Attachment A

Answering Affidavit of
Dr. Samuel A. Newell, Dr. Andrew W. Thompson, Dr. Bin Zhou, and Joshua C. Junge

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

	)	
PJM Interconnection L.L.C.	)	Docket No. ER26-455-000
	)	

ANSWERING AFFIDAVIT
OF
Dr. SAMUEL A. NEWELL, Dr. ANDREW W. THOMPSON, Dr. BIN ZHOU, AND JOSHUA C. JUNGE

On Behalf of PJM Interconnection, L.L.C. Regarding

PROTEST OF THE INDEPENDENT MARKET MONITOR FOR PJM ON UPDATES TO PJM'S CONE AND NET ENERGY AND ANCILLARY SERVICE OFFSET PARAMETERS FOR DELIVERY YEARS 2028/29 THROUGH 2031/32

December 19, 2025

1. Our names are Dr. Samuel A. Newell, Dr. Andrew W. Thompson, Dr. Bin Zhou, and Joshua C. Junge. Dr. Newell and Dr. Zhou are employed as Principals and Dr. Thompson as an Energy Associate by The Brattle Group ("Brattle"). Mr. Junge is employed as a Principal Energy Consultant at Sargent & Lundy ("S&L").

2. We are submitting this affidavit on behalf of PJM Interconnection, L.L.C. ("PJM") to respond to the comments and protests submitted in this docket that relate to our independent assessment of PJM's adjustments to the administrative Cost of New Entry ("CONE") parameter, representing the cost of building a generation plant for use in PJM's capacity market (known as the Reliability Pricing Model or "RPM"). On November 7, 2025, we submitted an affidavit ("CONE Affidavit") to the Federal Energy Regulatory Commission ("FERC" or "Commission") explaining how our analysis informed PJM's proposed revisions to the CONE and Net Energy and Ancillary Service ("Net EAS") Offset parameters in the PJM Open Access Transmission Tariff ("Tariff") for Delivery Years 2028/29 through 2031/32.[1]

3. We respond here to a subset of the comments and protests that relate to CONE parameters and the Net EAS Offset methodology. These comments and protests were submitted by Monitoring Analytics, L.L.C., the Independent Market Monitor ("IMM") for PJM.[2]

4. The IMM claims that CONE for the combustion turbine ("CT") reference resource should be lower overall as a result of different views on the timing of capital expenditures and tax deductions, which affect the project's installed cost and capital recovery requirements even if not the overnight cost. That is, in spite of modeling the project timeline starting earlier to explicitly model the timing of development costs that are incurred before the final investment decision ("FID"), the IMM's capital expenditures are more back-end loaded overall; this results in lower capital carrying costs and so reduces CONE. Regarding tax deductions, the IMM assumes investors in merchant generation could fully realize tax deductions from 100% bonus depreciation in their first year of operation, which maximizes the present value of tax deductions and thus lowers CONE. We disagree with these assumptions and respond below by clarifying and supplementing our original affidavit.

5. Separately, the IMM claims that the variable operation and maintenance ("VOM") cost for the CT should be higher but does not provide enough detail to evaluate this claim. Our VOM value remains reasonable.

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[1] *PJM Interconnection, L.L.C.*, Affidavit of Dr. Samuel A. Newell, Dr. Andrew W. Thompson, Dr. Bine Zhou, and Joshua C. Junge, Regarding Updates to PJM's CONE and Net Energy and Ancillary Service Offset Parameters for Delivery Years 2028/29 through 2031/32, Docket No. ER26-455-000 (Nov. 7, 2025) ("CONE Affidavit").

[2] *PJM Interconnection, L.L.C.*, Protest of the Independent Market Monitor for PJM, Docket No. ER26-455-000 (Dec. 18, 2025) ("IMM Protest").

A. Project Timeline and Capital Expenditure Schedule

6. Capital expenditure schedules affect the CONE calculation by defining the times at which various components of the overnight capital costs are incurred. Incurring more capital costs earlier increases capital carrying costs and thus total installed project costs and the CONE value.

7. The IMM's capital expenditures start 21 months earlier relative to the same commercial online date but are overall weighted much later, resulting in lower capital carrying costs and CONE estimates. The IMM's earlier project timeline simply reflects the explicit representation of project development (i.e., siting, permitting, design, etc.), whereas our model starts closer to construction, at the final investment decision and incorporates the development costs occurring both before and after FID into the overall overnight cost. Our approach is consistent with past PJM CONE studies which have all defined the project timeline as between FID and the commercial operation date ("COD").

8. The bigger difference arises from the timing of the much larger construction costs, especially payments for major equipment. Our version reflects current tight market conditions with long lead-times for major critical path equipment, whereas the IMM's version appears not to. These conditions have resulted in reservation fees and more front-loaded payment schedules for turbines and other major equipment provided by the OEMs. As Brattle/S&L explained in our Affidavit, in meetings with the IMM, and in presentations to the PJM Market Implementation Committee ("MIC"), our overall capital drawdown schedule reflects actual recent and ongoing projects for which S&L is serving as the owner's engineer, and we have validated the embedded payment schedule for major equipment through extensive dialogue with General Electric ("GE"). Given that both Brattle and the IMM assume the CT reference resource uses the GE 7HA.03 turbine technology, GE is the authoritative source on OEM payment requirements. GE confirmed S&L's interpretation of GE's standard contract terms for major equipment, which include a deposit for reservation of a turbine production slot, a lump-sum payment upon contract signing, then a series of milestone-based or monthly calendar payments for most of the contract duration, followed by further lump-sum payments upon equipment ready-to-ship and delivery, and finally a smaller payment or series of payments concluding at COD. GE provided Brattle/S&L with a standard payment schedule for the 7HA.03 technology and related major equipment for the CT. This payment schedule is consistent with S&L's modeling of payments for turbines and other major GE-provided equipment embedded in the

capital expenditure schedule. This standard payment schedule from GE was also shared with the IMM.[3]

9. Our assumptions are further corroborated by industry announcements. For example, in their recent filing before the Kentucky Public Service Commission, Kentucky Utilities and Louisville Gas & Electric noted that they were required to pay GE a $25 million reservation fee to lock-in firm pricing for the equipment.[4] In a recent interview with Mitsubishi Power's Vice President of Business Development for Emerging Technologies, Peter Sawicki noted that "We're back to the days of reservation fees similar to the 2000s… So it does make things challenging for power developers, really where you have to put this deposit down very early on a project."[5]

10. In contrast, the IMM's back-loaded capital drawdown and OEM payment schedule do not appear to align with current industry conditions, and this understates current CONE. Furthermore, the IMM does not clearly explain its specific assumptions or evidentiary basis and also has not released its drawdown schedule nor CONE model publicly.[6]

B. Bonus Depreciation

11. The IMM is incorrect in its claim that Brattle provided no evidence to support the assumption that investors would not be able to fully realize immediate tax deductions from 100% bonus depreciation. Our CONE Affidavit explained the rationale and cited our presentation in the

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3 *See* PJM, MIC Meeting, posted meeting materials (Aug. 18, 2025), https://www.pjm.com/committees-and-groups/committees/mic. Materials include the Brattle CONE model, which embeds the capital drawdown schedules, https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2025/20250822-special/updated-brattle-cone-model.xlsx.

4 *See* Direct Testimony of Lonnie E. Bellar, Senior Vice President, Engineering and Construction on Behalf of Kentucky Utilities Company and Louisville Gas and Electric Company, Kentucky PSC Case No. 2025-00045, at 11 (Feb. 28, 2025), https://psc.ky.gov/pscecf/2025-00045/rick.lovekamp%40lge-ku.com/02282025010202/12-Bellar_Direct_Testimony_2025-00045.pdf.

5 *See* POWER Magazine, "The POWER Interview: Mitsubishi Power Talks Turbine Constraints, Data Center Pressures, and Hydrogen Readiness" (Apr. 21, 2025), https://www.powermag.com/the-power-interview-mitsubishi-power-talks-turbine-constraints-data-center-pressures-and-hydrogen-readiness/.

6 The IMM's description of the drawdown schedule including "*EPC and GE payments in the middle months*" is vague and could mean many different possibilities over a 65-month project timeline. Based on descriptions by the IMM in public MIC meetings, the IMM assumes that 70% of the cost for turbines is paid as a lump-sum in a single month and the remaining 30% is incurred at later points somewhere in those "middle months," instead of the standard payment schedule provided by GE. However, at that time the IMM's project timeline for the CT was 37-months instead of the now revised 65-month schedule and it is not possible to determine additional differences or assess further the reasonableness of the IMM's drawdown schedule since this has not been provided publicly.

August 18th, 2025 MIC meeting, where Brattle presented supporting evidence.[7] It is the IMM's claims that are unsupported by evidence.

12. As explained in our CONE Affidavit, the One Big Beautiful Bill Act ("OBBBA") reinstated 100% bonus depreciation for eligible investments, which include gas power plant assets placed into service before January 2031.[8] 100% bonus depreciation enables investors to deduct the asset cost immediately from taxable income. However, a full deduction right away is possible only with sufficiently high taxable income. Otherwise, this tax benefit would have to be carried forward as a net operating loss ("NOL") to support future tax deductions with a lower present value. Our analysis and evidence presented showed that having such a high taxable income to be able to fully deduct the cost of a gas-fired plant is unrealistic for generation developers.

13. For example, even taking the IMM's understated total project costs, would require an investor in a single CT generator in CONE Area 3 to have a taxable income of at least $542 million to be able to fully realize 100% bonus depreciation in the first year.[9] This is high compared to the estimated taxable income of four publicly traded independent power producers ("IPPs") in PJM, as Dr. Zhou demonstrated at the August 18th PJM MIC meeting (Table 1).[10] Over the most recent three years (2022–2024), all but one IPP had much lower taxable income than the cost of a single CT project; and even the IPP with higher taxable income (Constellation) would find its tax appetite limited if it is building multiple projects nationally to meet the current high national demand for power.

TABLE 1: TAXABLE INCOME OF PUBLICLY TRADED INDEPENDENT POWER PRODUCERS IN PJM

Taxable Income for GAAP Reporting and US Tax Returns

($ in Millions)		2022	2023	2024	2022	2023	2024	2022	2023	2024	2022	2023	2024
		A. Constellation			B. NRG			C. Talen			D. Vistra		
GAAP Income Before Income Taxes	[A]	(542)	2,447	4,516	1,663	(213)	1,448	(1,328)	871	1,111	(1,560)	2,000	3,467
Federal Taxes - Current	[B]	219	464	426	3	26	55	(9)	(12)	(113)	2	(1)	2
Inferred Taxable Income	[C]	1,043	2,210	2,029	14	124	262	(43)	(57)	(538)	10	(5)	10

Sources and Notes: AES is excluded from the analysis because of its substantial international and regulated utility operations.
[A] and [B] from company 10-Ks. Talen for 2023 is the sum of two partial years.
[C] = [B] / 21%, where 21% is the federal tax rate.

Source: Sixth Review of PJM's RPM VRR Curve Parameters, Interim Update: Gross CONE with Technology Cost and Depreciation Updates (Presented at the August 18, 2025, PJM MIC Meeting).

7 *See* PJM, MIC Meeting, Sixth Review of PJM's RPM VRR Curve Parameters, Interim Update: Gross CONE with Technology Cost and Depreciation Updates (Aug. 18, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2025/20250822-special/brattle-updated-cone-presentation.pdf.

8 With the CT reference resource's COD of June 2028, this asset would qualify.

9 *See* IMM Protest at Table 1.

10 *See* PJM, MIC Meeting, Sixth Review of PJM's RPM VRR Curve Parameters, Interim Update: Gross CONE with Technology Cost and Depreciation Updates (Aug. 18, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2025/20250822-special/brattle-updated-cone-presentation.pdf.

14. The question arose whether IPPs could still monetize much of the value of bonus depreciation right away by structuring arrangements with tax equity investors, so Brattle consulted with experienced tax advisors in the energy space. They indicated that since the last time 100% bonus depreciation was introduced under the 2017 Tax Cuts and Jobs Act, no market has developed for depreciation-only investment structures with partner entities like it has for clean energy tax credits. We concluded that it is unrealistic for an IPP to recognize bonus depreciation more quickly than its own taxable income allows.

15. To develop a more realistic representation of how an IPP could monetize 100% bonus depreciation, we assumed that the marginal IPP would take the 100% bonus depreciation in year 1, carry the resulting NOL forward, and use it up as quickly as its taxable income allows. This will result in something in between the full year-1 realization of 100% bonus depreciation (a "Min" CONE benchmark) and the original MACRS of 15 years for CT (a "Max" CONE benchmark). While it is difficult to establish a single, precise value applicable to all marginal suppliers given their varying incomes, project development portfolios, and tax strategies, we assumed a 7-year straight-line depreciation as a reasonable approximation for CT plants.[11] The resulting present value of tax deductions and the resulting CT CONE is mathematically equivalent to a 40/60 weighted average between the Min and Max CONE benchmarks. We presented this calculation to stakeholders as a comparison point demonstrating that the CT CONE with a 7-year straight-line depreciation schedule is reasonably in between the two benchmarks.[12] The IMM incorrectly characterizes this 40/60 ratio however as related to Brattle's depreciation schedule and provides irrelevant and incorrect calculations examining the implied depreciation in year 1.[13]

C. Variable Operations & Maintenance Cost

16. The variable operations and maintenance ("VOM") costs used by Brattle/S&L ($2.65/MWh) and the IMM ($5.30/MWh) for calculation of the Net E&AS offset differ significantly, mostly

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[11] As defined by the then-current IRS guidance on depreciation for property. *See* U.S. Department of the Treasury, Internal Revenue Service, "Publication 946 (2023): How to Depreciate Property," Table A-10. Straight Line Method Mid Quarter Convention Placed in Service in Second Quarter.

[12] *See* PJM, MIC Meeting, Sixth Review of PJM's RPM VRR Curve Parameters, Interim Update: Gross CONE with Technology Cost and Depreciation Updates (Aug. 18, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2025/20250822-special/brattle-updated-cone-presentation.pdf.

[13] The IMM claims that Brattle's first-year depreciation is "40 percent bonus depreciation and 60 percent 15 year MACRS ($289 million) for a CT" by comparing this to implied first-year depreciation from other depreciation schedules. The IMM incorrectly characterizes Brattle's approach, as the 40/60 weighted average is related to the present value of a more realistic use of bonus depreciation over a CT plant's lifetime, not the first-year depreciation. Additionally, the IMM incorrectly applies depreciation percentages to total project costs instead of the depreciable basis. *See* IMM Protest at 5-6 and Table 1.

attributable to the difference in the major maintenance costs.[14] Major maintenance costs reflect variable monthly payments tied to that month's operations as defined in the OEM's long term service agreement ("LTSA"). Payments can be structured in a "starts-based" regime for plants with relatively large number of starts and a lower capacity factor, or an "hours-based" regime for those with higher capacity factors and fewer starts, but the rates per relevant determinant may vary somewhat with operating profiles. Given that PJM's E&AS simulations indicated high capacity factors for CTs, we modeled an hours-based (MWh-based) regime and identified VOM for a 40% capacity factor as a representative value for the diversity of areas in PJM. S&L then relied on an OEM quote for LTSA charges given a 40% capacity factor and applied this to all areas. This resulted in $1.93/MWh, which, when combined with other cost components resulted in a total variable major maintenance cost of $1.98/MWh and a grand total VOM of $2.65/MWh in 2028 dollars.[15] This is a reasonable intermediate value that does not vary by area even though one might be able to obtain quotes for different operating profiles among areas, with higher costs per MWh in areas with lower capacity factors.

17. The IMM's argument that the VOM should be determined iteratively with simulated capacity factors appears to be inconsistent with its assertion of a single VOM cost per MWh applicable to a diversity of areas. Further, since the IMM has not shared or published details of their VOM inputs such as LTSA fixed fees, variable fees, milestone fees, and other major maintenance cost inputs, it is not possible to provide an opinion to the reasonableness of the IMM's assumptions or evaluate the differences from ours.

18. **This concludes our affidavit.**

[14] The IMM assumes $4.90/MWh major maintenance + $0.40/MWh consumables while S&L assume $1.98/MWh major maintenance + $0.66/MWh consumables. See IMM Protest, Table 3.

[15] $1.93/MWh is from the LTSA and ~$0.05/MWh comes from plant staff overtime attributable to major maintenance activities which together make the $1.98/MWh major maintenance cost in our VOM estimate. Our VOM calculations are further documented in the 2025 PJM CONE Report, the CONE Affidavit, and the Brattle CONE model.

D. Certification

We hereby certify that we have read the filing signed and know its contents are true as stated to the best of our knowledge and belief. We possess full power and authority to sign this filing.

Respectfully Submitted,

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