersey efforts to subsidize new natural gas generation). His findings were that such subsidized entry would depress overall market prices by $1 billion dollars a year.[12] In my very realistic example, the impact of reducing

[11] http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2020-2021-base-residual-auction-report.ashx?la=en

[12] *Impact on New Jersey Assembly Bill 3442 on PJM Capacity Market*, The Independent Market Monitor for PJM, dated January 6, 2011, p. 3. [The IMM's numbers assumes the subsidized resources bid in at zero.]
http://www.monitoringanalytics.com/reports/Reports/2011/NJ_Assembly_3442_Impact_on_PJM_Capacity_Market.pdf

load by 1080 MWs would be expected to be larger (i.e., the removal should roughly equate to the addition of the 1350 MWs of generation).

26. The same type of impact would be associated with FRR unit exemptions for new generation. The prior (without the new generation) supply curve for the system remains the same, but net load served by the remaining generation decreases, directly resulting in lower prices. While "counting" rules related to the amount of load removed under the type of proposal suggested by the Commission can mitigate the magnitude of the suppression, *it can't be eliminated if any load is removed.* In other words, ss the IMM concluded, "There is no safe level and no level of resource specific FRR that would not significantly suppress prices."[13]

PJM's Modeling of the Unit Specific FRR In Stakeholder Discussions Confirms That a Unit Specific FRR Results in Price Suppression for Unsubsidized Resources.

27. During the stakeholder discussions leading up to its filing, PJM presented its own modeling to reflect what an implementation of the Commission's unit specific, or partial FRR, would look like.

28. PJM basically came to the same findings I summarize above—there is no distinction between the unit specific FRR proposal of removing both subsidized generation and comparable load versus simply the full inclusion of unmitigated, subsidized supply offering in at zero. In both cases the result is the same, and the level of price suppression is identical.

29. Given this realization, PJM's proposed modeling of a unit-specific FRR was to simply include all supply with an actionable subsidy in the auction as price takers, and use the resulting capacity auction clearing price to compensate all other supply, i.e. all other supply gets a price based on the presence of all subsidized units in the "bottom" of the supply curve. This is identical to no mitigation at all.

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[13] *See*, IMM MOPR FRR Report, p. 2.

30. PJM describes this process in its own summary of its proposal provided multiple times in the stakeholder process (the term ReCO refers to PJM title for the partial FRR/carve out approach):

> "--Resources and the associated load that are part of ReCO will be included in the clearing of RPM auctions.
>
> --The ReCO resources will be self-scheduled in the auction and no adjustments will be made to the demand curve
>
> --In the capacity market settlement process, the ReCO resources will not be paid the RPM clearing price and the associated load will not be charged for capacity
>
> --Cleared capacity from ReCO resources will not be paid the clearing price.
>
> --The dollars not paid to such resources will be allocated as a prorata credit back to all PJM load in the state subsidizing the specific resources on the basis of such loads' Locational Reliability Charges"[14]

31. I personally participated in the stakeholder process in which this approach was presented by PJM. I personally on several occasions asked Mr. Keech of PJM (the PJM subject matter expert presenting the summary of PJM's proposals) if he agreed that the pricing for the rest of supply (those not receiving subsidies) would be the same under this approach versus a scenario in which no mitigation had been applied. In each instance he agreed. [15]

32. As part of this partial FRR implementation without any mitigation impact, PJM also resolves several issues raised by the Commission, but their answers are very troubling. First, automatically the associated load "removed" is set at the same reserve margin as the rest PJM due to the fact that the load is not actually removed, but rather remains, being notionally matched with the subsidized price taking supply. This

[14] PJM Stakeholder Meeting, August 15, 2018 on Capacity Market Reforms, PJM slide presentation: https://pjm.com/-/media/committees-groups/committees/mrc/20180815-special/20180815-item-02-current-approach-to-ferc-order-on-capacity-markets.ashx

[15] These statements are based on my contemporaneous notes of PJM stakeholder meetings.

demonstrates that the status quo FRR approach, that sets the required reserves lower than the clearing RPM level of reserves (fixed at the IRM for the withdrawing area) actually would suppress prices more than PJM's no mitigation equivalent. (E.g. more load could be removed under the status quo FRR approach setting reserves at the IRM for any given MW level of subsidized entry due to the lower reserve requirement).[16] Under the PJM "equivalent" approach pricing is just set to reflect the financial result that occurs by placing the subsidized generation into the auction as a price taker. This is the same as if load was uniformly pro-rated down (E.g. this is equivalent to shifting the supply and demand curves to the left by the same amounts as was also noted by Dr. Bowring). [17]

33. Second, by recognizing the partial FRR effectively does nothing to mitigate the price suppression a related question is resolved in terms of Capacity Transfer Rights. These are similarly supplied pro-rata to the "associated" load in PJM's proposed approach. PJM stated it favored this approach because it was equivalent to the partial FRR suggested by the Commission, but simple to implement. While this does makes implementation easy, it also demonstrates the great difficulty to actually reflect the removal of specific load, which is also implied by the Commission's suggestion. Such an action would trigger the need for a very complex analysis of how transfer limits and reserves need to be adjusted as location specific load is modified. PJM effectively acknowledged this difficulty by defaulting to the equivalence of no mitigation at all, the associated price suppression, and the use of a financial equivalent to the reduction of load and generation.

34. The only distinction that PJM's approach would make from fully unmitigated participation would be with respect to the cash flow for the units with an actionable subsidy. Subsidized units would not receive the suppressed auction price directly from PJM. Rather those funds would be directed to the appropriate subsidizing entity acting on

[16] I address a potential remedy for this problem in the status quo FRR later in the context of appropriate adjustments to an FRR applied on a zonal or state level as currently allowed.

[17] IMM MOPR FRR Report, p. 1.

behalf of load or pro-rata to load (for the purposes of this discussion assume that is the state in which the subsidized facility is located that receives the credit from PJM.)

35. However, this is a distinction with no real difference. The funds that would otherwise go to the supplier in the auction now would flow to the state (or directly to LSE/load as a load credit). The state could then redistribute them in any fashion consistent with its own objectives, which would not necessarily be any different that had the payment gone directly to the supplier. This can be seen by simple examples. First, consider the case in which under a "no mitigation scenario" a supplier would receive $200/Mw-day from the state as a subsidy and agree to refund any capacity payments it received from PJM to the state.

36. This type of contract for differences approach was the general nature of the agreements proposed by Maryland and New Jersey that underlie the *Hughes* decision. Under PJM's partial FRR/carve out, implementation would now actually be easier, as the capacity auction credits could flow directly to the state (or load) and the same $200/MW-day flows to the supplier from the state (i.e. instant contract for differences). Variants of this could include adjustment formulas for different ranges of auction results, but in all cases the flow of funds is simply adjusted to achieve the same result. A second example might be where the state agreed to pay a $200/MW-day to a supplier and allow the supplier to keep the auction revenues. In this situation the only adjustment would be that the capacity auction payments would first flow to the state (or load), and then, under this structure, be paid to the supplier via a state payment (presumably either directly from the PJM credit, or from a load surcharge similar to how the subsidy might be collected.) [18]

37. The implications for load are again unchanged except for the flow of funds. However, the state recovered its subsidy costs without the PJM program would still apply and the auction payments to all other suppliers would remain unchanged.

[18] There is no material distinction between funds flowing back to the state or to load as a credit in terms of the result of load not paying the auction price for the subsidized supply. The dollars can always be adjusted by retail credits and charges. While this allocation is certainly of concern to load, other suppliers are indifferent and still see the fully suppressed market price from the subsidy.

38. Ultimately, because PJM recognized that the partial unit specific FRR or carve out had no real impacts and was effectively just a juggling of financial flows, any number of different arrangements would be possible between load and supplier charges. The important point to recognize is that the unit specific FRR leads to the exact price suppression that the Commission seeks to avoid.

39. The inevitable, and perhaps at some level regrettable, conclusion that I reach is that a unit specific FRR just doesn't work. From the view of other market participants, from one perspective load will be decreasing for the same level of supply whether the exempted unit is a new entrant or an uncompetitive existing supplier. This makes the price suppression worse, not better. Or alternatively, seen in the context of PJM's proposal, the effect would be as if no mitigation at all applied. Either way, the suppressed capacity prices stemming from the participation of unmitigated, subsidized units remain and PJM's capacity market rates remain unjust and unreasonable .

The Existing PJM FRR Mechanism.

40. As the Commission recognized in the June 29 order, the existing FRR mechanism provides a viable means for a state to procure capacity on its own outside of the centralized PJM capacity procurement. Several load serving entities have availed themselves of this option and there is no reason why any state in PJM could not do the same. The PJM capacity markets were designed to procure capacity in the least costs means. If a state believes it can procure a more desirable mix of capacity resources at a price it is comfortable paying, it has the ability to do so under PJM's existing tariff. But in doing so, any state would have to remove all of their load from the capacity auction market, and assume the full responsibilities for adequacy planning.

41. The existing FRR has many of the same features as the proposed unit specific FRR. FRR entities receive no capacity revenue (their revenue requirements would have to be met from state-based subsidies and/or load payments). FRR generators have

capacity performance obligations. FRR load does not pay any PJM capacity charges. PJM has developed a series of rules over the years and the construct largely works. Because FRR is elected on a LSE or more typically a zonal LDC basis, rather than unit specific basis, questions regarding load allocation are easily addressed. The existing FRR mechanism does admittedly raise similar price suppression concerns, although those concerns are more easily addressed in the existing construct as opposed to the proposed unit specific process. Further, by requiring a state or zonal long-term commitment to FRR, the true long-term costs of price discrimination and suppression will likely be recognized by the associated regulatory bodies making such decisions.

42. If this path is followed there are some changes that would be appropriate to the current FRR tariff rules. For example, currently the FRR entity only has to procure resources to meet the IRM (Installed Reserve Margin) whereas the rest of the pool has been procuring at a higher reserve level value associated with the downward sloping demand curve. The net effect is that the lower reserve margin for FRR entities effectively provides them a free ability to lean on the rest of the RTO for reliability support in excess of the level they are procuring.

43. Similarly, the current rules allow (with limits) FRR entities to purchase and sell bilaterally with the rest of the pool. This again encourages/results in a form of leaning on the rest of the pool to balance obligations, and fund the FRR entities excesses when carrying excess supply. This also should be addressed and modified to more fully reflect the objective of isolating the impact of subsidies from the portions of the market that have chosen not to engage in these practices. The Commission should direct PJM to explore correcting these and other issues as part of an abbreviated stakeholder process in advance of a PJM compliance filing.

44. This concludes my comments.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Calpine Corporation	)	
	)	**Docket No. EL16-49-000**
	)	
v.	)	
PJM Interconnection, L.L.C.	)	
	)	
PJM Interconnection, L.L.C.	)	**Docket No. ER18-1314-000**
	)	**Docket No. ER18-1314-001**
	)	
PJM Interconnection, L.L.C.	)	**Docket No. EL18-178-000**
		(Consolidated)

AFFIDAVIT

I, Roy J. Shanker, do hereby swear and affirm under penalty of law that the statements in the foregoing Affidavit of Roy J. Shanker, Ph.D. are true to the best of my knowledge, information and belief.

Executed this 30th day of September, 2018.

Roy J Shanker

Roy J. Shanker

Exhibit RJS-1

QUALIFICATIONS
AND
EXPERIENCE OF

DR. ROY J. SHANKER

EDUCATION:

Swarthmore College, Swarthmore, PA
A.B., Physics, 1970

Carnegie-Mellon University, Pittsburgh, PA
Graduate School of Industrial Administration
MSIA Industrial Administration, 1972
Ph.D., Industrial Administration, 1975

Doctoral research in the development of new non-parametric multivariate techniques for data analysis, with applications in business, marketing and finance.

EXPERIENCE:

1981 - Present	Independent Consultant P.O. Box 1480 Pebble Beach, CA 93953
	Providing management and economic consulting services in natural resource-related industries, primarily electric and natural gas utilities.
1979-81	Hagler, Bailly & Company 2301 M Street, N.W. Washington, D.C.
	Principal and a founding partner of the firm; director of electric utility practice area. The firm conducted economic, financial, and technical management consulting analyses in the natural resource area.
1976-79	Resource Planning Associates, Inc. 1901 L Street, N.W.

Washington, D.C.

Principal of the firm; management consultant on resource problems, director of the Washington, D.C. utility practice. Direct supervisor of approximately 20 people.

1973-76 Institute for Defense Analysis
Professional Staff
400 Army-Navy Drive
Arlington, VA

Member of 25 person doctoral level research staff conducting economic and operations research analyses of military and resource problems.

RELEVANT EXPERIENCE:

2018

244—On behalf of Joint Commentors. Federal Energy Regulatory Commission Docket EL18-34. Participation in the preparation of comments addressing PJM's proposed fast start pricing modifications and related price formation issues.

243—On behalf of the PJM Power Providers Group. Federal Energy Regulatory Commission Dockets EL17-32 and EL17-36. Pre-Technical Conference Comments and participant technical conference regarding seasonal products and specific related reliability and forecasting questions from Commission Staff.

2017

242—On behalf of the PSEG Companies. Federal Energy Regulatory Commission Docket No. ER13-535-000. Affidavit regarding implementation of Court of Appeals remand to FERC of the PJM capacity market Minimum Offer Price Rule.

241-- In the United States Court of Appeals for the Second Circuit. Case No. 17-2654.Co-writer/sponsor of the Brief of Energy Economists as Amici Cucriae in Support of Plaintiffs-Appealants-Reversal. Comments regarding the impacts of subsidies on the operation of organized electric markets.

240—In the United States Court of Appeals for the Seventh Circuit. No. 17-2433.Co-writer/sponsor of the Brief of Energy Economists as Amici

Cucriae in Support of Plaintiffs-Appealants. Comments regarding the impacts of subsidies on the operation of organized electric markets.

239—Invited speaker Federal Energy Regulatory Commission technical session, Docket AD17-11. Comments on the appropriate incorporation of state policies in wholesale electric markets. Submission of post technical session comments.

238—On behalf of PJM Power Providers. Federal Energy Regulatory Commission Dockets EL17-36 and EL17-32 addressing the current Capacity Performance design and criticisms related to the exclusion of an inferior seasonal product. Explanation of how PJM establishes its adequacy targets and whether or not the asserted criticisms were valid.

2016

237- On behalf of DC Energy, Vitol, Intertia Power, Saracen Energy East. Federal Energy Regulatory Commission Dockets EL16-6, ER16-121. Submission of post technical session statement regarding PJM FTR market "netting" proposal.

236-On behalf of DC Energy, Vitol, Intertia Power, Saracen Energy East. Federal Energy Regulatory Commission Dockets EL16-6, ER16-121. Participant in two Technical Session Panels addressing PJM FTR market design and deficiency in the pending proposal to remove netting in the market settlement.

2015

235- On behalf of the Electric Power Supply Associaton. Federal Energy Regulatory Commission Dockets EL15-70, 71, 72, 82. Affidavit regarding MISO capacity market design and also addressing use of opportunity costs in offers.

234-On behalf of the Electric Power Supply Associaton. Federal Energy Regulatory Commission Dockets EL15-70, 71, 72, 82. Discussant in technical session addressing the establishment of opportunity costs as the basis for capacity reference pricing in the MISO Planning Resource Auctions.

233-On behalf of Dominion Virginia Power. Federal Energy Regulatory Commission Docket ER15-1966. Affidavit regarding changing economic incentives for suppliers associated with the modification of PJM's calculation of Lost Opportunity Costs.

232-On behalf of "Indicated Suppliers" Federal Energy Regulatory Commission Docket No. EL15-64-000. Testimony addressing the appropriateness of proposed changes to the NYISO buyer side mitigation exemptions.

231-On behalf of Hydro Quebec, Energy Services U.S. Federal Energy Regulatory Commission Docket No. ER15-623. Affidavit addressing the consistent treatment of energy imports under PJM's Capacity Performance proposal.

230-Before the Supreme Court of the United States, No. 14-995, On Petition for a Writ of Certiorari to the United States Court of Appeals for the Third Circuit. Brief of electrical engineers, scientists and economists as amici curiae in support of petitioners. Metropolitan Edison et. al. versus Pennsylvania Public Utility Commission et. al.
http://www.americanbar.org/content/dam/aba/publications/supreme_court_preview/briefs_2015_2016/14-840_Borlick_et_al.pdf

2014

229-On behalf of Benton County Wind Farm. United States District Court Southern District of Indiana, Indianapolis Division, Civil Action No. 1:13-cv-1984-SEB-TAB. Expert Reports addressing custom and practice in electric power purchase agreements.

228-On behalf of FirstEnergy Services. FERC Docket EL14-55. Affidavit related to the appropriate characterization of Demand Response in Capacity Markets reflecting performance as the reduction of retail energy consumption.

227)-Federal Energy Regulatory Commission. Docket RM10-17. On my own behalf, a statement regarding the ability of the PJM capacity and energy markets to clear in the transition from any determination that demand response would be excluded jurisdictionally from wholesale markets. This could in turn result in a more appropriate representation of retail demand response.

226) Illinois Commerce Commission. Matter: No. 13-0657. On behalf of Commonwealth Edison Company. Testimony regarding the operation of the PJM regional transmission expansion planning process in general and particularly with regards to the preservation of long-term transmission rights (Stage 1A Auction Revenue Rights), and the consequences that occur when such mandated rights are infeasible.

225-Federal Energy Regulatory Commission. Docket ER14-1579. On behalf of H-P Energy. Affidavit explaining importance of property rights and associated contracts within the PJM transmission planning process, particularly as they pertain to Upgrade Construction Service Agreements.

2013

224-Federal Energy Regulatory Commission. Docket No. ER14-456. On behalf of NextEra Energy to analyze a proposed modification to the PJM Tariff allowing for "easily resolved constraints" to be address by transmission upgrades without any analyses of benefits.

223-Federal Energy Regulatory Commission. Docket No. ER14-504. Affidavit on behalf of PJM Power Producers addressing the interaction between the PJM adequacy planning processes and the formulation of saturation constraints on Limited and Extended Summer Demand Response products.

222-Federal Energy Regulatory Commission. Docket AD13-7. Invited speaker on the Commission's technical session regarding capacity markets in RTO's. Comments addressed basic principles of market design, market features, and consequences of market failures and deviations from design principles.

221-Federal Energy Regulatory Commission. Docket No. EL13-62 on behalf of TC Ravenswood LLC. Two affidavits addressing the treatment of reliability support services agreements and associated capacity in the NYISO capacity market design.

2012

220-Federal Energy Regulatory Commission. Docket No. ER12-715-003. On behalf of First Energy Services Company. An affidavit and testimony addressing the appropriateness of the application of a proposed new MISO tariff provision after the fact to a withdrawing MISO member.

219-Federal Energy Regulatory Commission. Docket ER13-335. On behalf of Hydro Quebec U.S. Affidavit addressing appropriate application of ISO-NE Market Rule 1/ Tariff with respect to the qualification of new external capacity to participate in the Forward Capacity Market.

218-Federal Energy Regulatory Commission. Docket IN12-4. On behalf of Deutsche Bank Energy Trading. Affidavit regarding a review of specific transactions, related congestion revenue rights, and deficiencies in

CAISO tariff implementation during periods when market software produces multiple feasible pricing solutions.

217-Federal Energy Regulatory Commission. Docket No. ER12-715-003. On behalf of FirstEnergy Services Company. Affidavit regarding implementation of the MISO Tariff with respect to the determination of appropriate exit fees and charges related to certain transmission facilities.

216-Federal Energy Regulatory Commission. Docket No. IN12-11. On behalf of Rumford Paper Company. Affidavit regarding free riding behavior in the design of demand response programs, and its relationship to accusations of market manipulation.

215-Federal Energy Regulatory Commission. Docket No. IN12-10. On behalf of Lincoln Paper and Tissue LLC. Affidavit regarding relationship of demand response behavior and value established in Order 745 to claimed market impacts associated with accusations of market manipulation.

214-Federal Energy Regulatory Commission. Docket No. AD12-16-000. On behalf of PJM Power Providers, testimony regarding deliverability of capacity between the MISO and PJM RTO's and associated basic adequacy planning concepts.

213-United States Court Of Appeals, District of Columbia Circuit. Electric Power Supply Asociation, et al (Petitioners) v. Federal Energy Regulatory Commission et al (Respondents) Nos. 11-1486. Amici Curiae brief regarding the appropriate pricing of demand reduction services in wholesale markets vis a vis the FERC determinations in Order 745.

212-United States Supreme Court. Metropolitan Edison Company and Pennsyvalnia electric Company (Petitioners), Pennsylvania Public Utility Commission (Respondent) (No. 12-4) Amici Curiae brief regarding the nature of physical losses in electric transmission and relationship to proper marginal cost pricing of electric power and the marginal cost of transmission service.

2011

211-Federal Energy Regulatory Commission Docket No. ER12-513-000. On behalf of PJM Power Providers, testimony regarding the establishment of system wide values for the net cost of new entry related to modifications of the Reliability Planning Model.

210-Federal Energy Regulatory Commission Docket No. EL11-56-000, on behalf of First Energy Services. Affidavit regarding the appropriateness of proposed transmission cost allocation of Multi-Value Projects to an exiting member of the Midwest Independent System Operator.

209-Federal Energy Regulatory Commission Docket No. ER11-4081-000, on behalf of "Capacity Suppliers". Affidavit addressing correct market design elements for Midwest Independent System Operator proposed resource adequacy market.

208-Public Utility Commission of Ohio, Case Nos. 11-346-EL-SSO,11-348-EL-SSO,Nos. 11-349-EL-AAM, 11-350-EL-AAM, on behalf of First Energy Services. Testimony regarding the interaction between the capacity default rates for retail access under the PJM Fixed Resource Requirement and the PJM Reliability Planning Model valuations.

207-Federal Energy Regulatory Commission Dockets No. ER11-2875, EL11-20, Staff Technical Conference on behalf of PJM Power Providers, addressing self supply and the Fixed Resource Requirement elements of PJM's capacity market design.

206-New Jersey Board of Public Utilities, Docket Number EO11050309 on behalf of PSEG Companies. Affidavit addressing the implications of markets and market design elements, and regulatory actions on the relative risk and trade-offs between capital versus energy intensive generation investments.

205-Federal Energy Regulatory Commission Docket No. ER11-2875. Affidavit and supplemental statement on behalf of PJM Power Providers addressing flaws in the PJM tariff's Minimum Offer Price Rule regarding new capacity entry and recommendations for tariff revisions.

204-Federal Energy Regulatory Commission Docket No. EL11-20. Affidavit on behalf of PJM Power Providers addressing flaws in the PJM tariff's Minimum Offer Price Rule regarding new capacity entry.

203-Federal Energy Regulatory Commission Docket Nos. ER04-449. Affidavit and supplemental statement on behalf of New York Suppliers addressing the appropriate criteria for the establishment of a new capacity zone in the NYISO markets.

2010

202-New Jersey State Assembly and Senate. Statements on behalf of the Competitive Supplier Coalition addressing market power and reliability impacts of proposed legislation, Assembly Bill 3442 and Senate Bill 2381.

201-Federal Energy Reglatory Commission. Docket ER11-2183. Affidavit on behalf of First Energy Services Company addressing default capacity charges for Fixed Resource Requirement participants in the PJM Reliability Pricing Model capacity market design.

200-Federal Energy Regulatory Commission. Docket ER11-2059Affidavit on behalf of First Energy Services Company addressing deficiencies and computational problems in the proposed "exit charges" for transmission owners leaving the MISO RTO related to long term transmission rights.

199-Federal Energy Regulatory Commission Docket RM10-17. Invited panelist addressing metrics for cost effectiveness of demand response and associated cost allocations and implications for monopsony power.

198-Federal Energy Regualtory Commission Consolidated Dockets ER10-787-000, EL10-50-000, and EL10-57-000. Two affidavits on behalf of the New England Power Generators Association regarding ISO-NE modified proposals for alternative price rule mitigation and zonal definitions/functions of locational capacity markets.

197-Federal Energy Regulatory Commission Docket No. ER10-2220-000. Affidavit on behalf of the Independent Energy Producers of New York. Addressing rest of state mitigation thresholds and procedures for adjusting thresholds for frequently mitigated units and reliability must run units.

196-Federal Energy Regulatory Commission Docket PA10-1. Affidavit on behalf of Entergy Services related to development of security constrained unit commitment software and its performance.

195-Federal Energy Regulatory Commission Docket No. ER09-1063-004. Testimony on behalf of the PJM Power Providers Group (P3) regarding the proposed shortage pricing mechanism to be implemented in the PJM energy market. Reply comments related to a similar proposal by the independent market monitor.

194-PJM RTO. Statement regarding the impact of the exercise of buyer market power in the PJM RPM/Capacity market. Panel discussant on the issue at the associated Long Term Capacity Market Issues Sympossium.

193-Federal Energy Regulatory Commission Docket No. ER10-787-000. Affidavit on behalf of New England Power Generators Association addressing proper design of the alternative price rules (APR) for the ISO-NE Forward Capacity Auctions. Second affidavit offered in reply. Supplemental affidavit also submitted

192-Federal Energy Regulatory Commission Docket No. RM10-17-000. Affidavit on behalf of New England Power Generators Association addressing proper pricing for demand response compensation in organized wholesale regional transmissiom organizations.

191-Federal Energy Regulatory Commission Docket No. RM10-17-000, Affidavit on my on behalf regarding inconsistent representations made between filings in this docket and contemporaneous materials presented in the PJM stakeholder process.

2009

190-Federal Energy Regulatory Commission Docket No. ER09-1682. Two affidavits on behalf of an un-named party regarding confidential treatment of market data coupled with specific market participant bidding, and associated issues.

189-American Arbitration Assoication, Case No. 75-198-Y-00042-09 JMLE, on behalf of Rathdrum Power LLC. Report on the operation of specific pricing provision of a tolling power purchase agreement.

188-Federal Energy Regulatory Commission. Docket No. IN06-3-003. Analyses on behalf of Energy Transfer Partners L.P. regarding trading activity in physical and financial natural gas markets.

187-Federal Energy Regulatory Commission. Docket No. ER08-1281-000. Analyses on behalf of Fortis Energy Trading related to the impacts of loop flow on trading activities and pricing.

186-American Arbitration Association. Report on behalf of PEPCO Energy Services regarding several trading transactions related to the purchase and sale of Installed Capacity under the PJM Reliability Pricing Model.

185-Federal Energy Regulatory Commission Docket No. EL-0-47. Analyses on behalf of HQ Energy services (U.S.) regarding pricing and sale of energy associated with capacity imports into ISO-NE.

184-Federal Energy Regulatory Commission Docket No. ER04-449 019, Affidavit on behalf of HQ Energy Services (U.S.) regarding the implementation of the consensus deliverability plan for the NYISO, and associated reliability impacts of imports.

183-Federal Energy Regulatory Commission Docket ER09-412-000, ER05-1410-010, EL05-148-010. Affidavit and Reply Affidavit on behalf of PSEG Companies addressing proposed changes to the PJM Reliability Pricing Model and rebuttal related to other parties' filings.

2008

182-Pennsylvania Public Service Commission. *En Banc* Public Hearing on "Current and Future Wholesale Electricity Markets", comments regarding the design of PJM wholesale market pricing and state restructuring.

181-Maine Public Utility Commission. Docket No. 2008-156. Testimony on behalf of a consortion of energy producers and suppliers addressing the potential withdrawal of Maine from ISO New England and associated market and supplier response.

180-Federal Energy Regulatory Commission. Docket No. EL08-67-000. Affidavit on behalf of Duke Energy Ohio and Reliant Energy regarding criticisms of the PJM reliability pricing model (RPM) transitional auctions.

179-Federal Energy Regulatory Commission. Docket AD08-4, on behalf of the PJM Power Providers. Statement and participation in technical session regarding the design and operation of capacity markets, the status of the PJM RPM market and comments regarding additional market design proposals.

178-Federal Energy Regulatory Commission. Docket ER06-456-006, Testimony on behalf of East Coast Power and Long Island Power Authority regarding appropriate cost allocation procedures for merchant transmission facilities within PJM.

2007

177-FERC Docket No. EL07-39-000. Testimony on behalf of Mirant Companies and Entergy Nuclear Power Marketing regarding the operation of the NYISO In-City Capacity market and the associated rules and proposed rule modifications.

176-FERC Dockets: RM07-19-000 and AD07-7-000, filing on behalf of the PJM Power Providers addressing conservation and scarcity pricing issues identified in the Commission's ANOPR on Competition.

175-FERC Docket No. EL07-67-000. Testimony and reply comments on behalf of Hydro Quebec U.S. regarding the operation of the NYISO TCC market and appropriate bidding and competitive practices in the TCC and Energy markets.

174-FERC Docket Nos. EL06-45-003. Testimony on behalf of El Paso Electric regarding the appropriate interpretation of a bilateral transmission and exchange agreement.

2006

173-United States Bankruptcy Court for the Southern District of New York. Case No. 01-16034 (AJG). Report on Behalf of EPMI regarding the properties and operation of a power purchase agreement.

172-FERC Docket No. EL05-148-000. Testimony regarding the proposed Reliability Pricing Model settlement submitted for the PJM RTO.

171-FERC Docket No. ER06-1474-000, FERC. Testimony on behalf othe PSEG Companies regarding the PJM proposed new policy for including "market efficiency" transmission upgrades in the regional transmission expansion plan.

170-FERC Docket No. EL05-148-000, FERC. Participation in Commission technical sessions regarding the PJM proposed Reliability Pricing Model.

169-FERC Docket No. EL05-148-000, FERC. Comments filed on behalf of six PJM market participants concerning the proposed rules for participation in the PJM Reliability Pricing Model Installed Capacity market, and related rules for opting out of the RPM market.

168-FERC Docket No. ER06-407-000. Testimony on behalf of GSG, regarding interconnection issues for new wind generation facilities within PJM.

2005

167-FERC Docket No. EL05-121-000, Testimony on behalf of several PJM Transmission Owners (Responsible Pricing Alliance) regarding alternative regional rate designs for transmission service and associated market design issues.

166-FERC Technical Conference of June 16, 2005. (Docket Nos. PL05-7-000, EL03-236-000, ER04-539-000). Invited participant. Statement regarding the operation of the PJM Capacity market and the proposed new Reliability Pricing Model Market design.

165-American Arbitration Association Nos. 16-198-00206-03 16-198-002070.On behalf of PG&E Energy Trading. Analyses related to the operation and interpretation of power purchase and sale/tolling agreements and electrical interconnection requirements.

164-Arbitration on behalf of Black Hills Power, Inc. Expert testimony related to a power purchase and sale and energy exchange agreement, as well as FERC criteria related to the applicable code and standards of conduct.

2004

163-Federal Energy Regulatory Commission. Docket No. Docket No. EL03-236-003 Testimony on behalf of Mirant companies relating to PJM proposal for compensation of frequently mitigated generation facilities.

162-Federal Energy Regulatory Commission. Docket No. ER03-563-030. Testimony on behalf of Calpine Energy Services regarding the development of a locational Installed Capacity market and associated generator service obligations for ISO-NE. Supplemental testimony filed 2005.

161-Federal Energy Regulatory Commission. Docket No. EL04-135-000. Testimony on behalf on the Unified Plan Supporters regarding implications of using a flow based rate design to allocate embedded costs.

160-Federal Energy Regulatory Commission. Docket No. ER04-1229-000. Testimony on behalf of EME Companies regarding the allocation and recovery of administrative charges in the NYISO markets.

159-Federal Energy Regulatory Commission. Dockets No. EL01-19-000, No. EL01-19-001, No. EL02-16-000, EL02-16-000. Testimony on behalf of PSE&G Energy Resources and Trade regarding pricing in the New York Independent System Operator energy markets.

158-Federal Energy Regulatory Commission. Invited panelist regarding performance based regulation (PBR) and wholesale market design. Comments related to the potential role of PBR in transmission expansion, and its interaction with market mechanisms for new transmission.

157-Federal Energy Regulatory Commission. Docket No. ER04-539-000 Testimony on behalf of EME Companies regarding proposed market mitigation in the energy and capacity markets of the Northern Illinois Control Area.

156-Federal Energy Regulatory Commission. Standardization of Generator Interconnection Agreements and Procedures Docket No. RM02-1-001, Order 2003-A, Affidavit on Behalf of PSEG Companies regarding the modifications on rehearing to interconnection crediting procedures.

155-Federal Energy Regulatory Commission. Dockets ER03-236-000,ER04-364-000,ER04-367-000,ER04-375-000. Testimony on behalf of the EME Companies regarding proposed market mitigation measures in the Northern Illinois Control Area of PJM.

154-Federal Energy Regulatory Commission. Dockets PL04-2-000, EL03-236-000. Invited panelist, testimony related to local market power and the appropriate levels of compensation for reliability must run resources.

2003

153-American Arbitration Association. 16 Y 198 00204 03. Report on behalf of Trigen-Cineregy Solutions regarding an energy services agreement related to a cogeneration facility.

152-Federal Energy Regulatory Commission. Docket No. EL03-236-000. Testimony on behalf of EME Companies regarding the PJM proposed tariff changes addressing mitigation of local market power and the implementation of a related auction process.

151-Federal Energy Regulatory Commission. Docket No. PA03-12-000. Testimony on behalf of Pepco Holdings Incorporated regarding transmission congestion and related issues in market design in general, and specifically addressing congestion on the Delmarva Peninsula.

150-Federal Energy Regulatory Commission. Docket Nos. ER03-262-007, Affidavit on behalf of EME Companies regarding the cost benefit analysis of the operation of an expanded PJM including Commonwealth Edison.

149-Supreme Court of the State of New York, Index No. 601505/01. Report on behalf of Trigen-Syracuse Energy Corporation regarding energy trading and sales agreements and the operation of the New York Independent System Operator.

148-Federal Energy Regulatory Commission. Docket No. ER03-262-000. Affidavit on behalf of the EME Companies regarding the issues associated with the integration of the Commonwealth Edison Company into PJM.

147-Federal Energy Regulatory Commission. Docket No. ER03-690-000. Affidavit on behalf of Hydro Quebec US regarding New York ISO market rules at external generator proxy buses when such buses are deemed non-competitive.

146-Federal Energy Regulatory Commission. Docket RT01-2-006,007. Affidavit on behalf of the PSEG Companies regarding the PJM Regional Transmission Expansion Planning Protocol, and proper incentives and structure for merchant transmission expansion.

145-Federal Energy Regulatory Commission. Docket No. ER03-406-000. Affidavit on behalf of seven PJM Stakeholders addressing the appropriateness of the proposed new Auction Revenue Rights/Financial Transmission Rights process to be implemented by the PJM ISO.

144-Federal Energy Regulatory Commission. Docket No. ER01-2998-002. Testimony on behalf of Pacific Gas and Electric Company related to the cause and allocation of transmission congestion charges.

143-Federal Energy Regulatory Commission. Docket No. RM01-12-000. On behalf of six different companies including both independent generators, integrated utilities and distribution companies comments on the proposed resource adequacy requirements of the Standard Market Design.

142-United States Bankruptcy Court, Northern District of California, San Francisco Division, Case No. 01-30923 DM. On behalf of Pacific Gas and Electric Dr. Shanker presented testimony addressing issues related to transmission congestion, and the proposed FERC SMD and California MD02 market design proposals.

2002

141-Arbitration. Testimony on behalf of AES Ironwood regarding the operation of a tolling agreement and its interaction with PJM market rules.

140-Federal Energy Regulatory Commission. Docket No. RM01-12-000. Dr. Shanker was asked by the three Northeast ISO's to present a summary of his resource adequacy proposal developed in the Joint Capacity Adequacy Group. This was part of the Standard Market Design NOPR process.

139-Federal Energy Regulatory Commission. Docket No. ER02-456-000. Testimony on behalf of Electric Gen LLC addressing comparability of a contract among affiliates with respect to non-price terms and conditions.

138-Circuit Court for Baltimore City. Case 24-C-01-000234. Testimony on behalf of Baltimore Refuse Energy Systems Company regarding the appropriate implementation and pricing of a power purchase agreement and related Installed Capacity credits.

137-Federal Energy Regulatory Commission. Docket No. RM01-12-000. Comments on the characteristics of capacity adequacy markets and alternative market design systems for implementing capacity adequacy markets.

2001

136-Federal Energy Regulatory Commission. Docket ER02-456-000. Testimony on behalf of Electric Gen LLC regarding the terms and conditions of a power sales agreement between PG&E and Electric Generating Company LLC.

135-Delaware Public Service Commission. Docket 01-194. On behalf of Conectiv et al. Testimony relating to the proper calculation of Locational Marginal Prices in the PJM market design, and the function of Fixed Transmission Rights.

134-Federal Energy Regulatory Commission. Docket No. IN01-7-000 On behalf of Exelon Corporation . Testimony relating to the function of Fixed Transmission Rights, and associated business strategies in the PJM market system.

133-Federal Energy Regulatory Commission. Docket No. RM01-12-000. Comments on the basic elements of RTO market design and the required market elements.

132-Federal Energy Regulatory Commission. Docket No. RT01-99-000. On behalf of the One RTO Coalition. Affadavit on the computational feasibility of large scale regional transmission organizations and related issues in the PJM and NYISO market design.

131-Arbitration. On behalf of Hydro Quebec. Testimony related to the eligibility of power sales to qualify as Installed Capacitywithin the New York Independent system operator.

130-Virginia State Corporation Commission. Case No. PUE000584. On behalf of the Virginia Independent Power Producers. Testimony related to the proposed restructuring of Dominion Power and its impact on private power contracts.

129-United States District Court, Northern District of Ohio, Eastern Division, Case: 1:00CV1729. On behalf of Federal Energy Sales, Inc. Testimony related to damages in disputed electric energy trading transactions.

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116-Virginia State Corporation Commission. Case No. PUE 980463. Testimony on behalf of Appomattax Cogeneration related to the proper implementation of avoided cost methodology.

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113-U.S. District Court, Western Oklahoma. CIV96-1595-L. Testimony related to anti-competitive elements of utility rate design and promotional actions.

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1995

94-American Arbitration Association. Arbitration No. 14 198 012795 H/K. Report concerning the correct measurement of savings resulting from a commercial building cogeneration system and associated contract compensation issues.

93-Circuit Court City of Richmond. Law No. LX-2859-1. Analyses related to IPP contract structure and interpretation regarding plant compensation under different operating conditions.

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1988

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43-Virginia State Corporation Commission. Case No. PUE880014. Testimony on the design and level of standby, maintenance and supplemental power rates for qualifying facilities.

42-Virginia State Corporation Commission. Case No. PUE99038. Testimony on the natural gas transportation rate design and service provisions.

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40-Oklahoma Corporation Commission. Cause Pud No. 00345. Testimony on estimation and level of avoided cost payments for qualifying facilities.

39-Florida Public Service Commission. Docket No.8700197-EI. Testimony on the methodology for establishing non-firm load service levels.

38-Arizona Corporation Commission. Docket No. U-1551-86-300. Analysis of cost-of-service studies and related terms and conditions for material gas transportation rates.

1987

37-Virginia State Corporation Commission. Case No. PUE870028. Analysis of Virginia Power fuel factorapplication and relationship to avoided costs.

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35-Virginia State Corporation Commission. Case No. PUE860058. Testimony on the relationship of small power producers and cogenerators to the need for power and new generation facilities.

34-Virginia State Corporation Commission. Case No. PUE870025. Testimony addressing the proper design of rates for standby, maintenance and supplement power sales to cogenerators.

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1986

32-Florida Public Service Commission. Docket No. 860001 EI-E. Testimony on the proper methodology for the estimation of avoided O&M costs.

31-Florida Public Service Commission. Docket No. 860786-EI. Testimony on the proper economic analysis for the evaluation of self-service wheeling.

30-U.S. Bankruptcy Court, District of Ohio. Testimony on capabilities to develop and operate wood-fired qualifying facility.

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1985

22-Virginia Natural Gas. Docket No. 85-0036. Testimony and cost of service procedures and rate design for natural gas transportation service.

21-Arkansas Louisiana Gas. Louisiana Docket No. U-16534. Testimony on proper cost of service procedures and rate design for natural gas service.

20-Connecticut Light and Power. Docket No. 85-08-08. Assist in the development of testimony for industrial natural gas transportation rates.

19-Oklahoma Gas and Electric. Cause 29727. Testimony and system operations and the development of avoided cost measurements as the basis for rates to qualifying facilities.

18-Florida Public Service Commission. Docket No. 840399EU. Testimony on self-service wheeling and business arrangements for qualifying facilities.

17-Virginia Electric and Power Company. General Rate application No. PUE840071. Testimony on proper rate design procedures and computations for development of supplemental, maintenance and standby service for cogenerators.

16-Virginia Electric and Power Company. Fuel Factor Proceeding No. PUE850001. Testimony on the proper use of the PROMOD model and associated procedures in setting avoided cost energy rates for cogenerators.

15-New York State Public Service Commission. Case No. 28962. Development of the use of multi-area PROMOD models to estimate avoided energy costs for six private utilities in New York State.

14-Vermont Rate Hearings on Payments to Small Power Producers. Case No. 4933. Testimony on proper assumptions, procedures and analysis for the development of avoided cost rates.

1984

13-Northern Virginia Electric Cooperative. Case No. PUE840041. Testimony on class cost-of-serviceprocedures, class rate of return and rate design.

12-BPA 1985 Wholesale Rate Proceedings. Analysis of Power 1985 Rate Directives. Testimony on theory and implementation of marginal cost rate design.

11-Virginia Electric Power Company. Application to Revise Rate Schedule 19 -- Power Purchases from Cogeneration and Small Power Production Qualifying Facilities. Case No. PUE830067. Testimony on proper PROMOD modeling procedures for power purchases and properties of PROMOD model.

10-Northern Virginia Electric Cooperative. Case No. PUE840041. Testimony on class cost-of-service procedures, class rate of return and rate design.

9-BPA 1985 Wholesale Rate Proceedings. Analysis of Power 1985 Rate Directives. Testimony on the theory and implementation of marginal cost rate design, financial performance of BPA; interactions between rate design, demand, system expansion and operation.

1983

8-Northern Virginia Electric Cooperative. Case No. PUE830040. Testimony on class cost-of-service procedures, class rate of return and rate design.

7-Vermont Rate Hearings to Small Power Producers. No.4804. Testimony on proper use and application of production costing analyses to the estimation of avoided costs.

6-BPA Wholesale Rate Proceedings. Testimony on the theory and implementation of marginal cost rate design; financial performance of BPA; interactions between rate design, demand, system expansion and operation.

5-Idaho Power Company, PUC-U-1006-185. Analysis of system planning/production costing model play of hydro regulation and associated energy costs.

1982

4-Generic Conservation Proceedings, New York State. Case No. 18223. Testimony on the economic criteria for the evaluation of conservation activities; impacts on utility financial performance and rate design.

3-PEPCO, Washington Gas Light. DCPSC-743. Financial evaluation of conservation activities; procedures for cost classification, allocation; rate design.

2-PEPCO, Maryland PSC Case Nos. 7597-I, 7597-II, and 7652. Testimony on class rates of return, cost classification and allocation, power pool operations and sales.

1981

1-Pacific Gas and Electric. California PSC Case No. 60153. Testimony on rate design; class cost-of-service and rate of return.

Previous testimony before the District of Columbia Public Service Commission, Maryland PSC, New York Public Service Commission, FERC; Economic Regulatory Administration

Attachment C

to the

Prepared Comments

of Paul M. Sotkiewicz, Ph.D.

In Docket No. EO18080899

PAUL M SOTKIEWICZ, Ph.D.

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EDUCATION

PhD, Economics, University of Minnesota, 2003
M.A., Economics, University of Minnesota, 1995
B.A. (High Honors), History/Economics, University of Florida, 1991

PROFESSIONAL AND ACADEMIC EXPERIENCE

2016- President and Founder, E-Cubed Policy Associates, LLC, Gainesville, FL

- Founded to provide expert advice, testimony, and policy research to private sector and government clients at the intersection of energy, environmental, and economic policy and regulation
- Provided capacity market design expertise to the Alberta Electric System Operator in 2017 as they started their transition from an energy-only market to a combined energy and capacity market
- Authored a Meter Data Study for the NYISO encompassing a survey of metering requirements for demand resources and distributed energy resources in key ISO/RTO markets, the current use of demand response baseline methodologies and possible use of such baselines for distributed energy resources in the context of REV in New York.
- Work with clients in generation and merchant transmission development projects in different parts of PJM related to helping them through the interconnection process, understanding market rules, and regulatory policy and economic advice in the face of changing market rules.
- Supporting clients in docketed proceedings at FERC and at the Florida Public Service Commission providing expert testimony and analysis to be used in regulatory proceedings. These proceedings include need determinations, rate filings, RTO market design changes, and policy related proceedings.
- Supporting US government initiatives in exporting knowledge and experience regarding US electric power market development to the Chinese government as they undertake green energy initiatives and look to improve the overall efficiency of the power system.

2015-2016 Contractor, YOH Inc. and working under the title of Senior Economic Policy Advisor, PJM Interconnection, L.L.C., Audubon, PA
2010-2015 Chief Economist, Market Services Division, PJM Interconnection, L.L.C., Audubon, PA
2008-2010 Senior Economist, Market Services Division, PJM Interconnection, L.L.C., Audubon, PA

- Provide analysis and advice with respect to the PJM market design and market performance including demand response mechanisms, intermittent and renewable resource integration, market power mitigation strategies, capacity markets, ancillary service markets, and the potential effects of environmental policies on the PJM markets.
- Co-authored papers related to effects of the proposed Waxman-Markey climate change bill in 2009, the implementation of the Mercury and Air Toxics Standards (MATS) and Cross State Air Pollution Rule in 2011, and the potential effects of the EPA-proposed Clean Power Plan in 2015.
- Led the Stakeholder Process to implement reserve shortage pricing in PJM in 2009-2010 and provided expert testimony associated with FERC filings in 2010.
- Co-authored paper to explain various market and policy concepts for PJM and its stakeholders including a paper explaining generator costs and compensation in 2010, a paper on possible routes to take on transmission cost allocation in 2010, and a whitepaper on capacity market issues in 2012.
- Advised PJM executives on market power mitigation issues related to the Three Pivotal Supplier test and cost-based offers used for market power mitigation in the PJM Energy Market in 2008-2009

- Advised PJM executives and Board of Managers on demand response compensation prior to the issuance of FERC Order 745.
- Supported and advised the Capacity Market Operations staff and PJM executives on all matters related to the Reliability Pricing Model (RPM) capacity market including implementation of the Minimum Offer Pricing Rule in its various iterations, determinations and/or reasonableness of Market Seller Offer Caps during disputes between Capacity Market Sellers and the Independent Market Monitor.
- Provided advice to Capacity Market Operations staff and PJM executives on the RPM Triennial Parameter Review Process in 2011 and in 2014 including supporting legal staff in making filings, providing expert testimony, and providing expert advice during the 2011 and 2012 hearing and settlement process at FERC.
  Supported and provided advice to Capacity Market Operations staff and PJM executives on Capacity Performance through stakeholder presentations, regulatory filings, and working jointly with the IMM in developing many of the ideas and concepts taken from ISO New England's Pay for Performance design for us in PJM.
- Supported the Federal State Government Policy outreach through by providing subject matter expertise during one-on-one meetings with regulatory staff and Commissioners related to any issues of mutual interest and import between PJM and state commission, state environmental regulators, FERC staff, and EPA staff as needed.
- Co-authored and co-led PJM's responses to the Independent Market Monitor's (IMM's) *State of the Market Reports* as well as remaining in communication with the IMM on various matters of concern and interest related to PJM market performance and design.
- Led technical and non-technical external outreach efforts to promote PJM markets or explain PJM positions on policy or market design issues of current interest to industry stakeholders including academic audiences, and invited presentations at industry sponsored events.
- Provided support in gas/electric coordination discussions within PJM and the between the power and gas industries, as well as operations support during critical operating periods in January 2014 through calls and inquiries to PJM generators and pulling environmental permits to better understand generator operating limitations on back-up fuel.
- Provided periodic reports on market performance and the state of PJM's markets to the PJM Board of Managers Competitive Markets Committee including the relationship between PJM's markets and major fuel market, environmental policy, and macroeconomic trends.
- Acted in the role of an internal consultant and advisor to all PJM departments and divisions, as needed, to address any questions or concerns surround market performance, market design, and general economic or environmental policy questions.
- Supported development and issuance of the PJM Renewable Integration Study by outsidevendors.

2000–2008 Director of Energy Studies, Public Utility Research Center and Lecturer, Department of Economics, University of Florida, Gainesville, FL

- Designed and delivered executive education and outreach programs in electric utility and regulatory policy and strategy for professionals in government, regulatory agencies, and industry primarily for developing countries.
- Responsible for electricity regulatory policy curriculum for the *PURC/World Bank International Training Program on Utility Regulation and Strategy* offered twice per year for 65 to 95 industry and regulatory professionals in each course.
- Acted as the electricity expert and liaison to the Florida electric utilities who were contributing members of PURC.
- Developed electricity related topics and obtained speakers for the PURC Annual Conferences held each February on matters related to environmental policy, wholesale market restructuring, so-called "hurricane hardening" of power systems after the 2004-2005 hurricane seasons, and other policy related matters of interest to the state of Florida.

- Served the PURC liaison to the consultants retained by PURC to evaluate the hardening of electricity infrastructure in the wake of the 2004 and 2005 hurricane seasons.
- Conducted original academic research related to electricity regulation and policy and published in peer reviewed academic and policy journals
- Developed customized regulatory training courses or sessions jointly prepared with other organizations for on-site delivery in Panama, Trinidad & Tobago, Brazil, Mexico, Peru, Bolivia, Argentina, Grenada, South Africa, Zambia, Namibia, and Cambodia
- Served as an advisor and subject matter expert on wholesale restructuring and market issue to Florida Governor Jeb Bush's *Energy 2020 Study Commission* 2000-2001.
- Taught classes as needed in the Economics Department on environmental economics, regulatory economics, and a large lecture class of managerial economics

1999–2000 Economist, Office of Markets, Tariffs, and Rates, United States Federal Energy Regulatory Commission, Washington, DC

1998–1999 Economist, Office of Economic Policy, United States Federal Energy Regulatory Commission

- Provided analysis and research related to filings made by ISO/RTO markets as they commenced operations as centralized wholesale power markets.
- Led the economic analysis and evaluation of the NYISO wholesale power market in its initial filings of its market design and subsequent filings after operations commenced.
- Led economic analysis and evaluation of multiple filings by the California ISO related to requested market design changes filed after starting operations in 1998.
- Supported analysis and evaluation of other ISO/RTO markets as needed.
- Supported and provided analysis on merger applications as needed.
- Conducted original research while on the staff of the Chief Economic Advisor in the Office of Markets, Tariffs, and Rates related to unit commitment models used in day-ahead electricity markets and pricing in the presence of lumpy decisions and operational characteristics (technically known as non-convexities).

1992–1998 Instructor, Department of Economics, Augsburg College, Minneapolis, MN

- Taught small classes of introductory microeconomics, labor economics, money and banking, and environmental economics

1992–1998 Instructor, Department of Economics, University of Minnesota, Minneapolis, MN

- Taught large lecture classes of primarily introductory microeconomics to classes of up to 600 students 3 times per year, managing a staff of teaching assistants and graders and developing curriculum and exams.
- Taught smaller classes of introductory microeconomics as well as environmental economics

PUBLICATIONS AND BOOK CHAPTERS

Covino, Susan, Andrew Levitt, and Paul Sotkiewicz, "The Fully Integrated Grid: Wholesale and Retail, Transmission and Distribution", in *Future of Utilities- Utilities of the Future: How Technological Innovations in Distributed Energy Resources Will Reshape the Electric Power Sector*, Fereidoon P. Sioshansi, editor, Chapter 22, pp.417-434, 2016.

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Bresler, Stuart, Paul Centollela, Susan Covino, and Paul Sotkiewicz, "Smarter Demand Response in RTO Markets: The Evolution Towards Price Responsive Demand in PJM", in *Energy Efficiency: Towards the End of Demand Growth*, Fereidoon P. Sioshansi, editor, Chapter 16, pp.419-442, 2013.

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P. M. Sotkiewicz, "Value of Conventional Fossil Generation in PJM Considering Renewable Portfolio Standards: A Look into the Future", *Power and Energy Society General Meeting, 2012 IEEE*

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Sotkiewicz, Paul M. "Cross-Subsidies That Minimize Electricity Consumption Distortions" University of Florida, Department of Economics, PURC Working Paper, 2003.

CONSULTING AND ADVISING EXPERIENCE PRIOR TO JOINING PJM IN 2008

2007 Advisor to the Government of Vietnam regarding the design and experience of wholesale electricity markets as Government looked at the creation of US style ISOs to attract investment in generation assets for IPPs

2007 Independent Expert in the Matter of the Public Utilities Commission of Belize Initial Decision in the 2007 Annual Review Proceeding for Belize Electricity Limited

2006 Advisor to the Division of Air Resource Management, Florida Department of Environmental Protection (FDEP) Regarding Implementation the Clean Air Interstate Rule (CAIR)

HONORS AND AWARDS

2007 Fulbright Senior Specialist Grant in Economics with a specific request for expertise in electricity markets, electricity regulation, and distribution tariff design, Universidad de la República, Montevideo, Uruguay.

2007 Principal Investigator, PPIAF/World Bank Grant to conduct two on-site training courses on the regulation of the electric power sector and on independent power producers and power purchase agreements for the Electricity Authority of Cambodia. Grant award $59,900.

2006 "Efficient Market Clearing Prices in Markets with Non-Convexities" published in European Journal of Operational Research received New Jersey Policy Research Organization Bright Idea Research Award in Decision Sciences.

2003 Transportation and Public Utilities Group, Ph.D. Utilities Dissertation Award for "The Impact of State-Level Public Utility Commission Regulation on the Market for Sulfur Dioxide Allowances, Compliance Costs, and the Distribution of Emissions"

1992-97 Distinguished Instructor, Department of Economics, University of Minnesota

1995-96
1994-95
1993-94
1992-93
Walter Heller Award for Outstanding Teaching of Economic Principles, Department of Economics, University of Minnesota

1991-92 Distinguished Teaching Assistant, Department of Economics, University of Minnesota

1991 Phi Beta Kappa, University of Florida

Referee and Review Experience

IEEE Transactions on Power Systems

Ecological Economics

Environmental Science and Technology

Determining the Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure, prepared for The Economic and Market Impacts of Coastal Restoration: America's Wetland Economic Forum II, September 28, 2006 Washington, DC

National Research Council of the National Academy of Sciences report entitled "Changes in New Source Review Programs for Stationary Sources of Air Pollutants", February 2006

California Energy Commission (CEC) Energy Innovations Small Grant (EISG) Program

Energy Journal

Journal of Environmental Economics and Management

IEEE PES Letters

IASTED International Journal of Power and Energy Systems

The Next Generation of Unit Commitment Models B. Hobbs, M. Rothkopf, R. O'Neill, and H.P. Chao editors
2001.

Professional Affiliations

American Economic Association
International Association for Energy Economics
Association of Environmental and Resource Economists
IEEE Power and Energy Society

EXPERT TESTIMONY

***PJM Interconnection, L.L.C.* FERC Docket No. ER09-1063-006, Affidavit in Support of PJM's Compliance Filing with Order No. 719 and Order on Compliance Filing *PJM Interconnection, L.L.C.*, 129 FERC ¶ 61,250 (2009). June 18, 2010**
In support of its compliance filing to establish a mechanism that ensures appropriate pricing during periods of operating reserve shortages, as required by the Commission's Order No. 719, I provided the following: 1) A high-level overview of PJM's markets, planning, and operations, including a description of what is meant by an operating reserve shortage, and how such shortages arise; 2) An overview of PJM reserve requirements, current reserve market structure, and data on PJM's prices and operations at times when the grid it manages has experienced operating reserve shortages; 3) A showing why PJM's then current scarcity pricing not satisfy the Commission's Order No. 719 criteria for operating reserve shortage pricing mechanisms; 4) Description of the main elements of PJM's proposal to comply with Order No. 719's shortage pricing policy, and how PJM's proposal satisfies the six criteria for reserve shortage pricing set by Order No. 719.

***PJM Interconnection, L.L.C.* FERC Docket No. ER09-1063-004, Affidavit in Support of Answer to Comments and Motion for Leave to Answer to Protests, August 23, 2010.** The purpose of this affidavit is to provide the following regarding PJM's proposed shortage pricing mechanism: 1) The complementary relationship between capacity adequacy in the Reliability Pricing Model ("RPM") and shortage pricing; 2) Additional evidence showing why PJM' shortage pricing proposal leads to energy prices that reflect the cost and/or value of energy, allocates energy to those who value it most, enhance operational reliability, and leads to efficient market outcomes while the alternate proposal from the Independent Market Monitor (IMM) fails to achieve any of these goals; 3) An explanation of how the proposed mechanism is consistent with shortage pricing mechanisms in the New York Independent System Operator ("NYISO") and ISO New England ("ISO-NE") that the Commission has already approved as Order 719 compliant.

***PJM Interconnection, L.L.C.* FERC Docket No. ER12-513, Affidavit in Support of Filing to Update its RPM Auction Parameters (aka Triennial Review) December 1, 2011.** This affidavit was submitted in support of three aspects of PJM's proposed changes related to PJM's capacity market, known as the Reliability Pricing Model ("RPM") including: 1) the continued use of a nominal levelized approach to calculating the estimated Cost of New Entry ("CONE") that is used in RPM's Variable Resource Requirement ("VRR") Curve; 2) retention of a combustion turbine ("CT") as the Reference Resource.

***PJM Interconnection, L.L.C.* FERC Docket No. ER-14-2490, Affidavit in Support of Filing to Update its RPM Auction Parameters (aka Quadrennial Review) September 25, 2014** This affidavit was submitted in support of five aspects of PJM's proposed changes related to PJM's capacity market, known as the Reliability Pricing Model ("RPM"): 1) adoption of The Brattle Group's ("Brattle") recommended VRR Curve shape right shifted by 1% of the Installed Reserve Margin ("IRM"); 2) continued use of a nominal levelized approach to calculating the estimated Cost of New Entry ("CONE") that is used in RPM's Variable Resource Requirement ("VRR") Curve; 3) retention of a combustion turbine ("CT") as the Reference Resource; 4) use of a composite of Bureau of Labor Statistics ("BLS") indices to adjust Gross CONE estimates in between periodic VRR parameter reviews; and 5) adoption of the labor estimates provided by the PJM Independent Market Monitor ("IMM") to determine Gross CONE values.

Grid Reliability and Resilience Pricing **FERC Docket No. RM18-1, Affidavit in Support of the Electric Power Supply Association (EPSA), October 23, 2017.** This affidavit provides evidence the Department of Energy Notice of Proposed Rulemaking ("NOPR" or "Proposal") released on September 28, 20171 and appearing in the Federal Register on October 2, 2017 does nothing to enhance reliability or "resiliency" of the bulk power system and will only succeed in distorting wholesale power markets while also raising costs. Consequently, my affidavit supports EPSA's contention the NOPR should be rejected outright by the Commission.

ISO New England Inc. and New England Power Pool Participants Committee**, FERC Docket No. ER18-620-000, Affidavit in Support of the Protest of the New England Power Generators Association, Inc. January 29, 2018.** In summary, my affidavit explains that the proposed updated DDBT from $5.50/kW-month to $4.30/kW-month: 1) Relies on a flawed and logically inconsistent methodology that differs from the DDBT methodology approved by the Commission three years ago; 2) Sets a dangerous precedent in ISO-NE taking a position on the direction of its Forward Capacity Market ("FCM") in terms of supply-demand balance and expected market prices that could anchor expectation of market participants. The anchoring of such expectations can change FCA bidding and operational behavior that could harm reliability; 3) The previous methodology approved by the Commission of using Static De-List Bids from oil steam and oil combustion turbine generators remains the appropriate methodology for determining the DDBT; and 4) The cost-based DDBT is likely higher than for FCAs 10-12 given that net going forward costs for oil steam and oil combustion turbine units has likely increased given their age, and other risks and opportunity costs that may be coming into play. My affidavit concludes that the current DDBT should be retained until such time as a new DDBT threshold and be determined using the current Commission-approved methodology following the discovery of the actual costs and risks faced by oil units.

Petition for Determination of Need for Seminole Combined Cycle Facility in Docket No. 20170266-EC and Joint Petition for Determination of Need for Shady Hills Generating Facility in Docket No. 20170267-EC, January 29, 2018. Testimony and Exhibits on Behalf of Quantum Pasco Power, LP, Michael Tulk, and Patrick Daly. My testimony supports the notion that there is no need for either combined cycle facility as Seminole Electric has consistently over-forecast its load growth since the "great recession" and that once correcting for these large errors, there is no need to build two new combined cycle facilities when there where other lower cost merchant generator facilities that offered their capacity to Seminole.

PJM Interconnection, L.L.C. **FERC Docket No. E18-34, Affidavit in Support of EPSA's Filing and Comments in PJM's Fast Start Pricing Proposal, March 14, 2018** My affidavit in this proceeding provides support for PJM's desire to allow resources with up to two-hour start up times to be considered "fast start" resources and to set price in accordance with the fast start pricing principles the Commission has enumerated in its Fast Start Pricing NOPR. I explain PJM's use of IT SCED and request to allow two-hour start time resources to set prices as fast start resources is entirely consistent with the ideas the Commission has enumerated with respect to fast start pricing.

PJM Interconnection, L.L.C. Capacity Repricing or in the Alternative MOPR-Ex Proposal: Tariff Revisions to Address Impacts of State Public Policies on the PJM Capacity Market**, FERC Docket No. ER18-1314-000, Affidavit is Support of Comments of American Petroleum Institute, JPower USA Development, Ltd., and Panda Power generation Infrastructure Fund, LLC May 7, 2018.** My affidavit provides evidence that 1) The PJM Capacity Repricing Proposal is not just and reasonable and is unduly discriminatory and results in an inefficient commitment of resources; 2) The alternative proposal from PJM, MOPR-Ex, is just and reasonable and results in the most efficient and cost-effective se of resource commitments; and 3) The current and previous iterations of the MOPR are not just and reasonable and are unduly discriminatory because they do not apply to existing resources and they only apply to gas-fired resources. Furthermore, my affidavit provides evidence that MOPR has always been viewed as a market power mitigation mechanism that was originally intended to thwart or mitigate the exercise of buyer-side market power. I show in this affidavit that MOPR, and in particular MOPR-Ex, still is a powerful market power mitigation tool that mitigates exercise of supplier market power that are facilitated by the current round of state subsidies to generation. Moreover, I show that Capacity Repricing helps facilitate the exercise of supplier market power through three different means.

***Grid Resilience in Regional Transmission Organizations and Independent System Operators*, FERC Docket No. AD18-7-000, Affidavit is Support of Comments of the American Petroleum Institute, May 9, 2018.** This affidavit focuses of the comments submitted by PJM and: 1) Supports the idea that in the context bulk power system markets and operation resilience and reliability are indistinguishable and that markets and well-designed incentives are the best avenue to achieve a resilient and reliable bulk power system; 2) Explains why market mechanisms rather than suspension of market and command and control regimes are better at achieving resiliency/reliability even during emergency conditions and that PJM has not made a case for being given the authority to suspend markets; 3) That PJM has not made the case that price formation through integer relaxation is linked to resilience/reliability while other price formations that are crucial to reliability/resilience such as shortage pricing and fast start pricing are being considered concurrently; and 4) So-called "fuel security" is only a minimal contributor to resilience/reliability while transmission and distribution assets are the leading causes for shedding firm load and gas-fired units have been shown to not even being the leading category of generation outages. With respect to generator reliability/resilience, simply providing additional compensation (or minimize penalties) to generators in wholesale markets, without any ties to generator performance, does nothing to enhance reliability/resilience of generators to withstand or minimize the impact of adverse events on the bulk power system. Experience in PJM prior to, and following the discussion and implementation of capacity performance has shown this to be the case as generator performance has improved even in the face of lower energy market prices.

***New England Power Generators Association, Complainant v. ISO New England Inc., Respondent.* FERC Docket No. Docket No. EL18-154-000, Affidavit in Support of Complaint and Request for Expedited Consideration of the New England Power Generators Association, Inc. May 24, 2018** This affidavit in support of NEPGA's complaint shows the impact of treating Mystic Units 8 and 9 as a price taker on the ISO-NE markets as well as NEPGA's proposed alternative to accommodating the participation of the Mystic units. Discussions include: 1) treating Mystic and other resources retained for fuel security as price takers will do significant harm to the competitiveness of the FCM market and is inconsistent with the first principles of capacity markets articulated by the Commission; 2) the proposal to insert an above market cost resource into the FCM as a price taker does exactly the same harm as an exercise of buyer-side market power, which he Commission has found to be unjust, unreasonable, and unduly discriminatory; and 3) the proposed remedy offered by NEPGA does not distort the results of the Forward Capacity Auction, results in competitive pricing outcomes in FCA, does not displace otherwise economic resources, and provides better reliability outcomes for ISO-NE load than the current ISO-NE proposal.

***New England Power Generators Association, Complainant v. ISO New England Inc., Respondent.* FERC Docket No. Docket No. EL18-154-000, Affidavit in Support of the Motion for Leave and Answer of the New England Power Generators Association, Inc. June 19, 2018.** This affidavit in support of NEPGA's answer refutes the answer of ISO-NE and protesters and responds that nothing in ISO-NE's answer to the Complaint or the protests to the Complaint provides a basis for ignoring that treating the Mystic Units as price takers would suppress prices below competitive levels and inefficiently displace otherwise economic resources in a manner that is observationally equivalent to the harm done by an exercise of buyer-side market power.

***Panda Stonewall, LLC.* FERC Docket No. ER17-1821-002, Testimony is Support of Panda Stonewall, LLC Reactive Power Filing, July 2, 2018.** This testimony supports Panda Stonewall's reactive power rate case that has gone to hearing and in particular supports the inclusion of firm gas pipeline transportation, the use of proxy cost of capital values from the PJM CONE study, and supports the inclusion of other administrative and overhead costs consistent with fixed, going forward costs incurred by Panda Stonewall to remain in commercial operation. Furthermore, the testimony puts the costs of reactive power into the context of the wiser PJM market and other opportunities for compensation and well as providing historical context around the Commission-approved AEP Methodology for reactive power rates.

***ISO New England Inc.* FERC Docket No. ER18-2364-000, Affidavit in Support of the Protest of the New England Power Generators Association, Inc. September 21, 2018.** This testimony supports NEPGAs protest that the proposed ISO-NE treatment of resources held for winter fuel security as price takers in the FCA makes no sense since winter fuel security is not associated with overall resource adequacy which is based on the summer peak. Moreover, the testimony shows clearly the artificial price suppression that would occur based on ISO-NE proposed treatment of resources held for winter fuel security in the FCA.

Calpine Corporation v. PJM Interconnection, L.L.C. Docket No, EL16-49; PJM Interconnection L.L.C. Docket No. ER18-1314-000, ER18-1314-001, EL18-178 **Affidavit in Support of the Electric Power Supply Association, October 2, 2018.** This testimony refutes the idea that the Commission proposed remedy a resource specific FRR Alternative equally removes both demand and supply from the market and therefore does no harm. Such a mechanism is the equivalent of an exercise of buyer side market power, artificially reduces price below competitive levels, inefficiently displaces lower cost, economic resources with higher cost resources, shifts cost and benefits between market participants, and reduces overall market efficiency. Additionally, PJM market simulations for scenarios from the 2020/2021 auction show the kind of damage that can be done to the market through the proposed remedy or equivalently buyer sider market power by showing prospective price decreases and generation displacement, and the level of subsidy that could be used to facilitate a successful exercise of buyer-side market power.