STATE OF NEW JERSEY
BEFORE THE
BOARD OF PUBLIC UTILITIES

INVESTIGATION INTO RESOURCE ADEQUACY ALTERNATIVE	))))))))	**BPU Docket No. EO20030203**

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") [1] to submit these reply comments that respond to the initial brief filed by parties in the New Jersey Board of Public Utilities ("NJ BPU" or "BPU") in its March 27, 2020[2] and April 17, 2020[3] notices in BPU Docket No. EO20030203.

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] 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

[2] *Investigation of Resource Adequacy Alternatives*, Request for Written Comments, Docket No. EO20030203 (Mar. 27, 2020) (the "Request for Comments").

[3] *Investigation of Resource Adequacy Alternatives*, Supplemental Notice for Written Comments, Docket No. EO20030203 (Apr. 17, 2020).

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 short biography in Attachment A and my CV Attachment B.

4. I have previously provided affidavits to the BPU in BPU Docket No. EO18080899 on October 22, 2018[4] and in reply comments in the same docket on March 19, 2019.[5]

A. Specific Experience with Respect to PJM's Reliability Pricing Model ("RPM") and the Fixed Resource Requirement ("FRR").

5. As the Chief Economist at PJM, I was responsible for all matters of market design and market related policies. Specifically, I was responsible for administering and overseeing the Minimum Offer Price Rule ("MOPR"). Those responsibilities included the review and determination of unit specific MOPR offer price floors as well as competitive entry and self-supply exemptions as they had existed over time within the PJM Tariff.[6]

6. Additionally, I worked with the Capacity Market Operations group at PJM to review Base Residual Auction ("BRA") results to verify their accuracy and then provided broad analyses regarding the dynamics of how and why the BRA prices that appeared in the BRA Reports made sense. As PJM's Chief Economist, I also supported various market

[4] *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. *See* Prepared Comments of Paul M. Sotkiewicz, Ph.D.,, BPU Docket No. EO18080899 October 22, 2018 in ("Sotkiewicz Initial Comments")

[5] Reply Testimony of Paul M. Sotkiewicz, Ph.D. on Behalf of the PJM Power Providers Group in Regard to PSEG Reply Comments, BPU Docket No. EO18080899, March 19, 2019. ("Sotkiewicz Reply")

[6] 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).

design changes and parameter updates (Triennial/Quadrennial Reviews) to the RPM Capacity Market.[7]

7. With respect to generator costs, especially avoidable costs, I led the effort in 2012 to update the default Avoidable Cost Rate ("ACR") values that currently appear in the PJM Tariff.[8] In this same vein, I have also been a reviewer for the United States Environmental Protection Agency ("US EPA") Integrated Planning Model ("IPM") in which I reviewed and verified the fixed operations and maintenance costs for all resources types, including nuclear resources and ensured overall modeling fidelity.[9] This experience and knowledge provides me with additional insight into generator costs and how they may behave in PJM's RPM Capacity Market.

8. Finally, with my former responsibilities at PJM with respect to the RPM Capacity Market, I have great familiarity with the FRR methods for satisfying PJM resource adequacy requirements. I have reviewed the resources that have been designated as part of FRR plans in the past and have understanding generator costs associated with FRR. That experience provides insights as to the rationale for entities to choose the FRR alternative over participating in the RPM Capacity Market.

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[7] *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").

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

[9] 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

II. EXECUTIVE SUMMARY: KEY FINDINGS AND CONCLUSIONS

9. Overall, it is in the best interests of New Jersey and its electricity customers to avoid the siren song of the FRR alternative, especially the joint proposal from Exelon ("EXC") and Public Service Enterprise Group ("PSEG"). The FRR alternative only provides the illusion of control, but in reality, it results in creating opportunities to exercise market power for "chosen" resource owners where prices will likely be negotiated in a non-transparent manner leading to higher costs for consumers. Moreover, the FRR will shift the performance risk of PJM's RPM Capacity Market from the "chosen" generation resource owners back to New Jersey customers who will either be exposed to penalties or pay for generators to take on those risks within the FRR contract.

A. The FRR as Proposed Would Lead to an Additional $700 million in Costs to New Jersey Customers only to Save $21 million in Double Counted Wind Capacity Through 2027.

10. Under the Proposal from PSEG and EXC,[10] giving up ZEC payments and combining these revenues into capacity payments would add an estimated $233.71/MW-day to capacity prices.[11] Adding these considerations to the PSEG LDA and EMAAC LDA prices leads to implied capacity prices of $438/MW-day and $399.44/MW-day respectively.[12]

11. Further, under the tiered procurement proposal that would likely contract not just with the Salem and Hope Creek units, but also target the Limerick and Peach Bottom units in

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[10] *See also* PSEG and Exelon Generation Company, LLC ("PSEG/EXC Proposal"), Joint Comments in *Investigation of Resource Adequacy Alternatives* BPU Docket No. EO20030203, May 20, 2020.

[11] This is $10.82/MWh * 8760 hours * capacity factor / 365. At a 90 percent capacity this is $233.71/MW-day. The $10.82 comes from Sotkiewicz Initial Comments p 11.

[12] PJM Interconnection, LLC ("PJM"), *2021/2022 RPM Base Residual Auction Results* at 1, Table 1. EMAAC prices were $165.73/MW-day and PSEG LDA prices $204.29/MW-day.

southeast Pennsylvania. The combined capacity of these resources is 8,153 MW of UCAP value.[13] Adding the ZEC implied capacity cost to all the capacity prices collected by these resources in the 2021/2022 Base Residual Auction (BRA) would raise costs by just under $700 million.[14]

12. In addition, Ørsted has stated that it would be giving up approximately $40 million in capacity revenues if it were not in an FRR and had to be exposed to MOPR in the RPM Capacity Market.[15] This implies a capacity price of approximately $383/MW-day based on a 26 percent capacity factor for the 1100 MW ICAP (286 MW UCAP) of wind Ørsted plans to bring into service in 2024. This would raise costs to about $735 million. But it also indicates how it expects to benefit from market power under FRR.

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[13] Salem 1 and Salem 2 have ICAP values of 1,170 MW and 1,158 MW respectively for a total of 2,328 MW. Hope Creek has an ICAP value of 1,190 MW. The UCAP values are 98 percent of the ICAP based on a assumed two percent equivalent forced outage rate under demand ("EFORd"). The total for these units is 3,518 MW ICAP and 3,458 MW UCAP. Limerick 1 and Limerick 2 have ICAP values of 1,120 MW and 1,122 MW respectively. Peach Bottom 2 and 3 have 1,245 MW and 1, 248 MW respectively. The UCAP values are 98 percent of the ICAP based on a assumed two percent EFORd. The total for these units is 4,735 MW ICAP and 4,695 MW UCAP. The ICAP data comes from United 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"). The two percent EFORd assumption comes from 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 most recent forced outage rate was just below 1 percent, but historically this figure has been around 3 percent. I have assumed a 2 percent EFORd as the mid-range point.

[14] The figure is $695 million. $233.71/MW-day multiplied by 8,153 MW UCAP for all the nuclear resources and then multiplied by 365 days in the year.

[15] Ørsted, *Comments to the New Jersey Board of Public Utilities on its Resource Adequacy Investigation* Docket No. EO20030203 at 5. Available at https://www.nj.gov/bpu/pdf/ofrp/Comments/Ørsted%20[May%2020,%202020].pdf ("Ørsted Comments")

13. The reality is that if Ørsted could not be a capacity resource, 286 MW UCAP at the PSEG LDA prices of just over $204/MW-day in the 2021/2022 BRA would need to be purchased. This is also known as the so-called "double payment for capacity" which could be purchased at about $21 million from the RPM Capacity Market while New Jersey also pays for the wind resource.

14. Also, there is not a concern that the New Jersey nuclear resources will fail to clear in any RPM Auction going forward given their low costs and sufficient revenues as has been presented previously to the BPU.[16] And recently, the Independent Market Monitor for PJM ("PJM IMM") calculated the MOPR offer floor for multi-unit nuclear resources to be $0/MW-day.[17] That is, even if they did not receive ZEC payments and being subject to the Minimum Offer Price Rule ("MOPR"), Salem and Hope Creek will clear in the BRA.

15. The bottom line is that if: New Jersey elects to move toward and FRR plan as envisioned by PSEG and EXC, New Jersey electricity consumers will spend an extra $735 million to "save the double payment" of a mere $21 million. A benefit-cost ratio of -35 does not seem like a good deal for anybody, let alone the electricity customer in New Jersey.

B. The FRR Alternative Makes the Costs of Capacity Non-Transparent and Hides Costs/Payments that are Above Market Prices

16. As has been seen empirically, entities that have elected FRR to date have costs that are much higher than market prices. Yet, this inflated capacity cost is not transparent to the

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[16] *See* Sotkiewicz Initial Comments P 8 summarizing analysis. *See also* Sotkiewicz Reply P 15, Table 2

[17] Monitoring Analytics, Independent Market Monitor for PJM ("PJM IMM"), *CONE and ACR Values – Preliminary*, January 21, 2020. *See* Table 1, at 4, where the floor is $0.00/MW-day for multi-unit nuclear facilities. Available at https://pjm.com/-/media/committees-groups/committees/mic/2020/20200128-special/20200128-item-04b-cone-and-acr-values-imm-presentation.ashx

regulated customers who are responsible for paying these costs. They do not see the costs that they would have paid if their provider were not in an FRR. Experience with the AEP FRR election shows this very clearly. AEP capacity charges in its service territories that have elected FRR are greater than \$400/MW-day which is more than three times the going RPM BRA prices for the RTO in which AEP operates.

17. Unlike the AEP service areas with FRR, New Jersey is not vertically integrated and rate regulated at the state level. New Jersey operates in a competitive retail environment in which even serving load from the Provider of Last Resort (POLR") is open to competitive forces through the Basic Generation Service ("BGS") auctions. The FRR takes away the ability for bidders into the BGS auction to leverage the competitive and transparent RPM Capacity Market to develop packages that would minimize the cost of serving New Jersey consumers through BGS auctions.

18. Consequently, BGS auctions would not produce the kind of competitive results they have to date because bidders will not have price transparency in an FRR construct the way they do in the PJM auction structure. Nor can they hedge against such costs without transparency. Such uncertainty will only drive up BGS costs above competitive levels to account for such risk.

C. The New Jersey Nuclear Resources are Already Profitable and Do Not Need FRR to Ensure They will be Committed as Capacity Resources

19. As has been shown previously in the ZEC docket, the New Jersey nuclear resources are already profitable and will continue to remain so based on publicly available data. Currently, PSEG has stated they have hedges in place for their nuclear output at \$37/MWh in 2020 for nearly 100 percent of their output, and \$36/MWh in 2021 and 2022

for 80 percent and 30 percent of their output respectively in those years.[18] Effectively, for a resource specific exemption, they will easily clear the market based on historic and projected RPM Capacity Market dynamics.

20. Even if the New Jersey nuclear units used the default MOPR floor for multi-unit nuclear units to offer into the BRA at the price floor estimated by the PJM IMM to be $0/MW-day, given past prices and projected future RPM dynamics, the New Jersey nuclear units will undoubtedly clear unless they are providing supply offers well above their net going forward costs.[19] The default floors are consistent with analysis I have previously provided to the BPU.[20] With a default floor price of zero, there is no need to use the Resource Specific exemption in MOPR.

D. PSEG and EXC Offering to Give Up ZEC Payments in Exchange for an FRR Indicates that they will Require Significantly Higher Capacity Prices than Market Price

21. 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.[21] These ZEC

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[18]Public Service Enterprise Group, Inc, Form 8-K, February 26, 2020, EX. 99.1, PSEG Earnings Conference Call 4thQuarter & Full Year 2019, February 26, 2020. Available at https://www.sec.gov/Archives/edgar/data/81033/000119312520049323/d894238dex991.htm. ("PSEG 2019 Earnings Call") *See.* Slide 27.

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[19] Monitoring Analytics, Independent Market Monitor for PJM ("PJM IMM"), *CONE and ACR Values – Preliminary*, January 21, 2020. *See* Table 1, at 4, where the floor is $0.00/MW-day for multi-unit nuclear facilities. Available at https://pjm.com/-/media/committees-groups/committees/mic/2020/20200128-special/20200128-item-04b-cone-and-acr-values-imm-presentation.ashx

[20] *See* Sotkiewicz Initial Comments P 8 summarizing analysis. *See also* Sotkiewicz Reply P 15, Table 2.

[21] 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.

payments amount to an extra payment of $10.82/MWh for these resources over and above what they are paid through PJM's markets and/or through hedging contracts to manage risk. This has been confirmed by PSEG in its 2019 10-K filing.[22] These payments are in addition to the $6.40-$10.91/MWh of net profits for each MWh[23] given the current hedges and known capacity market prices.

22. The capacity pricing impacts of this are enormous. To give up the ZEC payments in exchange for an FRR, EXC and PSEG would expect an additional $233.71 in additional capacity payments to make them break even with the current ZECs.[24] That implies a capacity price for New Jersey nuclear units in the range of $385/MW-day minimum if using the EMAAC prices at the low end estimate up to $465/MW-day at the PSEG LDA prices at the high end estimate. These prices are far above those estimated by the IMM in its report for a New Jersey FRR of $235.42/MW-day, showing that the IMM results and study took a more conservative approach. Also, when it did its study, the IMM did not have the PSEG/EXC proposal to examine.[25]

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[22] Public Service Enterprise Group, Inc. Form 10-K for the Fiscal Year Ended December 31, 2019 ("PSEG 10-K") at 45, "In April 2019, PSEG Power's Salem 1, Salem 2 and Hope Creek nuclear plants were awarded ZECs by the BPU. Pursuant to a process established by the BPU, ZECs are purchased from selected nuclear plants and recovered through a non-bypassable distribution charge in the amount of $0.004 per kilowatt-hour used (which is equivalent to approximately $10 per megawatt hour generated in payments to selected nuclear plants (ZEC payment)). These nuclear plants are expected to receive ZEC revenue for approximately three years, through May 2022." Filing available at https://www.sec.gov/ix?doc=/Archives/edgar/data/81033/000078878420000004/pseg201910k.htm.

[23] Sotkiewicz Reply P 15 Table 2.

[24] This is $10.82/MWh * 8760 hours * capacity factor / 365. At a 90 percent capacity this is $233.71/MW-day

[25] PJM IMM, *Potential Impacts of the Creation of New Jersey FRRs*, May 13, 2020. Available at http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_New_Jersey_FRRs_20200513.pdf. ("NJ FRR Study"). For all of NJ the weighted average Net CONE * B is $235.42/MW-day (at 1). *See also* PSEG and Exelon Generation Company, LLC ("PSEG/EXC Proposal"), Joint Comments in *Investigation of Resource Adequacy Alternatives* BPU Docket No. EO20030203, May 20, 2020.

E. NRDC's Proposal for Pooling Performance Risk under FRR Shifts Performance Risk Back to New Jersey Customers

23. NRDC proposes to pool risk for all FRR resources (including renewable resources) with the idea that currently renewable resources are not offering all of their eligible capacity into the RPM Capacity Market due to performance risk. In this way NRDC claims that renewables will provide greater capacity value to New Jersey, and that the pooling of risk will provide greater capacity value.

24. However, this approach places an additional burden of performance on controllable resources to over-perform. If controllable resources are unable to over-perform, this leaves the FRR fleet in the position of under-performing and thus places the burden of non-performance risk and associated penalties on New Jersey customers absent any terms in the FRR contracts to hold generators accountable for their performance. Even if the FRR contracts require generators to be responsible for performance penalties as is currently the case in the RPM Capacity Market, customers will still bear this burden in additional costs up front with a mark-up for the market power exacerbated by the FRR. This is an inefficient and inappropriate shifting of risk to customers that will only increase costs beyond the higher implied capacity costs.

III. INCENTIVES FOR ELECTING THE FRR AND PRACTICAL REALITIES OF FRR

25. The FRR alternative to participating directly in the PJM RPM Capacity Market has been in place since the start of RPM. Other than being used in transition periods as new transmission zones were integrated into PJM,[26] it has only been utilized by vertically

[26] As a transition mechanism for ATSI to integrate into PJM, they ran auctions under the FRR alternative for the 2011/12 and 2012/2013 Delivery Years. After that ATSI's load participated in the RPM Capacity Market.

integrated, regulated entities participating in the PJM market: American Electric Power ("AEP") and its various operating companies and Duke Energy Kentucky ("DEK").[27] These utilities are both load serving entities ("LSEs") and generation owners ("GO").

26. These LSEs choosing FRR is not surprising. As vertically integrated and regulated utilities are monopolies in their service areas, they do not face any kind of retail competition. Moreover, consistent with being a monopoly on the generation side, these entities electing FRR have incentives to avoid competition whenever possible to collect rents/profits that are more consistent with being a monopoly than operating in competitive markets.

27. Finally, there is the illusion of control. The regulators who oversee those entities electing the FRR alternative may easily view continued monopoly regulation and cost-of-service/rate of return treatment as more stable than markets. Afterall, markets reflect the underlying changing economic conditions and technological advancements relatively rapidly. But these underlying fundamentals and unpredictability may be seen as "undesirable" because they are volatile and cannot be controlled, and thus regulators may feel they can better control these underlying fundamental changes, when in fact such changes cannot be controlled at all.

A. Protecting High Cost Generation from Competition

28. The FRR alternative denies regulators the ability to compare regulated rates with competitive rates and opt for the least-cost option. Consider an LSE with self-owned resources that has costs above the market price and has made significant capital

[27] This can be verified by filed and posted FRR Capacity rates found at https://pjm.com/markets-and-operations/billing-settlements-and-credit/frr-lse-capacity-rates.aspx.

investments in these resources. Further assume 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 deemed "used and useful." Moreover, these regulated returns are often much higher than those earned in a competitive market. In a competitive market environment, these uneconomic resources would fail to clear in the RPM Capacity Market and their higher costs would likely be called into question by their state regulators as the competitive market demonstrates they are no longer cost-effective.

29. 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, thus allowing the resources to 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.[28] For example, performing this type of analysis shows the most recent FRR Plan on file with PJM would charge retail competitors $480.90/MW-day for capacity in Appalachian Power Service Territory of AEP.[29] Over the previous four delivery years from the 2016/2017 Delivery year through the 2019/2020 Delivery the capacity charges were $437.46/MW-day, $393.86/MW-day, $435.86/MW-day, and $403.35/MW-day respectively.[30]

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

[29] *See* Appalachian Power Company*, APCO Capacity Compensation Formula Rate To be Effective June 1, 2020 through May 31, 2021 No. ER13-539*, available at https://pjm.com/-/media/markets-ops/settlements/frr-lse-capacity-rates/2020-capacity-formula-rate-summary.ashx?la=en

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

30. However, the incentive to charge consumers capacity charges above market rates revealed itself when the Ohio operating companies of AEP, Ohio Power and Columbus Southern Power when transitioning to retail competition. 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.[31] 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.[32]

31. 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.[33] It is worth noting that at the time AEP made this filing in 2011, 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.[34] [35] AEP's filed rate was more than double the market rate.

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

[32] *Id.*

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

[34] 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.

[35] 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.

32. 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.[36]

B. FRR Creates the Ideal Environment for the Exercise of Supply-Side Market Power

33. Generically, supply-side market power is the ability to withhold output from the market, either physically or economically, to raise market prices above competitive levels to earn higher profits than would otherwise be available in a competitive market environment. In the context of the RPM Capacity Market, this could be reasonably achievable only through physical or economic withholding almost all resources, but PJM rules have a must-offer requirement into the RPM Capacity Market with only a handful of exceptions[37] and offer capping rules that limit this behavior.[38]

34. Markets become increasingly competitive when there is a wider pool of resources that can compete to satisfy demand, when the ownership of resources is widely dispersed and when demand is highly responsive to price changes in the market. The confluence of all these forces incent suppliers to offer their resources at their marginal cost of supply as the optimal offer strategy. This leads to market prices that equal the marginal cost of supplying one more unit to satisfy demand. In the context of the RPM Capacity Market,

[36] 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.

[37] PJM Open Access Transmission Tariff ("PJM Tariff"), Attachment DD, Section 6.6 (a) and 6.6 (g).

[38] PJM Open Access Transmission Tariff ("PJM Tariff"), Attachment DD, Section 6.4.

this implies the market clearing prices should be equal to the net avoidable costs of the last resource needed to meet the demand for capacity.[39]

35. The FRR alternative is the antithesis to competition and competitive outcomes. The empirical evidence is a clear warning about the ability for the monopoly to extract returns above competitive levels as seen with AEP in the FRR plans and charges for capacity.

36. Under the FRR alternative there is no must offer requirement as there is in the RPM Capacity Market. Thus, the available supply is smaller due to the ability to physically withhold capacity from the FRR entity. As a result. the FRR alternative results in fewer distinct suppliers as generation owners who offer to the FRR entity charge as high a price as possible due to the absence of market power mitigation. There is no way that a must-offer bid can be imposed on them in the FRR context, nor would they be subject to market power mitigation under PJM rules. Finally, the FRR alternative uses a vertical demand curve that is not price responsive which exacerbates the ability to exercise market power. As such an FRR plan in a competitive retail environment such as New Jersey is the perfect incubator for the exercise of market power.

C. The Market Power Potential of FRR is Real

37. The PJM Independent Market Monitor ("IMM") has already submitted comments in this proceeding showing that it would be easy to exercise market power through the FRR.

[39] The net avoidable costs are those costs that are required to keep a generator in commercial operation such as fixed O&M, insurance, property taxes, and other overhead costs less the net energy market revenues. If a unit retires, the aforementioned costs can be avoided. Capital investments and debt service are sunk costs and cannot be avoided even if the resource retires. The calculation of this can be found in the PJM Tariff, Attachment DD, Section 6.8.

The PJM IMM has used multiple different measures of market power that are summarized here.[40]

38. Without even considering the PSEG/EXC proposal for tiered procurement of resources for an FRR plan, The PJM IMM finds that a NJ FRR and a PSEG only zone would be considered moderately to highly concentrated according to DOJ/FTC guidelines from the computed HHI. The DOJ cutoff for highly concentrated is 2500.[41] The computed NJ HHI is 2245, and the computed PSEG zone HHI is 5562 while considering only resources in those zones or areas.[42] As discussed below in Section VII, when limiting the pool of resources to those with zero emissions leads to higher concentrations even though the geographic scope is expanded beyond New Jersey.

39. The PJM IMM also calculates what is known as the Residual Supply Index for a single pivotal supplier and three pivotal suppliers. The IMM finds that all suppliers are singly pivotal in the NJ, PSEG, or JCPL FRR scenarios.[43] Regardless of size, any supplier can exercise market power because the demand for capacity cannot be met without supply from any one supplier if it withheld capacity.

40. The IMM finds that when all eligible capacity for an FRR plan would require a price at Net CONE multiplied by the Balancing Ratio ("Net CONE * B"), New Jersey customers could pay as much as 29% more for capacity or $386 million while subsidizing customers

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[40] PJM IMM, NJ FRR Study at 8-11.

[41] See United States Department of Justice and the Federal Trade Commission, *Horizontal Merger Guidelines*, Issued August 19, 2010, at 19. Available at https://www.ftc.gov/sites/default/files/attachments/merger-review/100819hmg.pdf

[42] PJM IMM, NJ FRR Study at 10, Table 4

[43] *Id*. at 11, Table 5

in the rest of PJM by nearly $784 million.[44] This is a conservative assumption as Net CONE*B is the offer cap in PJM under which there is no other market power mitigation. This increase in prices exceeds the amount that is currently being paid for ZECs by New Jersey customers.[45] The increase in costs reported by the IMM in its analysis are market power rents that are taken from New Jersey electricity customers and transferred to generation resources satisfying the FRR requirement.

IV. FRR FALLACIES AND MISCONCEPTIONS

A. The Fallacy of Reducing Load Costs through Reduced Reserve Obligations

41. It has been stated by Public Interest Organizations ("PIOs")[46] that by electing the FRR path, New Jersey can reduce its capacity costs in part by reducing the overall amount of capacity it needs to procure. This is based on the observation that the FRR plan need only procure to the Installed Reserve Margin ("IRM") target which, over the years, has been lower than the amount of capacity cleared in the RPM Capacity Market.

42. The argument assumes that FRR capacity is the same price as market capacity which we know is not the case. Once the "rules of the game" change from the RPM Capacity Market with a wide pool of supply, low concentration of ownership, and a downward sloping demand supplier behavior will change. We also know empirically that FRR prices are not the same or lower as shown in the AEP experience with FRR.

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[44] *Id*. at 4, Table 1. The reason for this result is that NJ customers are now being forced to procure import less lower cost generation, increasing costs, but allowing that lower cost generation to benefits the rest of PJM.

[45] *See* PSEG 2019 10-K at 45, *supra* note 14.

[46] Initial Comments of Public Interest Organizations Regarding Resource Adequacy Alternatives, *In the Matter of Investigation of Resource Adequacy Alternatives* Docket No. EO20030203, ("PIO Comments") at 12.https://www.nj.gov/bpu/pdf/ofrp/Comments/Natural%20Resources%20Defense%20Council-Sierra%20Club%20Initial%20Comments%20[May%2020,%202020].pdf

43. We also know that FRR helps facilitate market power in three different ways as discussed above, and so it is not reasonable to believe that FRR will result in the same price as the RPM BRA, but rather will have higher prices paid to resources overall relative to the RPM Capacity Market.

B. The Misconception that the IRM or "1-in-10" Standard, the Target in FRR, is Optimal

44. PIOs in its filed comments refers to the traditional 1-in-10-year standard for a loss of load as "optimal".[47] The 1-in-10 year standard as defined by North American Reliability Corporation ("NERC") and ReliabilityFirst Corporation ("RFC"), [48] to which PJM sets its IRM is a standard[49] only requires PJM conduct a study to determine the reserve margin required to achieve the 1-in-10-year target must target based on NERC and RFC standards. There is nothing in the standard that says this is the least cost way of ensuring resource adequacy.

45. To attribute the word "optimal" to only the quantity associated with the 1-in-10-year standard misses the entire economic context. "Optimality" in the case of the IRM also means that costs must be considered along with quantity. The downward sloping demand curve for capacity in RPM has the property that when prices fall, quantities of committed capacity will rise. And by extension the total overall expenditures on capacity will decline. That is, more capacity will be committed only if it leads lower overall costs. The lower overall costs are due to the decrease in price along the downward sloping demand curve.

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[47] PIO Comments at 12.

[48] See PJM Interconnection, LLC, *2019 PJM Reserve Requirement Study,* October 17, 2019 at 7, 38-39. Available at https://pjm.com/-/media/planning/res-adeq/2019-pjm-reserve-requirement-study.ashx?la=en

[49] *Id*.

46. In the PJM RPM Capacity Market, when capacity in excess of the IRM is committed, it leads to lower overall costs to all load customers in PJM. Load customers thus enjoy greater reliability at lower costs. Moving from a competitive construct to an FRR-based construct, denies consumers the ability to enjoy this win-win.

47. Under the RPM Capacity Market demand curve, when only the IRM capacity is committed, prices will be higher and overall costs to load will be higher. But in this case, it is due to the higher costs of capacity overall, and because capacity costs more, it is not cost-effective to commit additional capacity (in other words, the benefits from additional reliability are outweighed by the additional costs).

48. In contrast, a vertical demand curve at IRM against the same supply curve will yield lower prices. But, the supply curve will not be the same. As noted above, changing the rules changes offer behavior. Under the FRR there is no must-offer requirement or offer capping for market power mitigation which allows generation to physically, and economically, withhold capacity under an FRR, in addition to no price responsiveness to the demand for capacity. This inevitably leads to higher prices than would be seen in the RPM Capacity Market. These prices would likely be at the cap set by the State of New Jersey.[50]

49. Under FRR, in contrast to the RPM Capacity Market, the market power facilitation that the FRR alternative provides is likely to lead to prices higher than the actual costs of providing capacity at the margin. The argument that only procuring to the IRM leads to

[50] PSEG/EXC Proposal at 3

lower costs is based on faulty assumptions as the FRR changes the behavior of supply resources that are needed to satisfy the FRR requirements.

C. The Fallacy That Price Discrimination Among Resources Will Reduce FRR Costs

50. Another argument from parties in favor of electing the FRR alternative is the ability to price discriminate will reduce the overall costs of the FRR alternative. In theory, the idea is to pay each resource in the FRR only its net avoidable or going forward costs. The problem with this notion is that it effectively turns the FRR alternative into a price/pay-as-bid auction as the PSEG/EXC proposal acknowledges.

51. The incentives for offer behavior under a first price or pay as bid auction are well understood. Generation resources will attempt to "guess" the costs of the highest cost unit to be required to satisfy the FRR requirement and thus prices will tend to converge to the highest cost resource. But because there is imperfect information, resources will tend to "overshoot" the cost of the highest resource leading to overall higher costs.

52. Moreover, since the FRR creates a platform for the exercise of market power, resources have further incentive to offer their capacity in a manner that is consistent with the exercise of market power. This makes the prospect of price discrimination to reduce costs even more implausible as resources can effectively "hold up" the FRR entity and name their price because they will be needed to satisfy the FRR resource requirement.

53. Finally, as discussed below in Section VII, the idea of creating tiers or tranches of resources based on their regulatory treatment and/or emissions profiles as intimated by the PSEG/EXC proposal and NRDC in its comments, only further exacerbates the "hold up problem" and market power. By introducing price discrimination in this manner, the

market power problem is magnified further, signaling that price discrimination will not lead to lower prices, but rather higher prices than could be obtained in the RPM BRA.

V. RISK POOLING OF RESOURCES UNDER FRR SHIFTS CAPACITY PERFORMANCE RISK FROM GENERATION RESOURCE TO THE CUSTOMERS

54. NRDC in its comments suggests renewable resources in PJM have not offered their full eligible capacity into the RPM Capacity Market because of the "onerous" penalties associated with the Capacity Performance construct. In this way, NRDC argues, New Jersey can maximize the amount of capacity they can count from renewable resources under the Energy Master Plan ("EMP") and get the most out of the renewable energy with which New Jersey in contracting. Unfortunately, NRDC fails to understand the risks and reward of taking on Capacity Performance obligations for intermittent renewable resources. Someone will have to bear performance risk: it will be either other controllable resources, which will be required to "over-perform" to make up the difference for potential renewable under performance, and whose offer price will surely reflect these obligations, or customers, who have no control over performance but will pay the non-performance penalties. Either way, the risks will ultimately be shifted onto the FRR load.

A. The Risks Outweigh the Rewards for Intermittent Renewable Resources to Take on Capacity Performance Obligations in RPM.

55. The capacity value of intermittent renewable resources is a fraction of the nameplate value of capacity. For example, the default capacity value of onshore wind is 14.7 percent and 17.6 percent for mountainous or flat terrain locations respectively, of nameplate capacity. For solar it ranges from 38 percent to 60 percent of nameplate capacity

depending on technology.[51] Moreover, these intermittent renewable resources do not have must offer requirements into the RPM Capacity Market.[52]

56. Under Capacity Performance, resources must provide energy and/or reserves up to their committed UCAP value from the RPM Capacity Market.[53] The penalty for shortfalls is equal to the LDA Net CONE value multiplied by 365 days and divided by 30.[54] For the EMAAC LDA, for which most of New Jersey is located (except for the PSEG and PS North LDAs) this value based on 2022/2023 BRA parameters released before the BRA was delayed is \$3,817.53/MWh.[55]

57. Consider an onshore wind resource with a 30 percent capacity factor and facing an average price for energy of \$25/MWh when it operates. This would produce an energy market revenue stream of \$65,700/MW-year. This onshore wind producer, if it offered in at its eligible capacity of 17.6 percent of nameplate at the EMAAC price in the 2021/2022 BRA would earn \$10,608/MW-year. The capacity revenue is only 16 percent of the energy revenue. It is clear capacity revenues are a small fraction of energy and total potential revenues. It is the energy payments, coupled with the Renewable Energy

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[51] *See* https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en Fixed, ground mounted solar PV gets 42 percent credit and ground mounted tracking PV gets 60 percent. All others are 38 percent.

[52] PJM Tariff, Attachment DD, Section 6.6A (c).

[53] This assumes that balancing ratio of 100 percent for ease of exposition. Technically, during any CP event, the performance obligation is the UCAP obligation multiplied by the balancing ratio. See PJM Tariff, Attachment DD, Section 10A (c)

[54] *Id*.

[55] *2022/2023 Base Residual Auction Planning Period Parameters* for the PSEG LDA Net CONE value of \$273.85 available at https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2022-2023/2022-2023-bra-planning-period-parameters.ashx?la=en ("2022/2023 BRA Planning Parameters").

Credit ("REC") payments from Renewable Portfolio Standards ("RPS") that incent investment in intermittent resources.

58. If this resource failed to perform at all in three CP hours per year, it would incur penalties of $11,452 for failing to produce at its UCAP value for all three CP hours,[56] basically eroding all the potential revenues from the capacity market. Failure to perform for 3 hours would completely take away all capacity revenues and the resources could still be exposed to additional penalties for non-performance for additional hours.

B. NRDC's FRR Risk Pooling Shifts the Burden of CP Compliance to Other Resources

59. If intermittent renewable resources fail to perform during CP events, then there is an additional burden placed upon more controllable resources, such as nuclear or fossil resources to over-perform to make up the difference for the entirety of the committed FRR capacity. This performance failure means the remaining resources will need to perform over their UCAP commitments just to make sure the entire FRR zone meets its UCAP obligation.

60. But because the risk of CP compliance is pooled, there is an incentive for the remaining resources to attempt to "free ride" on other resources over performance, while not making the necessary investments on the generating units to ensure performance during CP events. The reason for the "free rider" problem is that no one resource is held accountable for non-performance, but rather, non-performance is measured in aggregate. The Nash Equilibrium of this "game" would be for all controllable resources to minimize

[56] Assuming a balancing ratio of 100 percent.

expenditures that better guarantee performance during CP events as such cost cutting would be profit maximizing.

61. Finally, because individual resources will not be rewarded with additional payments for over-compliance in this pooling arrangement, they have no incentive to over-perform. Moreover, since the FRR entity is responsible for compliance, though it does not have control of the generation resources under the FRR plan, the performance risk and associated costs are shifted to the FRR load.

C. Ultimately it is FRR Load that Will Bear Capacity Performance Risk

62. Given the risk for renewable resources to perform during CP events, and the free rider problem for other controllable resources to not have incentives to over-perform, it will ultimately be the FRR load that will bear the costs of these risks. These risks can either be borne and monetized in advance during the process of signing FRR contracts with resources, or they will be realized during CP events when non-performance occurs. The only difference is the timing. Consumers will pay up front for the risk or pay after the fact for the risk.

63. Moreover, during the contracting process, the FRR entity may wish to write into the contract terms and conditions that generators are responsible for performance during a CP events despite the pooling of risk under FRR. The response from resource owners will predictably be to ask for higher capacity prices that will shift the costs/risk burden back to the FRR load up front. Yet, this shift happens without the competitive pressures to reflect minimize that risk as happens in the RPM Capacity Market and thus New Jersey consumers will pay a market power premium for risk under FRR.

64. For example, if the FRR entity attempts to write in clauses to place an individual resource at risk for performance, renewable resources may revert back to not offering all their

eligible capacity into FRR, and thus, the FRR load will need to procure additional resources to address the shortfall. For controllable resources, if they are required to perform better than required by the RPM Capacity Market (perform over UCAP), they have the option of simply moving back to the RPM Capacity Market where they have lower risk, or will demand greater payments up front to be an FRR committed resource. Again, the FRR load pays up front for this additional risk to be taken on by controllable resources.

65. Effectively, the FRR then creates the "double payment" issue all over again. With risk assigned to individual generators, creates an environment that incents intermittent renewable generation to not offer all their capacity to avoid CP event risk. In the end, FRR raises prices and still does not avoid the so-called "double payment," leaving New Jersey customers with the worst of both worlds.

66. If risk pooling takes place, but there are no terms and conditions on individual resources to perform when needed during a CP event, then the FRR load will bear these costs whenever they are incurred but the costs will not be known in advance. However, the prevailing incentives for FRR committed resources under risk pooling, as noted above, are such that they do not have any incentive to maintain their resources to the CP standard to avoid costs and increase profits, nor do they have incentives to over-perform. This leaves the FRR load exposed to penalties during CP events while having already paid for capacity. This stands in sharp contrast to the RPM Capacity Market where once capacity is paid for, any risk of CP penalties, and potential for bonus payments, rests only with the resource owners.

67. Consider the following example that recently occurred in New Jersey when the Salem 2 nuclear units had to unexpectedly shut down on a cold winter day, January 31, 2019, due to the freezing of water intakes used for cooling.[57] While this incident did not occur during a CP event during the morning ramp from 6am to 9am, Salem 2 would have incurred three hours of CP penalties amounting to $12.815 million. Under an FRR with risk pooling as proposed by NRDC, New Jersey load would have been faced with the $12.815 million penalty.[58] Further, imagine what would happen if one of the FRR contracted nuclear units went off-line for an extended period due to a severe maintenance problem like those experienced in the past by the Davis-Besse nuclear plant in Ohio.[59] This further exposes New Jersey customers to extreme risks of not just CP penalties when the resource is out for an extended period as Davis-Besse was, but also the liability that it may need to buy replacement resources after signing long-term contracts with resources for an FRR commitment that may not be available for long periods of time like Davis-Besse. Again, the FRR entity in New Jersey would find itself paying twice for capacity. However, if New Jersey stayed in the capacity market, the liability would rest with the generator owner and New Jersey load could easily find replacement capacity in the RPM Capacity Market without paying twice for capacity.

[57] Gavin Bade, "Cold Weather Forces Salem Nuclear Unit Offline as Owner PSE&G Presses for Subsidies", *Utility Dive*, February 1, 2019 available at https://www.utilitydive.com/news/cold-weather-forces-salem-nuclear-unit-offline-as-owner-pseg-presses-for-s/547446/.

[58] The Penalty rate for PSEG is $3817.53/MWh and Salem 2 has an estimated UCAP of 1,119 MW. Multiplying the penalty rate by three hours and then again by the UCAP value results in the $12.815 million penalty.

[59] Davis-Besse went offline for just over two years from February 2002 until March 2004 due to reactor vessel head corrosion. *See* United States Nuclear Regulatory Commission, Letter to Mr. Barry Allen, Site Vice President, FirstEnergy Nuclear Operating Company, Davis-Besse Nuclear Power Station, September 10, 2009. Available at https://www.nrc.gov/docs/ML0924/ML092450747.pdf.

VI. PSEG/EXC PROPOSAL IMPLIES CAPACITY PRICES GREATER THAN NET CONE FOR A SUBSET OF RESOURCES

68. PSEG/EXC in their response and proposal for implementing an FRR plan for New Jersey as a whole, or for a transmission zone in New Jersey, for example JCP and AECO, and stated that they are willing to give up the ZEC payments they currently receive for their output at the Salem and Hope Creek nuclear facilities.[60] From a profit maximizing perspective, the only reason EXC and PSEG would give up ZECs, that amount to just over $300 million per year[61] or an estimated $10.82/MWh,[62] is the amount of money PSEG/EXC expect to collect through increased capacity payments in the absence of ZECs and that may be even more lucrative than the ZECs. If one takes the $/MWh estimate, multiply by the total nuclear output for a year at a 90 percent capacity factor, this amounts to an additional $233.71/MW-day in additional capacity payments to New Jersey nuclear resources owned by EXC and PSEG.[63]

69. If this were added to the PSEG LDA price of $204.29/MW-day for the 2021/2022 BRA, giving up ZECs would imply a capacity price paid to the New Jersey nuclear units of $438.00/MW-day. When considering the Net CONE in PSEG is $311.13/MW-day for the 2021/2022 BRA, this implies a capacity price paid to nuclear units of 1.41 times Net CONE. That is close to the maximum capacity price that could be obtained when PJM is short the reserve requirement in PSEG. Such an exorbitant capacity price would by far

[60] *See supra* note 14.

[61] PSEG/EXC Proposal at 3.

[62] Sotkiewicz Initial Testimony P 11

[63] This is just $10.82/MWh multiplied by 8760 hours in a year and then multiplied by 90 capacity factor.

be the richest capacity prices in the history of PJM's capacity market. Only one time has any constrained LDA reached the Net CONE as a price, let alone 1.41 times Net CONE.[64]

70. From the perspective of covering gross avoidable costs, the implied capacity payment alone exceeds the publicly available fixed O&M costs of $425/MW-day for New Jersey Nuclear units as reported by the United States Environmental Protection Agency ("US EPA") in their Integrated Planning Model used to assess the impact of environmental policy on the power sector.[65]

71. Even if all other capacity were paid their respective market clearing price in New Jersey, this results in approximately $300 million dollars in additional costs through the capacity market that otherwise need not be incurred. But with this information in hand, given other elements of the PSEG/EXC Proposal, these kinds of capacity prices may be paid to other resources beyond just the Salem and Hope Creek generating stations as described below in Sections VII and VIII.

VII. PSEG/EXC PROPOSAL FOR CREATING TIERS FURTHER ENTRENCHES THE MARKET POWER PROBLEM

72. PSEG/EXC propose two tiers for capacity purchasing priority.[66] The first is those zero emitting resources subject to MOPR in New Jersey. The second tier are those zero

[64] In the 2013/2014 BRA, prices in PEPCO exceeded Net CONE, and nearly reach Net CONE in the PSEG LDA. Prices nearly reached Net CONE in the 2015/2016 BRA in the ATSO LDA. *See* https://pjm.com/markets-and-operations/rpm.aspx

[65] 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*, May2018. 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").

[66] PSEG/EXC Proposal at 7-8

emitting resources that are not subject to MOPR. All other resources that may be needed to satisfy the FRR plan and could be emitting resources, but with an emphasis on the lowest emitting resources, but those do not have priority under the second tier.

A. Tier One: Zero Emissions Resources Subject to MOPR is a De Facto Monopoly

73. If the PSEG/EXC proposal were to be adopted by New Jersey, the Tier 1 resources would include the New Jersey nuclear units at 3,458 MW ICAP and an estimated 3,389 MW UCAP.[67] For the 2022/2023 and the 2023/2024 BRAs there are no other major new renewable resources projected to come on-line.[68] Only the Ørsted offshore wind project, which is scheduled to come online in 2024 with 1,100 MW ICAP (about 286 MW UCAP capacity value),[69] and would be available for the 2024/2025 BRA.

74. The easy implication is that PSEG/EXC hold all the eligible Tier 1 capacity up to the 2024/2025 BRA. And even beyond the 2024/2025 BRA they would control 94 percent of the eligible Tier 1 capacity. From an HHI perspective, taking the PSEG/EXC units as under common ownership (since they are working in concert on these proposals and co-own some of the nuclear resources in question), the HHI is 10,000 for the 2022/2023 and 2023/2024 BRAs. That is, they are a monopolist and can name their price, as alluded to above.

75. Starting in 2024/2025, the HHI would be 8,872 or a near monopoly with the Ørsted wind project coming on-line. Ørsted explains that their project, if unable to be a capacity

[67] Based on an assumed 2 percent EFORd.

[68] The PSEG/EXC Proposal at 7-8. The proposal is not specific or clear that Tier 1 Resources would only be in New Jersey, but the only other state supported resources that could reach New Jersey would be in MAAC, and there are no other state supported resources that would meet the Tier 1 requirements as proposed

[69] This assumes a 26 percent capacity factor during peak hours.

resource, would lose about $40 million per year in capacity payments.[70] Given the 286 MW UCAP value, this implies a capacity price of $383.18/MW-day they would have expected to collect. The implication is clear that they would expect to benefit from the market power of PSEG/EXC for Tier 1 resources.

B. Tier 2: Other Zero Emitting Resources to Satisfy the FRR Plan

76. Tier 2 resources would consist of zero emitting resources in EMAAC and if possible MAAC when the available transfer capability is available, to bring in resources for one-year contracts. In EMAAC, most of this consists of nuclear resources, Peach Bottom (50/50 ownership split between PSEG and EXC) and Limerick (100 percent owned by EXC) with 4,791 MW ICAP or an estimated 4,695 MW UCAP.[71] Including these additional resources does nothing but exacerbate the market power problem as they are also owned by PSEG/EXC and still leaves New Jersey with the same Market Power Problem.

77. There are only 138 MW of nameplate onshore wind and 1,238 MW of solar in EMAAC.[72] After capacity factors at peak are considered, this translates to 18 MW of wind capacity value and 470 MW of solar capacity value. Of the available resources in EMAAC in Tier 2, PSEG/EXC controls nearly 91 percent of the eligible tier 2 capacity in EMAAC for another near monopoly position to go along with the de facto monopoly position in Tier 1.

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[70] Ørsted, *Comments to the New Jersey Board of Public Utilities on its Resource Adequacy Investigation* Docket No. EO20030203 at 5. Available at [https://www.nj.gov/bpu/pdf/ofrp/Comments/Ørsted%20[May%2020,%202020].pdf](https://www.nj.gov/bpu/pdf/ofrp/Comments/Ørsted%20[May%2020,%202020].pdf)

[71] Unites States Energy Information Administration (“EIA") Form EIA 860 2019 Early Release (“ER”) data. and 2% EFORd

[72] EIA Form 860 2019 ER and searching by location to find EMAAC and MAAC resources.

78. The bottom line again is that PSEG/EXC can name their price on a yearly basis for this capacity. And knowing that they could be converting ZECs to capacity payments for resources not currently subject to MOPR preserves the ability of the rest of their owned nuclear generation to receive the equivalent of ZEC payments through the FRR capacity contract, but not be subject to MOPR in future years. Again, New Jersey consumers would be exposed to the untenable reality that Exelon and PSEG (from a position of market power) would effectively be telling all the state's consumers (not to mention their shareholders) how much money they will accumulate with no real oversight of costs or operations and without being subject to market power mitigation by the PJM IMM.

C. Potential FRR Areas that Could Be Employed under the PSEG/EXC Proposal

79. PSEG/EXC propose to gradually transition New Jersey into FRR by using one transmission zone at first and then eventually expanding this across multiple transmission zones.[73] Examining the posted Planning Parameters for the 2022/2023 BRA, before the auction was postponed, shows that the JCPL has a forecast coincident peak load of 5,635 MW, and implied requirement of 6,931 MW.[74] The AECO zone has a forecast coincident peak load of 2,305 MW, and implied requirement of 2,835 MW.[75] If only JCPL was the chosen FRR entity, all the New Jersey nuclear resources plus either all of Limerick or all of Peach Bottom, located in eastern Pennsylvania and in EMAAC, could effectively

[73] PSEG/EXC Proposal at 16-17.

[74] 2022/2023 BRA Planning Parameters. Then calculating the share of the EMAAC reserve requirement to arrive at this figure

[75] *Id.*

satisfy this requirement.[76] If it is jointly JCPL and AECO serving as the FRR entity, then the PSEG/EXC nuclear resources satisfy 83 percent of the requirement.[77]

80. According to the posted Planning Parameters for the 2022/2023 BRA, the PSEG LDA had Capacity Emergency Transfers Limits ("CETL") of 7,445 MW and a Capacity Emergency Transfer Objective ("CETO") of 5,540 MW, leaving only 1,985 MW of capability to bring in other resources from EMAAC such as the Limerick and Peach Bottom nuclear units.[78] It is no wonder that EXC and PSEG have not suggested using the PSEG Zone for FRR.

81. Moreover, leaving the PSEG zone/LDA open to the RPM Capacity Market will also likely have the effect of causing the PSEG LDA to continue to observe price separation in the RPM BRAs to the benefit of other generation owned by PSEG in that LDA, as was seen in the 2021/2022 BRA.

VIII. POSSIBLE PRICING OUTCOMES UNDER THE FRR PROPOSED BY PSEG/EXC

82. If one were to add the ZEC payment for the EMAAC clearing price of $165.73/MW-day for the 2021/2022 BRA, the total price rises to $399.44/MW-day. Multiply this new price by the UCAP value of the Limerick and Peach Bottom nuclear units of 4,695 MW UCAP and then multiply that number by the 365 days in the year. The implied cost of Tier 2 resources under the PSEG/EXC proposal is $552,830,460.

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[76] The combined estimated UCAP value of Limerick and Peach Bottom are 4,695 MW based on ICAP taken from EIA Form 860 2019 ER.

[77] The combined UCAP of EMAAC nuclear units is 8,153 MW estimated using the 2 percent EFORd assumption.

[78] 2022/2023 BRA Planning Parameters.

83. For Tier 1 resources, multiply the implied $438/MW-day price by the 3,389 MW UCAP of the Salem and Hope Creek units and then multiply that number by 365 days in the year. The cost for the Tier 1 resources, absent the wind resources is $684,510,342. If one considers the Ørsted wind resource online for the 2024/2025 Delivery Year and its $40 million cost estimate for capacity, the capacity cost for Tier 1 rises to nearly $725 million per year.

84. The FRR as proposed by EXC and PSEG and taken to its logical conclusion herein does not change the overall supply and demand balance as all the capacity comes from within EMAAC. But the cost increase is about a $700 million ($695 million to be more precise) ($233.71/MW-day x 8,153 MW UCAP x 365 days) dollar increase over what would have been paid for capacity if the entirety of New Jersey remained in the RPM Capacity Market before even considering the first wind project from Ørsted which adds another $40 million for a total cost increase of $735 million.[79]

IX. IT IS WELL UNDERSTOOD THAT SALEM AND HOPE CREEK HAVE SUFFICIENTLY LOW NET AVOIDABLE COSTS AND PROFITABILITY TO EASILY CLEAR THE RPM BRA EVEN SUBJECT TO MOPR

A. The Salem and Hope Creek Nuclear Units Have Already Been Shown to Be Profitable.

85. On average across the Salem and Hope Creek units, the going forward/avoidable costs are $155.27/kW-year.[80] Translating this into units used by PJM, this translates into $425.40/MW-day of installed capacity ("ICAP"). Applying a class average forced outage

[79] This is just taking $233.71/MW-day caused by adding ZEC prices top the capacity prices from the 2021/2022 BRA for all the nuclear resources in EMAAC which includes all unit sat Salem, Hope Creek, Limerick, and Peach Bottom.

[80] *Supra* note 13.

rate for nuclear in PJM of approximately two percent converts the going forward/avoidable costs into unforced capacity ("UCAP") terms of \$434.08/MW-day UCAP.[81] The implied capacity price for the Salem and Hope Creek units is \$438/MW-day which means that the resources do not even need to run for energy to be profitable at covering their net avoidable or going forward costs.

86. Previous evidence has shown these nuclear units to be highly profitable going forward in PJM's markets absent any additional payments.[82] Furthermore, the IMM has estimated the default MOPR floor price for multi-unit nuclear facilities to be \$0.00/MW-day.[83] Moreover, the reported hedge price of \$36-\$37/MWh by PSEG for 2020 and 2021 for 100 percent and 80- percent of its nuclear output respectively, in it 2019 Earning Call Presentation , it is clear their current net going forward costs are zero.[84] That is, they will clear the market absent any ZEC payments or extra capacity payments. This shows that even with MOPR, Salem and Hope Creek will be economic in the market and that an FRR plan is not needed to keep these resources in service, nor is it need to avoid a "double payment" of resources subject to MOPR.

87. The bottom line is the cost of FRR as proposed by PSEG/EXC, by allowing an unfettered exercise of market power without any potential for market power mitigation by the PJM

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[81] 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 most recent forced outage rate was just below 1 percent, but historically this figure has been around 3 percent. I have assumed a 2 percent EFORd.

[82] *Supra* note 12.

[83] *Supra* note 11.

[84] PSEG 2019 Earnings Call Slide 27.

IMM, would be a $735 million increase in capacity prices paid by New Jersey consumers only to save $21 million from the offshore wind being double counted.[85] That is a benefit cost ration of -35. And these costs do not include the extra costs of shifting CP performance risk from generators to New Jersey consumers as discussed above.

* *

88. This concludes my prepared written testimony.

[85] While Ørsted claims they would have collected $40 million, if they had been a capacity resource in the RPM Capacity Market, assuming the PSEG LDA price is the most relevant price, they would have collected only $21 million in the 2021/2022 BRA.

STATE OF NEW JERSEY
BEFORE THE
BOARD OF PUBLIC UTILITIES

INVESTIGATION INTO RESOURCE ADEQUACY ALTERNATIVE	))))))))	**BPU Docket No. EO20030203**

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 24th day of June, 2020

Notary Public for
the State of Florida

My Commission expires: 09-06-2021

CHRISTOPHER SHEPHERD
Notary Public – State of Florida
Commission # GG 141777
My Comm. Expires Sep 6, 2021
Bonded through National Notary Assn.

NOTARY PUBLIC STATE OF FLORIDA

Attachment A

to the

Prepared Comments

of Paul M. Sotkiewicz, Ph.D.

In Docket No. EO20030203

Economics

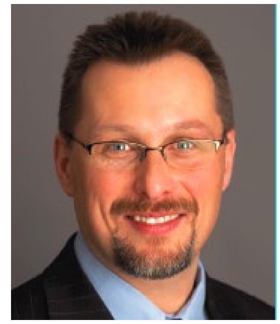
E³

Environment

Energy

E-CUBED POLICY ASSOCIATES, LLC

WWW.E-CUBEDPOLICY.COM | GAINESVILLE, FLORIDA



Paul M. Sotkiewicz, Ph.D

President, E-Cubed Policy Associates, LLC

Paul M. Sotkiewicz, Ph.D., Dr. Sotkiewicz is the President and Founder of E-Cubed Policy Associates, LLC ("E-Cubed"), an energy and environmental economic consultancy based in Gainesville, Florida that started in 2016. Dr. Sotkiewicz brings over 20 years of experience across parts of three decades at the intersection of utility regulatory policy, power system economics, and environmental economics to provide analysis and advice to private and public sector clients on a range of economic issues related to electricity market design and performance, power generation economics, market power mitigation, utility regulatory policy, and the economic impacts of state and federal environmental policies. Recent clients include market and system operators such as the Alberta Electric System Operator, New York Independent System Operator; trade associations such as the Electric Power Supply Association, New England Power Generators Association, and the American Petroleum Institute; and merchant generation and transmission developers in North American power markets. Dr. Sotkiewicz also supports law firms in litigation proceedings including rate case, need determinations, and market power/manipulation cases.

Prior to founding E-Cubed, Dr. Sotkiewicz worked for PJM Interconnection, LLC in the role of Chief Economist and as a Senior Economic Policy Advisor. At PJM, Dr. Sotkiewicz provided analysis and advice regarding all aspects of PJM's markets and supported regulatory filings and implementation of market design changes. At PJM Dr. Sotkiewicz led initiatives related to shortage pricing and real-time dispatch co-optimization of energy and reserves, integration of demand response in PJM's markets including price formation and compensation of demand resources. At PJM Dr. Sotkiewicz supported PJM's regulatory position with respect to the application of the Three Pivotal Supplier Test supplier market power, helped develop an opportunity cost calculator for run-limited resources used for market mitigation purposes, and administered implementation of the minimum offer price rule (MOPR) to curb buyer-side market power in the PJM capacity market. Paul also authored or co-authored a series of policy analyses and whitepapers on ranging from transmission cost allocation to gas-electric coordination to the effects of environmental rules on PJM's markets. While at PJM, Dr. Sotkiewicz was a frequent speaker at FERC Computation Technical Conferences related to advances in unit commitment models and computation methods that could be applied in ISO/RTO markets.

As an economist at the United States Federal Energy Regulatory Commission (FERC) in the Office of Economic Policy and later, on the Chief Economic Advisor's staff at Dr. Sotkiewicz conducted research and provided analysis and advice on market design issues related to the ISO/RTO markets, in particular the California ISO and New York ISO, as they were being formed and implemented and worked on merger cases to analyze any potential for market power. As part of this work, Dr. Sotkiewicz has co-authored peer review articles related to unit commitment models and price formation to account for discrete decisions related to start-up, shut-down, and minimum run conditions.

Dr. Sotkiewicz is the author or co-author of multiple book chapters and publications related to wholesale market design and policy including price formation in unit commitment models, the integration of demand response and distributed energy resources in markets and operations environmental economic policy, distribution rate design, economic decisions for nuclear resource build decisions, and renewable resource integration. In addition to his tenures at PJM and FERC, Dr. Sotkiewicz served as the Director of Energy Studies at the Public Utility Research Center (PURC), University of Florida was an Instructor in the Department of Economics at the University of Minnesota where he earned the Walter Heller Award for Outstanding Teaching of Economic Principles four times.

Dr. Sotkiewicz holds a Bachelor of Arts in history and economics from the University of Florida (1991), a Master of Arts (1995) and Doctorate in Economics from the University of Minnesota (2003).

Attachment B

to the

Prepared Comments

of Paul M. Sotkiewicz, Ph.D.

In Docket No. EO20030203

PAUL M SOTKIEWICZ, Ph.D.

President and Founder, E-Cubed Policy Associates, LLC
5502 NW 81st Avenue, Gainesville, FL 32653
E-mail: drpaulg8r@gmail.com Phone: +1-352-244-8800 Mobile: +1-610-955-2411

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
- Supporting litigation defending market participants against accusations of market manipulation in PJM's markets
- Conducting analysis of recent past and future expected profitability of nuclear power plants under consideration for state subsidies to keep these facilities in commercial operation and providing reports and testimony in front of state legislative bodies.
- Provide capacity market design and expertise to the ENMAX Corp. in Calgary, AB with regard to the AESO capacity market proposal filed in late 2018
- Supported rate case litigation for a reactive power rate case for Panda Stonewall explaining the history behind markets and that the filed rate from Panda Stonewall was consistent with precedent and lost market opportunities
- Providing PJM expertise to JPower USA Ltd in its development of new combined cycle gas facilities in PJM and help move the project through the PJM interconnection processes as well as advising on existing facilities in the PJM and NYISO market
- 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
- Supporting the Greek Electricity Market authoring, through ECCO International, a whitepaper on market power mitigation with a special look at buyer side market power mitigation in the energy market with the different indices that could be indicative of buyer market power.
- 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, administered 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 outside vendors.

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.

M. Ahlstrom; E. Ela; J. Riesz; J. O'Sullivan; B. F. Hobbs; M. O'Malley; M. Milligan; P. Sotkiewicz; J. Caldwell, “The Evolution of the Market: Designing a Market for High Levels of Variable Generation”, *IEEE Power and Energy Magazine*, Volume: 13, Issue: 6, 2015, Pages: 60 – 66.

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.

Covino, Susan, Pete Langbein, and Paul Sotkiewicz, “The Fully Integrated Grid: Wholesale and Retail, Transmission and Distribution”, in *Smart Grid: Integrating Renewable, Distributed, and Efficient Energy*, Fereidoon P. Sioshansi, editor, Chapter 17, pp.421-452, 2012.

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*

R. F. Chu; P. F. McGlynn; P. M. Sotkiewicz, “Transmission Planning for Generation at Risk due to Environmental Regulations and Public Policy Initiatives” *Power and Energy Society General Meeting, 2012 IEEE*

P. M. Sotkiewicz; J. M. Vignolo, “The Value of Intermittent Wind DG under Nodal Prices and Amp-mile Tariffs”, *Transmission and Distribution: Latin America Conference and Exposition (T&D-LA), 2012 Sixth IEEE/PES*

Helman, Udi, Harry Singh, and Paul Sotkiewicz, “RTOs, Regional Electricity Markets, and Climate Policy”, in *Generating Electricity in Carbon Constrained World,* Fereidoon P. Sioshansi, editor, Chapter 19, pp.527-564, 2010.

J. C. Smith; S. Beuning; H. Durrwachter; E. Ela; D. Hawkins; B. Kirby; W. Lasher; J. Lowell; K. Porter; K. Schuyler; P. Sotkiewicz, “The Wind at Our Backs”, *IEEE Power and Energy Magazine*, Volume: 8, Issue: 5, 2010 Pages: 63 - 71

J. C. Smith; S. Beuning; H. Durrwachter; E. Ela; D. Hawkins; B. Kirby; W. Lasher; J. Lowell; K. Porter; K. Schuyler; P. Sotkiewicz, “Impact of Variable Renewable Energy on US Electricity Markets”, *Power and Energy Society General Meeting, 2010 IEEE*

Holt, Lynne, Paul M. Sotkiewicz, and Sanford V. Berg. 2010. "Nuclear Power Expansion: Thinking About Uncertainty" *The Electricity Journal*, 235:26-33.

Holt, Lynne, Sotkiewicz, Paul, and Berg, Sanford, “(When) To Build or Not to Build? The Role of Uncertainty in Nuclear Power Expansion.” *Texas Journal of Oil, Gas, and Energy Law*, Volume 3, Number 2, 2008, pp. 174-217.

Sotkiewicz, Paul M. and Vignolo, J. Mario, "Towards a Cost Causation Based Tariff for Distribution Networks with DG." *IEEE Transaction on Power Systems,* Vol. 22, No. 3, August 2007, pp. 1051-1060.

Sotkiewicz, Paul and Vignolo, Jesus Mario. "Distributed Generation." The Encyclopedia of Energy Engineering and Technology, Vol. 1, pp 296-302. Ed. Barney Capehart. New York: CRC Press, Taylor and Francis Group, 2007.

Sotkiewicz, Paul. "Emissions Trading." The Encyclopedia of Energy Engineering and Technology, Vol. 1, pp. 430-437. Ed. Barney Capehart. New York: CRC Press, Taylor and Francis Group, 2007.

Vignolo, Jesus Mario and Sotkiewicz, Paul M., "Towards Efficient Tariffs for Distribution Networks with Distributed Generation", *Cogeneration and On-site Power Production*, November-December 2006, pp. 67-75.

Jamison, Mark A. and Sotkiewicz, Paul M., "Defining the New Policy Conflicts," *Public Utilities Fortnightly*, July 2006, pp. 36-40, 50.

Sotkiewicz, Paul M. and Vignolo, Jesus Mario "Nodal Pricing for Distribution Networks: Efficient Pricing for Efficiency Enhancing DG." *IEEE Transaction on Power Systems*, Vol. 21, No. 2, May 2006, pp. 639-652.

Sotkiewicz, Paul M. and Vignolo, Jesus Mario "Allocation of Fixed Costs in Distribution Networks with Distributed Generation," *IEEE Transaction on Power Systems*, Vol. 21, No. 2, May 2006, pp. 1013-1014.

Sotkiewicz, Paul M., and Lynne Holt, "Public Utility Commission Regulation and Cost Effectiveness of Title IV: Lessons for CAIR." *Electricity Journal* 18(8): 68-80, October 2005.

O'Neill, Richard P., Sotkiewicz, Paul M., Hobbs, Benjamin F., Rothkopf, Michael H., and Stewart, William R. Jr., "Efficient Market Clearing Prices in Markets with Non-Convexities." *European Journal of Operational Research*, Volume 164, Issue 1, 1 July 2005, Pages 269-285.

Sotkiewicz, Paul M., "The Impact of State-Level Public Utility Commission Regulation on the Market for Sulfur Dioxide Allowances, Compliance Costs, and the Distribution of Emissions" Ph.D. Dissertation, Department of Economics, University of Minnesota, January 2003.

O'Neill, Richard P., Helman, Udi, Sotkiewicz, Paul M., Rothkopf, Michael H., and Stewart, William R. Jr., "Regulatory Evolution, Market Design, and the Unit Commitment Problem" The Next Generation of Unit Commitment Models*,* B. Hobbs, M. Rothkopf, R. O'Neill, and H.P. Chao editors. 2001.

Sotkiewicz, Paul M. "Opening the Lines", Forum for Applied Research and Public Policy, Special Issue on the Role of Public Power in Utility Restructuring*,* Summer 2000, pp. 61-64.

SELECTED WORKING PAPERS AND UNPUBLISHED MANUSCRIPTS

Holt, Lynne, and Paul M. Sotkiewicz. "Understanding Fuel Diversity Trade-Offs and Risks: Making Decisions for the Future (pdf)" University of Florida, Department of Economics, PURC Working Paper, 2007.

O'Neill, Richard P., Sotkiewicz, Paul and Rothkopf, Michael. "Equilibrium Prices in Exchanges with Non-convex Bids." PURC Working Paper, January 2006, updated September 2007.

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 Walter Heller Award for Outstanding Teaching of Economic Principles, Department of Economics,
1993-94 University of Minnesota
1992-93

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. ER09-1063-004, 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. T**his 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 wider 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.

Panda Stonewall, LLC. **FERC Docket No. ER17-1821-002, Rebuttal Testimony is Support of Panda Stonewall, LLC Reactive Power Filing, October 12, 2018.** This rebuttal testimony supports Panda Stonewall's reactive power rate case responding to interveners and FERC staff 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 wider PJM market and other opportunities for compensation and well as providing historical context around the Commission-approved AEP Methodology for reactive power rates.

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, New Jersey Board of Public Utilities, **BPU Docket No. EO 18080899**, **Testimony in Support of PJM Power Providers, October 22, 2018.** This testimony responds to questions posed by the BPU in this docket and provides analysis showing that the nuclear units in New Jersey seeking ZECs are not in need of them to remain in commercial operation. The testimony shows that these resources, given know forward prices for energy and capacity prices are able to cover their going forward costs in the absence of subsidies in the form of ZECs and will remain in commercial operation in spite of warnings these resources will retire in the absence of ZEC payments.

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, November 6, 2018.** This testimony responds to the Illinois Commerce Commission's protest that suggests the RPM Capacity Market be eliminated and replaced by an energy-only market construct because the capacity market is not a market at all. It also responds to the notion that markets should account directly for environmental policy and because they do not, the Illinois zero emission credit program for nuclear resources is justified. The testimony refutes these ideas by describing in detail that all markets have administrative rules and that markets can account for environmental policies when properly formulated to put a price on emissions rather than subsidizing resources out-of-market. Moreover, this testimony provides evidence of the need for the RPM Capacity Market to maintain resource adequacy as an energy only construct would not result in sufficient resources covering going forward costs in the energy market alone.

Alberta Utilities Commission, Consideration of ISO Rules to Implement and Operate the Capacity Market, Proceeding No. 23757, **Evidence in Support of ENMAX Corporation, February 28, 2019.** This evidence outlines the elements of the Alberta Electric System Operator (AESO) proposed capacity market framework that require changes to make align the capacity market with fair, efficient, and openly competitive market principles. The evidence addresses the resource adequacy model, capacity value of resources, penalties and bonuses, market power mitigation, Net CONE determination, and interactions with the energy market framework. The evidence also provides a high-level overview of the objectives of a capacity market and how it should interact with the energy and retail markets in Alberta.

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, New Jersey Board of Public Utilities, **BPU Docket No. EO 18080899**, **Response to Staff Questions on Accounting for Risk in Support of PJM Power Providers, March 8, 2019.** This is a response to BPU staff questions regarding market risk. This response discusses the mitigation of overall market risk based on changing conditions, optimal energy market offers and mitigation of energy market operational risk, and optimal offers and risk mitigation in the capacity market that are available to all generation resources including nuclear resources.

***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, New Jersey Board of Public Utilities,* BPU Docket No. EO 18080899**, **Reply Testimony in Support of PJM Power Providers, March 19, 2019.** This reply testimony responds to PSEG comments regarding the need for ZECs for New Jersey's nuclear units. This reply testimony updates the economic analysis showing New Jersey nuclear units are currently profitable and expected to remain profitable in the future. Furthermore, this reply points out that PSEG did not dispute the costs used in the initial analysis or the idea that new entry of combined cycle gas generation can reduce emissions at zero cost at the margin given these resources will enter the market absent subsidies. The reply argues, contrary to what is stated by PSEG, that the threat to retire is not credible given the statements and evidence provided by PSEG in its Securities and Exchange Commission (SEC) filings. This reply also provides evidence that it would be infeasible for PSEG to buy out of its capacity commitments in Incremental Auctions (IAs) given the supply and demand conditions present in IAs to date.

***Alberta Utilities Commission, Consideration of ISO Rules to Implement and Operate the Capacity Market, Proceeding No. 23757,* Reply Evidence in Support of ENMAX Corporation, April 4, 2019.** This evidence replies to the comments of other interveners regarding various elements of the Alberta Electric System Operator (AESO) proposed capacity market framework. The reply evidence responds to intervener comments on elements of the Net CONE determination, capacity and energy market power mitigation, the capacity value of resources inconsistencies between the resource adequacy model and offered supply, and penalties and bonuses.

Colorado Public Utilities Commission in the Matter of the Commission's Implementation of §§ 40-2.3-101 and 102, C.R.S. The Colorado Transmission Coordination Act, PROCEEDING NO. 19M-0495E, in Support of the Intermountain Rural Electric Association, November 15, 2019. This evidence provides the Colorado Commission with an overview of the benefits of RTO markets for electric cooperatives.