Attachment C

Protest of the Electric Power Supply Association
with Affidavit of Paul M. Sotkiewicz, Ph.D.
FERC Docket No. EL24-148-000
October 24, 2024

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Sierra Club, *et al.*,	**)**	
Complainants,	**)**	
v.	**)**	**Docket No. EL24-148-000**
PJM Interconnection, L.L.C.,	**)**	
Respondent.	**)**	

PROTEST OF THE ELECTRIC POWER SUPPLY ASSOCIATION

Pursuant to Rule 211 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission (the "Commission")[1] and in accordance with the Commission's September 30, 2024, October 4, 2024, and October 16, 2024 notices,[2] the Electric Power Supply Association ("EPSA")[3] respectfully submits this protest to the complaint filed by the Sierra Club, Natural Resources Defense Council, Public Citizen, Sustainable FERC Project and the Union of Concerned Scientists (collectively, "Complainants") in the above-

[1] 18 C.F.R. § 385.211 (2024).

[2] *Sierra Club v. PJM Interconnection, L.L.C.*, Notice of Complaint, Docket No. EL24-148-000 (Sept. 30, 2024) (unreported); *Sierra Club v. PJM Interconnection, L.L.C.*, Notice of Extension of Time, Docket No. EL24-148-000 (Oct. 4, 2024) (unreported); *Sierra Club v. PJM Interconnection, L.L.C.*, Notice of Extension of Time, Docket No. EL24-148-000 (Oct. 16, 2024) (unreported).

[3] EPSA is the national trade association representing competitive power suppliers in the U.S. EPSA members provide reliable and competitively priced electricity from environmentally responsible facilities using a diverse mix of fuels and technologies. EPSA seeks to bring the benefits of competition to all power customers. This pleading represents the position of EPSA as an organization but not necessarily the views of any particular member with respect to any issue. EPSA has separately moved to intervene in these proceedings. *See* (doc-less) Motion to Intervene of Electric Power Supply Association, Docket No. EL24-148-000 (filed Sept. 30, 2024).

captioned proceeding.[4] The Complaint seeks to upend the longstanding rule that reliability must-run ("RMR") units are not required to offer Capacity[5] into RPM Auctions starting with the Base Residual Auction for the 2026/2027 Delivery Year (the "2026/2027 BRA"). Just last month, PJM's Board of Managers rejected a similar proposal, defending its approach as one that "make[s] sense" in PJM[6] and further cautioning that "it would be counterproductive to try to change our market rules prior to the [2026/2027] BRA to force RMR units to offer into [RPM A]uctions."[7] For the reasons set forth in the PJM Board Letter, herein, and in the affidavit of Paul M. Sotkiewicz, Ph.D., provided as Attachment A hereto (the "Sotkiewicz Affidavit"), the Commission should – and, as a matter of law, must – deny the Complaint.

I. BACKGROUND

Under the PJM Tariff, a Generation Owner desiring to deactivate a generating unit must submit a notice to PJM,[8] which then conducts an analysis to determine whether the

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[4] Complaint of Sierra Club, Natural Resources Defense Council, Public Citizen, Sustainable FERC Project and Union of Concerned Scientists, Docket No. EL24-148-000 (filed Sept. 27, 2024) (the "Complaint").

[5] This and other capitalized terms used and not otherwise defined herein have the meanings assigned to them in the PJM Interconnection, L.L.C. ("PJM") Open Access Transmission Tariff (the "PJM Tariff") or if not defined therein, in the Reliability Assurance Agreement among Load Serving Entities in the PJM Region (the "RAA"). As discussed herein, Capacity – with a capital "c" – under the PJM Tariff and the RAA is a product to which significant performance obligations attach and is distinguishable from both RMR service and capacity – with a small "c" – as that term is used in other settings.

[6] Letter from Mark Takahashi, Chair, PJM Board of Managers at 3 (Sept. 19, 2024) (the "PJM Board Letter"), https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/2024/20240919-pjm-board-response-consumer-advocates-letter-re-urgent-reforms-pjm-capacity-market-re-reliability-must-run-units.ashx. A copy of the PJM Board Letter is provided as Attachment B hereto.

[7] *Id.* at 4.

[8] *See* PJM Tariff, § 113.1.

deactivation "would adversely affect the reliability of the Transmission System . . . ."[9] If PJM identifies reliability concerns, it issues a Notice of Reliability Impact to the Generation Owner, which notice "shall (1) identify the specific reliability impact resulting from the proposed Deactivation of the generating unit; and (2) provide an initial estimate of the period of time it will take to complete the Transmission System reliability upgrades necessary to alleviate the reliability impact."[10] Under the PJM Tariff, the Generation Owner may proceed with the deactivation "[r]egardless of whether the Deactivation of the generating unit would adversely affect the reliability of the Transmission System . . . ."[11] Alternatively, it may agree to "continue operating beyond its desired Deactivation Date during the period of construction of the Transmission System reliability upgrades necessary to alleviate the reliability impact resulting from the Deactivation of the generating unit" and may "file with the Commission a cost of service rate to recover the entire cost of operating the generating unit until such time as the generating unit is deactivated" or "elect to receive the Deactivation Avoidable Cost Credit" set forth in the PJM Tariff.[12]

The PJM Tariff does not set forth any specific Capacity offer requirements for RMR units. Instead, where a Generation Owner files a cost-of-service rate schedule – *i.e.*, an RMR rate schedule – with the Commission, the proposed rate schedule will address whether the RMR unit must offer into the RPM Auctions.[13] In addition, the PJM Tariff

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[9] *Id.*, § 113.2.

[10] *Id.*

[11] *Id.*

[12] *Id.*

[13] *See* Complaint at 8 & n.20 (citing PJM presentations).

provides that a Capacity Market Seller may obtain an exception to the Capacity must-offer requirement if:

> [i]t has a documented plan in place to retire the resource prior to or during the Delivery Year, and has submitted a notice of Deactivation to the Office of the Interconnection consistent with Tariff, Part V, section 113.1, ***without regard to whether the Office of the Interconnection has requested the Capacity Market Seller to continue to operate the resource beyond its desired deactivation date in accordance with Tariff, Part V, section 113.2 for the purpose of maintaining the reliability of the PJM Transmission System and the Capacity Market Seller has agreed to do so*** . . . .[14]

There are currently three RMR rate schedules for continued service from existing generation facilities on file with the Commission:

- NRG Business Marketing LLC ("NBM"), on behalf of Indian River Power LLC, has on file a rate schedule (the "Indian River 4 RMR Rate Schedule") pursuant to which it is providing RMR service from Unit 4 at the Indian River Generating Station ("Indian River 4") for a term commencing June 1, 2022, and scheduled to end on December 31, 2026.[15] The Indian River 4 Rate Schedule is the subject of a settlement pending before the Commission,[16] and the settlement's terms are being implemented on an interim basis, pending Commission action.[17]

- Brandon Shores LLC ("Brandon Shores") has on file a rate schedule (the "Brandon Shores RMR Rate Schedule") pursuant to which it proposes to provide RMR service from Units 1 and 2 at the Brandon Shores Generating Station ("Brandon Shores 1 & 2") for a term scheduled to commence June 1,

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[14] PJM Tariff, Attachment DD, § 6.6(g)(A) (emphasis added).

[15] *See* Reliability Must-Run Rate Schedule, Electric Rate Schedule FERC No. 3, Docket No. ER22-1539-000 (filed Apr. 1, 2022) (the "Indian River 4 RMR Filing"), *accepted & suspended, subject to refund*, *NRG Power Mktg. LLC*, 179 FERC ¶ 61,156 (2022); Settlement Agreement and Offer of Settlement, Docket Nos. ER22-1539-002, *et al.* (filed Apr. 2, 2024) (the "Indian River 4 RMR Settlement Filing"). As used herein, the term "Indian River 4 RMR Rate Schedule" refers to both the version of this rate schedule included in Attachment A to the Indian River 4 RMR Filing (the "Accepted Indian River 4 RMR Rate Schedule") and the revised version included in the Indian River RMR Settlement Filing (the "Settlement Indian River 4 RMR Rate Schedule").

[16] *See NRG Power Mktg. LLC*, 188 FERC ¶ 63,007 (2024) (Nagel, ALJ) (reporting the Indian River 4 Settlement to the Commission).

[17] *See NRG Bus. Mktg. LLC*, 187 FERC ¶ 63,002 (2024) (Satten, Chief ALJ).

2025, and scheduled to end on December 31, 2028.[18] Settlement proceedings regarding the rates, terms and conditions of this RMR service are ongoing.

- H.A. Wagner LLC ("Wagner") has on file a rate schedule (the "Wagner RMR Rate Schedule" and collectively with the Indian River 4 RMR Rate Schedule and the Brandon Shores RMR Rate Schedule, the "Accepted RMR Rate Schedules") pursuant to which it proposes to provide RMR service from Units 3 and 4 at the H.A. Wagner Generating Station ("Brandon Shores 1 & 2") for a term scheduled to commence June 1, 2025, and scheduled to end on December 31, 2028.[19] Settlement proceedings regarding the rates, terms and conditions of this RMR service are ongoing.

Pointing to higher prices in the Base Residual Auction for the 2025/2026 Delivery Year (the "2025/2026 BRA"), Complainants allege that allowing Generation Owners to choose whether to offer Capacity from RMR units has "already caused $4 billion to $5 billion dollars in excessive costs for consumers . . . and . . . may cause $12 billion to $15 billion more in three upcoming [Base Residual A]uctions . . . ."[20] Complainants also assert that the New York Independent System Operator Inc. ("NYISO") and ISO New England Inc. ("ISO-NE") "have Commission-approved rules in place that require RMR units to participate in their capacity markets to avoid forcing consumers 'to pay twice for the same capacity need' – precisely the outcome that has occurred in PJM."[21]

Complainants propose that the Commission require RMR units to offer into the RPM Auctions or, alternatively, that the Locational Deliverability Area Reliability Requirements ("LDA Reliability Requirements") be adjusted to account for RMR units'

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[18] RMR Arrangement – Continuing Operations Rate Schedule, Docket No. ER24-1790-000 (filed Apr. 18, 2024), *accepted & suspended, subject to refund*, *H.A. Wagner LLC*, 187 FERC ¶ 61,176 (2024) ("*Wagner*").

[19] RMR Arrangement – Continuing Operations Rate Schedule, Docket No. ER24-1787-000 (filed Apr. 18, 2024), *accepted & suspended, subject to refund*, *Wagner*, 187 FERC ¶ 61,176.

[20] Complaint at 1.

[21] *Id.* at 2 (quoting *ISO-New Eng., Inc.*, 165 FERC ¶ 61,202 at P 83 (2018)).

deemed contributions to resource adequacy.[22] The Complaint urges the Commission to take "immediate action"[23] and further delay of the 2026/2027 BRA if needed to implement Complainants' proposed changes in that auction.[24]

On October 18, 2024, PJM filed an answer explaining, at length, why the Complaint should be denied.[25] Nonetheless, given "significant market uncertainty" resulting from the "timing of th[e] Complaint and its request for the establishment of a refund effective date prior to the upcoming [2026/2027 BRA],"[26] PJM proposed to delay the 2026/2027 BRA and subsequent RPM Auctions.[27] In accordance with the Commission's October 17, 2024 notice,[28] EPSA, together with The PJM Power Providers Group, filed comments supporting PJM's proposal, but only as a means of allowing PJM to address concerns

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[22] *See id.* at 53.

[23] *Id.* at 48.

[24] *Id.* at 53.

[25] *See* Answer of PJM Interconnection, L.L.C., Docket No. EL24-148-000 (filed Oct. 18, 2024) (the "PJM Answer").

[26] *Id.* at 2.

[27] *See id.* *See also* Motion of PJM Interconnection, L.L.C. to Delay the Reliability Pricing Model Auctions Beginning with the December, 2024 Base Residual Auction for Delivery Year 2026/2027 through the 2029/2030 Delivery Year, Request for Expediated Action and Order by November 8, 2024, and Request for Shortened 7-Day Comment Period, Docket No. EL24-118-000 (filed Oct. 15, 2024) (the "EL24-148 PJM Motion"); Request for Waiver of PJM Interconnection, L.L.C. to Delay the Reliability Pricing Model Auctions Beginning with the December, 2024 Base Residual Auction for Delivery Year 2026/2027 Through the 2029/2030 Delivery Year, Request for Expedited Action and Order by November 8, 2024, and Request for Shortened 7-Day Comment Period, Docket No. ER25-118-000 (filed Oct. 15, 2024) (the "ER25-118 Waiver Request").

[28] *See* Combined Notice of Filings #1, Docket Nos. EG25-11-000, *et al.* (Oct. 17, 2024) (unreported).

about the Reliability Pricing Market ("RPM") rules unrelated to the issues raised in the Complaint.[29]

II. PROTEST

The Commission should deny the Complaint. As discussed herein, Complainants have not met their burden under FPA Section 206 and granting the Complaint would undermine the ability of PJM's RPM market to ensure resource adequacy at exactly the wrong time. Moreover, providing the relief they seek as to generators under the Accepted RMR Rate Schedules for the 2026/2027 BRA would be both unlawful and impractical, regardless of when that auction is conducted.

A. Complainants Have Not Met Their Burden under FPA Section 206

Under Section 206(b) of the FPA, Complainants bear "the burden of proof to show that" PJM's existing rules relating to RMR units are "unjust, unreasonable, unduly discriminatory, or preferential . . . ."[30] Complainants have failed to satisfy that burden, and the Complaint must, therefore, be denied.[31]

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[29] *See* Joint Comments of the PJM Power Providers Group and the Electric Power Supply Association, Docket Nos. EL24-148-000, *et al.* (filed Oct. 22, 2024). Having addressed the issue of whether the 2026/2027 BRA and subsequent RPM Auctions should be delayed in those comments, EPSA will not burden the record by reiterating its position here.

[30] 16 U.S.C. § 824e(b) (2018). *See also, e.g.*, *New Eng. Power Generators Ass'n v. FERC*, 879 F.3d 1192, 1200 (D.C. Cir. 2018) ("In a proceeding under FPA § 206, . . . the challenging party, whether the Commission or the complainant, carries the burden of proving a rate is unjust and unreasonable."); *FirstEnergy Serv. Co. v. FERC*, 758 F.3d 346, 353 (D.C. Cir. 2014) ("Under section 206, 'the burden of proof to show that any rate, charge, classification, rule, regulation, practice, or contract is unjust, unreasonable, unduly discriminatory, or preferential shall be upon . . . the complainant.'" (quoting 16 U.S.C. § 824e(b)).

[31] *See e.g.*, *Montana-Dakota Utils. Co. v. Midcontinent Indep. Sys. Operator, Inc.*, 188 FERC ¶ 61,168 at P 43 (2024) (denying complaints where complainants "each failed to satisfy their respective burdens under FPA section 206"); *Central Hudson Gas & Elec. Corp. v. New York Indep. Sys. Operator, Inc.*, 176 FERC ¶ 61,149 at P 21 (2021) (denying complaint where complainants "failed to satisfy their burden under section 206 of the FPA to demonstrate that the

1. There is No Basis for Assertions that Consumers are "Paying Twice"

Apparently operating under the misapprehension that "the mere repetition of an inaccuracy begets truth,"[32] Complainants assert over and over that PJM's longstanding rule forces consumers "to pay twice for the same capacity needs . . . ."[33] Lost in this sloganeering is the fact that Capacity and RMR service are separate and distinct products that are, and always have been, procured separately in the PJM market. Literally from start to finish, RMR service under Part V of the PJM Tariff is directed to a transmission system need, not a resource adequacy need: The purpose of PJM's analysis of the generator's deactivation notice is to determine if "the Deactivation of the Generation Owner's generating unit would adversely affect the reliability of the Transmission System absent upgrades to the Transmission System,"[34] and in response, the Generation Owner is to inform PJM "whether the generating unit proposed for Deactivation will continue operating beyond its desired Deactivation Date during the period of construction of the Transmission System reliability upgrades necessary to alleviate the reliability impact resulting from the Deactivation of the generating unit . . . ."[35] Accordingly, as Dr.

[challenged rate practice] is unjust, unreasonable, unduly discriminatory, or preferential"), *on reh'g*, 178 FERC ¶ 61,194 (2022).

32 *National Mut. Ins. Co. of D.C. v. Tidewater Transfer Co.*, 337 U.S. 582, 654 (1949) (Frankfurter, J., dissenting).

33 Complaint at 35. *See also id.* at 2, 10, 11, 14, 29, 34, 35, 36, 59.

34 PJM Tariff, § 113.2.

35 *Id.* Where the Generator Owner opts to file a cost-of-service recovery rate schedule, the rate therein is to be designed "to recover the entire cost of operating the generating unit until such time as the generating unit is deactivated pursuant to this Part V," *id.*, § 119 – that is, until the deferred deactivation date. If the Generation Owner elects payment under the Deactivation Avoidable Cost Credit provisions of Part V, such compensation shall "continu[e] until the earlier of such time as the generating unit is deactivated or the completion date of the necessary Transmission System reliability upgrades that would alleviate the reliability impact resulting from the Deactivation of the generating unit . . . ." *Id.*, § 114.

Sotkiewicz explains, RMR service in PJM is a short-term substitute for ***transmission***.[36] By contrast, PJM's RPM market is intended to procure Capacity to "manag[e] resource adequacy and ensur[e] reliable energy supplies within PJM."[37] A customer asked to pay once for an apple and once for an orange cannot legitimately complain of being asked to "pay twice" for an apple. The same is true here, where PJM is paying for one product, RMR service, and separately paying for another product, Capacity.

The Complaint would have the Commission believe that units under RMR arrangements are effectively providing Capacity already, because PJM can "call these power plants to operate during capacity emergencies."[38] At the outset, while recent RMR rate schedules include some obligation to operate when dispatched during "capacity emergencies,"[39] there is no universal tariff requirement that RMR units operate during capacity emergencies. Tellingly, the only PJM document Complainants cite for the proposition that RMR units are "expected to produce MWs under emergency conditions""[40] is a presentation to stakeholders that described assumptions made about RMR units in the Capacity Emergency Transfer Limit ("CETL") calculation.[41] To begin,

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36 *See* Sotkiewicz Affidavit at ¶¶ 11-16. *See also id.* at ¶ 12 ("It cannot be emphasized enough that the reliability predicate under Part V is related to the 'Transmission System' and is not related to resource adequacy. . . .").

37 *PJM Interconnection, L.L.C.*, 119 FERC ¶ 61,318 at P 2, *reh'g denied*, 121 FERC ¶ 61,173 (2007).

38 Complaint at 2. *See also id.* at 4; *id.* at 10; *id.* at 20.

39 *Id.* at 2.

40 *Id.* at 9 (quoting Patricio Rocha-Garrido & Michael Herman, *PJM CETO/CETL & Load Deliverability* at slide 16 (Aug. 19, 2024), https://www.pjm.com/-/media/committees-groups/task-forces/destf/2024/20240819/20240819-item-04---ceto-cetl-and-load-deliverability-test.ashx)).

41 The same is true of the document cited for the related proposition that "the RMR units [are] expected to be operating and impacting power flows on the system during times of reliability need." Complaint at 9 (quoting PJM, *PJM Response to the 2023 State of the Market Report* at 4

these assumptions underscore the point that RMR service is a substitute for transmission and not a resource adequacy product akin to Capacity. As explained in the PJM Answer, its CETL and Capacity Emergency Transfer Objective ("CETO") analyses are intended "to reflect the best approximation of the expected system PJM will have in the future under different system conditions," and "these studies focus on ***transmission limitations*** in a particular area and do not consider whether or not resources in an area are Capacity Resources."[42] Indeed, as Dr. Sotkiewicz explains, PJM's ability to call on these units makes them "no different than other transmission assets that must be recalled into service from scheduled outages."[43] The fact that PJM accounts for all units in a specific area, including RMR units, in determining transmission capability says nothing about when a unit will actually operate.

Equally important, however, the PJM presentation was not discussing any sort of uniform performance requirement for RMR units but was only describing assumptions made in PJM's CETL and CETO calculations. The performance requirements for RMR units are instead set forth in individual RMR rate schedules.[44] These individual RMR rate schedules reflect the fact that, as PJM explains, "not all resources retained under an RMR agreement in PJM are willing to provide comparable capacity-like service."[45] That the actual performance requirements can and will vary is illustrated by Complainants' own

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(Aug. 2024) (the "*PJM SOM Response*"), https://www.pjm.com/-/media/library/reports-notices/state-of-the-market/20240822-pjm-response-to-the-2023-state-of-the-market-report.ashx).

42 PJM Answer at 36 (emphasis added) (footnote omitted).

43 Sotkiewicz Affidavit at ¶ 26.

44 *See* PJM Answer at 30 ("PJM has no authority to dictate standardized operating terms.").

45 *Id.* at 8.

summary chart regarding RMR arrangements in PJM.[46] Indeed, Dr. Sotkiewicz discusses RMR arrangements that "explicitly took the[] units out of all PJM markets" and only allowed for them to "be run for Transmission System Reliability issues."[47]

In any event, as Dr. Sotkiewicz explains, the availability of some RMR units for schedule and dispatch during capacity emergencies "cannot and do[es] not imply that RMR units are Capacity Resources in the sense of RPM committed capacity."[48] There is significantly more to providing Capacity in the PJM market than allowing one's resource to be dispatched during capacity emergencies, and by their deactivation notices, many owners of RMR units have already signaled that they are unwilling or unable to undertake all of the obligations and risks associated with a Capacity commitment. As the Commission has recognized, PJM's Capacity Performance construct imposes "substantial penalties for non-performance . . . ."[49] Under this construct, a resource is only excused from penalties for failure to perform during a capacity emergency to the extent it (1) "was unavailable . . . solely because the resource . . . was on a Generator Planned Outage or Generator Maintenance Outage approved by the Office of the Interconnection," or (2) "was not scheduled to operate by the Office of the Interconnection, or was online but was scheduled down, by the Office of the

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[46] *See* Complaint at 30-31, Table 1.

[47] Sotkiewicz Affidavit at ¶ 20. *See also* PJM Answer at 9 (discussing RMR agreements for resources that "precluded PJM from dispatching those resources for capacity emergencies and were instead limited to operating for transmission needs").

[48] Sotkiewicz Affidavit at ¶ 6.

[49] *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208 at P 15 (the "CP Order"), *on reh'g*, 152 FERC ¶ 61,064 (2015), *on reh'g*, 155 FERC ¶ 61,157 (2016), *on reh'g*, 162 FERC ¶ 61,047 (2018).

Interconnection . . . ."[50] Moreover, separate and apart from capacity penalties, a Capacity commitment "requires resources to offer their full physical capability into the energy market,"[51] which also exposes such resources to the risk of having to obtain replacement energy if they are unable to perform.[52]

By contrast, the performance obligations of the typical RMR unit are far more limited. For example, under the Settlement Indian River 4 RMR Rate Schedule,[53] Indian River 4 is to be offered into the PJM energy market "with a status of 'unavailable'"[54] and PJM may schedule and dispatch it:

> solely to address (i) an identified transmission reliability need, including transmission reliability needs that are the result of transmission maintenance or transmission work to support upgrades . . . ; (ii) a PJM transmission reliability need caused by a system restoration need . . . ; (iii) a capacity emergency . . . during which PJM determines that the resources scheduled for an operating day are not sufficient to maintain the appropriate reserve levels for PJM; (iv) any required testing of [Indian River] 4 . . . .[55]

PJM may not schedule or dispatch Indian River 4 to the extent it is "unavailable due to an Outage,"[56] where "Outage" is defined to include not only a Generator Planned Outage or a Generator Maintenance Outage but also an "Unplanned Forced Outage as defined in PJM Manual 10 (Revision 40), Section 2, or a partial outage/derate as utilized in the PJM

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50 PJM Tariff, Attachment DD, § 10A(d).

51 *PJM Interconnection, L.L.C.*, 186 FERC ¶ 61,080 at P 130 (2024).

52 *See* Sotkiewicz Affidavit at ¶ 29.

53 As indicated above, the Indian River 4 Settlement is being implemented on an interim basis pending Commission action on the settlement. *See supra* note 17.

54 Settlement Indian River 4 Rate Schedule, § 4.1(a).

55 *Id.*, § 3.3(a).

56 *Id.*, § 3.3(d).

Governing Documents."[57] PJM's ability to schedule and dispatch the unit is also "subject to . . . the availability of coal, equipment, parts, and the other inputs to energy production, consisting of, but not limited to, lime, and oil."[58] Indian River 4 is also excused from "operat[ing] in a manner that will cause it to violate the terms of any environmental restrictions or any operating permit limitations," as determined by the operator "[i]n its sole discretion . . . ."[59] The markedly higher performance obligations for a generation unit providing Capacity to PJM belie any suggestion that RMR units are already providing Capacity. As PJM warns, "[r]equiring PJM to rely on a resource without a Tariff-based or contractual commitment to operate during times of system stress would undermine the reliability benefits achieved through prior reforms – and undermine PJM's ability to maintain resource adequacy."[60]

It also bears emphasis that PJM can ask any number of other resources without Capacity obligations to run during emergencies, including energy-only generation resources, and can also call back transmission assets on outage.[61] But that does not mean any of these facilities will actually be available, much less that they can be conflated with a Capacity Resource, and application of a contrary rule exclusively to RMR units would be unduly discriminatory and thus unlawful. At bottom, Complainants get their math backwards: the issue is not that consumers are being asked to "pay twice" for Capacity;

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57 *Id.*, § 1.7.

58 *Id.*, § 3.2.

59 *Id.*, § 3.3(c).

60 PJM Answer at 29-30.

61 *See* Sotkiewicz Affidavit at ¶¶ 25-27. *See also* PJM Answer at 30 (noting that "many energy-only resources and any other Capacity Resource that does not clear an RPM Auction still provide energy to PJM on a daily basis, but are also not counted as cleared supply in the capacity market").

it is that they are asking that PJM "double count" these units[62] as providing both RMR service and Capacity when they are only providing the former.

Even disregarding the vastly different performance obligations, Complainants' argument that RMR units can be regarded as already providing the equivalent of Capacity during the Delivery Year associated with a given Base Residual Auction fails as a simple matter of timing. The mere existence or even effectiveness of an RMR rate schedule at the time of an RPM Auction is no guarantee that the resource will, in fact, remain operational (and thus even potentially available to be called during a capacity emergency) until, much less through, the applicable Delivery Year. Significantly, the PJM Tariff provides that a resource is only entitled to RMR compensation:

> until the earlier of such time as the generating unit is deactivated or the completion date of the necessary Transmission System reliability upgrades that would alleviate the reliability impact resulting from the Deactivation of the generating unit, or the Transmission Provider otherwise determines, in accordance with established reliability criteria, that the continued operation of the generating unit is no longer necessary for the reliability of the Transmission System.[63]

Moreover, Section 113.3 of the PJM Tariff expressly provides that a Generation Owner that has agreed to continue operating a unit to address a reliability need may nonetheless "deactivate such generating unit prior to the completion date of the Transmission System reliability upgrades necessary to alleviate the reliability impact resulting from the Deactivation of the generating unit" upon 90 days' written notice.[64] Individual RMR rate

62 Sotkiewicz Affidavit at ¶ 38.

63 PJM Tariff, § 114.

64 *Id.*, § 113.3.

schedules typically allow for early termination in accordance with this provision[65] and further provide for early termination by the Generation Owner under certain circumstances.[66] Against that backdrop and taking into account that PJM's RPM market is meant to procure Capacity three years ahead – and even under the compressed schedules in place and proposed for the 2026/2027 BRA, will still procure Capacity at least 12-18 months ahead – of the Delivery Year, it is eminently reasonable for PJM not to assume that RMR units will remain in service through the Delivery Year. Indeed, a contrary assumption would be unreasonable and irrational.[67]

The bottom line is that PJM cannot reasonably be said to have procured Capacity for a Delivery Year simply because there is currently an RMR rate schedule on file or in effect.

2. The 2025/2026 BRA Clearing Price Reflected Market Fundamentals

Complainants allege that permitting RMR units not to offer into the 2025/2026 BRA resulted in "excessive costs" of "at least $4.2 billion" and will have "similar impacts" in

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65 *See, e.g.*, Accepted Indian River 4 RMR Rate Schedule, § 2.3; Settlement Indian River 4 RMR Rate Schedule, § 2.3; Brandon Shores RMR Rate Schedule, § 2.3; Wagner RMR Rate Schedule, § 2.3.

66 *See, e.g.*, Accepted Indian River 4 RMR Rate Schedule, § 2.5 (allowing the generator to terminate if a request for new project investment needed to continue operating is declined); Settlement Indian River 4 RMR Rate Schedule, § 2.5 (same); Brandon Shores RMR Rate Schedule, § 2.5(b) (same); Wagner RMR Rate Schedule, § 2.5(b) (same). *See also* Brandon Shores RMR Rate Schedule, § 2.5(a) (allowing the generator to suspend performance if continuing to operate "would violate any applicable law, regulation, or ordinance"); Wagner RMR Rate Schedule, § 2.5(a) (same).

67 As PJM observes, Complainants have failed to "address[] the circumstance where an RMR resource may be terminated early because necessary transmission upgrades are completed ahead of schedule and whether PJM would be required to acquire additional capacity to replace the RMR resource in such scenarios." PJM Answer at 39.

upcoming auctions.[68] This claim ignores not only the critical difference between RMR service and Capacity discussed above in Section II.A.1 but other market fundamentals that drove prices higher in the 2025/2026 BRA. The reality is that clearing prices in this RPM Auction reflected market fundamentals and were consistent with the intent of the RPM market to provide the price signals necessary to incentivize new investment in light of looming Capacity shortages.

After the 2025/2026 BRA, PJM issued a report explaining that the higher clearing prices reflected:

- Planning Parameters . . . changes which include:

  − 3,243 MW increase in forecasted load

  − IRM increase from 14.7% to 17.8%

- Significant decrease in overall supply from retirements (actual retirements plus must offer exceptions for future retirements), change in status from capacity resource to energy only and must offer exceptions for exports (see change of status and must offer exception report)

- Critical Issue Fast Path (CIFP) changes were approved by FERC (ER24-99-000). These changes included marginal resource accreditation (ELCC), Forecast Pool Requirement (FPR) and a binding notice of intent for planned resources among other changes.

- Dominion FRR has changed to RPM and therefore the entire Dominion zone is now in RPM.

- Net CONE values used to determine the VRR Curve changed significantly in some LDAs. In most cases, LDAs received lower Net CONE values, and the range was

[68] Complaint at 52.

> between +4.1% in the PE zone to -80.6% in the BGE zone.[69]

Similarly, in the PJM Board Letter, PJM's Board of Managers explained:

> As PJM has been warning for some time now, our region is experiencing a combination of trends that have served to rapidly tighten the supply-demand balance on our system. These trends include:
>
> - Electrification coupled with the proliferation of high-demand data centers in the region that will result in material load growth
> - Retirement of thermal generators at a rapid pace due to policy pressure as well as economics
> - Slow new entry of replacement generation resources due to a combination of industry forces, including siting, permitting and supply chain constraints
> - The high proportion of our interconnection queue that is composed of intermittent and limited-duration resources, many of which are valuable energy resources but are much less effective providers of capacity than the thermal resources they are replacing . . . .[70]

In their zeal to lower prices in the short term, Complainants lose sight of the larger issue that the clearing prices in the 2025/2026 BRA sent "a new build investment price signal" that is "consistent with market fundamentals" in a region that "will require the buildout of a significant quantity of new generation . . . in order to maintain the reliable electricity supply [PJM] consumers expect."[71] Indeed, while fixating on the treatment of

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69 PJM, *2025/2026 Base Residual Auction Report* at 3-4 (July 30, 2024) (the "Auction Report"),https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.ashx. *See also* PJM Answer at 6-7 (explaining that "higher clearing prices are the natural result of supply and demand fundamentals given resource retirements (without timely replacements) and a large increase in expected load growth, driven in large part by electrification trends and data center development in the PJM Region.").

70 PJM Board Letter at 1-2 (footnote omitted).

71 *Id.* at 2.

RMR units in that auction, Complainants ignore the fact that many of these RMR units, as well as numerous other resources, are deactivating precisely because of economic conditions in the PJM region.[72] Dr. Sotkiewicz concurs with PJM's assessment that the clearing prices in the 2025/2026 BRA "are sending the right price signals to attract . . . resources to the market to maintain resource adequacy in PJM"[73] and to retain resources that are at risk of retiring due to recent market conditions and the cost of complying with environmental mandates.[74]

The Complaint relies heavily on a report prepared by Synapse Energy Economics for the Maryland Office of People's Counsel,[75] which alleged that Brandon Shores' and Wagner's "non-participation in the [2025/2026 BRA] cost consumers roughly $5 billion."[76] Neither the Complaint nor the Synapse Report, however, demonstrate that these prices are inconsistent with the expected market fundamentals during the Delivery Year or on a

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72 *See* Letter from Dale Lebsack, President, Brandon Shores LLC, to Yuri Smolanitsky, PJM Office of Interconnection, Re: Notice of Deactivation Date for Brandon Shore 1&2 under Brandon Shores LLC (Apr. 6, 2023), https://www.pjm.com/-/media/planning/gen-retire/deactivation-notices/brandon-shores-deactiviation.ashx; Letter from Dale Lebsack, President, H.A. Wagner LLC, to Yuri Smolanitsky, PJM Office of Interconnection, Re: Notice of Deactivation Date for H.A. Wagner 1, 3, 4 & CT under H.A. Wagner LLC (Oct. 16, 2023), https://www.pjm.com/-/media/planning/gen-retire/deactivation-notices/wagner-deactiviation-notice.ashx. Other deactivation notices are available at https://www.pjm.com/planning/service-requests/gen-deactivations/generator-deactivation-notices. *See also* Protest of Talen Energy Corporation, Attachment A, Affidavit of A. Joseph Cavicchi at ¶ 9, Docket No. EL24-148-000 (filed Oct. 21, 2024) (the "Talen Protest").

73 Sotkiewicz Affidavit at ¶ 46.

74 *See id.* at ¶¶ 56-57.

75 Synapse Energy Economics, Inc., *Bill and Rate Impacts of PJM's 2025/2026 Capacity Market Results & Reliability Must-Run Units in Maryland* (corrected Aug. 29, 2024) (the "Synapse Report") (provided as Attachment 2 to the Complaint).

76 Letter from David S. Lapp, People's Counsel, Maryland Office of the People's Counsel, *et al.*, to Mark Takahashi, Chair, PJM Board of Managers and Manu Asthana, President and CEO, PJM Interconnection, L.L.C., Re: Urgent Reforms to the Capacity Market Regarding Reliability Must Run Units at 2 (provided as Attachment 2 to the Complaint).

going forward basis. To the contrary, both the Complaint and the Synapse Report fail to acknowledge that, at the time of the 2025/2026 BRA and even as of the date of this filing, Brandon Shores and Wagner ***do not have RMR agreements in place for the 2025/2026 Delivery Year***.[77] Brandon Shores and Wagner have only filed rate schedules proposing to provide RMR service during the 2025/2026 Delivery Year, the terms of which are still under negotiation. And even if Brandon Shores and Wagner do eventually agree to provide RMR service during the 2025/2026 Delivery Year, the RPM Auctions are intended to provide forward price signals to allow the construction of new Capacity Resources necessary to satisfy demand and replace resources that, like Brandon Shores and Wagner, are retiring.

Complainants' witness, James F. Wilson, correctly recognizes that "RPM is designed to set appropriately high prices when resources are needed," but then goes on to claim that "it is not necessary or appropriate to distort the supply-demand balance to send a stronger price signal."[78] But this begs the question of how one distorts the supply-demand balance by recognizing in the market that these RMR units have undertaken no commitment to provide Capacity and will be deactivated, at the latest, when the short-term transmission need they are addressing is resolved.[79] Moreover, while Mr. Wilson claims that "[i]nvestors know that transmission to relieve the constraints that the retirement would cause are under construction,"[80] he wrongly conflates RMR service and

77 *See* Talen Protest at 3 (stating that "Brandon Shores and [] Wagner have yet to execute RMR agreements with PJM").

78 Complaint, Affidavit of James F. Wilson in Support of the Complaint of the Public Interest Organizations at ¶ 32 (the "Wilson Affidavit").

79 *See* Sotkiewicz Affidavit at ¶ 65.

80 Wilson Affidavit at ¶ 33.

Capacity and ignores the fact that while the long-term transmission solution will resolve the transmission reliability issue, it will not replace the generation capacity being deactivated.[81]

To be sure, granting the Complaint may, in the short run, produce the lower clearing prices Complainants desire. But lower prices are not the same as the "just and reasonable" prices the Commission is tasked with preserving. As PJM points out, Complainants want to lower prices by "effectively substitut[ing] a potentially lower quality product (RMR resources) for a superior one (Capacity Resource),"[82] which results in "price suppression and price[] signals that do not match the actual supply and demand balance."[83] Dr. Sotkiewicz further states Complainants' proposals will inaccurately "signal with lower prices that there is no impending resource adequacy problem, when in fact the RMR agreements will disappear once transmission upgrades are in service."[84] To make matters worse, the RMR resources will also displace other resources, meaning that, over time, prices will "spike to levels well above those in [an] economically efficient outcome . . . ."[85] As a result, "[r]ather than allowing the RPM capacity market to reflect the supply-demand balance and send prices that signify the need for the retention of existing resources and new entry," Complainants' proposals "would create year to year

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81 *See* Sotkiewicz Affidavit at ¶¶ 31-38. *See also* PJM Answer at 34-36 (responding to Mr. Wilson and explaining, among other things, that "more transmission is not a panacea" as "[e]ven after the transmission constraints in the BGE area are alleviated by the transmission upgrades, the *PJM Region* will still require additional resources to serve the increasing load" (emphasis in original)).

82 PJM Answer at 10.

83 *Id.* at 11.

84 Sotkiewicz Affidavit at ¶ 65.

85 *Id.*

volatility in prices, by artificially lowering prices with RMR resources . . . for some period of time, only to see prices spike . . . with the retirements of the RMR resources and inefficient deactivations of economic resources."[86] The short-sighted pursuit of lower prices in the face of a "rapidly tighten[ing] . . . supply-demand balance on [PJM's] system,"[87] would be irreconcilable with not only the Commission's statutory obligation to ensure that rates are just and reasonable but also its broader statutory mission "to encourage the orderly development of plentiful supplies of electricity . . . at reasonable prices."[88]

3. Complainants' Comparisons to Other Markets' Approaches are Incomplete, Inapposite and Misleading

Pointing selectively to approaches taken by certain other regional transmission organizations ("RTOs")/independent system operators ("ISOs"), Complainants boldly (and inaccurately) declare that "Commission precedent is overwhelmingly in favor of requiring RMR units to offer into capacity markets as price takers to prevent consumers from being saddled with unnecessary capacity costs."[89] In support of this claim, Complainants overread orders relating to the organized capacity markets administered by NYISO and ISO-NE and point to the approach taken by the California Independent System Operator Corporation ("CAISO"), which does not administer an organized capacity market, while inexplicably ignoring the Midcontinent Independent System Operator, Inc. ("MISO"), which does and whose approach is the same as PJM's.

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86 *Id.* at ¶ 67.

87 PJM Board Letter at 1.

88 *NAACP v. FPC*, 425 U.S. 662, 669-670 (1976) (footnote omitted).

89 Complaint at 36.

At the outset, the implication that PJM's approach would be unjust and unreasonable merely by virtue of differing from approaches taken elsewhere runs counter to longstanding Commission precedent "reject[ing] a one-size-fits-all approach in the various RTOs/ISOs due, in large part, to significant differences between each region and [holding] that there can be more than one just and reasonable rate."[90] The Commission has consistently made clear that "market design and rules need not be identical among the regions and may instead reflect the unique characteristics of the markets as necessary."[91] As explained in the PJM Board Letter, PJM's approach "make[s] sense" given the characteristics of the PJM market and has "been in place for many years and . . . approved by the FERC."[92]

(a) NYISO

Even as support for what the Commission has required in the NYISO market, the orders cited in the Complaint do not establish that it would be unjust and unreasonable to allow RMR units to choose whether to offer into the NYISO-administered capacity market. As indicated in the Complaint, the Commission found the NYISO's Market Administration

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90 *Midcontinent Indep. Transmission Sys. Operator, Inc.*, 162 FERC ¶ 61,176 at P 57 (2018) (footnote omitted), *reh'g denied*, 170 FERC ¶ 61,215 (2020). *See also, e.g., Southwest Power Pool, Inc.*, 181 FERC ¶ 61,053 at P 25 (2022) ("The fact that the Commission found the PJM transmission owners' proposal to be just and reasonable does not signify that SPP's proposal, which serves a different objective, is not just and reasonable, and the Commission's approval of more stringent voting rules in one region does not require rejection of less stringent voting rules in another." (footnote omitted)); *Calpine Corp. v. PJM Interconnection, L.L.C.*, 169 FERC ¶ 61,239 at P 204 n.431 (2019) (noting that "regional markets are not required to have the same rules" as "what rules may be just and reasonable for a particular market depends on the relevant facts"), *reh'g denied*, 170 FERC ¶ 61,215 (2020); *Southwest Power Pool, Inc.*, 158 FERC ¶ 61,063 at P 13 (2017) (stating that "market rules need not be identical among the regions to be just and reasonable, and there can be more than one just and reasonable rate" (footnote omitted)).

91 *ISO New Eng. Inc.*, 150 FERC ¶ 61,065 at P 18 (2015) (footnote omitted).

92 PJM Board Letter at 3-4.

and Control Area Services Tariff (the "NYISO MST") to be unjust and unreasonable under Section 206 of the FPA, because it failed to address the retention of, and compensation for, units needed for reliability.[93] On compliance, NYISO proposed to require that RMR units be offered into its monthly capacity auctions and that their offers be priced at $0.00/kW-month except in two circumstances in which their offers would be priced at the unit's avoidable cost.[94] The Commission did not substantively address NYISO's proposed must-offer requirement but only the pricing of offers, finding "NYISO's proposal to impose a capacity offer price on RMR generators higher than $0.00/kW-month [to be] unjust and unreasonable."[95] Even as they relate to NYISO, therefore, the cited orders do not support the proposition that there is anything unjust and unreasonable about not requiring that RMR units offer into PJM's RPM Auctions. Rather, as PJM put it, these orders "were limited to a determination of the required offer price that RMR units are required to offer into NYISO auctions."[96]

Even if one could read these orders as mandating a capacity must-offer rule in the NYISO market, they would not support any comparable mandate in PJM. The Commission has properly recognized that "PJM's markets are fundamentally different from NYISO's, such that what may be appropriate for PJM is not necessarily appropriate

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93 *See New York Indep. Sys. Operator, Inc.*, 150 FERC ¶ 61,116 at P 4 (2015) ("*NYISO*"), *on reh'g*, 155 FERC ¶ 61,076 (2016), *on reh'g*, 161 FERC ¶ 61,189 (2017), *on reh'g*, 163 FERC ¶ 61,047 (2018).

94 *See New York Indep. Sys. Operator, Inc.*, 155 FERC ¶ 61,076 at P 74 (2016), *on reh'g*, 161 FERC ¶ 61,189 (2017), *on reh'g*, 163 FERC ¶ 61,047 (2018).

95 *Id.* at P 82.

96 PJM Board Letter at 4. *See also* PJM Answer at 41-42.

for NYISO."[97] Of particular relevance here, the Commission has found the markets to be "fundamentally different" because "NYISO's capacity market is short-term in nature – with auctions for spot, monthly, and three month (strip) capacity – whereas PJM's auction occurs three years in advance awarding a year-long capacity obligation."[98] The differences in the timing of the auctions and the duration of commitments are critical when considering the treatment of RMR units in PJM's RPM Auctions, because RMR arrangements are, by their nature, designed to be short-term, temporary agreements.[99] NYISO's rules only require RMR resources to submit offers into NYISO's monthly ICAP Spot Market Auctions,[100] meaning that an RMR resource will only be required to take on capacity obligations in the near future and on a short-term basis. By contrast, the Complaint would force RMR resources to assume Capacity obligations (along with the corresponding obligations and risks) for full Delivery Years that do not begin for years into the future. Given the inherently temporary nature of RMR arrangements, there is a substantial likelihood that these obligations will extend well beyond the termination of the RMR arrangements, when the RMR units are supposed to be allowed to deactivate.

The obligations undertaken by capacity resources in the two markets also differ significantly, and assuming a capacity commitment has substantially more onerous

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97 *New York Pub. Serv. Comm'n v. New York Indep. Sys. Operator, Inc.*, 153 FERC ¶ 61,022 at P 78 (2015) (footnote omitted), *reh'g denied*, 154 FERC ¶ 61,088 (2016).

98 *Id.* at P 38.

99 *See, e.g.*, PJM Tariff, § 113.2 (providing that an owner shall inform PJM whether "unit proposed for Deactivation will continue operating beyond its desired Deactivation Date during the period of construction of the Transmission System reliability upgrades necessary to alleviate the reliability impact resulting from the Deactivation of the generating unit"); *NYISO*, 150 FERC ¶ 61,116 at P 2 (referring to "short-term remedies, such as RMR agreements").

100 *See* NYISO MST, § 23.4.5.8.1 ("All UCAP from an RMR Generator shall be offered in each ICAP Spot Market Auction . . . .").

implications in PJM than it does in NYISO. In particular, PJM's Capacity Performance rules are designed to impose "substantial penalties for non-performance,"[101] with only narrow excuses for failing to perform during an emergency.[102] NYISO has not adopted any similar construct. In the NYISO market, the principal consequence when a capacity resource fails to perform up to its capacity obligation is that its Equivalent Demand Forced Outage Rate will, over time, increase and thereby reduce the amount of unforced capacity the resource can offer into future auctions.[103]

(b) ISO-NE

Complainants' comparison of PJM's approach to RMR participation in RPM Auctions with ISO-NE's treatment of fuel security resources in its Forward Capacity Market (the "FCM") is even less persuasive. Importantly, the orders cited in the Complaint do not establish that it would have been unjust and unreasonable not to mandate price-taker FCM participation by fuel security resources. Indeed, while finding ISO-NE's approach acceptable, the Commission also expressly stated that "it may be reasonable for ISO-NE to either (1) retain fuel security resources ***outside of the FCM construct***, or (2) offer fuel security resources into the FCM ***at a non-zero price*** that is still subject to mitigation by the [Internal Market Monitor]."[104] The Commission's clarification is in perfect accord with the fundamental principle that "there can be more than one just and

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101 CP Order, 151 FERC ¶ 61,208 at P 15.

102 *See* PJM Tariff, Attachment DD, § 10A(d).

103 *See* NYISO MST, § 23.4.5.8.1.

104 *ISO New Eng. Inc.*, 165 FERC ¶ 61,202 at P 86 (2018) ("*ISO-NE*") (original emphasis removed) (emphases added) (footnote omitted), *on reh'g*, 173 FERC ¶ 61,204 (2020).

reasonable rate."[105] That being the case, a finding that one rate is just and reasonable "d[oes] not amount to a finding that every other rate . . . [i]s not."[106]

In addition, there are significant structural differences between the PJM and ISO-NE markets that would make cookie-cutter application of ISO-NE's approach wholly inappropriate for RMR units in PJM. Most notably, in contrast with PJM, ISO-NE's deactivation process is integrated into its FCM. As the Commission has recognized, "[t]he ISO-NE Tariff specifies rules and procedures for existing FCM resources that seek to retire," where "a resource must submit a Retirement De-list Bid 11 months before the associated auction" – over four years before the relevant commitment period – that "specifies the minimum capacity price that a resource must receive from the FCM for it to stay in the market, rather than retire."[107] The deactivation process in PJM, on the other

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105 *Midcontinent Indep. Sys. Operator, Inc.*, 182 FERC ¶ 61,033 at P 30 (2023). *See also, e.g.*, *Cities of Bethany, Ill. v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984) (explaining that a rate can be just and reasonable even if there is another rate that would be "*more* reasonable"); *Shanker v. PJM Interconnection, L.L.C.*, 187 FERC ¶ 61,209 at P 49 (2024) (stating a finding that a new approach is just and reasonable "does not make the prior approach unjust and unreasonable as . . . both [may] be just and reasonable"); *ISO New Eng. Inc.*, 153 FERC ¶ 61,223 at P 90 (2015) ("[I]t is well-established that there can be more than one just and reasonable rate." (citing *Maine Pub. Utils. Comm'n v. FERC*, 520 F.3d 464, 470-71 (D.C. Cir. 2008), *rev'd in part on other grounds sub nom., NRG Power Mktg., LLC v. Maine Pub. Utils. Comm'n*, 558 U.S. 165 (2010); *City of Winnfield, La. v. FERC*, 744 F.2d 871, 875-76 (D.C. Cir. 1984))); *American Elec. Power Serv. Corp. v. Midwest Indep. Transmission Sys. Operator, Inc.*, 122 FERC ¶ 61,083 at P 88 (2008) (stating that "on the same set of facts there can be 'multiple just and reasonable rates'" (quoting *"Complex" Consol. Edison Co. of N.Y., Inc. v. FERC*, 165 F.3d 992, 1003 (D.C. Cir. 1999))), *on reh'g*, 125 FERC ¶ 61,341 (2008).

106 *Emera Me. v. FERC*, 854 F.3d 9, 26 (D.C. Cir. 2017) (citation omitted). *See also, e.g., Montana-Dakota Utils. Co. v. Northwestern Pub. Serv. Co.*, 341 U.S. 246, 251 (1951) (explaining that "[s]tatutory reasonableness is an abstract quality represented by an area rather than a pinpoint"); *Maine Pub. Utils. Comm'n v. FERC*, 520 F.3d 464, 471 (D.C. Cir. 2008) ("[T]here is not a single 'just and reasonable rate'" but rather a "zone of reasonableness," bounded "on one end by investor interest and [on] the other by the public interest against excessive rates." (citations omitted)), *rev'd in part on other grounds sub nom. NRG Power Mktg., LLC v. Maine Pub. Utils. Comm'n*, 558 U.S. 165 (2010).

107 *ISO New Eng. Inc.*, 164 FERC ¶ 61,003 at P 7 (2018) (footnote omitted), *on reh'g*, 173 FERC ¶ 61,205 (2020). *See also ISO-NE*, 165 FERC ¶ 61,202 at n.8 (same).

hand, exists outside the RPM market, and notices of deactivation can be submitted just three to six months before the proposed deactivation date.[108] Moreover, the RPM rules expressly allow any resource that has submitted a deactivation notice to obtain an exception to the RPM must-offer requirement.[109]

(c) CAISO

In their discussion of CAISO's approach, Complainants start by conceding that CAISO "does not administer a capacity market like those in NYISO, ISO-NE, or PJM . . . ."[110] They should have stopped there too. The question in this case is whether RMR units should be offered into a particular organized capacity market, and the approach to market participation by RMR units in an RTO/ISO that does not administer an organized capacity market has no conceivable relevance to that question.

The only "must-offer" obligations that CAISO imposes on RMR units relate to energy and ancillary services markets.[111] Recent RMR rate schedules in PJM already impose similar obligations to submit "cost-based offers of energy," albeit "with a status of 'unavailable' . . . ."[112] But taking on a Capacity must-offer obligation in PJM is an entirely

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108 *See* PJM Tariff, § 113.1 (stating that the deactivation date in the notice provided to PJM "may be no earlier than the following: (a) July 1 of the current calendar year, if the Transmission Provider receives the notice between January 1 and March 31; (b) October 1 of the current calendar year, if the Transmission Provider receives the notice between April 1 and June 30; (c) January 1 of the following calendar year, if the Transmission Provider receives the notice between July 1 and September 30; or (d) April 1 of the following calendar year, if the Transmission Provider receives the notice between October 1 and December 31").

109 *See* PJM Tariff, Attachment DD, § 6.6(g)(A).

110 Complaint at 16.

111 *See* CAISO, Fifth Replacement Electronic Tariff, Appendix G, Pro Forma Reliability Must Run Contract, § 6.1(a).

112 Settlement Indian River 4 RMR Rate Schedule, § 4.1(a). *See also* Accepted Indian River 4 RMR Rate Schedule, § 4.1(a) (same); Brandon Shores RMR Rate Schedule, § 3.5(a) (same); Wagner RMR Rate Schedule, § 3.5(a) (same).

different thing. Moreover, CAISO does not require that RMR units submit price-taker offers – of the sort Complainants would have RMR units required to make into the RPM Auctions – into the energy and ancillary services markets. Indeed, the Commission has observed that CAISO's rules "will likely mean that RMR resources are higher-cost units that run less frequently" and further that "RMR resources will have the opportunity to manage use limitations through CAISO's outage process."[113]

(d) MISO

Curiously, even as Complainants grasp at straws in regard to CAISO, they conveniently forget all about MISO, which, unlike CAISO, actually administers a capacity market. Like PJM, MISO allows owners of RMR units to choose whether to offer into its capacity market.[114] The Commission has accepted this approach, recognizing, among other things, that an RMR unit may have "operational limitations" that prevent it from "serv[ing] as a capacity resource . . . ."[115]

As discussed above, the Commission's acceptance of regional differences and the very real differences between RPM and capacity markets administered by other RTOs/ISOs make simplistic comparisons of the sort offered by Complainants unpersuasive, if not irrelevant. Nonetheless, even if this were an exercise in counting RTO/ISO noses, Complainants have miscounted. As PJM observes: "Of the four

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[113] *California Indep. Sys. Operator Corp.*, 168 FERC ¶ 61,199 at P 73 (2019).

[114] *See* MISO, FERC Electric Tariff, Attachment Y-1, Standard Form System Support Resource ("SSR") Agreement, § 8.C(4) (providing that "Participant ***may*** also offer, from the SSR Unit(s), Zonal Resource Credits into the Planning Resource Auction or include the SSR Unit(s) in a Fixed Resource Adequacy Plan pursuant to the terms of the Tariff" (emphasis added)).

[115] *Midcontinent Indep. Sys. Operator, Inc.*, 148 FERC ¶ 61,057 at P 218 (2014), *on reh'g*, 153 FERC ¶ 61,062 (2015).

RTOs/ISOs with capacity markets, two – NYISO and ISO-NE – require RMR resources to participate in their capacity markets. Two – PJM and MISO – *do not*."[116]

4. Complainants' Allegations that PJM's Existing Rule Increases the Risk of Manipulation are Baseless

The Complaint alleges that "the absence of any requirement for RMR units to participate in the capacity market renders the market more vulnerable to manipulation through withholding than similar markets in other RTOs/ISOs."[117] Complainants offer no evidence that the treatment of RMR units in RPM Auctions actually presents market power or manipulation concerns. Instead, they use the Complaint to air grievances about the lack of visibility into the analyses of deactivation requests conducted by the Independent Market Monitor for PJM (the "IMM") and to express generalized concerns about PJM's RMR regime that have little or nothing to do with the issue of whether RMR units should be subject to a Capacity must-offer requirement or otherwise accounted for in the clearing of RPM Auctions.

As Complainants acknowledge, PJM's deactivation rules provide for the IMM to review deactivation requests in order to "evaluat[e] whether a generator's deactivation constitutes an exercise of market power."[118] Nonetheless, Complainants assert that "several factors make it difficult to discern whether that process actually prevents distortion of the capacity market from RMR units' decisions not to participate."[119] But instead of providing any evidence that the IMM has missed an exercise of market power

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116 PJM Answer at 40 (emphasis in original).

117 Complaint at 43.

118 *Id.* at 46.

119 *Id.*

or manipulation, Complainants only voice dissatisfaction with the fact that the IMM's evaluation is not publicly available.[120] In addition, based on the IMM's statement that the IMM's analysis does "not consider any market power issues that could arise in connection with any PJM determination that reliable system operations may require this unit to continue operating after the retirement dates,"[121] Complainants jump to the conclusion that "the IMM does not evaluate whether an RMR unit's decision not to participate in the capacity market may qualify as an exercise of market power."[122] This misrepresents what the IMM said. In fact, as the IMM has made clear, the IMM's analysis includes "a market power study to ensure that the deactivation is economic, not an exercise of market power through withholding, and consistent with competition."[123] To date, the only "market power" concerns identified by the IMM have been unrelated to any sort of withholding scheme and instead have been directed to the IMM's concerns about full cost-of-service rates under RMR rate schedules.[124] These concerns have nothing to do with any alleged distortion of market clearing prices and instead reflect the IMM's misguided view that the RMR unit owner has "significant market power in establishing the terms of this reliability service . . . ."[125]

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[120] *See id.*

[121] *Id.* at 46 n.189.

[122] *Id.* (footnote omitted).

[123] Monitoring Analytics, LLC, *State of the Market Report for PJM: January through June*, at 360 (Aug. 8, 2024) (the "IMM Quarterly Report") (footnote omitted), https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2024/2024q2-som-pjm.pdf.

[124] *See id.* at 363 (arguing RMR units should only recover "only the incremental costs"). *See also id.* at 360-363 (discussing same).

[125] Complaint at 47 (quoting IMM Quarterly Report at 363). The notion that a regulated seller is exercising market power by seeking to charge a cost-of-service rate makes no sense when one considers that cost-of-service ratemaking was and to a large degree remains the standard

Complainants also point to statements by the IMM about the importance of enforcing the Capacity must-offer requirement.[126] But, as Complainants concede, those statements were made "in the context of objecting to must-offer exceptions to other resources than RMR units."[127] The Complaint puts forward no rationale for treating an RMR unit differently from any other resource that has submitted a deactivation request and that is, therefore, eligible for an exception to the Capacity must-offer requirement.[128] Nor does it offer any basis for treating RMR units less favorably than the resources whose must-offer exceptions were actually the target of the IMM's concern.

Similarly misleading and ultimately irrelevant is the Complaint's reliance on the IMM's proposal that Capacity Interconnection Rights ("CIRs") be surrendered upon the deactivation date, rather than a year after deactivation as the PJM Tariff provides.[129] Those statements were not directed at RMR units and instead reflected the IMM's preference that all deactivating "'resources return CIRs to the market on the day of retirement.'"[130] This statement has no bearing on the issue of how RMR units should be treated in the RPM Auctions. That said, a discriminatory rule stripping RMR units of their

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methodology for setting rates of presumed natural monopolists under the FPA and its sister statute, the Natural Gas Act. *See Incentive Ratemaking for Interstate Nat. Gas Pipelines, Oil Pipelines, & Elec. Utils.*, 58 FERC ¶ 61,287 at 61,900 (1992) (noting that the Commission has historically "used cost-of-service rate regulation as a regulatory tool for preventing pipelines and electric utilities from exercising market power"). In any case, this issue is entirely irrelevant to the question before the Commission in this proceeding: how RMR units are treated in the RPM Auctions.

126 *See* Complaint at 44. *See also* IMM Quarterly Report at 311 (stating that "[c]urrently, intermittent and storage resources are exempt from the must offer requirement, although that is not a viable long term design element for the capacity market").

127 Complaint at 44.

128 *See* PJM Tariff, Attachment DD, § 6.6(g)(A).

129 *See id.*, § 230.3.3.

130 Complaint at 44 (quoting IMM Quarterly Report at 321).

CIRs earlier than other deactivating resources would be unwise, as it would provide yet another disincentive to provide RMR service.

The closest Complainants come to alleging anything even remotely resembling an exercise of market power is to claim that the Synapse Report provides “troubling hints” of “physical withholding” in the BGE Local Deliverability Area (“LDA”) in the 2025/2026 BRA.[131] To be sure, “physical withholding” may be deemed to occur when “a multi-plant generator prematurely withdraws a unit from participation in the [capacity auction], thereby dampening supply, driving up prices, and enjoying higher returns from other plants.”[132] But even assuming *arguendo* that the decision by RMR units not to offer increased the clearing price and that “the owners of the RMR units in the BGE LDA likely earned . . . more than they would have by bidding the RMR units into the auction,”[133] that does not “hint[]”[134] at, much less demonstrate, any physical withholding. What Complainants conveniently omit from the story is that the RMR units’ owners, Brandon Shores and Wagner, are deactivating all of their resources in the BGE LDA and have no affiliates with generation in this LDA, so they derive no benefit from any increase in the BGE LDA clearing price. Any alleged incremental earnings would thus be earnings on the RMR units pursuant to the proposed RMR rate schedules – not “higher returns from other plants” resulting from having “driv[en] up prices . . . .”[135] Moreover, Complainants have not even alleged that the deactivation decisions were uneconomic.

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131 *Id.* at 45-46 (citing Synapse Report at 24, 27).

132 *Id.* (quoting *Exelon Corp. v. FERC*, 911 F.3d 1236, 1238 (D.C. Cir. 2018) (“*Exelon*”)).

133 *Id.* at 46.

134 *Id.*

135 *Exelon*, 911 F.3d at 1238.

B. Complainants' Requested Relief Would Threaten Reliability in the PJM Region

Complainants' requested relief presents a grave threat to reliability in the PJM Region, as it would both undermine RPM's ability to maintain resource adequacy and discourage resources needed for transmission reliability from accepting RMR arrangements. On the first point, the PJM Board Letter warned that "requiring participation of a deactivating unit in the capacity auction under the existing RMR agreements could distort the price signal and fail to incent the new build needed in" the PJM region.[136] While Complainants' alternative approach would not require RMR units to offer into RPM Auctions, it is designed to "lead to roughly the same RPM clearing prices,"[137] and would, therefore, have roughly the same distortive effect on price signals.[138] In both cases, the price distortion is a direct and inevitable consequence of failing to distinguish between RMR service and Capacity, which are, as discussed above in Section II.A.1, very different products.[139] In the first case, Complainants would have PJM help itself to an apple when it has only paid for an orange. In the second, they would have the Commission engage in the exercise of "subtracting apples from

[136] PJM Board Letter at 3. *See also PJM SOM Response* at 4 (explaining that the existing approach under which "RMR units typically do not participate in capacity auctions . . . help[s] ensure that RMR units do not directly influence capacity market clearing prices or artificially suppress market signals").

[137] Wilson Affidavit at ¶ 41.

[138] *See* Sotkiewicz Affidavit at ¶¶ 62-63.

[139] *See* PJM Answer at 10 ("[T]he Complaint essentially argues that PJM should count all RMR resources as capacity in the RPM Auctions even though they may not be able to or even be expected to provide resource adequacy value commensurate with their accredited levels as would be expected of a committed Capacity Resource.").

oranges" – something the courts have recognized as inadequate to satisfy the requirements of reasoned decision-making.[140]

A core purpose, if not ***the*** core purpose, of a capacity market is to "provide price signals that guide the orderly entry and exit of capacity resources . . . ."[141] Consequently, artificial price suppression is always undesirable and always threatens reliability, even in the best of times. What makes Complainants' proposal even more troubling is that these are hardly the best of times in PJM. As has been well documented in recent years and as indicated in the PJM Board Letter, PJM "is experiencing a combination of trends that have served to rapidly tighten the supply-demand balance on our system."[142] Specifically, PJM has pointed to "[t]he potential for an asymmetrical pace in the energy transition, in which resource retirements and load growth exceed the pace of new entry, underscores the need to enhance the accreditation, qualification and performance requirements of capacity resources."[143]

In the context of this potential mismatch between retirements and load growth, on the one hand, and new entry, on the other hand, and the region's related need for a

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140 *MCI Telecomms. Corp. v. FCC*, 143 F.3d 606, 608 (D.C. Cir. 1998) ("*MCI*"). *See also id.* ("If the Commission simply subtracted one quantity from another, logically independent quantity, its action was unreasoned.").

141 *ISO New Eng. Inc.*, 162 FERC ¶ 61,205 at P 21 (2018), *on reh'g*, 173 FERC ¶ 61,161 (2020), *reh'g denied*, 174 FERC ¶ 61,120 (2021). *See also, e.g.*, *ISO New Eng. Inc.*, 155 FERC ¶ 61,023, at P 35 (2016) (describing the purpose of a capacity market as "ensuring that price signals are sufficient to incent existing resources to stay in the capacity market, and new resources to enter, so that [the RTO/ISO] meets its reliability requirements at least cost") (footnote omitted), *on reh'g*, 158 FERC ¶ 61,138 (2017).

142 PJM Board Letter at 1.

143 PJM, *Energy Transition in PJM: Resource Retirements, Replacements & Risks* at 3 (Feb. 24, 2023), https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx.

"buildout of a significant quantity of new generation,"[144] PJM described the clearing prices in the 2025/2026 BRA as a "new-build investment price signal" that was "consistent with market fundamentals."[145] Yet, according to Complainants' own figures, their proposed relief would have reduced Capacity revenues from this auction by $4-5 billion dollars[146] – or approximately 27-35 percent.[147] In this regard, it is important to bear in mind that auction clearing prices convey signals not just to generation resources but to non-generation resources. Dr. Sotkiewicz notes that in bemoaning the state of PJM's generator interconnection queue, Complainants ignore other sources of supply in the form of Price Responsive Demand, Demand Resources, and intermittent resources that can and, if price signals are right, will participate in RPM Auctions.[148]

Complainants' proposal to require price-taker Capacity offers from RMR units would double-down on the reliability threat and compound a potential resource adequacy problem with unmitigated – and potentially unmitigable – transmission reliability problems. As discussed above in Section II.A.1, Capacity commitments impose significant costs and risks over and above those associated with providing RMR service. Imposing such costs and risks on a resource that, by its notice of deactivation, has already signaled an unwillingness or inability to accept them will create a powerful disincentive to

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144 PJM Board Letter at 2.

145 *Id.*

146 Complaint at 1.

147 *See* Auction Report at 3 (stating that "the total cost to load for the 2025/2026 BRA was $14.7 billion").

148 *See* Sotkiewicz Affidavit at ¶¶ 39-46.

agreeing to remain in service to address an identified transmission reliability need.[149] PJM discussed this concern in the PJM Board Letter, stating:

> [A] resource that intends to retire but is being forced to offer into the capacity market is likely to be more reluctant to agree to an RMR arrangement. This will be deleterious to maintaining system reliability. The obligations of being a capacity resource and any associated performance penalty risks may be a bridge too far for that unit owner. PJM views RMR arrangements as a last resort but a necessary action to keep units temporarily operational in order to maintain system reliability.[150]

Acknowledging the penalty risks, Complainants' witness opines that it would be "appropriate for the RMR contract to specify to what extent [Capacity Performance] penalties and incentives flow through to consumers or are partially borne by the owner in order to create performance incentives."[151] But that misses the more important point. As a general rule, owners of RMR units are required to credit market revenues against their cost-of-service revenue requirement.[152] An entity that is giving up the Capacity revenues will have no incentive to accept ***any*** penalty risk, much less to accept that risk and the other incremental burdens of providing Capacity in addition to RMR service.

Further exacerbating the reliability problem is the likelihood that the price suppression from requiring RMR units to offer into RPM Auctions will increase the pace

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[149] *See id.* at ¶ 30.

[150] PJM Board Letter at 4. *See also* PJM Answer at 11 ("Extending the rules and obligations for resources undertaking a capacity commitment to resources seeking to avoid such obligations and retire very likely would adversely affect whether the seller chooses to stay in operation or retire. In other words, encumbering resources seeking to retire with additional performance obligations would act as a disincentive for such resources to accept PJM's request and stay online.").

[151] Wilson Affidavit at ¶ 38.

[152] *See, e.g.*, Accepted Indian River 4 RMR Rate Schedule, § 6.2; Settlement Indian River 4 RMR Rate Schedule, § 6.2(a); Brandon Shores RMR Rate Schedule, § 5.5; Wagner RMR Rate Schedule, § 5.5.

of deactivations and of RMR arrangements to delay deactivation of resources needed to preserve transmission reliability. Accordingly, Dr. Sotkiewicz states that "the pattern that the [Complainants] are setting is one of chaos with extreme price volatility driven by repeated interventions into the market, or, in the alternative, continued intervention to keep prices below otherwise competitive levels that promote reliability," which, in the long-term "will only lead to even higher prices as economically viable resources are inefficiently pushed from the market."[153] In this regard, Complainants' concern that PJM will "enter into an increasing number of RMR contracts in coming years"[154] could prove to be a self-fulfilling prophecy if their Complaint is granted.[155]

C. The Complaint Does Not Provide a Vehicle for Requiring Resources with Accepted RMR Rate Schedules to Offer into RPM Auctions

As Complainants concede, a Generation Owner opting for an RMR arrangement "has a choice whether or not to offer the retained resource into the capacity market,"[156] and the specific "[RMR] arrangement [will] stipulate whether [the] unit is subject to [the Capacity] must-offer [requirement] . . . .'"[157] Such choices are reflected in the Accepted RMR Rate Schedules, none of which requires that the RMR units offer Capacity into RPM Auctions.[158] Yet, Complainants are attempting to use an FPA Section 206 complaint

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153 Sotkiewicz Affidavit at ¶ 68.

154 Complaint at 24.

155 *See* Sotkiewicz Affidavit at ¶¶ 65-68.

156 Complaint at 8 (footnote omitted).

157 *Id.* at 8 n.20 (quoting David Mroz and Tim Bachus, *Treatment of Deactivations in RPM* at slide 2 (Nov. 9, 2023), https://www.pjm.com/-/media/committees-groups/task-forces/destf/2023/20231109/20231109-item-06---treatment-of-resources-in-rpm.ashx).

158 *See* Accepted Indian River 4 RMR Rate Schedule, § 4.1(a) (stating that RMR unit "shall not be subject to any must-offer obligation in the PJM capacity market"); Settlement Indian River 4 RMR Rate Schedule, § 4.1(a) (same) Brandon Shores RMR Rate Schedule, § 3.5 (requiring

against PJM – not any or all of public utilities that filed the Accepted RMR Rate Schedules – as the vehicle to request that the Commission "require the RMR units to offer into the capacity market . . . ."[159]

Section 306 of the FPA provides that any person "***complaining of anything done or omitted to be done by any*** . . . ***public utility in contravention of the provisions of this chapter*** may apply to the Commission by petition,"[160] and similarly, Rule 206 of the Commission's Rules of Practice and Procedure provides that "[a]ny person may file a complaint seeking Commission action ***against any other person alleged to be in contravention or violation of any statute***, rule, order, or other law administered by the Commission, or for any other alleged wrong over which the Commission may have jurisdiction."[161] Because the FPA declares unjust and unreasonable rates "to be unlawful,"[162] a public utility may be the target of a complaint where its rates are alleged to be unjust and unreasonable. Indeed, Section 206 of the FPA also provides a complaint can be used to allege "any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory or preferential . . . ."[163] The problem – and it is a fatal problem to Complainants' case where the units subject to the Accepted RMR Rate Schedules are concerned – is that the rate

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Brandon Shores to submit cost-based energy offers for, and to provide reactive power from, Brandon Shores 1 & 2 but establishing no requirement to offer Capacity); Wagner RMR Rate Schedule, § 3.5 (requiring Wagner to submit cost-based energy offers for, and to provide reactive power from, Wagner 3 & 4 but establishing no requirement to offer Capacity).

[159] Complaint at 53.

[160] 16 U.S.C. § 825e (2018) (emphasis added).

[161] 18 C.F.R. § 385.206(a) (2024) (emphasis added).

[162] 16 U.S.C. § 824d(a) (2018).

[163] 16 U.S.C. § 824e(a) (2018).

practice relevant to whether the RMR units are offered into RPM Auctions is a rate practice of the public utilities that filed the Accepted RMR Rate Schedules, not of PJM.[164] As such, it is a rate practice that cannot lawfully be modified through a complaint against PJM. The FPA and the Commission's rules do not permit such a "bank-shot" complaint, whereby a complaint against one public utility is used to obtain relief against another public utility.

To make matters worse, each of the Accepted RMR Rate Schedules (except the Settlement Indian River 4 RMR Rate Schedule) provides, by its terms, that the *Mobile-Sierra*[165] public interest standard applies to proposed modifications to the rate schedule and in all but one case, it applies regardless of whether such changes are proposed by PJM, a third party or the Commission.[166] While Sierra Club objected to the *Mobile-Sierra* provisions of the Brandon Shores RMR Rate Schedule and the Wagner RMR Rate Schedule, the Commission accepted both rate schedule filings, subject to refund, without

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[164] *Cf. Southern Mont. Elec. Generation & Transmission Coop., Inc. v. NorthWestern Corp.*, 113 FERC ¶ 61,023 at P 19 (2005) (dismissing complaint as to a respondent where that complaint was "appropriately directed" against its co-respondent).

[165] The doctrine takes its name from companion decisions of the United States Supreme Court in *FPC v. Sierra Pac. Power Co.*, 350 U.S. 348 (1956) ("*Sierra*"), and *United Gas Pipe Line Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332 (1956) ("*Mobile*").

[166] *See* Accepted Indian River 4 RMR Rate Schedule, § 8.1 ("The standard of review for changes to any rate, charge, classification, term or condition of this Rate Schedule, whether proposed by PJM, any party with standing under Federal Power Act § 206, or FERC acting *sua sponte*, shall solely be the most stringent standard of review set forth in *United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 332 (1956) and *Federal Power Commission v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956) and clarified by *Morgan Stanley Capital Group, Inc. v. Public Util. Dist. No. 1 of Snohomish*, 554 U.S. 527, 128 S. Ct. 2733 (2008) and *NRG Power Marketing, LLC, et al. v. Maine Public Utilities Commission*, 558 U.S. 165, 130 S.Ct. 693 (2010)."); Brandon Shores RMR Rate Schedule, § 5.9 (same); Wagner RMR Rate Schedule, § 5.9 (same). The Settlement Indian River RMR Rate Schedule provides for "the statutory just and reasonable standard of review" to apply to challenges by persons that were not parties to the underlying proceeding or the Commission acting *sua sponte*. Settlement Indian River 4 RMR Rate Schedule, § 8.1.

addressing those objections. That being the case, the Commission cannot modify the terms of these rate schedules absent a finding that they "seriously harm[] the public interest"[167] or a determination "that the *Mobile-Sierra* framework does not apply."[168] Importantly, as the U.S. Court of Appeals for the District of Columbia recently made clear, the Commission cannot avoid *Mobile-Sierra* by pointing to requirements imposed through other tariffs or rules.[169]

Even if the Commission could entertain the Section 206 bank shot contemplated by the Complainants, it could not do so in a way that circumvented the requirements of the *Mobile-Sierra* doctrine. To do so would violate not only *Mobile-Sierra* but also the fundamental principle that "[w]hat the Commission is prohibited from doing directly it may not achieve by indirection."[170]

D. Complainants' Proposed Changes Cannot Practically or Lawfully Be Implemented for the 2026/2027 BRA

Even setting aside all the other fatal defects in the Complaint, Complainants' proposed changes cannot be implemented for the 2026/2027 BRA. Doing so would be impractical and unlawful even if the 2026/2027 BRA is delayed and associated deadlines

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167 *Morgan Stanley Cap. Grp. Inc. v. Public Util. Dist. No. 1 of Snohomish Cnty.*, 554 U.S. 527, 530 (2008). *See also, e.g.*, *In re Permian Basin Area Rate Cases*, 390 U.S. 747, 822 (1968) (explaining that the statutory scheme "contemplates abrogation of [fixed-rate] agreements only in circumstances of unequivocal public necessity" (citation omitted)); *Mobile*, 350 U.S. at 345 (finding that the Commission may only modify a contract rate that "conflict[s] with the public interest"); *Sierra*, 350 U.S. at 355 (holding that where a contractually agreed rate is involved, "the sole concern of the Commission would seem to be whether the rate . . . adversely affect[s] the public interest").

168 *Shell N. Am. (US), L.P. v. FERC*, 107 F.4th 981, 992 (D.C. Cir. 2024) (citation omitted).

169 *See id.* at 992 (rejecting claim that requirement incorporated into market-based rate tariffs to justify prices for certain sales above a soft cap "displace[d] the *Mobile-Sierra* presumption" where contracts entered into under such tariffs were involved).

170 *Richmond Power & Light v. FERC*, 574 F.2d 610, 620 (D.C. Cir. 1978) (footnote omitted).

are extended and would be a blatant violation of the filed rate doctrine if the 2026/2027 BRA is held, as scheduled, in December 2024.

1. Implementing Complainants' Proposed Changes for the 2026/2027 BRA Would Be Impractical and Unlawful

As discussed above, there are five existing generating units currently subject to RMR rate schedules on file with the Commission: Indian River 4, Brandon 1 & 2 and Wagner 3 & 4. There is no basis to assume that any, much less all, of these units will remain in service through the 2026/2027 Delivery Year.

One of these units, Indian River 4, will be deactivated during, if not before, the 2026/2027 Delivery Year, when the Indian River RMR Rate Schedule expires.[171] This unit will, therefore, be in no position to provide Capacity for the 2026/2027 Delivery Year, as recognized by the RPM must-offer exception where a Capacity Market Seller has "a documented plan in place to retire the resource prior to ***or during*** the Delivery Year . . . ."[172]

As for Brandon 1 & 2 and Wagner 3 & 4, it would be entirely speculative to assume that any or all of these units will be in service during the 2026/2027 Delivery Year.[173] To be sure, Brandon, Wagner and their upstream owner, Talen Energy Corporation, have

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171 The delivery term under the Indian River RMR Rate Schedule is scheduled to end on December 31, 2026. *See* Accepted Indian River RMR Rate Schedule, § 2.2; Settlement Indian River RMR Rate Schedule, § 2.2. The Indian River RMR Rate Schedule provides for early termination of the delivery term if PJM determines that it no longer requires RMR service from Indian River 4.

172 PJM Tariff, Attachment DD, § 6.6(g)(A) (emphasis added).

173 PJM explains that, "[c]entral to the Complaint is the claim PJM should have considered Brandon Shores and Wagner as capacity," but that "it is unclear whether either resource may actually be in operation after December 31, 2025." PJM Answer at 26 (footnote omitted). Among other things, PJM points out that "Sierra Club and Talen [Energy Corporation] currently have an agreement in place that prohibits Brandon Shores from burning coal—its only fuel source—after December 31, 2025." *Id.* at 31.

committed "to work with the Commission and all stakeholders to keep [the units] available to run."[174] But that is a far cry from a binding commitment to continue operating Brandon Shores 1 & 2 and Wagner 3 & 4 under any and all circumstances. Indeed, they have made it quite clear that they "should not be asked to do so without fully recovering all costs, the investments needed to maintain the plants, and a fair return of and on equity"[175] and have emphasized their need for "maximum certainty as soon as possible . . . ."[176] They have also indicated that their decision about continuing to operate "will be informed by the Commission's actions in this proceeding."[177] That being the case, these units are, for purposes of the 2026/2027 BRA, similarly situated to, if not indistinguishable from, other units with documented plans to deactivate before or during the 2026/2027 Delivery Year and to treat them differently by denying them must-offer exceptions would violate the FPA's prohibition against undue discrimination.[178]

An assumption that Brandon Shores 1 & 2 can be required or assumed to provide Capacity during the 2026/2027 Delivery Year would also be unreasonable in light of Brandon Shores' binding agreement with the lead Complainant, Sierra Club, to stop burning coal at these coal-fired units by the end of 2025.[179] It is all well and good that

[174] Brandon Shores RMR Filing, Transmittal Letter at 3; Wagner RMR Filing, Transmittal Letter at 3.

[175] Brandon Shores RMR Filing, Transmittal Letter at 3; Wagner RMR Filing, Transmittal Letter at 3.

[176] Brandon Shores RMR Filing, Transmittal Letter at 19; Wagner RMR Filing, Transmittal Letter at 19.

[177] Talen Protest at 3.

[178] *See* 16 U.S.C. § 824d(b) (2018). *See also Consolidated Edison Co. of N.Y. v. FERC*, 45 F.4th 265, 271 (D.C. Cir. 2022) (""[U]ndue discrimination occurs [where] entities [that] are similarly situated' are charged different rates for no discernable reason." (quoting *Missouri River Energy Servs. v. FERC*, 918 F.3d 954, 958 (D.C. Cir. 2019))).

[179] *See* Talen Protest at 8; PJM Answer at 9-10.

Sierra Club "remains willing to negotiate to reach reasonable terms regarding continued coal combustion under an RMR arrangement."[180] But that does not alter the fact that as matters stand today, Brandon Shores 1 & 2 are barred by the agreement with Sierra Club from operating even as RMR units during the 2026/2027 Delivery Year.[181] Nor does it temper the irony that having succeeded in getting Brandon Shores 1 & 2 shut down, Sierra Club now complains about the natural and inevitable consequences of that success.[182]

2. Implementing Complainants' Proposed Changes for the 2026/2027 BRA in December 2024 Would Violate the Filed Rate Doctrine and Otherwise Be Unlawful

PJM has proposed to delay the 2026/2027 BRA to June 2025 and has also proposed a new schedule for this and the subsequent two Base Residual Auctions.[183] Nonetheless, the auction schedule currently in effect still has the auction window opening on December 4, 2024, with no opportunity for market participants to change elections made under deadlines that already have passed under the current schedule.[184] Implementing Complainants' proposed changes for the 2026/2027 BRA on the current schedule would violate the filed rate doctrine just as surely as the orders allowing after-

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180 Complaint, Attachment 4, Declaration of Justin Vickers at ¶ 6.

181 That Sierra Club's remedy for a breach of this agreement would be "to renew its efforts to enforce certain environmental laws at Talen's facilities," *id.* at ¶ 9, hardly justifies a contrary assumption.

182 *See* PJM Answer at 4 ("Ironically, the circumstances which currently prevent PJM from relying on Brandon Shores during the 2026/2027 Delivery Year are caused by the very agreement that one of the Complainants, the Sierra Club, insisted on as part of its agreement with Talen.").

183 *See* EL24-148 PJM Motion, Attachment A; ER25-118 Waiver Request, Attachment A. Under this schedule, requests for deactivation-related must-offer exception requests will be due 120 days before the auction window opens, and PJM will post auction planning parameters 100 days before the auction window opens. *See* EL24-148 PJM Motion, Attachment A at 3; ER25-118 Waiver Request, Attachment A at 3.

184 *See* PJM, Auction Schedule ("RPM Schedule"), https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/rpm-auction-schedule.ashx.

the-fact adjustments to the DPL South LDA Reliability Requirements that were vacated by the U.S. Court of Appeals for the Third Circuit (the "Third Circuit") in *PJM Power Providers Group v. FERC*.[185] While Complainants emphasize the frustration expressed by the three then-sitting commissioners with their "inability to redress inequities"[186] in the aftermath of that decision, they overlook the fact that none of the commissioners dissented to the remand order.[187] Instead, all three commissioners accepted that, as Chairman Phillips put it, the Third Circuit "has spoken and, as always, the Commission will adhere to that ruling."[188]

Just like the orders vacated in *PJM Power*, an order implementing Complainants' proposals for the 2026/2027 BRA in December 2024 would violate the filed rate doctrine by "alter[ing] the legal consequences attached to past actions."[189] Complainants' primary remedy, requiring that RMR units offer into RPM Auctions, would do so by failing to account for any number of critical pre-auction deadlines that have passed.[190] These include the deadline for a Capacity Market Seller with a documented plan to deactivate a unit to request an exception to the Capacity must-offer requirement (July 22, 2024) and

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185 96 F.4th 390 (3d Cir. 2024) ("*PJM Power*").

186 Complaint at 51.

187 *See PJM Interconnection, L.L.C.*, 187 FERC ¶ 61,065, *on reh'g*, 187 FERC ¶ 61,107 (2024).

188 *Id.*, Statement of Chairman Phillips at P 2. *See also id.*, Statement of Commissioner Clements at P 1 (noting the Third Circuit's decision and stating that "we are now compelled to follow that decision"); *id.*, Statement of Commissioner Christie at P 1 (noting the Third Circuit's decision and stating that reversing its earlier orders was "the only realistic alternative at this point in the process" (footnote omitted)).

189 *PJM Power*, 96 F.4th at 400.

190 *See* RPM Schedule, Tab 26-27 BRA Post.

the deadline for PJM to act on any such request (September 30, 2024).[191] As noted above, such an exception is available regardless of whether the Capacity Market Seller has agreed "to continue to operate the resource beyond its desired deactivation date . . . for the purpose of maintaining the reliability of the PJM Transmission System and the Capacity Market Seller has agreed to do so . . . ."[192] Forcing a unit that has obtained a must-offer exception to offer into the 2026/2027 BRA under the current schedule would clearly "alter[] a legal consequence that attached to a past action in the Auction,"[193] and thereby violate the filed rate doctrine.

Implementing Complainants' alternative proposal for a 2026/2027 BRA held in December 2024 would be equally (and even more obviously) problematic under *PJM Power*. As described by their expert, this approach would involve "the RMR unit's contribution to resource adequacy . . . be[ing] modeled within the resource adequacy analysis that determines the locational . . . Reliability Requirements that will be acquired through RPM."[194] Under the auction schedule currently in effect, PJM was required to post and posted the auction planning parameters, including the Reliability Requirements, for the 2026/2027 BRA on August 26, 2024.[195] Tinkering with the LDA Reliability Requirements just weeks before the offer window opens would almost perfectly replicate the legal error identified in *PJM Power*, where the Third Circuit found the rate change

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191 *See id.*

192 PJM Tariff, Attachment DD, § 6.6(g)(A).

193 *PJM Power*, 96 F.4th at 401.

194 Wilson Affidavit at ¶ 39.

195 *See* PJM, 2026/2027 *RPM Base Residual Auction Planning Period Parameters* (Aug. 26, 2024), https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-planning-period-parameters-for-base-residual-auction-pdf.ashx.

"retroactive because it altered the legal consequence attached to a past action when it allowed PJM to use a different LDA Reliability Requirement than the one it had calculated and posted."[196]

III. CONCLUSION

Wherefore, EPSA respectfully requests that the Commission deny the Complaint.

Respectfully submitted,

ELECTRIC POWER SUPPLY ASSOCIATION

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On behalf of the
Electric Power Supply Association

Dated: October 24, 2024

196 *PJM Power*, 96 F.4th at 399.

CERTIFICATE OF SERVICE

I hereby certify that I have this day electronically served the foregoing document on each person designated on the official service list compiled by the Secretary of the Federal Energy Regulatory Commission in this proceeding.

Dated at Washington, D.C., this 24^{th} day of October 2024

/s/ *David G. Tewksbury*
David G. Tewksbury

Attachment A

The Sotkiewicz Affidavit

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Sierra Club, *et al.*,	)	
	)	
Complainants,	)	
	)	
v.	)	
	)	**Docket No. EL24-148-000**
PJM Interconnection, L.L.C.,	)	
	)	
Respondent.	)	
	)	
	)	

AFFIDAVIT OF PAUL M. SOTKIEWICZ, PH.D.
ON BEHALF OF ELECTRIC POWER SUPPLY ASSOCIATION

I. INTRODUCTION

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 retained by the Electric Power Supply Association ("EPSA") to submit this affidavit in support of its response to the complaint of Sierra Club, Natural Resources Defense Council, Public Citizen, Sustainable FERC Project and the Union of Concerned Scientists ("PIOs") regarding the treatment of deactivating resources retained under Part V of PJM's Open Access Transmission Tariff ("PJM OATT" or "Tariff") in the PJM Reliability Pricing Model ("RPM") Capacity Market.

2. As the former Chief Economist at PJM, I have firsthand knowledge of the purpose behind Part V of the PJM OATT, and the treatment of deactivating resources under Part V relative to the operation of PJM's Energy and RPM Capacity Markets. First, Part V of PJM's Tariff

allows for the retention of deactivating resources under what has colloquially become known as a reliability must run ("RMR") agreement ***only*** for providing transmission security and ensuring there are no NERC reliability criteria violations on the PJM operated transmission system.

3. Second, PJM's historic and current treatment of deactivating resources operating under RMR agreements under Part V is designed to avoid undermining and distorting PJM's markets in ways that could lead to inefficient deactivation decisions and/or delay needed new entry of supply resources in the future. Resources operating under RMR agreements are only used when needed for transmission security and are not a part of PJM's Energy or RPM Capacity Markets. ***Thus, RMR agreements are an operational tool that allow resources to remain online to act as transmission assets*** available to PJM until such time as transmission reinforcements are completed and deactivating resources receiving RMR treatment are no longer needed under Part V.

4. Following the statement of my qualifications in Section II, the remainder of my affidavit is organized as follows. Section III explains that, under Part V of the PJM Tariff, transmission system reliability is the predicate for initiating an RMR agreement and that RMR units are at their core transmission assets and effectively no longer generating assets.

5. Section IV discusses why deactivating resources retained under RMR agreements are treated as transmission assets.

6. Section V explains why the terms and conditions of RMR agreements allowing RMR units to be operated during so-called capacity emergencies cannot and do not imply that RMR units are Capacity Resources in the sense of RPM committed capacity.

7. Section VI debunks the notion that if consumers are paying for RMR service and the RMR

units are not required or assumed to provide capacity, then they are paying twice for capacity. In short, consumers are only paying for transmission through the RMR agreements and must separately procure and pay for capacity as the RMR units are not RPM committed resources and do not have the same obligations nor risks as RPM committed resources. Section VI also shows that the PIOs' proposed remedies are economically inefficient and erodes reliability over time as those remedies prevent the RPM Capacity Market from retaining existing resources that are otherwise economic as RPM has done in the past.

II. QUALIFICATIONS

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

9. I have over 25 years of experience in 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. As an economist at FERC, I worked on market design issues and filings related to the newly formed independent system operator/regional transmission organization ("RTO") markets concentrating primarily on the New York Independent System Operator, Inc. and the California Independent System Operator Corporation markets.

10. More details on my experience and work history can be found in my CV attached as Attachment 1.

III. TRANSMISSION SYSTEM IMPACTS ALONE ARE THE RELIABILITY PREDICATE UNDER PART V OF THE TARIFF

11. Part V, Section 113 of the PJM Tariff requires any generation resource that wishes to deactivate to provide notice to PJM. PJM, as the Transmission Provider will then conduct a study to assess "whether the Deactivation of the generating unit would adversely affect the reliability of the Transmission System[.]"[1]

12. It cannot be emphasized enough that the reliability predicate under Part V is related to the "Transmission System" and is not related to resource adequacy, meeting PJM's Installed Reserve Margin, effects on PJM's Energy and RPM Capacity Market, or even deficiencies related to the provision of energy or operating reserves.

13. Section 113.2 of the PJM Tariff goes on to state clearly, "In the event the Transmission Provider determines that, in accordance with established reliability criteria, the ***Deactivation of the Generation Owner's generating unit would adversely affect the reliability of the Transmission System absent upgrades to the Transmission System***, the

[1] PJM OATT Part V, Section 113.2.

Notice of Reliability Impact shall notify the Generation Owner, or its Designated Agent, of the reliability concerns."[2] Unequivocally, the issue at hand is the reliability effect solely upon the PJM Transmission System.

14. The Generation Owner of a deactivating resource is not required to keep the resource in service even when deactivation would have Transmission System reliability impacts, but such Generation Owner may elect to remain in service "***during the period of construction of the Transmission System reliability upgrades*** necessary to alleviate the reliability impact resulting from the Deactivation of the generating unit[.]"[3] Again, the reliability solution for the deactivation of the generation resource is transmission, not the construction or operation of another supply-side resource.

15. If a deactivating Generation Resource chooses to remain in service while Transmission System reliability upgrades are being constructed, "the Generation Owner shall immediately be entitled to file with the Commission a cost of service rate to recover the entire cost of operating the generating unit until such time as the generating unit is deactivated pursuant to this Part V ("Cost of Service Recovery Rate")"[4] in the same manner a Transmission Owner would be allowed to file for cost recovery for Transmission System assets it builds under its respective Attachment H portion of the PJM Tariff.[5]

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[2] *Id*. (emphasis added)

[3] *Id*. (emphasis added)

[4] *Id*. Filing of this Cost of Service Recovery Rate is covered under Section 119 of Part V. In the alternative a Generation Owner may elect a Deactivation Avoidable Cost Rate under Sections 115, 116, 117, 118, 118A, and 119 of Part V of the PJM OATT.

[5] For example, *see* PJM OATT, Attachment H-2 Annual Transmission Rates – Baltimore Gas and Electric Company Zone for Network Integration Transmission Service and associated Attachments H2-A, Part 1, Part 1b, and Part 2, and Attachment H2-B.

16. Taken in its totality, from the reasons to request the Generation Owner of a deactivating resource to remain in service for the reliability of the PJM Transmission System until a Transmission System reliability upgrade can be placed into service, to entitlement to file for a cost of service rate just like Transmission Owners are allowed, it is clear that any deactivating resource is not treated as a Generation Resource participating in PJM's markets, and is instead treated like a part of the PJM Transmission System.

IV. THE TERMS AND CONDITIONS OF RMR AGREEMENTS TREAT DEACTIVATING GENERATION RESOURCES RETAINED FOR TRANSMISSION SYSTEM RELIABILITY AS TRANSMISSION ASSETS FOR OPERATIONAL PURPOSES

17. The PIOs cite various RMR agreements that have been filed with the Commission with the following terms and conditions such as those included in the Brandon Shores RMR filing and the almost identical H.A. Wagner and Indian River 4 RMR agreement filings:

> PJM may schedule and dispatch either or both Units solely to address (i) an identified transmission reliability need in support of the requirement to operate such transmission facilities within established thermal, voltage and stability limits under Sections 2 and 3 of PJM Manual 3 and when such transmission reliability needs cannot otherwise be met with available economically dispatched generating resources; (ii) a PJM transmission reliability need caused by a system restoration need as described in PJM Manual 36.[6]

18. Furthermore, for the Brandon Shores and H.A. Wagner units that are the main target of the PIOs' complaint, the terms and conditions offered explicitly take Brandon Shores and H.A. Wagner out of the PJM Energy Market in Section 3.5 (a)-(c):

> [H.A. Wagner or Brandon Shores] will submit cost-based offers of

[6] PIO Attachment 6 at 6-7. *See also* Docket No. ER24-1790-000, *Brandon Shores, LLC*, RMR Arrangement Continuing Operations Rate Schedule, Request for Expedited Consideration, April 18, 2024, Section 3.3(a). Identical provisions are also found in PIO Attachment 6, at 6-21 for H.A. Wagner, Docket No. ER24-1787-000, *H.A. Wagner LLC*, RMR Arrangement Continuing Operations Rate Schedule, Request for Expedited Consideration, April 18, 2024, Section 3.3(a), PIO Attachment 6, at 6-32 for Indian River 4, Docket No. ER22-1539-002, *NRG Business Marketing LLC*, Settlement Agreement and Offer of Settlement, April 2, 2024 Section 3.3(a),

> energy from the Units in the PJM Interchange Energy Market in accordance with PJM Operating Agreement, Schedule 2 and PJM Manual 15. ***The Units will be offered with a status of 'unavailable' in the PJM Interchange Energy Market but will be available to be scheduled pursuant to Section 3.3.***[7]
>
> Except when the Units are unavailable due to an Outage, the Units may be offered based on its cost-based schedule into the Synchronized Reserve market when the Units are otherwise scheduled or dispatched for reliability.
>
> Except when the Units are unavailable due to an Outage, the Units will, when otherwise scheduled or dispatched for reliability, provide reactive power consistent with the available capability of the Unit and voltage schedules provided for in the relevant interconnection agreement.

19. These terms make clear that neither Brandon Shores nor H.A. Wagner are available for economic dispatch in the PJM Energy Market and thus are being only run with respect to there being transmission-related needs. Moreover, there is nothing in either of the Brandon Shores or H.A. Wagner RMR agreements that specifies these resources are to be made available in any way to the RPM Capacity Market. Under the Indian River 4 RMR, it is explicitly stated, "Unit 4 shall not be subject to any must-offer obligation in the PJM capacity market"[8] in addition to being unavailable to the PJM Energy Market.

20. Such terms and conditions for RMR Resources not to be included in the market are not new. In 2010, the RMR agreements for Eddystone Unit 2 and Cromby Unit 2 explicitly took these units out of all PJM markets,[9] and further in the Attachment C to the RMR agreement under operating procedures, Eddystone 2 and Cromby 2 would only be run for

[7] PIO Attachment 6 at 6-9 to 6-10, 6-23 to 6-24.

[8] PIO Attachment 6 at 6-33 (Section 4.1(a) of RMR agreement).

[9] PIO Attachment 6 at 6-74 (Section 4.1(a) and (b) of RMR agreement). *See also* Attachment C Operating Procedures 2b and 2c, PIO Attachment 6 at 6-79.

Transmission System reliability issues.[10]

21. In short, the terms and conditions of these RMR agreements are clear. The purpose of such arrangements is to support the reliability of the transmission system and not to participate in PJM's markets or to support resource adequacy. In fact, the terms and conditions of being outside the PJM markets are economically consistent with the idea that these deactivating resources were no longer economic, and, absent the transmission reliability needs, would no longer be in operation and be available to PJM's markets.

V. TERMS AND CONDITIONS ALLOWING PJM TO COMMIT AND DISPATCH RESOURCES FOR CAPACITY EMERGENCIES DO NOT MAKE RESOURCES OPERATING UNDER RMR AGREEMENTS CAPACITY RESOURCES IN RPM

22. PJM does not have an explicit or formal definition for "capacity emergency." Given the language of PJM Manual 13, a capacity emergency may entail situations where PJM is deficient operating reserves, may recall off-system sales from Capacity Resources, or may request purchases of emergency energy from outside the PJM Control Area.[11]

23. PJM does however generically define "Emergency" as follows:

> "Emergency" shall mean (i) an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm load, ***equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system*** or the safety of persons or property; or (ii) a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or (iii) a condition that requires implementation of emergency procedures as defined in the PJM Manuals.[12]

Thus, an Emergency not only encompasses the threat of a loss of load, but also issues

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[10] Attachment C Operating Procedures 2b and 2c, PIO Attachment 6 at 6-80.

[11] PJM Manual 13: Emergency Operations Revision: 93 Effective Date: July 25, 2024, available at https://www.pjm.com/-/media/documents/manuals/m13.ashx ("PJM Manual 13"), Section 2.1 at 16.

[12] Reliability Assurance Agreement Among Load Serving Entities in the PJM Region ("RAA"), Article 1 -- Definitions (Emphasis added).

affecting transmission assets such as equipment damage or tripping of system elements. An Emergency therefore also includes issues related to Transmission System elements and reliability.

A. <u>PIOs Misunderstand the Implications of "Capacity Emergency" for the Operation of Deactivating Resources Retained under RMR Agreements</u>

24. The PIOs tenuously grab onto one specific term and condition within a subset of the RMR agreements and PJM presentations that have RMR units operate when there is "a capacity emergency (as described in PJM Manual 13) during which PJM determines that the resources scheduled for an operating day are not sufficient to maintain the appropriate reserve levels for PJM." As noted above, there is no formal definition of a "capacity emergency" but certainly an Emergency, which is defined, encompasses transmission as well as generation.

25. PJM has a number of ways of addressing a "capacity emergency" but that does not mean that any and all resources that may help alleviate the emergency can or should be equated to a Capacity Resource.

26. For example, PJM often relies on Energy Resources in emergencies, but such resources are, by definition, not Capacity Resources.[13] Indeed, an Energy Resource cannot participate in the RPM Capacity Market because it does not have Capacity Interconnection Rights ("CIRs").[14] There are also resources that have CIRs but that do not have capacity

[13] Section 1 of the PJM OATT defines "Energy Resource" as "a Generating Facility that is not a Capacity Resource."

[14] PJM OATT Attachment O – Form of Interconnection Service Agreement, Section 2.1, "{Instructions: this section will not apply if the Customer Facility is exclusively an Energy Resource and thus is granted no CIRs; see alternate section 2.1 below} and Section 2.1a, "To the extent that any portion of the Customer Facility described in section 1.0 is not a Capacity Resource with Capacity Interconnection Rights, such portion of the Customer Facility shall be an Energy Resource."

commitments. These include resources without must-offer obligations and resources whose capacity did not clear in a PJM capacity auction. PJM can also ask these resources to provide energy to alleviate any Emergency, yet these are not required to participate in RPM. Similarly, PJM can make off-system energy purchases. Here, again, you have resources that are helping alleviate an emergency but that are not participants in RPM.[15] Finally, and perhaps most significantly considering the role of RMR units, PJM can recall certain transmission assets from outage to help alleviate an Emergency condition. But it would obviously be absurd to characterize transmission assets as Capacity Resources, just as it is absurd to say that PJM's ability to call an RMR unit during a capacity emergency makes it a Capacity Resource. In this sense, generating resources operating under RMR agreements as elements of the Transmission System, are no different than other transmission assets that must be recalled into service from scheduled outages.

27. The truth is that there are any number of assets other than Capacity Resources that PJM may turn to during a "capacity emergency" or other Emergency, but that does not transform any or all of those assets, including RMR units, into Capacity Resources. Yet, the PIOs only ask the Commission, in an irrational and discriminatory fashion, to find resources retained under RMR agreements for Transmission System reliability needs alone be included in RPM.

B. <u>RPM Committed Resources Have Obligations that Transmission Assets and Units under RMR Agreements Do Not</u>

28. Resources with RPM Capacity Commitments face the obligation to perform when called

[15] PJM Manual 13, Section 2.1 at 16-17.

upon, and otherwise face penalties under the Capacity Performance construct.[16] Transmission owners face no such obligation or penalty risk should a transmission facility unexpectedly trip out of service. RMR units, operating as transmission assets, also do not have explicit guarantees to perform,[17] and thus are not subject to any performance penalties just as transmission assets are not.

29. As noted previously, the terms and conditions in the Brandon Shores, H.A. Wagner and Indian River 4 RMR agreements do not make those RMR units available for economic dispatch. In contrast, all RPM committed resources do have must offer obligations to be available to PJM for economic dispatch in the PJM Energy Market.[18] RPM Committed Resources with a must offer requirement into the Day-ahead Energy Market take on real-time risk if their resources do not perform in real-time and would need to settle the difference between Day-ahead commitments and real-time performance at real-time prices. In contrast, transmission does not face any settlement between Day-ahead and real-time prices at all with or without tripping out of service. RMR units face the same conditions as other transmission assets.

30. The PIOs are essentially asking the Commission to subject RMR units, which are operating as transmission assets, to risks that are not borne by Transmission Owners and their assets. Moreover, the idea that RMR units could be subject to such risks and penalties will only increase the cost of providing the necessary transmission service, and with this risk, possibly increase the costs of RMR agreements under a cost-of-service rate and increase

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[16] PJM OATT, Attachment DD, Section 10A.

[17] *Id.* An examination of the PJM OATT nowhere mentions any penalties for transmission owners and their assets if they happen to be unavailable or trip out of service during performance events.

[18] PJM OATT, Attachment K – Appendix Section 1.10.4.

the cost to consumers of meeting the transmission reliability needs as these costs would flow through to transmission customers. Moreover, subjecting RMR units to those risks and penalties will increase the likelihood that the generation owner elects to not accept an RMR agreement and instead proceeds with the deactivation, as planned.

VI. IT IS JUST AND REASONABLE FOR DEACTIVATING RESOURCES UNDER RMR AGREEMENTS TO BE EXEMPTED FROM PJM'S RPM CAPACITY MARKET

A. Consumers Do Not Pay Twice for Capacity under RMR Agreements

31. As has been established above, RMR resources provide transmission service and are not providing capacity in the sense of the RPM Capacity Market and thus are properly excluded from the RPM Capacity Market. A useful thought-experiment makes this point clear.

32. The owner of a resource operating under an RMR agreement has already made plain its desire to deactivate and permanently exit the PJM Markets. However, a substitute for transmission service is required from the RMR resource to ensure reliability of the Transmission System until such time as additional transmission upgrades are in service that would permanently address the transmission reliability issue. In this end state, the supply side in the RPM Capacity Market does not include the resource operating under an RMR agreement.

33. Now imagine that the new transmission upgrades required can be built "overnight," albeit at an additional cost, in effect allowing the resource to deactivate as planned. For example, Brandon Shores and H.A. Wagner would deactivate on June 1, 2025, as planned. In concept, the additional cost to expedite the upgrades is akin to the payments by customers under RMR agreement. If PJM were to pay that additional cost, however, nobody would claim that customers were "paying twice for capacity" since those transmission upgrades are not participants in PJM's markets.

34. Both the "overnight" transmission upgrades and the RMR agreement will impact the RPM Capacity Market indirectly through the Capacity Emergency Transfer Limit ("CETL"). Apart from any differences in the CETL, the impact of the transmission upgrades and the deactivating unit under an RMR agreement on the RPM Auction outcomes would the same. If, for instance, the transmission upgrades that will eliminate the need for Brandon Shores and H.A. Wagner could have been completed "overnight," the 2025/2026 BRA outcomes would have been the same, except to the extent the transmission upgrades had a different impact on CETL. Yet, there would be no question of "consumers paying twice for capacity" with the June 1, 2025 deactivation of Brandon Shores and H.A. Wagner in the "overnight" upgrade scenario. Logically, there should also be no such question in the real-life scenario, where Brandon Shores and H.A. Wagner were retained under RMR agreements for the narrow purpose of acting as a substitute for that "overnight" upgrade.

35. Another alternative is to consider Brandon Shores and H.A. Wagner retiring as they initially requested and as they are permitted to do under Part V. In this hypothetical, when Brandon Shores and H.A. Wagner retire, there will be a period in which the CETL is reduced by the amount of transmission capability they provided when in service until the new transmission upgrades are in service.

36. With the CETL reduced due to the deactivations, the BGE Locational Deliverability Area ("LDA") price would have still hit the cap as it did in the 2025/2026 BRA, but the BGE LDA would be less reliable as the amount of capacity that could be "cleared" has been reduced by the decrease in the CETL due to the hypothetical immediate retirements of Brandon Shores and H.A. Wagner by June 1, 2025.

37. In fact, PJM has stated as recently as October 17, 2024 at the Deactivation Enhancements Senior Task Force meeting that, absent the modeling of the Brandon Shores and H.A. Wagner resources, PJM's transmission models would be unable to even determine a CETL for the BGE LDA. This admission by PJM is just one more confirmation that retaining Brandon Shores and H.A. Wagner under RMR agreements is solely for transmission and has nothing to do with these resources being retained or needed for resource adequacy.

38. What PIOs seek to obscure through their allegations of "paying twice" is that they are seeking to double-count the capacity available to the BGE LDA (and effectively to the entire PJM RPM Capacity Market), first by rightfully including the increased CETL Brandon Shores and H.A. Wagner provide to bring imports into the BGE LDA, and second by wrongfully including the physical assets of Brandons Shores and H.A. Wagner when all they are doing is providing transmission service under the RMR agreements. The PIOs then wish to use this double counting of capacity to artificially, and anti-competitively reduce prices below the competitive levels in a tight market.

B. <u>The PIOs Ignore the Necessity of Price Signals to Address Resource Adequacy Issues</u>

39. The PIOs lament, "The clogged state of PJM's interconnection queue, and the slow pace of its interconnection studies, create a significant risk that new generation may not come online quickly enough to prevent reliability issues associated with the large scale of expected retirements."[19] But the PIOs ignore other sources of supply that could be immediately available in the form of Price Responsive Demand ("PRD"), Demand Resources ("DR"), and variable and intermittent resources such as wind and solar that are

[19] PIO at 25.

already in service, but that heretofore may not have had adequate incentive to participate in the RPM Capacity Market. However, markets are dynamic and innovative, and the recent 2025/2026 BRA clearing price will give these resources more incentive to offer into future auctions.

40. Prior to the 2025/2026 BRA, RTO prices were at their lowest three-year span in its history starting with the 2007/2008 Delivery Year. During this period, there was a small drop-off in the amount of DR that cleared[20] and the amount of DR participation.[21] Yet, the amount of participating DR was as high as 19,243 MW ICAP ten years ago in the 2015/2016 BRA.[22] Under the ELCC values of 74 percent for DR for the 2026/2027 Delivery Year, the amount of potential DR that could participate in the BRA is up to 14,240 MW Accredited UCAP ("AUCAP"), or nearly 7,900 MW AUCAP more DR than participated in the 2025/2026 BRA, if participation levels are the same as 10 years ago.[23]

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[20] PJM Interconnection, L.L.C., "Commitments by Fuel Type and Delivery Year" available at https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/rpm-commitment-by-fuel-type-by-dy.ashx ("RPM Commitment Report"). DR cleared went from 8,903 to 8,631, to 8,173 MW UCAP in the 2022/2023, 2023/2024, and 2024/2025 BRAs respectively.

[21] RPM Commitment Report and PJM Interconnection, L.L.C., "2024/2025 RPM Base Residual Auction Results," available at https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2024-2025/2024-2025-base-residual-auction-report.ashx ("24/25 BRA Report"), showing in ICAP terms 9,678, 9,282, and 9,321 MW ICAP in the 2022/2023, 2023/2024, and 2024/2025 BRAs respectively.

[22] 2024/2025 BRA Report at 10, Table 5. It is important to note that DR in this BRA included shorter terms resources such as Limited Summer and Extended Summer DR. There is no reason to believe 10 years later that this form of DR could not be converted to Annual DR that exists today and participate in the market if DR could receive prices that were commensurate with giving up consumption that is highly valued. The differentiation of DR has since been discontinued (*see* 146 FERC ¶ 61,052, January 30, 2014). If one looks at the last BRA run three years prior to delivery (2012/2022), there were 10,992 MW ICAP of DR offered. If one takes this value and multiplies by the 0.74 value for Demand Resources (*see infra* note 24) there is 8,134 MW AUCAP of DR, which is still nearly 1800 MW AUCAP more than was offered in the 2025/2026 BRA.

[23] PJM Interconnection, L.L.C., "ELCC Class Ratings for the 2026/2027 Base Residual Auction." available at https://www.pjm.com/-/media/planning/res-adeq/elcc/2026-27-bra-elcc-class-ratings.ashx. Take the ICAP and multiply by 0.74 for DR.

41. Furthermore, as indicated by the Independent Market Monitor ("IMM") as of June 30, 2024, there is 10,289 MW ICAP of solar which translates to 1,337 MW AUCAP of solar that can participate in the market.[24]

42. There is also 12,072 MW ICAP of wind in service as of June 30, 2024 that translates to 4,104 MW AUCAP available to offer for the 2026/2027 BRA.[25] If all this available wind offered, this would be an addition of nearly 1,500 MW AUCAP over what was offered in 2025/2026, and nearly 2,500 MW AUCAP of potential wind resources that may clear at prices higher than those observed in the 2025/2026 BRA.[26]

43. In short, there are over 10,000 MW AUCAP (7,900 MW of potential DR and 2,500 MW of potential wind resources) capacity that could possibly offer into and clear in the 2026/2027 and future Delivery Year BRAs in response to the direction of prices shown in the 2025/2026 BRA.[27]

44. It would not be surprising or inefficient for prices to rise above those observed in the 2025/2026 BRA to attract these potentially immediately available resources. For DR, there is a value associated with consuming energy, especially at peak times. This value of consuming energy can be quite high reflecting the lost opportunities for industrial customers to deliver products to their respective markets, or costs with interrupting production processes that can waste time and materials that otherwise cannot be recovered

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[24] *Id.* Multiply ICAP by 0.13 for tracking solar.

[25] *Id.* Multiply ICAP by 0.34 for onshore wind.

[26] *See* RMP Commitment Report. In the 2025/2026 BRA 2,618 MW AUCAP of wind offered, and only 1,676 MW AUCAP of wind cleared.

[27] *See* RMP Commitment Report. There appears to be no additional existing solar available to offer into the 2026/2027 BRA as 1,337 MW AUCAP of solar offered and cleared and this exactly matches the values in P 41.

from their respective customers. By revealed preference this has been shown in previous BRAs where there was a significant amount of DR offered but not cleared.[28]

45. For wind and solar resources, these are variable and intermittent resources that cannot control their output in response to an Emergency that would force PJM to declare a Performance Assessment Interval ("PAI"), thereby subjecting the owners of such resources to penalties for non-performance. Variable and intermittent resources must therefore factor in their risk of non-performance into their offers for the RPM Capacity Market. These resources would only clear at prices that are sufficient to mitigate their assessment of performance risk.

46. In short, to attract resources that are immediately available, prices will need to reflect their value of energy consumption (DR) and risks of taking on a capacity obligation (wind and solar), and thus the 2025/2026 BRA results are sending the right price signals to attract these resources to the market to maintain resource adequacy in RPM.

C. Higher Prices in RPM Help Retain Existing Resources that May be at Risk for Retirement

47. The RPM Capacity Market not only is designed to attract new resources, but to also retain existing resources that are economic. At the time of the start of the RPM Capacity Market, PJM was facing a potential shortfall of capacity in transmission constrained areas, which was one of the driving forces behind the development and implementation of the RPM Capacity Market starting with the 2007/2008 Delivery Year.[29]

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[28] 24/25 BRA Report at 11, Table 6.

[29] The Brattle Group, Johannes Pfeifenberger, Samuel Newell, Robert Earle, Attila Hajos, Mariko Geronimo, *Review of PJM's Reliability Pricing Model (RPM)*, June 30, 2008 ("Brattle 2008 RPM Report) at 6-7. Available at https://www.brattle.com/wp-content/uploads/2017/10/6328_review_of_pjms_reliability_pricing_model_pfeifenberger_et_al_jun_30_2008-2.pdf.

48. At that time, there were units facing environmental restrictions that were presented with retrofit, repower, or retire decisions.[30] Retirement looked like the best option given the pricing and nature of PJM's Capacity Credit Market mechanisms that preceded RPM, which was posting prices that were effectively zero or near zero.[31]

49. Maryland passed the Healthy Air Act in 2006, which required coal fired power plants in Maryland to reduce nitrogen oxide and sulfur dioxide emissions that would require those resources to install pollution control retrofits or retire.[32] Again, prior to the implementation of RPM, these resources would have had no market mechanisms through which to reflect their costs of environmental controls and be retained for reliability.

50. Over the broader PJM footprint, there were also EPA coal power plant enforcement actions,[33] increased stringency of the Clean Air Interstate Rule[34] which evolved into the Cross State Air Pollution Rule as promulgated by EPA,[35] all of which required costs for environmental retrofits.

51. Table 1 shows the evolution of BRA prices over time with key events.

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[30] *See* https://www.epa.gov/enforcement/pseg-fossil-llc-settlement.

[31] PJM Market Monitoring Unit, *2007 State of the Market Report, Volume 2 Detailed Analysis,* at 245 and 246 Figure 5-6 and Table 5-10, available at https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2007/2007-som-volume2.pdf.

[32] *See* https://mde.maryland.gov/programs/air/pages/md_haa.aspx.

[33] *See* https://www.epa.gov/enforcement/coal-fired-power-plant-enforcement#:~:text=The%20coal-fired%20power%20plant%20industry%20is%20an%20EPA,compliance%20issues%20at%20the%20nation%27s%20coal-fired%20power%20plants.

[34] *See* https://archive.epa.gov/airmarkets/programs/cair/web/html/index.html.

[35] *See* https://www.epa.gov/Cross-State-Air-Pollution.

Table 1: PJM RTO and Large LDA BRA Prices with Corresponding Key Events[36]

Delivery Year BRA	Event	RTO	MAAC	EMAAC	SWMAAC
2007/2008	Transition to 3-year Forward	$40.80	$40.80	$197.67	$188.54
2008/2009	Transition to 3-year Forward	$111.92	$111.92	$148.80	$210.11
2009/2010	Transition to 3-year Forward	$102.04	$102.04	$102.04	$237.33
2010/2011	Transition to 3-year Forward	$174.29	$174.29	$174.29	$174.29
2011/2012	First Full 3-Year Forward	$110.00	$110.00	$110.00	$110.00
2012/2013	1st BRA DR Participates	$16.46	$133.37	$139.73	$133.37
2013/2014	2nd BRA DR Participates	$27.73	$226.15	$245.00	$226.15
2014/2015	MATS Costs Reflected	$125.99	$136.50	$136.50	$136.50
2015/2016	MATS Costs Reflected	$136.00	$167.46	$167.46	$167.46
2016/2017	Capacity Performance Transition	$134.00	$134.00	$134.00	$134.00
2017/2018	Capacity Performance Transition	$151.50	$151.50	$151.50	$151.50
2018/2019	Full CP Net CONE*B	$164.77	$164.77	$225.42	$164.77
2019/2020	Full CP Net CONE*B	$100.00	$100.00	$119.77	$100.00
2020/2021	Full CP Net CONE*B	$76.53	$86.04	$187.87	$86.04
2021/2022	Full CP Net CONE*B	$140.00	$140.00	$165.73	$140.00
2022/2023	MOPR Reform 1-year forward	$50.00	$95.79	$97.86	$95.79
2023/2024	Net ACR MSOC 15 months forward	$34.13	$49.49	$49.49	$49.49
2024/2025	Net ACR MSOC 17 months forward	$28.92	$49.49	$53.60	$49.49

[36] PJM Interconnection, L.L.C., "Resource Clearing Price Auction Summary," available at https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/rpm-auctions-resource-clearing-price-summary.ashx.

2025/2026	Marginal ELCC less than 1 year forward	$269.92	$269.92	$269.92	$269.92

52. In Table 1, the beginning of RPM witnessed four transition auctions that occurred less than three years prior to delivery with the first full three year forward BRA being for the 2011/2012 Delivery Year. One reaction to these prices was that they were considered high by some states and yet did not incent immediate new entry as many states in PJM wanted. But this misses the point. With the EPA coal power plant enforcement actions and Maryland Healthy Air Act, RPM was extremely successful in retaining those existing resources that could have easily retired in response to these environmental policies.[37]

53. As DR was able to participate directly in the BRA for the first time beginning with the 2012/2013 BRA, there was a rush of new entry of DR and this led to a reduction in prices in the RTO, but in constrained LDAs prices remained higher reflecting transmission constraints and higher costs associated with the costs of retaining existing resources.

54. With the EPA promulgation of the Mercury and Air Toxics Standards ("MATS"),[38] the costs of retrofits to comply with that EPA rule for the 2014/2015 and 2015/2016 BRAs raised prices throughout the RTO as shown in Table 1. Again, RPM helped retain existing resources that could reflect environmental retrofit costs.

55. Ignoring the role of RPM clearing prices in retaining existing resources that were at risk for retirement, states subsequently pushed for the Minimum Offer Price Rule ("MOPR") to be weakened to accommodate subsidized resources.

[37] Brattle 2008 RPM Report, Table 2 at 21 assessing that over 24,000 MW was at risk for retirement prior to RPM and over 4,500 MW of resources that deferred or delayed retirement due to RPM.

[38] *See* https://www.epa.gov/stationary-sources-air-pollution/mercury-and-air-toxics-standards.

56. The situation in PJM today is no different than the transition period at the start of RPM. As PJM has projected up to 24,000 MW of additional generation retirements by 2030 due to various state and environmental policies in the 4R Report.[39] However, many of these policy-driven retirements need not happen if the RPM Capacity Market can provide price signals to retain existing generation resources that could opt for making the necessary retrofits to comply with environmental policies as happened at the beginning of RPM and with MATS. There are many resources at risk for retirement, but with higher prices, the RPM Capacity Market may be able to retain them.

57. However, if the Commission takes up the PIOs on their Complaint, the Commission would short circuit the market process that has successfully worked in the past in meeting the challenge of environmental policies that allow resources to be retained through higher RPM prices that reflect their costs of meeting environmental policy mandates while maintaining resource adequacy in the PJM Region as we saw in the PJM transition auction period and with MATS.

D. <u>Including RMR Units in the RPM Capacity Market is Not Economically Efficient, Reduces Reliability, and Unnecessarily Creates More Volatility</u>

58. PIOs' Affiant, Mr. Wilson, has opined that it is "economically efficient" to include RMR resources into the capacity market.[40] Such a position is not just simply incorrect, but flies in the face of basic economic principles.

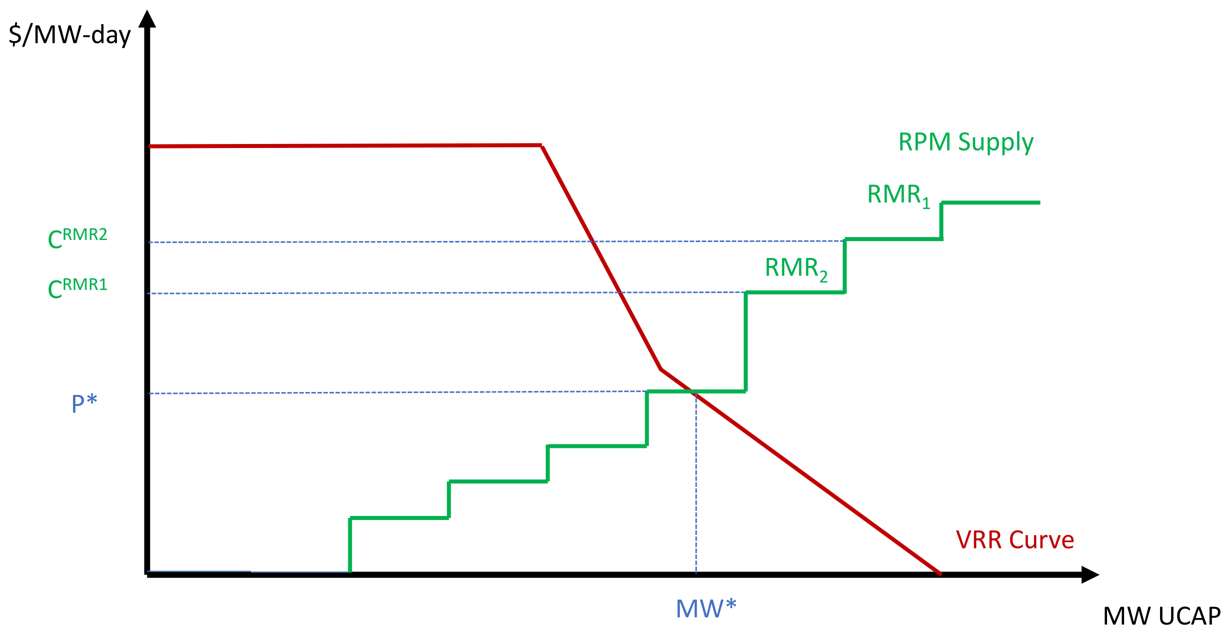
59. First, the algorithm that clears RPM maximizes economic surplus by choosing the lowest

[39] PJM Interconnection L.L.C., *Energy Transition in PJM: Resource Retirements, Replacements & Risks* ("4R Report"), February 24, 2023, Figure 3 at 8. Available at https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx.

[40] PJM Interconnection, L.L.C., "Base Residual Auction Optimization Formulation," Available at https://www.pjm.com/-/media/markets-ops/rpm/20071212-rpm-optimization-formulation.ashx.

cost set of resources to satisfy the demand.[41] Figure 1, which shows a graphical representation of the RPM Capacity Market with a market clearing price for capacity at P*, Cleared quantity of capacity at MW*, and the costs of two RMR resources that did not clear the market. It is clear in Figure 1 that the RMR resources' costs, denoted by C_{RMR1} and C_{RMR2} are above the clearing price, P*, and are not a part of the maximizing solution in PJM's RPM market clearing algorithm.

Figure 1: RPM Market Clearing with Resources that Have Elected to Retire but Are Retained as RMR Resources



60. Since the RPM auction algorithm maximizes surplus, the maximized surplus is shown in Figure 2. This surplus is split between consumer surplus in the blue shaded area, which is the difference between what demand is willing to pay and what it does pay, and the producer surplus, which is the difference between what suppliers are willing to accept for a price and what they receive. The RMR resources in Figure 2 do not contribute to

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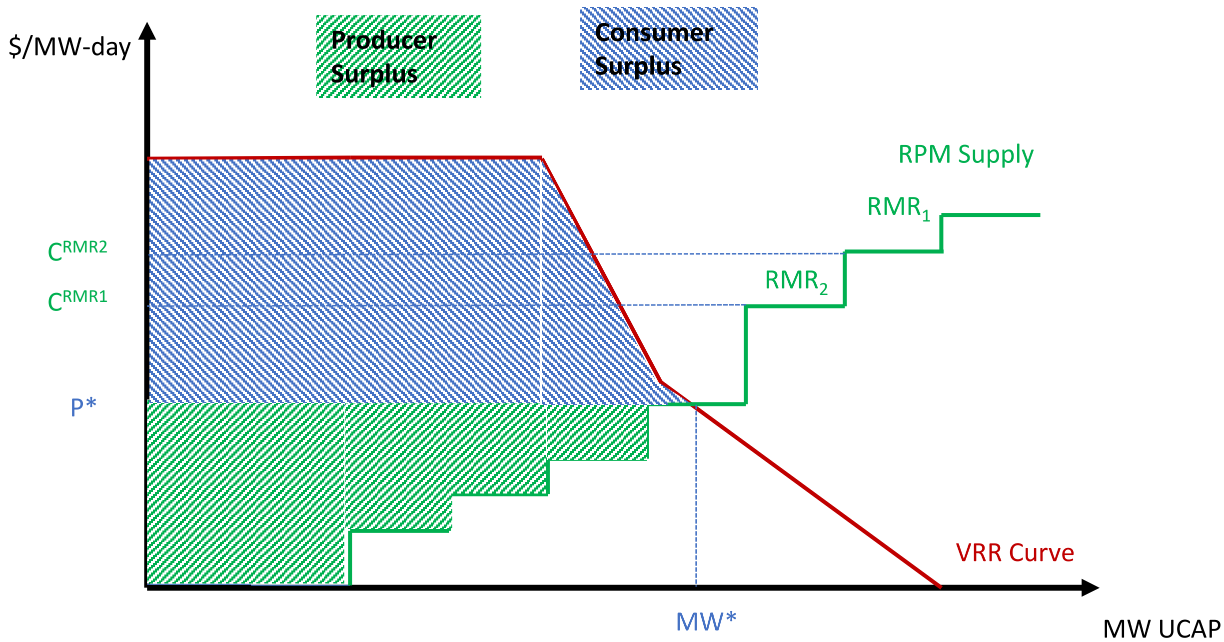
[41] *Id.* at 2.

maximizing surplus as their cost/willingness to accept is above the market clearing price, P*.

Figure 2: Efficient Market Clearing in RPM Maximizes Surplus and is Economically Efficient



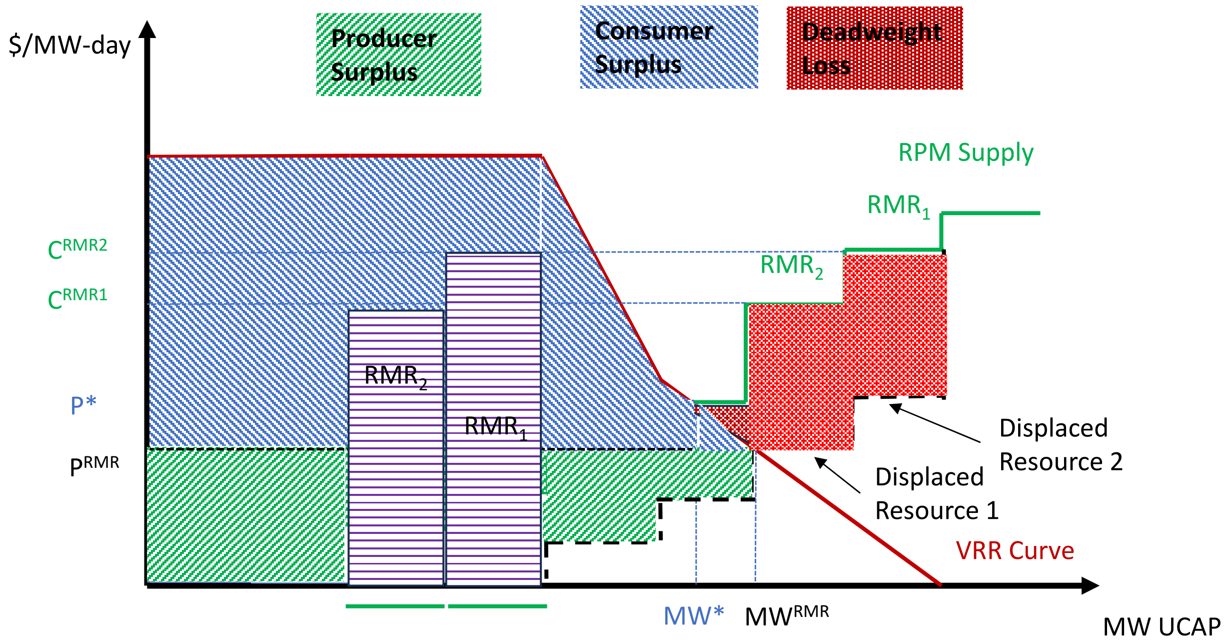
61. It has already been discussed herein that the RMR resources provide transmission service and that including them in Capacity Market is double counting capacity.[42] The RMR resources are providing support to the transmission system that provides CETL to bring in resources into a constrained LDA such as BGE, but otherwise would deactivate for economics as shown in Figure 1 and are not part of the surplus maximizing solution to the RPM Capacity Market shown in Figure 2.

62. However, let's assume that the RMR resources that would otherwise retire are inserted as price takers into the RPM Capacity Market as suggested by the PIOs. Inserting the out of market RMR resources as prices takers as shown in Figure 3 would result in the

[42] *See supra* Section V.

displacement of lower cost resources labeled "Displaced Resource 1" and "Displaced Resource 2" in Figure 3.

Figure 3: Inserting RMR Resources as Price Takers in the Capacity Market Results is Inefficient and Results in a Deadweight Loss of Efficiency and Forces Economic Resources from the Market



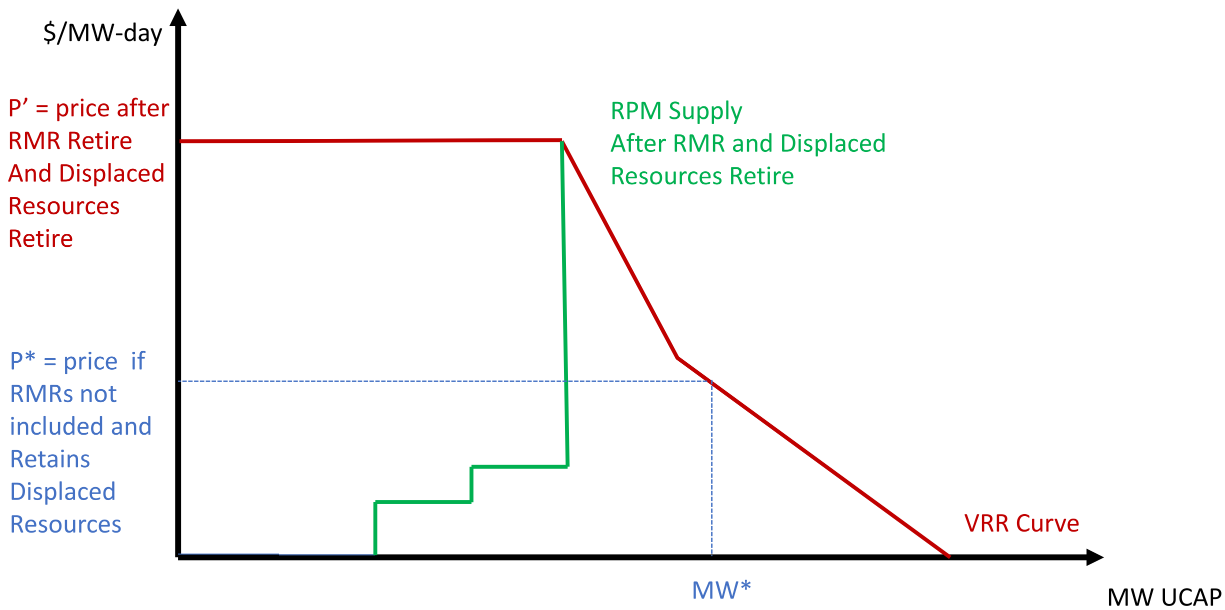
63. Figure 3 shows the RMR resources inserted into Figure 3 with their costs, as if they were considered capacity resources (they are not) and not transmission resources supporting CETL into a constrained LDA. This results in economic inefficiency known as a deadweight loss shaded in red, from displacing otherwise economic resources that were contributing to maximizing surplus in the PJM RPM market algorithm. The deadweight loss is a direct result of swapping out lower cost economic resources (Displaced Resources 1 and 2 in Figure 3) for uneconomic, out-of-market resources (RMR resources shown in Figure 3). The Commission must reject the erroneous notion proffered by the PIOs and their affiant, Mr. Wilson, that inserting RMR resources into the RPM solution is economically efficient. The RPM Capacity Market is a dynamic market and a single

snapshot in time does not tell the full story about the inefficiencies created by inappropriately inserting RMR resources in the RPM Capacity Market. What happens to the "Displaced Resources" in Figure 3? They are being given a signal to retire and that they are not needed for reliability. To the extent that Brandon Shores and H.A. Wagner remain under RMR agreements through the end of 2028, this retirement price signal would be repeated for the 2026/2027 BRA and the 2027/2028 BRA at minimum for those Displaced Resources.

64. What are the reliability implications of the "Displaced Resources" retiring as exemplified in Figure 3? Reliability in the form of resource adequacy suffers. Reliability is reduced because the PIOs want to insert high cost, uneconomic resources that cannot provide all the necessary attributes of PJM Capacity Resources, which would force the retirement of otherwise efficient resources that can provide all the necessary attributes of Capacity Resources.

65. What happens to the pattern of prices over time? Since the PIOs' solution will artificially lower prices during the period of the RMR agreements, the RPM market will signal with lower prices that there is no impending resource adequacy problem, when in fact the RMR agreements will disappear once transmission upgrades are in service. The "Displaced Resources" will also deactivate and disappear, assuming they are not needed to support the transmission system under RMR agreements. Then what happens to prices? They will spike to levels well above those in the economically efficient outcome as shown in Figure 4.

Figure 4: The Result of Inserting RMR Resources as Price Takers and Displacing Otherwise Economic Resources Results in Higher Prices in the Future



66. Figure 4 shows the contraction of supply that will eventually occur if the PIOs have their way. The contraction of supply comes from not only the retirements of the RMR resources but also the deactivations of otherwise economic resources that would be a direct result of the PIOs' economically inefficient and reliability eroding policy of inserting RMR resources into RPM.

67. Figure 4 is a result of the unnecessary interventions into the capacity market as requested by the PIOs. Rather than allowing the RPM capacity market to reflect the supply-demand balance and send prices that signify the need for the retention of existing resources and new entry that would exist at the price P*, the PIOs would create year to year volatility in prices, by artificially lowering prices with RMR resources as shown in Figure 3 for some period of time, only to see prices spike as shown in Figure 4 with the retirements of the RMR resources and inefficient deactivations of economic resources.

68. While volatility on its own can be a function of the underlying economic fundamentals (changes in technology, load growth), the kind of volatility introduced by the PIOs' proposed solution inefficiently chills investment. Why? In a game theoretic sense, investors view markets as a repeated game. Investors look for patterns that may be either somewhat predictable or can be anticipated. However, the pattern that the PIOs are setting is one of chaos with extreme price volatility driven by repeated interventions into the market, or, in the alternative, continued intervention to keep prices below otherwise competitive levels that promote reliability. But in the long-term, as shown in Figures 1 through 4, this will only lead to even higher prices as economically viable resources are inefficiently pushed from the market.

69. The PIOs' request to inefficiently insert RMR resources into the capacity market in an effort to artificially reduce prices is part of a larger problem created by the PIOs in recent years. As PJM and Talen have pointed out in their responses to the PIO complaint, Sierra Club helped force Brandon Shores and H.A. Wagner into retirement through various legal actions and threats, and now it is unhappy with the market and reliability consequences.

70. Addressing the 2022 PJM Quadrennial Review less than 2 years ago, many of the PIOs in this docket opined, "PJM's capacity market does not have any problem procuring sufficient resources to guarantee reliability. If anything, this market procures capacity too zealously."[43] So, today, they worry there is not enough capacity leading to high prices and not enough new entry available so we must retain RMR resources in the capacity market

[43] *See* Motion for Leave to File Answer and Answer of the Sierra Club, the Illinois Citizens Utility Board, New Jersey Division of Rate Counsel, Maryland Office of People's Counsel, the Office of the People's Counsel for the District of Columbia, the Delaware Division of the Public Advocate, PennFuture, Southern Environmental Law Center, Natural Resources Defense Council, and the Sustainable FERC Project in Docket No, ER22-2984 at 8.

that they themselves helped drive from the market. In the process, this would drive currently economic resources from the PJM market leading to greater resource adequacy issues and even higher prices as enumerated herein.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

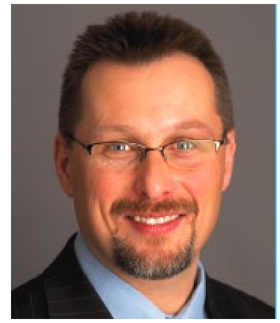
Sierra Club et al.,	)	
	)	
Complainants,	)	
	)	
v.	)	
	)	**Docket No. EL24-148-000**
PJM Interconnection, L.L.C.,	)	
	)	
Respondent.	)	
	)	
	)	

AFFIDAVIT

I, Paul M. Sotkiewicz, Ph.D., hereby state, under penalty of perjury, that the statements contained in the foregoing Affidavit on behalf of Electric Power Supply Association are true and correct to the best of my knowledge and belief.

Paul M. Sotkiewicz, Ph.D.

E-CUBED POLICY ASSOCIATES, LLC
WWW.E-CUBEDPOLICY.COM | GAINESVILLE, FLORIDA



Paul M. Sotkiewicz, Ph.D.

President and Founder, E-Cubed Policy Associates, LLC

Paul M. Sotkiewicz, Ph.D. 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 more than 25 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, distributed energy resources and the economic impacts of state and federal environmental policies on the power and gas industries. Dr. Sotkiewicz also supports law firms in litigation proceedings including rate cases, need determinations, rate design and market power/manipulation cases.

<u>Clients have included:</u>

Market and system operators

- Alberta Electric System Operator
- New York Independent System Operator
- Electric Reliability Council of Texas.

Trade associations such as the

- Electric Power Supply Association
- New England Power Generators Association
- PJM Power Providers Group
- American Petroleum Institute
- Industrial Power Consumers Association of Alberta
- Dual Use Customers of Alberta

Merchant generation and transmission developers in North American power markets

- ITC Holdings,
- JPower USA Ltd.
- Panda Power Funds
- Vistra Energy
- ENMAX
- Rockland Capital
- Kalina Distributed Power
- Capstone Infrastructure Corporation

- Pine Gate Renewables
- NextEra Energy Resources
- PVOne
- Bechtel
- Tenaska
- Earthrise Energy, PBC
- LS Power
- Coalition of PJM Capacity Resources which included resources owned by GenOn, Talen Energy, Tyr Energy, Clean Energy Futures, and Competitive Power Ventures among others.

Generation and transmission cooperatives

- Intermountain Rural Electric Association
- Buckeye Power
- East Kentucky Power

Non-Governmental Entities

- Natural Resources Defense Council
- Southern Environmental Law Center

Regulatory Agencies/Governmental Entities

- Delaware Public Service Commission
- US Department of State (via Lawrence Berkeley National Laboratory)
- Government of Vietnam
- Florida Department of Environmental Protection
- Belize Public Utilities Commission

Natural Gas Industry Customers

- Blue Racer Midstream

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. Dr. Sotkiewicz 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, and he 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) with High Honors, a Master of Arts (1995) and Doctorate in Economics from the University of Minnesota (2003). Dr. Sotkiewicz is also a member of Phi Beta Kappa academic honor society and a former Fulbright Scholar.

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EDUCATION

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

PROFESSIONAL AND ACADEMIC EXPERIENCE

2016- President and Founder, E-Cubed Policy Associates, LLC, Gainesville, FL

- Founded to provide expert advice, testimony, and policy research to private sector and government clients at the intersection of energy, environmental, and economic policy, and regulation.
- Supporting litigation defending market participants against accusations of market manipulation in PJM's markets
- Worked with the Ontario Independent System Operator (IESO), in conjunction with the Brattle Group, to help implement new settlement logic and protocols in their move to LMP-based market design.
- Assisted Brattle Group and NYISO in developing strategies and analysis to move the NYISO markets toward a less carbon intensive future in response to state climate change initiatives
- 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 regarding 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 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 various 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 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 and gas market development to the Chinese and Indian governments 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 alternatives for 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 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.
- Created and delivered 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.
- Served 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 six hundred students three 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.

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Erik Ela; Farhad Billimoria; Kenneth Ragsdale; Sai Moorty; Jon O'Sullivan; Rob Gramlich; Mark Rothleder; Bruce Rew; Matti Supponen; Paul Sotkiewicz, "Future Electricity Markets: Designing for Massive Amounts of Zero-Cost Variable Renewable Resources," *IEEE Power and Energy Magazine,* Volume 17, Issue 6, November/December 2019, Page 58-66.

Covino, Susan, Andrew Levitt, and Paul Sotkiewicz, "The Fully Integrated Grid: Wholesale and Retail, Transmission and Distribution," in *Future of Utilities- Utilities of the Future: How Technological Innovations in Distributed Energy Resources Will Reshape the Electric Power Sector*, Fereidoon P. Sioshansi, editor, Chapter 22, pp.417-434, 2016.

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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

Integrated Planning Model (IPM) Base Case Version 5.13 Peer Review, Prepared for US EPA Clean Air Markets Division, October 2014, prepared by Anthony Paul, Chair, Meghan McGuinness, Walter Short, Paul Sotkiewicz, John Weyant through RTI International.

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

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Ecological Economics

Environmental Science and Technology

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

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2001.

Professional Affiliations

American Economic Association
International Association for Energy Economics
Association of Environmental and Resource Economists
IEEE Power and Energy Society
Energy Systems Integration Group (ESIG)

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 Commission Order No. 719, I provided the following: 1) A high-level overview of PJM 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 retaining the current DDBT until such time as a new DDBT threshold can 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 were 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 are 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 MOPR-Ex are still powerful market power mitigation tools that mitigate the exercise of supplier market power 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 formation that are crucial to reliability/resilience, such as shortage pricing and fast start pricing, be 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 outages of gas-fired units are not 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 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 clearly shows 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 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 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 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 can cover their going forward costs in the absence of subsidies in the form of ZECs and will remain in commercial operation despite 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 eliminating the RPM Capacity Market and replacing it with 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, it justifies Illinois zero emission credit program for nuclear resources. The testimony refutes these ideas by describing in detail that all markets have administrative rules, and those 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 PSEG's position, 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.

PJM Interconnection, L.L.C. **FERC Docket Nos. ER19-1486 and EL19-58, Affidavit in Support of EPSA's Filing and Supporting Comments in PJM's Enhanced Price Formation in Reserve Markets Proposal, May 15, 2019.** This affidavit supports PJM's proposed extension of the ORDC concept to the Day-ahead Energy Market and further refinements to the ORDC construct that employs methods of using history of reserve levels, load forecast error, and generation output and reserves to determine an ORDC based on a loss of load probability. The affidavit also explains and supports other refinements proposed by PJM such as explicitly pricing what was known as Tier 1 reserves to accurately reflect the value those reserves provide to the system. Finally, I argue reserve pricing and the ORDC must explicitly account for operator discretion in making reliability commitments outside of the market framework.

PJM Interconnection, L.L.C. **FERC Docket Nos. ER19-1486 and EL19-58, Supplemental Affidavit in Support of EPSA's Reply Comments in PJM's Enhanced Price Formation in Reserve Markets Proposal, June 26, 2019.** This supplement affidavit rebuts assertions made during the initial comment period. First, positive reserve prices do not imply reserve shortage or scarcity conditions, but the price of reserves based on the value reserve provides beyond the Minimum Reserve Requirement. Second, that PJM's proposed ORDC appropriately accounts for out of market operator actions that would otherwise result in the wrong price signal to the market regarding reserve position and system needs. Third, that the proposed claw back of any revenues earned under the PJM proposal is inefficient and not just and reasonable and confuses capacity market concepts with short-term operational needs.

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.

American Transmission Systems Incorporated, Docket No. ER20-1740 **Affidavit is Support of Buckeye Power Inc. Counter the Capacity Market Benefits of ATSI Moving from MISO to PJM and Recovery of Transition Costs, May 29, 2020**. This affidavit provides empirical evidence and theoretical support that load connected to the ATSI transmission system paid more in capacity costs in PJM than they would have paid had ATSI stayed in MISO to counter ATSI's argument that ATSI connected load would have paid more for capacity had ATSI remained in MISO.

***Alberta Utilities Commission ("AUC") Distribution System Inquiry Proceeding 24116*, Response from Kalina to AUC Information Request Round 2, Jointly with Regulatory Law Chambers, Terradigm Energy, Inc, and Nican International Consulting, Ltd on Behalf of Kalina Distributed Power, June 17, 2020.** This response to information requests provides support for an optimal distribution tariff design that rewards resources that reduce the need for additional upgrades and reduce line losses and send price signals regarding the optimal location on the distribution system. This response also argues against tariff policies that would inefficiently charge such resources for costs they do not cause to either the distribution system or the transmission system and argues that efficient pricing is consistent with the competitive objectives of the Alberta energy market.

***Investigation into Resource Adequacy Alternative, New Jersey Board of Public Utilities,* BPU Docket No. EO 20030203, Prepared Comments in Support of PJM Power Providers, June 24, 2020.** These prepared comments address the benefits of Reliability Pricing Model (RPM) Participation for New Jersey customers and the additional costs of moving to a Fixed Resource Requirement (FRR) Plan as proposed by PSEG and Exelon in earlier comments. These comments note the extra costs could be over $700 million per year for New Jersey customers and would facilitate the exercise of market power by a small set of generation owners.

***American Transmission Systems Incorporated, Docket No. ER20-1740* Reply Affidavit is Support of Buckeye Power Inc. Counter the Capacity Market Benefits of ATSI Moving from MISO to PJM and Recovery of Transition Costs, June 25, 2020**. This reply affidavit supports the previously supplied empirical evidence and theoretical support that load connected to the ATSI transmission system paid more in capacity costs in PJM than they would have paid had ATSI stayed in MISO to counter ATSI's argument that ATSI connected load would have paid more for capacity had ATSI remained in MISO. Additionally, the reply affidavit responds to ATSI critiques of the original affidavit and the ATSI responses to answers.

***Alberta Utilities Commission ("AUC") Distribution System Inquiry Proceeding 24116*, Concluding Remarks of Kalina Distributed Power, Jointly with Regulatory Law Chambers, Terradigm Energy, Inc, and Nican International Consulting, Ltd on Behalf of Kalina Distributed Power, July 15, 2020.** These concluding remarks reiterates support for an optimal distribution tariff design that rewards resources that reduce the need for additional upgrades and reduce line losses and send price signals regarding the optimal location on the distribution system. These concluding remarks provide established economic theory to explain why the current policies that inefficiently charge such resources for costs they do not cause are not in the best interests of Alberta's energy market or Alberta energy customers.

***Investigation into Resource Adequacy Alternative, New Jersey Board of Public Utilities,* BPU Docket No. EO 20030203, "Prospective Minimum Offer Price Rule Price Floors and Cost-Effectiveness of the PSEG/Exelon Fixed Resource Requirement Plan for New Jersey" in Support of PJM Power Providers, July 22, 2020.** This whitepaper responds to the PSEG and Exelon comments submitted on June 24, 2020, and it responds to the report of the PSEG/Exelon Consultant assertions about the alleged cost savings of moving to a Fixed Resource Requirement (FRR) Plan as proposed by PSEG and Exelon in earlier comments. This paper also discusses the Minimum Offer Price Floor levels for various clean energy resources to show they would not be excluded from the RPM capacity market and would clear the market given historic capacity prices.

***PJM Interconnection, L.L.C. FERC Docket No. EL19-58-003 "Forward Looking Energy and Ancillary Service Offset,"* Affidavit in Support of Comments of the Electric Power Supply Association, September 2, 2020.** Supports and explains PJM's forward-looking energy and ancillary service offset filing in the context of Commission approved methods that use the same framework as the energy and environmentally limited opportunity costs which uses forward looking fuel and power prices in the same way as the PJM proposal. The Affidavit also calls for further analysis of the forward-looking methodology once there are realizations of actual power and gas prices compared to the forward prices used in the methodology.

***Alberta Utilities Commission ("AUC") Proceeding 26090 DG Credit Module for Fortis's 2022 Phase II Tariff Application*, Evidence in Support of Kalina Distributed Power and Capstone Infrastructure Corporation, December 14, 2020.** This expert report discusses the economic and electrical equivalence of distribution connected generation (DCG) to reduced load on the distribution level and the resulting effects on transmission rates and cost recovery in the Alberta power system. This report also points out that DCG is not the cause of so-called erosion of billing determinants from the transmission system costs, but those are caused by over-forecasting load and transmission overbuild. The report argues for retention of Fortis's DCG Credit based on cost causation principles given DCG helps reduce loading on the transmission system.

Alberta Utilities Commission ("AUC") Proceeding 26090 DG Credit Module for Fortis's 2022 Phase II Tariff Application, **Reply Evidence in Support of Kalina Distributed Power and Capstone Infrastructure Corporation, January 27, 2021.** This reply report provides additional detail regarding the subjects discussed in the initial report, responds to intervenor comments, and explains how DCG can enhanced the efficiency of the Alberta Energy Market as well as providing cost-effective reductions in future transmission build out.

Southeast Energy Exchange Market Agreement FERC Docket ER 21-1111, Affidavit is Support of Public Interest Organizations, March 15, 2021. This affidavit points out the market design and market power shortcoming of the proposed Southeast Energy Exchange Market (SEEM) rules and governance structure as well as problems with the supporting benefit/cost analysis supporting the proposed market design. The affidavit highlights transactional complexity, computational complexity, and rules that allow market power exercised through manipulating submitted parameters as why the Commission should not approve the proposed design and set a technical conference to discuss a more robust market for the Southeast.

Jackson Generation, LLC v. PJM Interconnection in FERC Docket No. EL21-062, Affidavit in Support of Jackson Generation's Complaint, March 30, 2021. This affidavit argues that it makes economic sense for PJM and the Independent Market Monitor to consider a longer asset life than 20 years and the consideration of sunk costs in determining the Minimum Offer Price that Jackson could offer into the 2022/2023 Base Residual Auction. Furthermore, I argued that the tariff language is explicitly consistent with the tariff language as well as previous PJM precedent in allowing longer asset lives and sunk costs when I served as PJM's Chief Economist and oversaw making Minimum Offer Price determinations.

Southeast Energy Exchange Market Agreement FERC Docket ER 21-1111, Affidavit is Support of Public Interest Organizations, June 28, 2021. This affidavit responds to the Southeast Energy Exchange Market (SEEM) filing responding the FERC Staff's Deficiency Letter and continues to point out the market design and market power shortcomings of the rules and monopoly position of the filing parties. This affidavit concentrates on data transparency and the lack of truly independent market monitor to guard against market abuses by large participants, uses existing data from Southern Company's auction market to show that market participation in the prosed design will be effectively non-existent and that this is all by design since the incentives of large franchise monopoly supporters of SEEM are to retain their monopoly positions. governance structure as well as problems with the supporting benefit/cost analysis supporting the proposed market design. The affidavit also highlights areas around computational complexity and the ability to foreclose transactions with other parties leads to an inability to run the market in the time allotted and results in de facto market manipulation.

Alberta Electric System Operator Transmission Rate Design, in Alberta Utilities Commission Proceeding 26911, Report in Support of Industrial Power Consumers Association of Alberta (IPCAA) and the Dual Use Customers (DUC), March 28, 2022. Report entitled "Transmission Rate Design and Energy Market Efficiency" shows why the AESO's proposed rate design to shift fixed costs into volumetric charges is inefficient and leads to uneconomic bypass and harms the Alberta Energy Market. This report also shows why a shift to non-coincident peak charges away from peak charges leads to inefficient decision making by customers and violated cost causality principles in rate design. The conclusion is that the optimal rate design for bulk power transmission should be based on coincident peak charges that includes all the fixed costs of the system.

Rebuttal Report Regarding the Review and Evaluation of Alternatives and Benefit Cost Analysis Prepared for Renovo Energy Center in Clean Air Council et al. v. Pennsylvania Department of Environmental Protection, Environmental Hearing Board Docket No. 2021-055, May 2, 2022. This report responds to Appellants refuting statements regarding benefit-cost analyses, facts regarding the PJM and NYISO markets, and assertions emissions increases of the proposed facility.

Department of Environmental Protection, Environmental Hearing Board Docket No. 2021-055 Affidavit Prepared for Renovo Energy Center, July 18, 2022. This responds to Appellants affidavits regarding emissions data, PA DEP not being responsible for generator entry and exit decisions, and logical flaws in Appellants Expert benefit-cost analysis.

PJM Interconnection, L.L.C., Docket No. ER22-2984-000; Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters, Affidavit in Support of Protest of J-Power USA Development Co. Ltd., October 21, 2022. This affidavit explains why PJM's choice of a 20-year asset life for the Reference Resource Net CONE in the ComEd LDA is in error due to the Climate and Equitable Jobs Act (CEJA) that requires all gas resources reach zero net emissions by 2045. Additionally, the affidavit explains that such LDA specific adjustments for the Energy and Ancillary Service Offset and CONE area differences for labor are common, hence reducing the asset life in ComEd would reasonably be accommodated.

PJM Interconnection, L.L.C., Docket No. ER22-2984-000; Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters, Reply Affidavit in Support of Protest of J-Power USA Development Co. Ltd., November 18, 2022. In response to the answers filed by PJM and the Public Interest Entities to explain why their responses are irrelevant and/or fail to address the concerns J-POWER brought up in its protest with regard to the effect of the Illinois Climate and Equitable Jobs Act on the Commonwealth Edison Company Locational Deliverability Area ("LDA") in the PJM capacity market. I explain here that what PJM proposes to do in its filing is a violation of the spirit and intent of PJM's FERC-approved Tariff and Reliability Assurance Agreement if not a direct failure to follow the plain terms of the governing documents and I provided evidence showing the reliability urgency that is forthcoming in the ComEd LDA requires a shorter asset life for the Reference Resource to be used in developing the Variable Resource Requirement Curve used in PJM's capacity auctions.

PJM Interconnection, L.L.C., Docket No. ER23-729 and EL23-19; Protest of PJM's Filing to Change the Locational Deliverability Area Reliability Requirement in the midst of the 2024/2025 BRA in support of the Electric Power Supply Association, January 20, 2023. This affidavit argues PJM's proposed solution is clearly retroactive rather than prospective, upsets settled expectations, introduces unnecessary uncertainty, and is bad market design, creates a false equivalence between physical reliability needs as determined by PJM's own planning methods with its own ideas of economic supply-demand balance, ignores the real reliability problems that exist in DPL-South as evidenced by historically high prices, tight supply-demand conditions, and the auction outcome PJM seeks to avoid, and the market outcome was easily anticipated.

Aurora Generation, LLC, Elwood Energy LLC, Jackson Generation, LLC, Lee County Generating Station, LLC, Lincoln Generating Facility, LLC, LSP University Park, LLC, Rockford Power, LLC, Rockford Power II, LLC, University Park Energy, LLC, Complainants, v. PJM Interconnection, L.L.C., Respondent. Docket No. EL23-54, April 3, 2023. I show throughout Elliott, PJM power prices and underlying transmission congestion and the ComEd supply-demand balance were inconsistent with the idea that PJM was in any kind of emergency condition in ComEd through the December 23 and 24 PAI intervals. ComEd Zone generators would not have been able to deploy reserves to the rest of PJM. During the final 12 hours of the PAI event on December 24, energy and reserve prices were inconsistent with the idea there were emergency conditions. The lack of timely commitments of generation in ComEd, the cost of gas fired generation in ComEd based on intra-day gas prices were inconsistent with economic dispatch of gas fired resources in ComEd to support the rest of PJM or exports out of PJM. I also showed PJM violated its Tariff, Operating Agreement ("OA"), NERC standards, and PJM Manuals by allowing exports to continue while PJM entered reserve shortages, failing to curtail Non-Firm export transactions prior to and during Emergency Actions, and failing to recall exports supported by PJM Capacity Resources, and in effect employing emergency load management to support non-firm exports.

Coalition of PJM Capacity Resources, Complainants, v. PJM Interconnection, L.L.C., Respondent. Docket No. EL23-55, April 4, 2023. In this testimony I showed how PJM lacked situational and operational awareness leading up to and during Winter Storm Elliott and violated its Tariff and operating procedures: 1) Despite the clear and consistent weather forecasts as early as seven days prior to Winter Storm Elliott, PJM's demand forecast failed to account for the impending weather conditions. PJM Day-ahead Energy Market commitments were inconsistent with the impending reliability needs that were being signaled by other factors and that were realized in real-time operations. 3) PJM failed to notice that gas pipelines serving PJM gas-fired generation had issued critical notices asking or ordering shippers to avoid gas imbalances and adhere to nomination and flow times and 24-hour ratable takes and failed to understand the timing of gas nominations and flows on pipelines and how that would affect the intra-day scheduling and commitment of gas fired resources to serve the load which had been grossly under-forecast. 4) PJM, ignoring the weather forecast relative to the load forecast and gas pipeline notices, failed to commit sufficient additional resources per its Emergency Operating Procedures to ensure sufficient generation was available. 5) PJM missed the clear signals from the natural gas markets that showed extremely high gas prices throughout PJM indicating the severity of the cold weather coming, contrary to the PJM load forecast.6) PJM continued to flow non-firm exports and exports that were likely supported by PJM Capacity Resources and while employing emergency load management contrary to the PJM Tariff and emergency operating procedures.

East Kentucky Power Cooperative, Inc., Complainant, v. PJM Interconnection, L.L.C., Respondent. Docket No. EL23-74, May 31, 2023. I supported EKPC's Complaint in an affidavit that builds upon testimony I have already provided in Complaints filed at FERC in Docket Nos. EL23-54 and EL23-55 with the following updates and additions: 1) Identification of 5-minute intervals experiencing Primary or Synchronized Reserve Shortages in which there was also a Maximum Emergency Generation event and/or emergency demand response in place. 2) Matching the identified 5-minute intervals with the volume of Net Scheduled Exports delineated by different levels of transmission service as posted by PJM on its OASIS. 3) A description of why PAIs should not be triggered by a PJM emergency declaration alone such as the call for Pre-Emergency and Emergency Demand Response and/or Maximum Generation Emergency Actions but should also be accompanied by evidence of a Primary and/or Synchronized Reserve Shortages.4) Assessed what Primary or Synchronized Reserve Shortages would have existed had all Non-Firm (on a transmission reservation basis) exports to the Tennessee Valley Authority and Duke Energy Carolinas and Duke Progress been curtailed as is required under NERC EOP 011-12. I also provided a background history regarding PJM's Capacity Performance ("CP") design explaining that CP did not envision or contemplate exports to neighboring control areas because it was assumed PJM, if it were in emergency conditions, would have been a net importer of energy, and why exports to support external loads during a PAI is inconsistent with cost causation principles. I also showed why the current Penalty Charge Rate based on Net CONE results in undesirable reliability outcomes as it can lead to a loss of multiple years of capacity revenue within the span of only two days, and the loss of capacity that occurred during Elliott.

POLICY WHITEPAPERS and Reports

NYISO Meter Data Study-Final Report, December 8, 2017. Available at https://www.nyiso.com/documents/20142/1391862/NYISO-Meter-Data-Study-Report.pdf/db0de386-04b1-8818-3f77-194bc71a8c37. This report examines the meter data policies in the NYISO in comparison to similar polices in PJM, CAISO, and ISO-NE and the role of entities providing meter services for DER as may be required into the future. This report address and provides recommendations on 1) Baselines for DER as required and modification to existing baselines if needed; 2) Potential for the statistical sampling of a subset of DERs for establishing baselines and for market settlement in the energy, capacity, and ancillary services markets; 3) Interactions of baselines and DER aggregation; and 4) Simultaneous participation in both retail and wholesale markets by DERs.

The Market and Financial Position of Nuclear Resources in Pennsylvania, April 5, 2019. Available at https://citizens-against-nuclear-bailouts.prezly.com/new-report-highlights-long-term-profit-projections-for-pennsylvania-nuclear-generators and https://cdn.uc.assets.prezly.com/210b1e76-c577-4ffb-9bb9-c60c1f4299b8/-/inline/no/
This paper shows that nuclear resources in Pennsylvania are profitable historically and going forward and are in no need of any subsides to keep these resources in service.

The Market and Financial Position of Nuclear Resources in Ohio, May 13, 2019. Available at https://img1.wsimg.com/blobby/go/30b6d3a5-dffd-4a1b-9b4d-0bf3451282cd/downloads/OH%20Nuclear%20Analysis%2020190513-final.pdf?ver=1559092681975
This paper shows that nuclear resources in Ohio, Davis-Besse and Perry, are profitable historically and going forward and are in no need of any subsides to keep these resources in service as proposed under House Bill 6.

Economic Benefits to Ohio Electricity Consumers from the Repeal of House Bill 6, September 16, 2020. This paper shows that the Repeal of HB 6 in Ohio would lead to lower electricity bills for Ohio consumers with saving coming from keeping energy efficiency and demand response programs, and the repeal of subsidies for legacy coal units and the Davis-Besse and Perry nuclear units.

Assessment of the Fixed Resource Requirement Option for Delaware, Prepared for the Delaware Public Service Commission, June 29, 2021. Presented to the Delaware Public Service Commission Open Meeting, October 6, 2021. This paper reviews the FRR Rules in PJM and analyzes the trade-offs for Delaware of opting into an FRR Plan with regard to costs, ability to meet RPS requirements, and overall feasibility. The meeting agenda and minutes are available at https://publicmeetings.delaware.gov/#/meeting/67673.

Attachment B

The PJM Board Letter

Mark Takahashi
Chair, PJM Board of Managers

PJM Interconnection
2750 Monroe Blvd.
Audubon, PA 19403

Via Electronic Delivery

September 19, 2024

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Dear Advocates,

Thank you for your correspondence dated Aug. 30, 2024, wherein you express concern about the most recent Base Residual Auction (BRA or capacity auction) results and request that the PJM Board of Managers (PJM Board) take immediate action to require the participation of Reliability Must Run (RMR) units in capacity auctions.

At PJM, we work hard to balance concerns around affordability with our obligation to ensure reliability for the 65 million consumers in the PJM footprint, all while trying to assist states and the federal government in the advancement of their policy objectives.

We understand that many consumers are financially stressed right now, and we appreciate you raising questions around appropriate price signals for capacity given the current supply-demand balance on our system. As we consider these questions, it is important to first understand how we arrived here.

As PJM has been warning[1] for some time now, our region is experiencing a combination of trends that have served to rapidly tighten the supply-demand balance on our system. These trends include:

- Electrification coupled with the proliferation of high-demand data centers in the region that will result in material load growth

[1] *See* Energy Transition in PJM: Resource Retirements, Replacements & Risk (4R Report).

- Retirement of thermal generators at a rapid pace due to policy pressure as well as economics
- Slow new entry of replacement generation resources due to a combination of industry forces, including siting, permitting and supply chain constraints
- The high proportion of our interconnection queue that is composed of intermittent and limited-duration resources, many of which are valuable energy resources but are much less effective providers of capacity than the thermal resources they are replacing

Given these trends, it has become very clear that our region will require the buildout of a significant quantity of new generation, including a material amount of natural gas-fueled generation, in order to maintain the reliable electricity supply our consumers expect. It is in this context that the BRA for the 2025/2026 Delivery Year, in conjunction with the forward energy market, sent a new-build investment price signal. This signal is consistent with market fundamentals.

It is also important to note that these reliability concerns associated with reducing supply and increasing demand are not limited to PJM; the North American Electric Reliability Corporation (NERC) has identified elevated risk to the reliability of the electrical grid for much of the country outside of PJM. In fact, PJM is currently situated with a stronger reserve position than several other regions in the U.S.

In addressing the acute issue of Brandon Shores mentioned in your letter, the facts of what has occurred with these units are not in dispute:

- In November 2020 the units' owner, Talen, announced a "strategic repositioning of its power generation fleet that will eliminate the use of coal at all Talen wholly owned facilities." Talen's press release identified the Brandon Shores units in particular and stated that Talen "will cease coal-fired operations by the end of 2025 and repower pending approvals by state agencies."
- Subsequently, in December 2021, Raven Power Fort Smallwood LLC, a subsidiary of Talen and the owner/operator of the Brandon Shores units, filed a request for a determination from the Maryland Public Service Commission (PSC) that the proposed fuel-switching from coal to oil at the Brandon Shores units would not constitute a modification to the generation stations, signaling Talen's intent to move forward with the repowering of the facility.
- In January 2022, the Maryland PSC issued a decision confirming that the "proposed fuel-switching would not be considered a 'modification' under the *Public Utilities Article* § 7-205 …" and approved the proposed fuel-switching from coal to oil, subject to certain conditions.
- Additionally, in parallel with Talen's press release and the Maryland PSC's proceeding described above, Talen contacted PJM in May 2021 to inquire about Brandon Shores' proposed fuel-switching from coal to oil. Talen also had subsequent discussions and meetings with PJM's transmission planning group on several occasions between May 2021 and August 2022 regarding whether any studies would be necessary to support the fuel conversion and to obtain information from PJM about requirements for PJM's upcoming capacity auction. Talen clearly communicated it was on a path to convert Brandon Shores to oil.

- PJM did not become aware that Talen had decided to pivot from its fuel conversion plan until April 6, 2023, when PJM received a deactivation notice for Brandon Shores. In that notice (which was provided in compliance with the PJM Tariff), Talen explained, for the first time, that although it had previously been working toward a conversion of the Brandon Shores units to fuel-oil combustion, it had determined that such a conversion would be uneconomic.

- Further, as you may be aware, Talen entered into a private agreement with the Sierra Club that prevents Brandon Shores from continuing to run without conversion beyond Dec. 31, 2025. PJM was not consulted on this agreement nor was PJM a party to the agreement.

- Shortly after receiving Talen's deactivation notice, PJM conducted a generator deactivation analysis, finding that the Brandon Shores retirement would result in over 600 reliability violations. PJM then acted quickly to initiate the process to find transmission solutions to resolve these violations. The PJM Board acted swiftly in approving these projects, as did the Federal Energy Regulatory Commission (FERC).

The sheer number of reliability violations resulting from the retirement of Brandon Shores indicates Maryland's urgent need for additional energy infrastructure. Brandon Shores (and Wagner) will be needed to preserve electric reliability for consumers in Maryland beyond their stated retirement dates and until required transmission is built. PJM's federally approved rules contemplate this scenario, and the rules provide the opportunity for retiring generation needed for grid reliability to operate under an RMR framework, pursuant to the PJM Tariff, until required transmission upgrades have been completed. There is a proceeding underway at FERC to discuss a possible RMR framework for Brandon Shores and Wagner (see FERC Docket No. ER24-1790). Further, there are currently discussions underway in the PJM stakeholder process that would allow for a more holistic planning effort in response to a generator deactivation notice submission.

As you note, PJM's current market rules (as approved by the FERC) do not require a deactivating resource to participate in a capacity auction, and PJM cannot require such participation if the resource is the subject of a valid must-offer exception. More particularly, Tariff, Attachment DD, section 6.6(g) explicitly provides that a resource qualifies for an exception to the capacity market must-offer requirement if it has a "documented plan in place to retire the resource prior to or during the delivery year, and has submitted a notice of Deactivation regardless of whether PJM has asked the unit to continue to operate beyond its requested deactivation date." These market rules make sense for several reasons:

- First, requiring participation of a deactivating unit in the capacity auction under the existing RMR agreements could distort the price signal and fail to incent the new build needed in Maryland and in the rest of the regional transmission organization (RTO). With Maryland already importing ~40% of its annual electricity needs from other states and the RTO needing new generation build to keep up with the combined effects of demand growth and generator retirements, suppressing this price signal now is likely to result in greater reserve shortfalls in the future. Additionally, suppressing this price signal now could discourage other forms of resources, such as Demand Response and other resources that may be available on shorter notice from increasing their market participation precisely at the time they are most needed.

- Second, requiring such market participation from a resource following a deactivation notice could have unintended market consequences for existing resources. For example, a generator that had the opportunity to continue operating by investing in technologies meant to lower emissions may decide to retire instead of investing in those technologies due to the lower price signal, thereby exacerbating reliability problems down the road.

- Third, a resource that intends to retire but is being forced to offer into the capacity market is likely to be more reluctant to agree to an RMR arrangement. This will be deleterious to maintaining system reliability. The obligations of being a capacity resource and any associated performance penalty risks may be a bridge too far for that unit owner. PJM views RMR arrangements as a last resort but a necessary action to keep units temporarily operational in order to maintain system reliability.

- Finally, in this instance it is our understanding that Talen's agreement with the Sierra Club precludes Brandon Shores from operating as a capacity resource beyond Dec. 31, 2025, unless the units convert to oil.

Further, these are the market rules that have been in place for many years and have been approved by the FERC. You make reference to rules currently in place for other Independent System Operators (ISOs). Each ISO/RTO has different market constructs and thus different rules for how RMR arrangements should be accounted for in those markets. NYISO, for example, has a significantly different market construct than PJM. In the case you cite related to NYISO, FERC did not definitively address this idea of "double counting" for RMR resources that are deemed needed for resource adequacy. In fact, the NYISO Orders cited by you were limited to a determination of the required offer price that RMR units are required to offer into NYISO auctions. On rehearing, FERC merely noted that it was unable to discern under what circumstances NYISO would need an RMR unit for resource adequacy, and thus, under NYISO's proposal, the unit should not be subjected to an offer floor.[2] On the other hand, PJM's treatment of RMR units' participation in ongoing capacity auctions is similar to those of the Midcontinent Independent System Operator (MISO).

For all of these reasons, we believe it would be counterproductive to try to change our market rules prior to the next BRA to force RMR units to offer into capacity auctions.

However, there are other actions we believe are important to pursue to try to ensure that market prices correctly reflect the supply-demand challenge we are experiencing. There are also actions we can pursue to enable the fastest possible supply response to these market signals.

1) Certain resource types, such as wind, solar, batteries and hydro, don't currently have a must-offer requirement. Many of these resources did in fact offer in the previous auction. However, several generators did not. Given how tight the supply-demand balance could be for the next auction, PJM will work with our Independent Market Monitor (IMM) to request information from these generators to ensure each decision to not offer a resource is economically justified on a stand-alone basis based upon current market conditions. Resources without a must-offer requirement generally should be evaluated to ensure that their decision not to offer is justified on a stand-alone basis and is not being done for the purposes of benefiting other units in the resource owner's portfolio. PJM should be given the ability to mandate participation in the capacity auction if there is found to be an exercise of market power.

[2] New York Independent System Operator, Inc., 161 FERC P 61,189 (2017).

2) There are several resources that have requested a must-offer exception for the 2026/2027 BRA because they intend to retire. PJM will work with our IMM to request information from these generators to ensure that these decisions to retire are still justified on a stand-alone basis.

PJM will work with the IMM to address any issues that may arise prior to the next auction. Further:

1) We intend to advance a proposed expedited framework to “fast-track” some incremental generation interconnection projects for consideration by our members in the near future.

2) We believe it is appropriate to review the choice of reference unit and shape of the demand curve, and we have launched an expedited quadrennial review to do this.

Additionally, PJM is certainly willing to have a more fulsome discussion on the issues you raise related to deactivating units and their positioning within our markets. There is currently a Deactivation Enhancements Senior Task Force (DESTF) that is convening to discuss particulars around deactivating units, and this discussion is perhaps best suited for that task force. The PJM Board respectfully requests that the Members focus attention on the DESTF and accomplish the tasks set out in the Task Force’s issue charge. The DESTF has been meeting for some time now and should complete its work as soon as practicable.

Again, we thank you for your correspondence and your focus on these important issues. To note, this PJM Board correspondence is meant to be responsive to the additional correspondences received on this topic.[3]

Sincerely,

Mark Takahashi

Mark Takahashi
Chair, PJM Board of Managers

[3] Public Interest Organizations’ Correspondence; PSA/P3 Correspondence.

Document Content(s)

FINAL EPSA protest to EL24-148 complaint.pdf..............................1