Attachment E

Affidavit of
Dr. Samuel A. Newell, Dr. Andrew W. Thompson, Dr. Bin 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

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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

AFFIDAVIT
OF
Dr. SAMUEL A. NEWELL, Dr. ANDREW W. THOMPSON, Dr. BIN 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

November 7, 2025

I. Qualifications

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 at The Brattle Group ("Brattle"). Mr. Junge is employed as a Principal Energy Consultant at Sargent & Lundy ("S&L"). We submit this affidavit to the Federal Energy Regulatory Commission in support of the proposal by PJM Interconnection, L.L.C. ("PJM") to adjust 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). Additionally, we assessed PJM's net energy and ancillary services offset ("EAS Offset") methodology to calculate Net CONE.

2. A complete description of the study approach regarding the selection of reference technologies, cost of capital, the bottom-up cost analysis, the calculation of CONE, and our review of the EAS Offset methodology can be found in our report titled Brattle 2025 CONE Report for PJM ("2025 CONE Report") and subsequent presentation updates attached to this affidavit.[1] The results of our independent review of the Variable Resource Requirement ("VRR") Curve parameters are set forth in a separate report ("2025 VRR Curve Study") and affidavit filed concurrently with this affidavit ("Brattle VRR Curve Affidavit").[2]

3. Our qualifications as experts derive from our extensive experience evaluating the Cost of New Entry and EAS Offset methodologies in the context of capacity markets and alternative market designs for resource adequacy.

4. Dr. Newell, who led the team, is an economist and engineer with over 25 years of experience analyzing and modeling electricity wholesale markets, the transmission system, and RTO market rules. He earned a Ph.D. in Technology Management and Policy from the Massachusetts Institute of Technology, an M.S. in Materials Science and Engineering from Stanford University, and a B.A. in Chemistry and Physics from Harvard College. His relevant experience includes: having co-

[1] *See* Exh. No. 2 (Newell, Thompson, Zhou, et al., *Brattle 2025 CONE Report for PJM, Informing Parameters for PJM's RPM Auctions for Delivery Year 2028/29 through 2031/32*, The Brattle Group (Apr. 9, 2025), https://www.brattle.com/wp-content/uploads/2025/04/Brattle-2025-CONE-Report-for-PJM.pdf). ("2025 CONE Report"). *See also* Exh. No. 3 (Newell, Zhou, Thompson, et al., *Sixth Review of PJM's RPM VRR Curve Parameters, Interim Update: Gross CONE with Technology Cost and Depreciation Updates*, PJM Interconnection, L.L.C. (Aug. 18, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2025/20250822-special/brattle-updated-cone-presentation.pdf (Presented at the August 18, 2025, PJM MIC Meeting.)).

[2] *See* Attach. D (Affidavit of Dr. Kathleen Spees, Dr. Samuel A. Newell, and Dr. Andrew W. Thompson, Regarding the Sixth Review of PJM's Variable Resource Requirement Curve (Nov. 7, 2025) ("Brattle VRR Curve Affidavit")); Attach. D, Exh. No. 2 (Spees, Newell, and Thompson, et al., *Sixth Review of PJM's Variable Resource Requirement Curve for Planning Years 2028/29 Through 2031/32*, The Brattle Group (Apr. 9, 2025), https://www.brattle.com/wp-content/uploads/2025/04/Sixth-Review-of-PJMs-Variable-Resource-Requirement-Curve.pdf ("2025 VRR Curve Study").

authored the prior five PJM CONE studies and submitted affidavits in ensuing litigation, which informed the Net CONE values PJM used in its annual capacity auctions for the last seventeen years; other CONE studies and/or market design assignments for the Independent System Operator of New England (ISO-NE), New York Independent System Operator, Inc., Midcontinent Independent System Operator, Inc., the Electric Reliability Council of Texas (ERCOT), and internationally; and numerous generation asset valuation studies and resource planning studies.

5. Dr. Thompson is an energy economist with a background in electrical engineering and expertise in wholesale electricity market design, regulatory economics, and policy analysis of network industries, particularly in the energy sector. He earned a Ph.D. in Economics from the Université Paris-Saclay, an M.S. in Energy Economics from the Universidad Pontificia Comillas, an M.Sc. in Engineering and Policy Analysis from the Delft University of Technology, and a B.Sc. in Electrical and Computer Engineering from Rowan University. His relevant experience includes: co-authoring the previous 2022 PJM Quadrennial Review; a 2024 CONE study for ERCOT; and similar studies for the Ontario Independent Electricity System Operator (IESO).

6. Dr. Zhou is an expert in valuation, corporate finance, and accounting, with over 25 years of consulting experience. He earned a Ph.D. in International Economics and Finance from Brandeis University, an M.A. in Economica from Washington State University, and a B.A. in Economics from Fudan University (China). His relevant experience includes: co-authoring the previous four CONE studies for PJM and extensive other studies on the cost of capital and topics in corporate finance.

7. Mr. Junge is an engineer with 14 years of experience in engineering design and consulting on a wide range of electric power projects including gas, coal, biomass, wind, solar PV, and battery energy storage technologies. He has extensive experience in the design of power projects, estimation of power project capital costs, operations and maintenance ("O&M") costs, and plant performance. His relevant experience includes: leading the S&L team working with Brattle for the 2022 PJM Quadrennial Review CONE Study and subsequent update in 2024 as well as a CONE Study with Brattle for ERCOT in 2024. In addition to these CONE studies, he led the S&L team supporting the U.S. Energy Information Administration (EIA) with its Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies report published in January of 2024. Mr. Junge is a licensed Professional Engineer in the States of Illinois and Texas and earned a B.S. in Mechanical Engineering from the University of Illinois-Urbana/Champaign.

8. Complete details of our qualifications, publications, reports, and prior experiences are set forth in our resumes included as Exhibit No. 1 to our affidavit.

II. Introduction

9. Beginning in fall 2024, PJM retained Brattle to conduct an independent review and performance assessment of the VRR Curve used as the demand curve in RPM auctions. Key components of the VRR Curve shape and parameters, including the CONE and the method to estimate the net revenues the Reference Technology could earn in PJM's energy and ancillary services markets ("EAS Offset"), were additionally reviewed as required periodically under PJM's Open Access Transmission Tariff ("Tariff").

10. Dr. Newell led the Brattle review of CONE parameters and EAS Offset approach together with Mr. Jungé leading the S&L team as a sub-contractor. The Brattle team's role was to estimate CONE by determining the configurations and locations of the reference plants for a gas-fired combustion turbine ("CT"), a gas-fired combined cycle ("CC"), and a 4-hour battery energy storage system ("BESS"); overseeing S&L's estimates of the plant proper costs and fixed O&M costs; estimating certain components of capital costs (e.g., gas and electric interconnection, sales tax, net start-up fuel costs, fuel inventories, land costs, and working capital); estimating certain components of fixed O&M costs (e.g., insurance, property and sales taxes and firm gas contracts); analyzing the key financial assumptions (e.g., cost of capital and tax depreciation schedule); reviewing the EAS Offset approach and recommending enhancements if necessary; and calculating the levelized costs to result in CONE.

11. S&L's role was to contribute expertise in determining the configurations and locations of the reference plants; contribute market-informed insights on recent trends in new merchant resources built or under construction primarily in PJM; and to provide detailed capital and fixed O&M cost estimates and performance characteristics of the reference plants for each PJM CONE Area. Working with Brattle, S&L refined the technical design and representative locations within each CONE Area for a CT, CC, and a BESS reference technology, and developed bottom-up cost estimates across all five CONE Areas for each technology (15 total estimates).

12. The analysis involved extensive input and feedback from stakeholders. At the PJM Market Implementation Committee ("MIC") meetings Brattle and S&L presented and iterated on findings, analysis, and potential recommendations related to the CONE analysis and VRR Curve parameters.[3] At the MIC meetings, stakeholders had a chance to ask questions, provide comments, and offer their own presentations. We responded to stakeholder questions at the MIC meetings and in writing. Throughout the process, we discussed the assumptions and results extensively with PJM

[3] *See* Market Implementation Committee, Meeting Materials, PJM Interconnection, L.L.C., https://www.pjm.com/committees-and-groups/committees/mic (last visited Nov. 7, 2025) (see proposals and evaluations in Meeting Materials for the Quadrennial Review from September 2024 to September 2025).

staff and with PJM's Independent Market Monitor ("IMM"). That process culminated in our publishing the 2025 CONE Report on April 9, 2025. After the publication of the 2025 CONE Report, Brattle, S&L, PJM, the IMM, and stakeholders continued to iterate on the reference technologies, various technical and economic assumptions, and corresponding CONE values. At the August 18, 2025 MIC meeting, Brattle and S&L presented final CONE estimates incorporating various updates from the 2025 CONE Report (see Section IV.B Post-April 2025 Updates, below).[4]

III. Summary of Conclusions

13. The principal conclusions of the CONE Study and subsequent refinements that inform PJM's filing include: the reference technology specifications, CONE estimates and annual update formulas, and EAS methodology. Although PJM and stakeholders have selected a CT as the reference technology for the VRR curve, we describe below the specifications and CONE estimates for CCs and BESS candidates as well.

14. Technical specifications are as follows: the representative **CT resource** is a 440 MW (ICAP) plant consisting of a single General Electric ("GE") Frame 7HA.03 CT, selective catalytic reduction (SCR), an evaporative cooler, wet compression, and dual-fuel capability with on-site storage of distillate oil sufficient for three days.[5] The CT has a higher-heating value ("HHV") heat rate of 9,300 British thermal unit/kilowatt hour (Btu/kWh) at full load (average of 5 CONE Areas at max summer conditions with wet compression and evaporative cooling on) and an HHV heat rate of 9,199 Btu/kWh under the same conditions but with wet compression off. The CT is assumed to have an economic life of 20 years except in the Commonwealth Edison ("ComEd") zone, where the life would be truncated in 2040 by Illinois' Clean Energy and Jobs Act ("CEJA").[6]

15. The representative **CC resource** is a 1,401 MW ICAP plant with GE 7HA.03 turbines in two trains of a single-shaft CC plant, each with a single CT, heat recovery steam generator ("HRSG"), and steam turbine (i.e., two "single-shaft 1×1s"). Additionally, the CC has SCR, dry air-cooled condensers, duct-firing, and a firm gas transportation contract instead of dual-fuel capability. The CC has an HHV heat rate of 6,509 Btu/kWh at full load (average of 5 CONE Areas at max summer conditions with wet compression, evaporative cooling, and duct-firing on) and an HHV heat rate of 6,434 Btu/kWh

[4] *See* Sixth Review of PJM's RPM VRR Curve Parameters, Interim Update: Gross CONE with Technology Cost and Depreciation Updates; *see also* Market Implementation Committee, Meeting Materials, PJM Interconnection, L.L.C. https://www.pjm.com/committees-and-groups/committees/mic (last visited Nov. 7, 2025) (for additional presentations for the Quadrennial Review between September 2024 to August 2025).

[5] 440 MW ICAP is the average of the 5 CONE Areas at Max Summer conditions firing natural gas with wet compression and evaporative cooling on.

[6] *See* 2025 CONE Report § IV.A; Climate and Equitable Jobs Act, Pub. Act 102-0662, 2021 Ill. Laws 11852 ("CEJA").

under the same conditions but with wet compression off. Like with the CT, the CC is assumed to have an economic life of 20 years, except in ComEd where it is 16.5 years for 2028/29 due to CEJA.[7]

16. The representative **BESS resource** is a 200 MWac battery storage with a 4-hour duration and a 26.09% initial oversizing with five capacity augmentations to maintain charge capability and duration throughout the lifetime of the plant. Augmentations are planned for every three years starting in the fifth year of operation. The BESS has an economic life of 20 years in all CONE Areas since it would be unaffected by CEJA in ComEd.

17. For each of these technologies, Table 1 below summarizes plant capital and annual fixed O&M costs based on our bottom-up cost estimates as described further below. Table 1 also shows resulting CONE estimates for each CONE Area, based on nominally levelizing the capital and fixed costs over an assumed 20-year life with an estimated after-tax weighted-average cost of capital (ATWACC) of 9.5%[8] As discussed further below, the CONE for CT and CC are substantially higher than in past studies because they reflect tight market conditions for combustion turbines and other key inputs.

[7] *See* 2025 CONE Report § V.A; CEJA.

[8] Except for the CT and CC in ComEd due to CEJA. *See* 2025 CONE Report §§ IV.A, V.A.

TABLE 1: FINAL CONE RESULTS BY TECHNOLOGY AND CONE AREA

CONE Area	Technology	Overnight Capital Cost	Capital Charge Rate	Year 1 Capital Recovery	Levelized Fixed O&M	Gross CONE ICAP	Gross CONE UCAP
		[A]	[B]	[C]	[D]	[E]	[F]
Nominal$ for 2028 Online Y		$/kW	%/year	$/MW-day	$/MW-day	$/MW-day	$/MW-day
1. EMAAC	Gas CT	$1,278	15.3%	$535	$61	**$596**	**$754**
	Gas CC	$1,449	16.3%	$645	$106	**$752**	**$928**
	BESS 4-hr	$1,832	9.4%	$470	$197	**$667**	**$1,026**
2. SWMAAC	Gas CT	$1,235	15.3%	$516	$91	**$608**	**$769**
	Gas CC	$1,354	16.2%	$601	$159	**$761**	**$939**
	BESS 4-hr	$1,753	9.4%	$450	$208	**$658**	**$1,013**
3. Rest of RTO	Gas CT	$1,247	15.2%	$521	$69	**$590**	**$747**
	Gas CC	$1,363	16.2%	$605	$152	**$757**	**$934**
	BESS 4-hr	$1,750	9.4%	$449	$191	**$640**	**$984**
4. WMAAC	Gas CT	$1,274	15.2%	$532	$60	**$592**	**$749**
	Gas CC	$1,415	16.2%	$628	$127	**$754**	**$931**
	BESS 4-hr	$1,784	9.4%	$458	$196	**$655**	**$1,007**
5. COMED	Gas CT	$1,369	16.5%	$619	$60	**$679**	**$860**
	Gas CC	$1,579	17.6%	$760	$100	**$860**	**$1,061**
	BESS 4-hr	$1,980	9.3%	$507	$204	**$711**	**$1,093**

Notes and Sources:
See 2025 CONE Report for more details.
[A], [B], [D]: Brattle CONE analysis.
[C]: [A] × [B] × 1000/365.
[E]: [C] + [D].
[F]: [E]/ELCC of reference technology. ELCC for CT = 79%, CC = 81%, and BESS = 65% for 2028/29.

18. While Table 1 summarizes CONE values for delivery year 2028/29, these values also serve as a basis for the following three delivery years until the next Quadrennial Review. The PJM Tariff specifies that prior to each Base Residual Auction, PJM will develop CONE values by escalating prior CONE values to account for changes in input costs. For this purpose, S&L recommended a blend of cost indices that can be used to update CONE, as described in the 2025 CONE Report and below.[9]

19. Regarding our review of PJM's EAS Offset methodology, we conclude that PJM's forward-looking EAS offset methodology remains reasonable and aligned with industry standard practice.[10] We

[9] 2025 CONE Report § IX.B.

[10] Application of this forward methodology leads to indicative EAS offset values that are much greater than in prior years because of tight market conditions with high spark spreads embedded in forward prices, especially for CCs.

recommend, however, a refinement to the PJM RTO-wide calculation of Net CONE, to no longer conduct a virtual dispatch on a single set of synthetic energy and gas prices averaged across all Locational Deliverability Areas ("LDAs"), but rather to calculate the EAS Offset and Net CONE for each LDA, then represent the RTO Net CONE as the 33rd percentile among the constituent LDA Net CONEs (see Section V below).[11] It will be reasonable for PJM to continue to update the CONE and EAS Offsets prior to each auction for MOPR purposes using these approaches.

IV. Development of CONE Estimates

A. April 2025 Study

CONE Estimates for 2028/29

20. We estimated CONE by following the same methodology as in past reviews, but in a notably different context with tight markets for supply causing high and rapidly changing costs.[12] Frame combustion turbines are particularly scarce, as are high-voltage transformers, switch gear, and other components. Scarcity of these components alongside strong demand for qualified labor and for engineering, procurement, and construction (EPC) contractors with experience in thermal power has driven the cost of new gas-fired generation plants 43%–46% higher than in the CONE study conducted 2.5 years ago after accounting for inflation.[13] In these tight conditions, prices are not only high but subject to substantial uncertainty and rapidly evolving market conditions, as evidenced by original equipment manufacturer ("OEM") quotes obtained at several points in the study. Prices are likely to remain high and volatile for several years until supply chains and labor forces can develop sufficient capacity to support demand. Volatility is compounded by increased and ongoing fluctuations in trade tariffs.

21. As in previous reviews, our approach to estimate CONE was to first specify representative plant locations, technology choices, and configurations informed by actual projects and confirmed through consultation with stakeholders. The 2022 PJM CONE Report characterized all the recent CT plants either built or under construction by size, configuration, turbine type, cooling system, emissions controls, and fuel-firming approach to determine the most representative technical

See 2025 CONE Report § VII; Attach. C, Affidavit of Skyler Marzewski on behalf of PJM Interconnection, L.L.C., ¶ III.B.

11 This approach was also recommended to calculate the parent LDA Net CONE for EMAAC, SWMAAC, Rest of RTO, WMAAC, ComEd, and MAAC.

12 2025 CONE Report § II.

13 As of the April 2025 publication of the 2025 CONE Report.

specifications as revealed by developer's preferences for merchant generation in PJM.[14] This analysis was supplemented by reviewing the one additional gas-fired CT plant that has entered since 2022 as well as input from stakeholders and the IMM. Additionally, since the 2022 PJM CONE Report, PJM has adopted a new capacity accreditation approach based on the Marginal Effective Load Carrying Capability ("ELCC"), which results in a substantial premium on the capacity value for CTs with dual fuel capability compared to CTs without. Notably, the one new CT plant in development since the 2022 PJM CONE Report is planning to install dual-fuel capability. Based on conversations with S&L, developers, and the IMM, the 7HA.03 GE turbine model was chosen over the 7HA.02 model used in the 2022 PJM CONE Report because of its improved performance at a lower cost per-kW which is making it an increasingly attractive option. It is thus more likely that plants that will be finished for the 2028/29 delivery year will feature 7HA.03 turbines, as observed in recently proposed projects. This analysis resulted in the CT plant configuration explained above, with the exception of wet compression which was added later (see following section). Based on these representative plant configurations, Brattle and S&L conducted a comprehensive, bottom-up analysis of the capital costs to build the plant including owner-furnished equipment, EPC, and non-EPC owners' costs for each CONE Area. Brattle and S&L additionally estimated annual fixed O&M costs, including labor, materials, property taxes, insurance, and, in the case of the BESS, battery augmentation costs.

22. In this review, however, we adjusted our approach to cost estimation to recognize the current scarcity in capital and labor inputs, uncertainty in costs, and rapidly evolving market conditions in PJM and throughout North America. We solicited input from a wide range of stakeholders and industry experts. We placed more emphasis on benchmarking costs to updated quotes from OEMs and conducted many interviews with GE and other OEMs, BESS developers and integrators. As such, we believe the resulting cost estimates are reflective of the very recent market conditions and constitute our best estimates given the substantial uncertainty and dynamism in the market. Given the estimated capital and fixed costs of each technology, we then calculated a levelized CONE value in all CONE Areas, assuming an economic lifespan and revenue trajectory, an appropriate ATWACC, and other standard financial parameters. Consistent with prior reviews, we assumed 20 years of cash flows that are constant in nominal terms ("level-nominal," meaning declining in real terms), but shorter in ComEd.[15] While alternative levelization and benchmarking approaches were explored in the 2025 CONE Report, PJM and stakeholders elected to maintain the level-nominal approach applied to the CT reference resource to send a stable long-term signal in line with

[14] *See* Newell, Hagerty, Pfeifenberger, et al., *PJM CONE 2026/2027 Report*, The Brattle Group (Apr. 21, 2022), https://www.brattle.com/wp-content/uploads/2022/05/PJM-CONE-2026-27-Report.pdf ("2022 PJM CONE Report").

[15] For all technologies and in all CONE Areas, except for ComEd for the thermal plants, which used 16.5 years of cashflows in line with the economic life for 2028/29.

previous reviews. The ATWACC was estimated using the same methodology as in prior reviews, but with updated data from capital markets. The result was a 9.5% ATWACC for merchant generation, which we applied to all technologies' CONE calculations.[16]

Annual CONE Updating Process

23. The PJM Tariff specifies that, prior to each auction, PJM will escalate CONE to track changes in costs for each year between CONE studies. Accordingly, and consistent with current practice, PJM proposes to adjust CONE annually by the percentage change in a composite capital cost index over the twelve-month period immediately prior to the required publication date for updated CONE values in each BRA. The composite capital cost index for each technology is provided in the 2025 CONE Report.[17]

24. To develop the composite capital cost indexes, S&L characterized the major components of plant costs and then selected corresponding public, transparent, and frequently-updated indexes from the Bureau of Labor Statistics (BLS) and Bureau and Economic Analysis (BEA), consistent with the Association for the Advancement of Cost Engineering (AACE) industry standards and S&L's cost estimating process guidelines as a professional engineering services firm.[18] These components and indexes include construction labor (BLS QCEW),[19] construction materials (BLS PPI ID6 Materials and Components for Construction),[20] OEM turbine equipment (BLS PPI Turbines and Turbine Generator Sets),[21] and other costs (BEA GDP implicit price deflator).[22] The latter—a newly defined component since the 2022 PJM CONE Report—helps better account for cost components that do not fall within

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16 *See* 2025 CONE Report § III.C.

17 While Brattle and S&L developed more granular composite indices that could be applied to capital cost recovery and fixed O&M cost separately, PJM's application of only the capital component to CONE is reasonable since CONE consists primarily of capital costs (for the CT, for example, fixed O&M costs account for only 12% of CONE). *See* 2025 CONE Report, § IX.B.

18 *See* Newell, Thompson, Zhou, et al., Brattle 2025 CONE Report for PJM, Informing Parameters for PJM's RPM Auctions for Delivery Year 2028/29 through 2031/32, The Brattle Group, at 90 tbl. 28 (Apr. 9, 2025), https://www.brattle.com/wp-content/uploads/2025/04/Brattle-2025-CONE-Report-for-PJM.pdf ("2025 CONE Report Table 28")

19 2025 CONE Report Table 28. (The BLS' Quarterly Census of Employment and Wages for the CONE Zone representative state, NAICS 2371 Utility System Construction, Private, All Establishment Sizes.)

20 2025 CONE Report Table 28. (The BLS' Producer Price Index "Intermediate Demand by Commodity Type" Materials and Components for Construction, not seasonally adjusted.)

21 2025 CONE Report Table 28. (The BLS' Producer Price Index for Commodities, Machinery and Equipment, Turbines and Turbine Generator Sets, not seasonally adjusted.)

22 2025 CONE Report Table 28. (BEA: Gross Domestic Product Implicit Price Deflator, Seasonally Adjusted.)

the definitions of labor, materials, or equipment.[23] Finally, the weighting of each index for the CT, CC, and BESS reference technologies corresponds to the cost structures of each technology, accounting for current market conditions.[24]

B. Post-April 2025 Updates

25. After the publication of the 2025 CONE Report, Brattle, S&L, PJM, the IMM, and stakeholders continued to refine, update, and validate the CONE estimates and VRR Curve shapes. CONE refinements focused on both physical updates and financial ones, including adding wet compression, incorporating updated performance specifications from GE (including higher firing temperature), and an updated inlet pressure drop assumption. Financial updates consisted of incorporating the value of 100% bonus depreciation being reinstated in law.[25] We did not update other financial assumptions since the original ones were validated by further inquiry, as discussed below.

26. These refinements culminated in revised CONE values, as presented at the August 18, 2025 MIC meeting and are incorporated in the summary of results, in Table 1, above. Relative to the April 2025 CONE study, the physical updates (including wet compression, a higher firing temperature, and reduced inlet pressure drop) for the CT increased ICAP by 13% while increasing overnight costs by only 3.5%, resulting in 8.5% lower overnight cost in $/kW ICAP terms and a $50/MW-day ICAP reduction in CONE.[26] For the CC, these refinements increased ICAP by 9% while increasing

[23] Since many of the project costs are not driven by labor, construction materials, or OEM turbine producer pricing, a broad economy-wide index like the GDP implicit price deflator is a more appropriate escalator for these uncategorized components and is frequently used in other CONE studies. S&L reassigned some costs that previously were escalated with labor and materials indices in the 2022 PJM CONE Report to the GDP implicit price deflator which better reflects the escalation of these cost components. As a consequence, the relative weights of the labor and materials indices reduced relative to the 2022 PJM CONE Report. *See* 2025 CONE Report § IX.B; 2022 PJM CONE Report § III.G; and *Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2025-2026 through 2028-2029 Capability Years: Final Report (Updated Version)*, Analysis Group, Inc. & 1989 & Co. (Oct. 2, 2024), https://www.nyiso.com/documents/20142/47366127/Analysis-Group-2025-2029-DCR-Final-Report-Updated.pdf.

[24] For example, turbines make up a greater proportion of total capital costs for the CT reference technology than for CCs. CCs include more balance-of-plant equipment and associated labor and materials for construction, so the relative proportion of turbine cost to total capital cost is lower than for CTs. This difference has become even more pronounced with recent escalation of turbine costs far outpacing most other cost components. *See* 2025 CONE Report § IX.B; 2022 PJM CONE Report § III.G.

[25] *See* Sixth Review of PJM's RPM VRR Curve Parameters, Interim Update: Gross CONE with Technology Cost and Depreciation Updates.

[26] *See* Newell, Thompson, et al., *Sixth Review of PJM's RPM VRR Curve Parameters, Interim Update: Gross CONE for Area 3, Rest of RTO*, PJM Interconnection, L.L.C., at 2 (Aug. 6, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2025/20250806/20250806-item-05-2---review-of-pjm-

overnight cost by 4.8%, resulting in 4% lower $/kW ICAP overnight cost and a $36/MW-day ICAP reduction in CONE.[27] The net result of introducing 100% bonus depreciation with realistic timelines for realizing tax deductions was to slightly reduce CONE for the CC, CT, and BESS.[28]

1. Validation from GE on Turbine Payment Schedules

27. Brattle, S&L, PJM, the IMM, and stakeholders had extensively discussed the project development timelines for the CC and CT reference technologies including the monthly capital drawdown schedules, of which payments for turbines to OEMs like GE make up a large proportion of the total capital spend. The capital drawdown schedule expresses the percentage of the total nominal capital costs that are expended each month over the development period and is used to calculate capital carrying costs during development to arrive at a complete Installed Cost.

28. S&L had developed its monthly capital drawdown schedules for the CT and CC (44 and 50 months respectively) based on recent/ongoing experience as owner's engineer for several similar plants, and through conversations they had with GE. After we issued the April 2025 CONE report, the IMM challenged the drawdown schedule, especially the payment schedule for combustion turbines and other major equipment, which it believed was more back-weighted, with payments occurring later. To resolve the disagreement, Brattle/S&L and PJM engaged further with GE, through several discussions on the overall drawdown schedule and on turbine payment requirements. GE also provided indicative turbine payment schedules they expect to receive from plant developers over the development period starting from the equipment contract lock-in date through manufacturing, shipment, and delivery of the turbine. These inquiries validated that the turbine payment schedules embedded in the capital drawdown schedules in our April 2025 CONE report aligned with GE's progress-based payment schedules, and that the overall capital drawdown schedule was representative.[29] Given this extensive validation, no changes were made to the project drawdown assumptions used in the CONE calculation in the 2025 CONE Report.

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rpm-vrr-curve-parameters---brattle-group.pdf. (Presented August 6, 2025, by the Brattle Group at the PJM Market Implementation Committee Meeting).

[27] *See* Sixth Review of PJM's RPM VRR Curve Parameters, Interim Update: Gross CONE for Area 3, Rest of RTO at 3.

[28] *See* Sixth Review of PJM's RPM VRR Curve Parameters, Interim Update: Gross CONE with Technology Cost and Depreciation Updates.

[29] Because the progress-based payment schedule for turbines to the OEM are nominal and locked at contract execution, escalating these costs to the lock-in month accurately reflects this portion of the owner's financial commitment. The remainder of EPC and owner's costs escalate to the midpoint of the capital drawdown schedule, which together produce Installed Costs that reflect nominal levelized costs for the assumed commercial online date (June 1, 2028). Since OEM turbine costs are a large and growing proportion of the total project capital drawdown, the turbine payment schedule timeline has significant implications for the project's capital carrying costs prior to commercial operation and thus the final Installed Costs.

2. Addition of Wet Compression Technology

29. "Wet compression" refers to injecting atomized water into the compressor inlet air stream to increase gas turbine power and efficiency. We understand that GE has been promoting it as a way to increase maximum output capacity at relatively low additional cost. While using wet compression frequently can dramatically increase a plant's demand for demineralized water, using it rarely as a way to augment capacity requires only a modest water tank (that is already needed for other purposes).[30] We agreed with the IMM that it would be reasonable to include wet compression as a means to increase ICAP and not to adjust EAS Offsets for the augmented capacity, given the assumed rare usage. The impact on capacity for the CT is to increase it by approximately 7% with a small increase in costs.

30. In the process of updating performance modeling for the wet compression technical assumptions, S&L solicited and received updated performance tables for the GE 7HA.03 CT and CC plant types from GE. These OEM performance inputs are integrated into S&L's performance estimates and inform key parameters affecting thermal plant performance. GE's updated performance tables reflected increased firing temperatures as another way to increase capacity at minimal cost. Higher firing temperatures increase nitrous oxide (NO_x) production in the turbine, but evidently the SCR still limits NOx emissions to within acceptable levels for environmental regulations.

31. Grounding the heat balances and EAS specifications in OEM data provides testable performance predictions (even though the thermal resources themselves are approximations of a representative plant) and a clear, auditable lineage for stakeholders, while keeping mechanical and commercial models synchronized. These changes also impact downstream considerations such as firm gas transportation reservation sizing based on max summer capacity and heat rate with duct firing and must align with HRSG/condenser sizing and fuel-system design (including gas heating) to be consistent with the same operating points used in market simulations.

3. Updated Inlet Pressure Drop Assumptions

32. In the course of re-evaluating the CT and CC performance parameters, S&L identified overly conservative inlet pressure-drop assumptions used to produce performance estimates in the 2025 CONE Report. For subsequent performance modeling of the CT and CC resources, these pressure-drop assumptions were revised to align with GE's updated design guidance for the 7HA.03 platform equipped with standard inlet filtering and evaporative coolers. This inlet pressure-drop parameter

[30] Both the CC and CT reference technologies already are assumed to have demineralized water tanks on site. For the dual-fuel CT, injection nozzles use demineralized water to reduce NOx emissions while firing liquid fuel. For the CC demineralized water is needed for generating steam.

calibrates compressor airflow modeling and avoids understating mass flow and resultant generator output at the evaluated ambient conditions.

4. Bonus Depreciation Modeling

33. In the interim period after the April 2025 publication of the 2025 CONE Report, the One Big Beautiful Bill Act ("OBBBA") was passed into law, which reinstated the ability of generation asset owners to claim 100% bonus depreciation in the first year of placing a new asset into service. Brattle's August 6, 2025 MIC presentation represented updated CONE values that incorporated 100% bonus depreciation per the OBBBA, assuming a typical independent power producer ("IPP") could take full advantage of the bonus depreciation in year 1 of the project, as in our past reviews.[31] LS Power commented that this assumption was unrealistic because IPPs tend to have limited taxable income to absorb 100% bonus depreciation in year 1 and pointed to its testimony in 2018.[32] We ultimately agreed with them that tax deductions could not be realized immediately, but over several years through carried-forward net operating losses (NOLs), with a lower present value.

34. Two principal developments in market conditions warrant this change. First, the current capital costs of new CTs and CCs are substantially higher than in past CONE studies. For example the CT reference resource now has an installed cost of $670 million (in Area 3, Rest of RTO) vs. a $270 million CT that PJM used in the 2018 CONE study when 100% bonus depreciation was previously instated.[33] This single-plant cost is more than a typical IPP's annual taxable income; even more so for multiple plants that an IPP is likely to build in the current high growth environment nationally. As such, the typical IPP would not be able to realize a tax deduction for even close to 100% of bonus depreciation in year 1.[34] Private equity investors might also be relevant, but their financing structures are non-transparent, including the taxable income of their ultimate investors to whom depreciation tax deductions could be passed.

35. Second, Brattle consulted with tax structuring experts who revealed that since 100% bonus depreciation was allowed between 2018 and 2022 under the Tax Cuts and Jobs Act, no market has

[31] *See* Sixth Review of PJM's RPM VRR Curve Parameters, Interim Update: Gross CONE for Area 3, Rest of RTO at 2; 2022 PJM CONE Report; and Newell, Hagerty, Pfeifenberger, et al., *PJM Cost of New Entry: Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date*, The Brattle Group (Apr. 19, 2018), https://www.brattle.com/wp-content/uploads/2021/05/13896_20180420-pjm-2018-cost-of-new-entry-study.pdf.

[32] *See* Comments and Limited Protest of LS Power Associates, L.P., Docket No. ER19-105-000 (Nov. 19, 2018).

[33] The installed cost for the CC is $2.4 billion and the BESS is $380 million in CONE Area 3, Rest of RTO. *See also* 2022 PJM CONE Report; *see also* PJM Cost of New Entry: Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date

[34] *See* Sixth Review of PJM's RPM VRR Curve Parameters, Interim Update: Gross CONE with Technology Cost and Depreciation Updates (showing taxable incomes of publicly-traded IPPs).

developed for depreciation-only investment structures with partner entities (such as tax equity flips or sales-and-lease backs) to enable IPPs with insufficient taxable income in year 1 to quickly monetize the benefits of 100% bonus depreciation.

36. Therefore, it is reasonable to assume that the merchant generation investor would realize only a small portion of the tax deduction in year 1, then carry forward the rest as a net operating loss and realize the value of tax deductions over several years (resulting in a lower present value of tax savings). As Dr. Zhou described in our August 18 presentation to stakeholders, it is reasonable to assume an updated schedule of realizing deductions equivalent to a 10-year straight-line depreciation for the CC, a 7-year straight-line depreciation for CT, and a 3-year straight-line depreciation for the BESS.[35]

37. The net impact on CONE for the CT was a reduction of $23/MW-day, a reduction of $21/MW-day for the CC, and a reduction of $13/MW-day for the BESS.

V. EAS Offset Review

38. We reviewed PJM's forward-looking EAS Offset and found it remains reasonable and aligned with industry standard practice, although we did recommend a refinement to PJM's approach to calculate the RTO-wide Net CONE.[36] In place of PJM's current approach to conduct a virtual dispatch against a synthesized all-LDA average energy gas price to develop the RTO EAS, instead we recommended PJM derive RTO Net CONE from the 33rd percentile Net CONE of all LDAs. Choosing the 33rd percentile LDA Net CONE would reflect the fact that developers will likely build in areas with advantageous characteristics (either lower CONE or higher EAS) but balance against risks of misestimation. That is, while in theory the minimum LDA Net CONE might seem more appropriate, choosing the minimum could understate costs if the minimum is driven by estimation errors, if siting opportunities are limited in that area, or if the location of the minimum fluctuates from review to review. If the least costly area changed between reviews, choosing an RTO-wide Net CONE based on this (shifting) minimum could result in a lower overall Net CONE trajectory than any plant could receive if investing in the single LDA with most favorable long-term average economics. Therefore, the 33rd percentile among LDA Net CONEs is more reasonable for the RTO. Similarly, we recommended the same approach of choosing the 33rd percentile of the LDA Net CONEs to determine the parent LDA Net CONEs (e.g. for EMAAC, SWMAAC, Rest of RTO, WMAAC, ComEd, and MAAC).

35 *See* 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).

36 *See* 2025 CONE Report § VII.

39. Additionally, Brattle and S&L adjusted the variable maintenance modeling approach for the CT reference resource in the EAS Offset. For frame-type gas turbines, OEMs will establish a set number of "factored starts" or "factored fired hours" between major maintenance inspections/overhauls based on the life expectancies for high-wear components, with maintenance being carried out at whichever limit is reached first.[37] Depending on the operating profile and expected annual run hours, variable operations and maintenance ("VOM") can therefore be modeled as following either a starts-based or hours-based regime. A peaking gas plant typically has many starts and relatively few run-hours in a year, which favors a starts-based maintenance regime, while gas-fired plants with higher capacity factors and more run-hours are more accurately modeled as following an hours-based maintenance regime. EAS modeling for the 2025 PJM CONE study revealed dispatch projections for the CT with capacity factors resulting in sufficiently high annual run-times, so S&L calculated the major maintenance variable costs for a CT based on an hours-based maintenance regime and presented in $/MWh terms instead of a starts-based regime used in the 2022 PJM CONE Report. S&L developed a VOM cost of $2.65/MWh for the CT which encompasses major maintenance, consumables, waste disposal, and other variable O&M averaged across the five CONE Areas.[38]

40. **This concludes our affidavit.**

[37] OEMs structure LTSA variable maintenance around two primary life drivers: the fatigue stresses induced by start/stop cycling and the creep degradation mechanisms delivered by fired-hours.

[38] S&L developed this VOM cost estimate by referencing OEM LTSA quotes from S&L's internal cost database for total variable fees and outage milestone payments for two major inspection cycles for similar CT plants. S&L separately estimated the total cost for staff overtime based on typical outage durations, assumed overtime percentages, and overtime wage rates. Summing these totals and dividing by the MWh generated during the period yields the major maintenance component of VOM. Other VOM costs including SCR catalyst, aqueous ammonia, CO oxidation catalyst, water, and other chemicals and consumables which are based on unit costs from S&L's internal cost database and modeled usage rates for the reference technology. For EAS modeling of the CT reference technology, the variable O&M rate of $2.65/MWh is calculated as the average across the five CONE regions and consists of approximately $1.98/MWh for major maintenance, and $0.66/MWh for consumables, waste disposal, and other variable O&M. Total variable O&M costs for the five CONE areas were calculated to be EMAAC: $2.65/MWh, SWMAAC: $2.64/MWh, Rest of RTO: $2.61/MWh, WMAAC: $2.70/MWh, and COMED: $2.64/MWh.

VI. 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,

Samuel A. Newell
The Brattle Group
One Beacon Street, Suite 2600
Boston, MA 02106
617.234.5725
Sam.Newell@brattle.com

Andrew W. Thompson
The Brattle Group
Calle José Abascal, Nº58
Planta 6 Derecha
28003 Madrid, Spain
+34.910.487121
Andrew.Thompson@brattle.com

Bin Zhou
The Brattle Group
One Beacon Street, Suite 2600
Boston, MA 02106
617. 234.5677
Bin.Zhou@brattle.com

Joshua C. Jungé P.E.
Sargent & Lundy LLC
55 East Monroe Street
Chicago IL 60603
312.269.2129
joshua.c.junge@sargentlundy.com

November 7, 2025

Exhibit No. 1

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

Qualifications

Samuel Newell

PRINCIPAL

Boston | +1.617.234.5725 | Sam.Newell@brattle.com

Dr. Newell leads Brattle's Electricity Group of 60 consultants addressing economic questions in the industry's energy transition.

His 25 years of consulting experience centers on electricity wholesale markets, market design, transmission planning, resource planning and contracting, resource valuation, and policy analysis. He advises, conducts studies, and testifies in state and federal proceedings for a variety of clients, including ISOs, state energy agencies, infrastructure investors, and wholesale market participants.

AREAS OF EXPERTISE

- Electricity Wholesale Markets & Planning
- Electricity Litigation & Regulatory Disputes

EDUCATION

- **Massachusetts Institute of Technology**
  PhD in Technology Management and Policy
- **Stanford University**
  MS in Materials Science and Engineering
- **Harvard University**
  AB in Chemistry and Physics

PROFESSIONAL EXPERIENCE

- **The Brattle Group (2004–Present)**
  Principal and Electricity Group Leader
- **Cambridge Energy Research Associates (2003–2004)**
  Director of Transmission
- **Kearney**, f.k.a "A.T.Kearney" **(1998–2002)**
  Manager

CAPACITY MARKET DESIGN (ORGANIZED BY JURISDICTION)

- **PJM's Capacity Market Reviews and Parameters**. For PJM, co-led all six official reviews of its Reliability Pricing Model (2008, '11, '14, '18, '22, and '25). Analyzed capacity auctions and interviewed stakeholders. Evaluated the demand curve shape, the Cost of New Entry (CONE), the methodology for estimating net energy and ancillary services revenues, and indicative Net CONE. Recommended improvements to support participation and competition, to avoid excessive price volatility, and to safeguard future reliability performance. Separately, provided Avoidable Cost Rates for existing resources and Net CONE for new energy efficiency resources for use in the Minimum Offer Price Rule and in Market Seller Offer Caps. Submitted testimonies before the FERC.
- **Forward Energy and Ancillary Services (EA&S) Revenues in PJM**. For PJM, developed a method for using forward prices to estimate energy and ancillary services revenues for the purposes of determining capacity market parameters. Collaborated with Sargent & Lundy to establish resource characteristics, and with PJM staff to conduct hourly virtual dispatch. Filed testimony with the FERC.
- **Seasonal Capacity in PJM.** On behalf of the Natural Resources Defense Council, analyzed the ability of PJM's capacity market to efficiently accommodate seasonal capacity resources and meet seasonal resource adequacy needs. Co-authored a whitepaper proposing a co-optimized two-season auction and estimating the efficiency benefits. Filed and presented report at the FERC.
- **Buyer Market Power Mitigation in PJM**. On behalf of the "Competitive Markets Coalition" group of generating companies, helped develop and evaluate proposals for improving PJM's Minimum Offer Price Rule so that it more effectively protected the capacity market from manipulation by buyers while reducing interference with non-manipulative activity. Participated in discussions with other stakeholders. Submitted testimony to the FERC supporting tariff revisions that PJM filed.
- **Resource Accreditation**. Co-authored two whitepapers in 2022 for the Massachusetts Attorney General's Office on resource accreditation methodologies, including "ELCC" and empirical methods; evaluated reform options for New England.
- **ISO-NE Capacity Demand Curve**. For ISO-NE, designed the first demand curve for its Forward Capacity Market. Solicited input from staff and stakeholders on objectives. Provided and evaluated curves, showing tradeoffs between reliability uncertainty and price volatility using Brattle's probabilistic capacity market simulation model. Worked with Sargent & Lundy to estimate the Net Cost of New Entry to which demand curve prices were indexed. Submitted testimonies to the FERC, which accepted the proposed curve.
- **Offer Review Trigger Prices**. For ISO-NE's Internal Market Monitor, developed benchmark prices for screening for uncompetitively low offers in the Forward Capacity

Market. Worked with Sargent & Lundy to analyze the costs of constructing and operating gas-fired generation technologies and onshore wind and estimated the costs of energy efficiency and demand response. For each technology, estimated capacity payments needed to make the resource economically viable given their costs and expected non-capacity revenues. Recommendations were filed with and accepted by the FERC.

- **ISO-NE Forward Capacity Market (FCM) Performance.** With ISO-NE's internal market monitor, reviewed the performance of the first two forward auctions. Evaluated demand response participation, capacity zone definition and price formation, an alternative pricing rule for mitigating the effects of buyer market power, whether to have an auction price ceiling and floor, and other auction parameters.
- **Evaluation of Tie-Benefits**. For ISO-NE, analyzed the implications of different levels of tie-benefits from neighbors for capacity costs and prices, emergency procurement costs, and energy prices. Submitted whitepaper to the FERC.
- **New York State Resource Adequacy Constructs**. For NYSERDA, evaluated the customer cost impacts of several alternative constructs that differed in whether the FERC or the state set the rules and how buyer-side mitigation was implemented.
- **Evaluation of Moving to a Forward Capacity Market in NYISO.** For NYISO, conducted a benefit-cost analysis of replacing its prompt capacity market with a four-year forward capacity market. Evaluated options based on stakeholder interviews and experience from PJM and ISO-NE. Addressed risks to buyers and suppliers, market power mitigation, implementation costs, and long-run costs.
- **MISO Resource Adequacy Framework for a Transforming Fleet**. Advised MISO on its Resource Availability and Need initiative (2020-2022) to address year-round shortage risks as the fleet transformed. Presented to stakeholders on resource accreditation, determination of load requirements, modifications to the Planning Reserve Auction, and interactions with outage scheduling and with energy and ancillary services markets.
- **MISO Competitive Retail Choice Solution.** For MISO, evaluated design alternatives for accommodating the differing needs of states relying on competitive retail choice and integrated resource planning. Conducted probabilistic simulations of likely market results under alternative market designs and demand curves. Provided expert support in stakeholder forums and submitted expert testimony before the FERC.
- **MISO's Resource Adequacy Construct and Market Design Elements.** For MISO, conducted the first major assessment of its resource adequacy construct. Identified several successes and recommended improvements in load forecasting, locational resource adequacy, and the determination of reliability targets. Incorporated stakeholder input and review. Continued to consult with MISO in its work with the Supply Adequacy Working Group on design improvements, including market design elements for its annual locational capacity auctions.
- **Singapore Capacity Market Development**. For Singapore's Energy Market Authority (EMA), developed a complete forward capacity market (FCM) design in 2018-2021.

Worked with EMA, other government entities, and stakeholders. Analyzed Singapore's market and regulatory context. Published high-level design documents and presented to stakeholders. The FCM was shelved due to a change in government priorities.

- **Western Australia Capacity Market Design**. For the Public Utilities Office (PUO) of Western Australia, led a Brattle team to advise on the design of a new forward capacity market. Reviewed design proposed by the PUO; evaluated options for auction parameters such as the demand curve; recommended supplier-side and buyer-side market power mitigation measures; and helped define administrative processes needed to conduct the auction and the governance of such processes.
- **Western Australia Reserve Capacity Mechanism.** For EnerNOC, evaluated Western Australia's Reserve Capacity Mechanism in comparison to international capacity markets, and recommended improvements to meet reliability objectives more cost effectively. Evaluated whether to develop an auction-based capacity market compared or an energy-only market design. Submitted report and presented recommendations to the Electricity Market Review Steering Committee and other officials.
- **Preparing a Gentailer for a Transformed Wholesale Market Design.** Supported a gentailer in Alberta to prepare its generation and retail businesses for the proposed implementation of a capacity market.

ENERGY & ANCILLARY SERVICES (AND OTHER) MARKET DESIGN AND ANALYSIS

- **Independent Monitoring Report.** For Vistra Corp., prepared an independent monitoring report on certain natural gas-fired generation assets' offers into PJM's energy market to ensure that they complied with requirements imposed by the FERC to offer their energy at cost for an interim period until the assets could be divested following a merger.
- **Market & Regulatory Mechanisms to Maintain Reliability in Transforming Grid.** For MISO, led a study to identify, evaluate, and recommend solutions to MISO's projected challenges with resource adequacy, flexibility, and system stability, as input into MISO's market development roadmap. Resource adequacy solutions included enhanced accreditation bolstered by stronger real-time incentives; flexibility solutions pointed to a suite of ancillary service products and to enhancements to unit commitment and multi-interval dispatch; system stability solutions pointed mostly to transmission planning but also identified a need for standardizing inverter capabilities and settings.
- **Market Development Vision for MISO**. For MISO, worked with staff and stakeholders to codify a Market Vision as the basis for motivating and prioritizing market development initiatives over the next two to five years. Authored a foundational report for that Vision, including describing the core services MISO must continue to provide to support a well-functioning market; establishing a set of principles for enhancing those services; identifying seven focus areas offering the greatest opportunities; and proposing criteria for prioritizing initiatives within and across focus areas.

- **RTO Accommodation of Retail Access**. For MISO, identified business practice improvements to facilitate retail access. Analyzed retail access programs in IL, MI, and OH. Studied retail accommodation practices in other RTOs, focusing on how they modified their procedures surrounding transmission access, qualification of capacity resources, capacity markets, FTR allocations, and settlement.
- **Gas-Electric Reliability Challenges.** For MISO, provided a report assessing future gas-electric challenges as gas reliance increases. Characterized solutions from other ISOs. Provided inputs on the cost of firm pipeline gas vs. the cost and operational characteristics of dual-fuel capability.
- **ERCOT Cost of New Entry**. For ERCOT, estimated the cost of new entry for merchant entry in the ERCOT market for 2026, for use in various analyses and energy market parameters. Focused on aeroderivative turbines and solar-storage hybrid plants, as the predominant resource types being built in ERCOT. Collaborated with Sargent & Lundy on bottom-up cost analyses, and developed financial model to produce levelized costs. Presented to stakeholders and met with PUCT Commissioners.
- **ERCOT Post-Uri Market Reform**. Advised ERCOT and the Public Utility Commission of Texas (PUCT) regarding market design for reliability. Interviewed commissioners, ERCOT, and stakeholders. Helped frame the problem as primarily resource adequacy and secondarily as operational flexibility; evaluated market design proposals to support resource adequacy; evaluated refinements to the Operating Reserve Demand Curve and to Ancillary Services; presented recommendations and commented on stakeholder proposals at numerous PUCT workshops. Later invited by the State Energy Plan Advisory Committee to testify.
- **ERCOT's Proposed Future Ancillary Services Design**. For ERCOT, evaluated the benefits of its proposal to create more ancillary services, enable broader participation by load resources and new technologies, and tune procurement amounts to system conditions. Worked with ERCOT staff to assess each ancillary service and how generation, load resources, and new technologies could participate. Directed their simulation of the market using PLEXOS and evaluated non-modeled benefits.
- **Investment Incentives in ERCOT**. For ERCOT, led a Brattle team to: (1) interview stakeholders and characterize the factors influencing generation investment decisions; (2) analyze the energy market's ability to support investment and resource adequacy; and (3) evaluate options to enhance resource adequacy while maintaining market efficiency. Worked with ERCOT staff to understand their operations and market data. Performed probabilistic simulation analyses of prices, investment costs, and reliability. Conclusions were filed and presented at a subsequent PUCT proceeding.
- **Operating Reserve Demand Curve (ORDC) in ERCOT**. For ERCOT, evaluated several alternative ORDCs' effects on real-time price formation and investment incentives. Conducted back-cast analyses using interval-level data provided by ERCOT and assuming generators modified their commitment and dispatch in response to higher prices under the ORDC. Informed ERCOT's and the PUCT's selection of final ORDC parameters.

- **Economically Optimal Reserve Margins in ERCOT**. For ERCOT, co-led studies (2014 and 2018) estimating the economically optimal reserve margin and the market equilibrium reserve margins in its energy-only market. Collaborated with ERCOT staff and Astrape Consulting to construct Monte Carlo economic and reliability simulations. Accounted for uncertainty and correlations in weather-driven load, renewable energy production, generator outages, and load forecasting errors. Incorporated intermittent wind and solar generation profiles, fossil generators' variable costs, operating reserve requirements, various types of demand response, emergency procedures, administrative shortage pricing under ERCOT's ORDC, and criteria for load shedding. Reported economic and reliability metrics across a range of renewable penetration and other scenarios. Results informed the PUCT's adjustments to the ORDC to support desired reliability outcomes.
- **Vertical Market Power**. Before the New York Public Service Commission (NYPSC), examined whether the merger between National Grid and KeySpan could create incentives to exercise vertical market power. Employed nodal production cost simulations using the DAYZER model and examined whether outages of National Grid's transmission assets significantly affected KeySpan's generation profits.
- **Energy Price Formation in PJM**. For NextEra Energy, analyzed PJM's integer relaxation proposal and evaluated implications for day-ahead and real-time market prices. Reviewed PJM's Fast-Start pricing proposal and authored report recommending improvements, which NextEra and other parties filed with the FERC, and which the FERC largely accepted and cited in its April 2019 Order.
- **Energy Market Monitoring & Market Power Mitigation**. For PJM, co-authored a whitepaper, "Review of PJM's Market Power Mitigation Practices in Comparison to Other Organized Electricity Markets."
- **Market Design for Energy Security in ISO-NE**. For NextEra Energy, evaluated and developed proposals for meeting winter energy security needs in New England when pipeline gas becomes scarce. Evaluated ISO-NE's proposed multi-day energy market with new day-ahead operating reserves. Developed competing proposal for new operating reserves in both day-ahead and real-time to incent preparedness for fuel shortages; also developed criteria and high-level approach for potentially incorporating energy security into the forward capacity market. Presented evaluations and proposals to stakeholders.
- **Evaluation of Major Initiatives**. With ISO-NE and its stakeholders, developed criteria for identifying "major" market and planning initiatives that trigger the need for the ISO to provide qualitative and quantitative information to help stakeholders evaluate the initiative, as required in ISO-NE's tariff. Developed guidelines on the kinds of information ISO-NE should provide for major initiatives.
- **LMP Impacts on Contracts**. For a California agency, reviewed the California ISO's proposed implementation of locational marginal pricing (LMP) in 2007 and analyzed implications for "seller's choice" supply contracts where the supplier could select the delivery point. Estimated congestion costs ratepayers would face if suppliers financially delivered power to the lowest priced nodes; estimated incremental contract costs using

a third party's GE-MAPS market simulations (and helped to improve their model inputs to more accurately reflect the transmission system in California). Applied findings to support the ISO in design modifications of the California market under LMP.

- **Wholesale Rates**. On behalf of Tri-State Electric Co-op before the Public Service Commission of Colorado, provided testimony regarding its wholesale rates, which were contested by member co-ops. Analyzed the co-op's cost of service and its marginal cost of meeting customers' energy and peak demand requirements.
- **IESO's Market Renewal Program / Energy Market Settlements**. For the Ontario Independent Electricity System Operator (IESO), helped develop settlement equations for new day-ahead and real-time nodal markets, including make-whole payments for combined-cycle plants participating as "pseudo-units" and for cascading hydro systems.
- **Alberta Market Design**. For a utility in Alberta, presented market/regulatory design reform options for the province to attract and retain enough resources and efficiently allocate risk in the transition to clean energy.
- **Australian Electricity Market Operator (AEMO) Redesign**. Advised AEMO on reforms for the National Electricity Market (NEM) to address concerns about operational reliability and resource adequacy as renewable generation displaces traditional resources. Also provided a report on potential auctions to ensure sufficient capabilities in the near-term.
- **Energy Market Power Mitigation in Western Australia.** Led a Brattle team to help Western Australia's Public Utilities Office design market power mitigation measures for its newly reformed energy market. Established objectives, interviewed stakeholders, assessed local market characteristics, and synthesized lessons learned from the existing energy market and from several international markets. Recommended criteria, screens, and mitigation measures for day-ahead and real-time energy and ancillary services markets. The client used our whitepaper to support its conclusions.

CLEAN ENERGY MARKET DESIGN

- **Malaysia Clean Energy Exchange**. Worked with Single Buyer to develop the market design for an international clean energy exchange for selling solar power into Singapore and to/between other adjacent countries. Work scope encompassed product definition, demand and supply participation, auction format, scheduling and delivery, financial settlements, market power mitigation, governance, and implementation plan.
- **Carbon Pricing to Harmonize NY's Wholesale Market and Environmental Goals.** Led a Brattle team to help NYISO: (1) develop and evaluate market design options, including mechanisms for charging emitters and allocating revenues to customers, border adjustments to prevent leakage, and interactions with other market design and policy elements; and (2) develop a model to evaluate how carbon pricing would affect market outcomes, emissions, system costs, and customer costs under a range of assumptions. Whitepaper initiated discussions with NY DPS and stakeholders. Supported NYISO in detailed market design and stakeholder engagement.

ELECTRICITY LITIGATION

- **Expert Testimony in Ongoing Contract Disputes over Ancillary Services**. In several similar cases in Texas state court, on behalf of two energy services companies that served as qualified scheduling entities for and/or as bilateral buyers of Responsive Reserve Service (RRS) supply responsibility credits from industrial companies with Load Resources, testified on which party was responsibility for paying ancillary services imbalance charges incurred when the resources were deployed in February 2021 during Winter Storm Uri. Assessed, in relation to the agreements between the parties, ERCOT's protocols for financially settling imbalance charges and other related credits surrounding RRS, and the economic implications of allocating imbalance charges to one party versus the other. Submitted expert reports and rebuttal reports and was deposed in each case.
- **Expert Testimony in Contract Disputes over Ancillary Services Imbalance Charges**. In another ongoing case similar to the above, on behalf of the same company against a different plaintiff in Texas state court, submitted expert report and rebuttal report.
- **Consulting Support in Brazos Bankruptcy.** For a major generation company intervening in the Brazos Bankruptcy in Texas state court, provided consulting support regarding ERCOT wholesale power prices during Winter Storm Uri, when extreme weather conditions caused nearly half of Texas to lose power for several days.
- **Expert Testimony in FERC Enforcement Matter**. In the U.S. District Court of Maine, provided expert testimony on behalf of the FERC Office of Enforcement in *Fed. Energy Regulatory Comm'n v. Silkman* regarding allegations that defendant "engag[ed] in a fraudulent scheme to manipulate the ISO New England, Inc. (ISO-NE) Day-Ahead Load Response Program" by gaming the baseline and claiming false reductions in load. Submitted initial and rebuttal reports analyzing if defendant's conduct was consistent with industry practice and the purpose of demand response. The matter settled.
- **Expert Testimony in Contract Dispute in New England**. On behalf of an international engineering, procurement, and construction (EPC) contractor in a dispute with a plant owner regarding payments for constructing the plant and in support of client's motion about the use of its letter of credit; co-authored written testimony on the fair market value of the plant and on whether the value would suffice to cover the plant's debt and certain other obligations. Simulated energy and capacity markets to forecast net revenues and estimated exposure to capacity performance penalties. Compared the valuation to transaction prices of similar plants. Submitted report to the American Arbitration Association and the International Centre for Dispute Resolution.
- **Expert Testimony on Damages from Alleged Misrepresentations of a DR Company.** Provided testimony on behalf of a client alleging that a demand response (DR) company it had acquired had overstated its DR capacity and technical capabilities. Analyzed discovery materials including detailed DR data to assess the magnitude of alleged overstatements. Calculated damages primarily based on a fair market valuation of the company with and without alleged overstatements. Provided expert report, deposition, and testimony at hearing before the American Arbitration Association (non-public).

- **Litigation Support on Damages in Contract Dispute.** For California's Department of Water Resources and Attorney General's office, supported testifying expert on damages resulting from an electricity supplier's alleged breaches of a power purchase agreement. Analyzed two years of hourly data on energy deliveries, market prices, ISO charges, and invoice charges to identify and evaluate performance violations and invoice overcharges. Assisted counsel in developing the theory of the case and provided general litigation support in preparation for and during arbitration.
- **Litigation Support on Damages in Contract Dispute**. For the California Department of Water Resources and the California Attorney General's office, supported expert providing testimony in arbitration regarding the supplier's alleged breaches in which its scheduled deliveries were not deliverable due to transmission congestion. Quantified damages and demonstrated the predictability of congestion, which the supplier was allegedly supposed to avoid in its choice of delivery points.
- **Litigation Support on Contract Termination Payment.** For an independent power producer, supported testifying expert on damages from a buyer's termination of a long-term tolling contract for a gas-fired plant in PJM. Involved wholesale market price forecasting, assessing the plant's costs and operations, and financial valuation. Prepared witness for arbitration; helped counsel to depose and cross-examine opposing experts.

TRANSMISSION PLANNING AND MODELING

- **Initial Report on the New York Power Grid Study**. With NYSERDA, NYDPS, and Pterra, submitted a report to the NYPSC projecting New York's transmission needs to support its long-term clean energy goals under the Climate Leadership and Community Protection Act. Our work synthesized findings from three sub-reports addressing local T&D needs, offshore wind, and overall bulk system needs.
- **Value of a NY Public Policy Transmission Project**. On behalf of NY Transco LLC, submitted testimony in 2020 regarding the economic benefits of Transco's proposed "Segment B" transmission project. Critiqued an opposing expert's production cost analysis and broader benefit-cost analysis.
- **Benefit-Cost Analysis of New York AC Transmission Upgrades**. For the NYDPS and NYISO, led a team to evaluate 21 alternative projects to increase transfer capability from Upstate to Southeast NY. Quantified a broad scope of benefits: traditional production cost savings from reduced congestion, using GE-MAPS; additional production cost savings considering non-normal conditions; resource cost savings from being able to retire Downstate capacity, delay new entry, and shift future entry Upstate; avoided costs from replacing aging transmission that would have to be refurbished soon; reduced costs of integrating renewable resources Upstate; and tax receipts. Identified projects with greatest and most robust net value. Informed DPS's recommendation to the NYPSC to declare a Public Policy Need to build a project such as the best ones identified.

- **Evaluation of New York Transmission Projects**. For the NYDPS, provided a cost-benefit analysis for the "TOTS" transmission projects. Found net production cost and capacity resource cost savings exceeding project costs, and the lines were approved. Involved running GE-MAPS and a capacity market model, and providing insights to DPS staff.
- **Economic and Environmental Evaluation of New Transmission to Quebec**. For the New Hampshire Attorney General's Office in a proceeding before the state Site Evaluation Committee, co-sponsored testimony on the benefits of the proposed Northern Pass Transmission line. Responded to the applicant's analysis and developed our own, focusing on wholesale market participation, price impacts, and net emissions savings.
- **Benefit-Cost Analysis of a Transmission Project for Offshore Wind**. Submitted testimony on the economic benefits of the Atlantic Wind Connection, a proposed 2,000 MW DC offshore backbone from New Jersey to Virginia with seven landing points. Described and quantified the effects on congestion, capacity markets, CO_2 emissions, system reliability and operations, jobs and the economic, and the installed cost of offshore wind farms. Directed Ventyx staff to simulate energy market impacts using the PROMOD model.
- **Benefits of New 765kV Transmission Line**. For a utility joint venture between AEP and ComEd, analyzed renewable integration and congestion relief benefits of their proposed $1.2 billion RITELine project in western PJM. Guided client staff to conduct simulations using PROMOD. Submitted testimony to the FERC.
- **Benefit-Cost Analysis of New Transmission in the Midwest**. For American Transmission Company (ATC), supported Brattle witness evaluating the benefits of a proposed Paddock-Rockdale 345 kV line. Advised client on running PROMOD IV to quantify energy benefits, and developed metrics to account for the effects of changes in congestion, losses, FTR revenues, and LMPs on customer costs. Developed and applied new methods for analyzing benefits not quantified in PROMOD IV, including competitiveness, long-run resource cost advantages, reliability, and emissions. Testimony was submitted to the Public Service Commission of Wisconsin, which approved the line.
- **Analysis of Transmission Congestion and Benefits**. Analyzed impacts on transmission congestion and customer benefits in California and Arizona of a proposed interstate transmission line. Used the DAYZER model to simulate congestion and power market conditions considering increasing renewable generation requirements.
- **Benefit-Cost Analysis of New Transmission**. For a transmission developer's application before the California Public Utility Commission (CPUC) to build a new 500 kV line, analyzed the benefits to ratepayers. Evaluated benefits beyond those captured in a production cost model, including the value of integrating a pumped storage facility for accommodating a larger amount of intermittent renewable resources at a reduced cost.
- **Transmission Investments and Congestion**. Worked with executives and board of an independent transmission company to develop a metric indicating congestion-related benefits provided by its transmission investments and operations.

- **Analysis of Transmission Constraints and Solutions**. Performed a multi-client study identifying major transmission bottlenecks in the western and eastern Interconnections and evaluating potential solutions. Worked with transmission engineers from client organizations to refine the data in a load flow model and a security-constrained, unit commitment and dispatch model for each interconnection. Ran 12-year, LMP-based market simulations using GE-MAPS across multiple scenarios and quantified congestion costs on major constraints. Collaborated with engineers to design potential transmission (and generation) solutions. Evaluated the benefits and costs of candidate solutions and identified several major economic transmission projects.
- **Market Impacts of RTO Seams.** For a consortium of Midwestern utilities, submitted written testimony to the FERC analyzing the financial and operational impact of the MISO-PJM seam on Michigan and Wisconsin. Evaluated economic hurdles across RTO seams and assessed the effectiveness of inter-RTO coordination efforts underway. Collaborated with MISO staff to leverage their PROMOD IV model to simulate electricity markets under alternative RTO configurations.
- **Analysis of RTO Seams.** For a Wisconsin utility in a proceeding before the FERC, assisted expert witness on: (1) MISO and PJM's real-time inter-RTO coordination process; and (2) the benefits of implementing a full joint-and-common market. Analyzed lack of convergence between MISO and PJM energy prices and shadow prices on reciprocal coordinated flow gates.
- **RTO Participation**. For an integrated Midwest utility, advised on alternative RTO choices. Used GE-MAPS to model the transmission system and wholesale markets under various scenarios. Subsequently, in support of testimonies submitted to two state commissions, quantified the benefits and costs of RTO membership on customers, considering energy costs, FTR revenues, and wheeling revenues.
- **Transmission Tariffs**. For a merchant generating company participating in FERC hearings on developing a Long-Term Transmission Pricing Structure, helped a stakeholder coalition develop a position on how to eliminate pancaked transmission rates while allowing transmission owners to continue to earn their allowed rate of return. Analyzed and presented the implications of various transmission pricing proposals on system efficiency, incentives for new investment, and customer rates throughout MISO-PJM.
- **Merchant Transmission Impacts**. For a merchant transmission company, used GE-MAPS to analyze the effects of the Cross Sound Cable on energy prices.
- **Security-Constrained Unit Commitment and Dispatch Model Calibration.** For a Midwestern utility, calibrated its PROMOD IV model, focusing on LMPs, unit commitment, flows, and transmission constraints. Helped client understand the model's shortcomings and identify improvements. Assisted with initial assessments of FTRs in preparation for its submission of nominations in MISO's first allocation of FTRs.

VALUATION OF GENERATION, FUEL, STORAGE ASSET VALUATION, AND PROCUREMENTS

- **Solar and Storage Procurements**. On behalf of the Carolinas Clean Energy Business Association, submitted testimony and presented at workshop regarding Duke Energy's Carbon Plan. Assessed opportunities for Duke Energy to procure solar PV energy from independent power producers to avail itself of the lowest cost option for ratepayers to meet clean energy goals and system needs: evaluated drivers of recent attrition of contracted projects and prospects going forward; evaluate the cost savings Duke and its ratepayers could enjoy if Duke exercised its ability to competitively solicit standalone storage projects in "Build Own Transfer" (BOT) arrangements.
- **Value of Flexibility in ERCOT**. For a company evaluating a range of investment strategies, assessed the value of flexibility in ERCOT both in present day and in the future as wind and solar penetration increased. Used Brattle's GridSIM model to project investments and retirements over the next ten years. Analyzed the likely increase in demand for ancillary services. Simulated system operations accounting for short-term uncertainty in net load forecasts, using ENELYTIX PSO to model day-ahead and real-time operations.
- **Storage Development Company Due Diligence**. For an investor considering an equity investment in a storage development company in ERCOT, reviewed the developer's business model, interviewed the developer, and evaluated its revenue projections.
- **Storage Asset Development in New York**. For a renewable generation company considering developing new storage assets in New York City and Long Island, provided a wholesale market analysis, including a 20-year estimate of net revenues. Used Brattle's GridSIM model to simulate investment, operations, prices, and revenues over that timeframe, after calibrating the model to current actual prices.
- **Evaluation of Clean Energy & Transmission Procurement Options**. For a potential buyer of new transmission and remote clean resources (incl. hydropower from Canada), supported the development of a regulatory order and subsequent RFP drafting. Evaluated costs and benefits under various contracting approaches; assessed the possibility of resource shuffling and emissions backfilling; considered the value of storage services. After the RFP was issued, helped evaluate responses, informing awards.
- **Offshore Wind Developer Bid Analysis.** Supported an offshore wind developer with its Index OREC bid of an 800+ MW project into NYSERDA's NY1 solicitation. Informed energy basis risk by conducting nodal market simulations at various candidate interconnection points; informed capacity basis risk by modeling the ICAP market and estimated marginal capacity accreditations that could be applicable in the future.
- **Valuation of a Gas-Fired Combined-Cycle Plant in ERCOT**. For a generation company, estimated net revenues for an existing plant using Brattle's GridSIM model to project investment/retirement, operations, prices, and revenues over that time period, after calibrating the model to recent prices. Assessed market risks.
- **Valuation of a Portfolio of Combined-Cycle Plants across the US.** For a lender to a portfolio of plants, estimated the fair market value of each plant in 2018 and the

plausible range of values five years hence. Reviewed comparables. Analyzed electricity markets in New England, New York, Texas, Arizona, and California using our models and reference points from futures markets and publicly available studies. Performed probability-weighted discounted cash flow valuations across a range of scenarios. Provided insights into market and regulatory drivers and how they might evolve.

- **Wholesale Market Value of Storage in PJM**. For an investor in battery storage, estimated the energy, ancillary services, and capacity market revenues it could earn in PJM. Reviewed market participation rules. Forecasted capacity market revenues and performance penalties. Developed a real-time energy and ancillary service bidding algorithm the asset owner could employ to optimize its operations, given expected prices and operating constraints. Identified changes in real-time bid/offer rules that PJM could implement to improve the efficiency of market participation by storage resources.
- **Valuation of a Generation Portfolio in ERCOT**. For the owners of a portfolio of gas-fired assets (including a cogen plant), estimated the market value of their assets by modeling future cash flows from energy and ancillary services markets over several plausible scenarios. Analyzed the effects that load growth, entry, retirements, environmental regulations, and gas prices could have on energy prices, including scarcity prices under ERCOT's Operating Reserve Demand Curve. Evaluated how changes in drivers could change the value over time.
- **Gas Pipeline Investment for Electricity**. For the Maine Office of Public Advocate, co-sponsored testimony regarding the reliability and economic impacts if the Maine PUC signed long-term contracts for electricity customers to pay for new gas pipeline capacity into New England. Analyzed other expert reports and provided a framework for evaluating whether such procurements would be in the public interest, considering their costs and benefits vs. alternatives.
- **Gas Pipeline Investment for Electricity**. For the Massachusetts Attorney General's office, provided input for their comments in the Massachusetts Department of Public Utilities' docket investigating whether and how new natural gas delivery capacity should be added to the New England market.
- **Valuation Methodology for a Coal Plant Transaction in PJM**. For an owner of a large coal plant being transferred at a value yet to be assessed by a third party, wrote a guide on how to conduct a market valuation of the plant. Addressed drivers of energy and capacity value; worked with an engineering subcontractor to describe how to determine the remaining life of the plant and CapEx needs. Our guide was used to inform their pre-assessment negotiation strategy.
- **Valuation of a Coal Plant in PJM**. For the lender to a bidder on a coal plant being auctioned, estimated the market value of the plant. Valuation analysis focused on effects of coal and gas prices on cash flows and fixed O&M costs and CapEx needs of the plant.
- **Valuation of a Coal Plant in New England**. For a utility, evaluated a coal plant's economic viability and market value. Projected market revenues, operating costs, and capital investments needed to comply with future environmental mandates.

- **Valuation of Generation Assets in New England**. To inform several potential buyers' valuations of existing assets, provided energy and capacity price forecasts and cash flows under multiple scenarios. Explained the market rules and fundamentals to assess key risks to cash flows.
- **Valuation of Generation Asset Bundle in New England**. For the lender to the potential buyer of generation assets, provided long-term energy and capacity price forecasts, with scenarios to test whether the plant could be worth less than the debt. Reviewed documents in the "data room" to identify market, operational, and fuel supply risks.
- **Valuation of Generation Asset Bundle in PJM**. For a potential buyer, provided energy and capacity price forecasts and reviewed their valuation analysis. Analyzed supply and demand fundamentals of the PJM capacity market. Performed locational market simulations using the DAYZER model to project nodal prices as market fundamentals evolve. Reviewed the client's spark spread options model.
- **Wind Power Development**. For a developer of a wind farm in Michigan, forecasted energy and capacity revenues under a range of scenarios.
- **Wind Power Financial Modeling**. For an offshore wind developer proposing a 350 MW project off the coast of New Jersey, analyzed market prices for energy, RECs, and capacity. Provided a financial model of project funding and cash distributions to various types of investors (including production tax credit). Resulting financial statements were used in an application to the state of New Jersey for project grants.
- **Contract Review for Cogeneration Plant**. For the owner of a large cogen plant in PJM, analyzed revenues under the terms of a long-term PPA (in renegotiation) vs. potential merchant revenues. Accounted for multiple operating modes of the plant and its sales of energy, capacity, ancillary services, and steam over time.
- **Generation Strategy**. For an independent power producer, served for two years as an advisor on its growth. Led a team to assess the profitability of proposed power plants and acquisitions of plants throughout the US. Used GE-MAPS to simulate power prices, congestion, and generator dispatch, and forecasted capacity prices.
- **Generation Asset Valuation**. For multiple banks and energy companies, provided valuations of financially distressed generating assets. Used GE-MAPS to simulate net energy revenues; a capacity model to estimate capacity revenues; and a financial valuation model to value several natural gas, coal, and nuclear power plants across a range of scenarios. Identified key uncertainties and risks.

ENERGY POLICY ANALYSIS

- **Effect of Clean Energy Tax Credits on Electricity Costs and the Economy**. For ConservAmerica, led a study of the effects of clean energy tax credits on US investment in generation, electricity rates, economic growth, and jobs through 2035. Leveraged Brattle's gridSIM capacity expansion model and its BEYOND model of the US economy.

- **Blueprint for Consideration of Advanced Nuclear Energy Technologies**. Co-led a Brattle team to support NYSERDA's development of a blueprint for pursuing possible nuclear development in New York state. Addressed the potential value, technology options, and a broad range of issues that would need to be considered; helped incorporate responses to stakeholder comments.
- **Life Extension for Diablo Canyon**. For an environmental organization in California in 2022, evaluated the net benefits of extending the operating life of the Diablo Canyon Nuclear Power Plant. Calibrated the base case in Brattle's gridSIM capacity expansion model to existing studies sponsored by CA state agencies and estimated the impacts of retaining Diablo Canyon in terms of emissions, fixed and variable costs, and ability to meet both reliability objectives and clean energy goals.
- **Tariffs on PVs**. For a renewable energy advocacy group in 2022, evaluated the impacts of potential anti-circumvention tariffs that the Department of Commerce was considering imposing on PVs from four countries. Our team developed a trade model to estimate the impact on market prices for panels in the US; leveraged our gridSIM capacity expansion model to estimate the impact on utility-scale investments, emissions, and energy prices/costs, and then created a macroeconomic model to estimate effects on jobs and GDP.
- **Renewable Energy Tax Policy Impacts**. For ACORE, a renewable energy advocacy group, evaluated alternative proposals to extend and expand tax credits in 2021. Simulated investment, costs, prices and emissions nationally to 2050 using gridSIM, Brattle's capacity expansion model.
- **Clean Energy Transformation**. For NYISO, led a team to project how the fleet might evolve to meet the state's mandates for 70% renewable electricity by 2030 and 100% carbon-free electricity by 2040. Used gridSIM to model investment and operations subject to constraints on reliability and clean energy. Evaluated technology needs for meeting load during extended periods of low wind/solar. The study helped inform questions about future market design and reliability.
- **Response to DOE's "Grid Reliability and Resiliency Pricing" Proposal**. For a broad group of stakeholders opposing the rule in a filing before the FERC, evaluated the Department of Energy's (DOE) proposed rule: the need (or lack thereof) for bolstering reliability and resilience by supporting resources with a 90-day fuel supply, the likely cost of the rule, and the incompatibility of DOE's proposal with the principles and function of competitive wholesale electricity markets.
- **Retail Rate Riders**. For a traditionally regulated Midwest utility, helped general counsel to evaluate and support legislation and proposed commission rules addressing rate riders for fuel and purchased power and the costs of complying with environmental regulations. Performed research on rate riders in other states and drafted proposed rules and tariff riders for client.

INTEGRATED RESOURCE PLANNING (IRP)

- **Resource Planning in Hawaii**. Assisted the Hawaiian Electric Companies in developing its Power Supply Improvement Plan, filed April 2016. Our work addressed how to maintain system security as renewable penetration increases toward 100% and displaces traditional synchronous generation. Solutions involved defining technology-neutral requirements that may be met by demand response, distributed resources, and new technologies as well as traditional resources.
- **IRP in Connecticut (for 2008, 2009, 2010, 2012, and 2014 Plans)**. For two utilities and the state Department of Energy and Environmental Protection (DEEP), led the analysis for five IRPs, coordinating multiple teams across several organizations. Projected a ten-year scenarios for resource adequacy, customer costs, emissions, and RPS compliance; evaluated resource procurement strategies for energy efficiency, renewables, and traditional sources. Used an integrated modeling system to simulate the New England locational energy market, the Forward Capacity Market, REC markets, and investments and retirements. Addressed electricity supply risks, natural gas supply, RPS standards, environmental regulations, transmission planning, emerging technologies, and energy security. Solicited input from stakeholders. Provided testimony before the DEEP.
- **Contingency Plan for Indian Point Nuclear Retirement**. For the New York Department of Public Service (DPS), assisted in developing contingency plans for maintaining reliability if the Indian Point nuclear plant retired. Evaluated generation and transmission proposals on three dimensions: reliability contributions, viability for completion by 2016, and the net present value of costs. Partnered with engineering sub-contractors, ran GE-MAPS and a capacity market model, and provided insights to DPS staff.
- **Analysis of Potential Retirements to Inform Transmission Planning**. For a large utility in Eastern PJM, analyzed the potential economic retirement of each coal unit in PJM under a range of scenarios regarding climate legislation, legislation requiring mercury controls, and various capacity price trajectories.
- **Resource Planning in Wisconsin**. For a utility considering constructing new capacity, demonstrated the need to consider locational marginal pricing, gas price uncertainty, and potential CO_2 liabilities. Guided client to look beyond building a large coal plant. Led them to mitigate exposures, preserve options, and achieve nearly the lowest expected cost by pursuing a series of smaller projects, including a promising cogeneration application at a location with persistently high LMPs. Conducted interviews and facilitated discussions with senior executives to help client gain support internally and begin to prepare for regulatory communications.

DEMAND RESPONSE MARKET PARTICIPATION, MARKET POTENTIAL, AND MARKET IMPACT

- **Demand Response (DR) Integration in MISO**. Through several assignments, helped MISO incorporate DR into its energy market and resource adequacy constructs, including: (1) conducted an independent assessment of MISO's progress in integrating DR into its resource adequacy, energy and ancillary services markets; (2) analyzed market participation barriers; (3) wrote a whitepaper evaluating various approaches to incorporating economic DR in energy markets and identified implementation barriers and recommended improvements to efficiently accommodate curtailment service providers; and (4) helped modify MISO's tariff and business practices to accommodate DR in its resource adequacy construct by defining appropriate participation rules. Informed design by surveying other RTOs' practices and by characterizing the DR resources within the MISO footprint.

- **Survey of Demand Response Provision of Energy, Ancillary Services, and Capacity.** For the Australian Energy Market Commission (AEMC), co-authored a report on market designs and participation patterns in several international markets. AEMC used the findings to inform its integration of DR into its National Energy Market.
- **Integration of DR into ISO-NE's Energy Markets.** For ISO-NE, provided analysis and assisted with a stakeholder process to develop economic DR programs to replace the ISO's initial economic DR programs when they expired.
- **Compensation Options for DR in ISO-NE's Energy Market**. For ISO-NE, analyzed the implications of various DR compensation options on consumption patterns, LMPs, capacity prices, consumer surplus, producer surplus, and economic efficiency. Presented findings in a whitepaper that ISO-NE submitted to the FERC.
- **ERCOT DR Potential Study**. For ERCOT, estimated the market size for DR by end-user segment based on interviews with curtailment service providers and utilities and informed by penetration levels achieved in other regions. Presented findings to the Public Utility Commission of Texas at a workshop on resource adequacy.
- **DR Potential Study**. For an eastern ISO, analyzed the potential for DR and price responsive demand in the footprint, and what the ISO could do to facilitate them. For each segment of the market, identified the ISO and/or state and utility initiatives that would be needed to develop various levels of capacity and energy market response. Also estimated the potential and cost characteristics for each segment. Interviewed curtailment service providers and ISO personnel.
- **Wholesale Market Impacts of Price-Responsive Demand (PRD)**. For NYISO, evaluated the potential effects of widespread implementation of dynamic retail rates. Utilized the PRISM model to estimate effects on consumption by customer class, applied empirically based elasticities to hourly differences between flat retail rates and projected dynamic retail rates. Utilized the DAYZER model to estimate the effects of load changes on energy costs and prices.
- **Energy Market Impacts of DR**. For PJM and the Mid-Atlantic Distributed Resources Initiative (sponsored by five state commissions), quantified the market impacts and customer benefits of DR programs. Used a simulation-based approach to quantify the impact that a three percent reduction of peak loads during the top 20 five-hour blocks would have had in 2005 and under a variety of alternative market conditions. Utilized the DAYZER market simulation model, which we calibrated to represent the PJM market using data provided by PJM and public sources. Results were presented in multiple

forums and cited widely, including by several utilities in their filings with state commissions regarding investment in advanced metering infrastructure and implementation of DR programs.

- **Value of DR Investments**. For Pepco Holdings, Inc., evaluated its proposed DR-enabling investments in advanced metering infrastructure and its efficiency programs. Estimated reductions in peak load that would be realized from dynamic pricing, direct load control, and efficiency. Built on the Brattle-PJM-MADRI study to estimate short-term energy market price impacts and addressed long-run equilibrium offsetting effects through supplier response scenarios. Estimated capacity price impacts and resource cost savings over time. Submitted a whitepaper to the DE, NJ, MD, and DC commissions. Presented findings to the Delaware Public Service Commission.

- Before the FERC, Docket No. ER25-682-000, Affidavit of Dr. Samuel A. Newell, Attachment C to on behalf of PJM Interconnection, L.L.C.'s filing, *Revisions to Reliability Pricing Model*, December 9, 2024.
- Before the North Carolina Utilities Commission, Docket No. E-100, Sub 190, "Direct Testimony of Samuel A. Newell on behalf of Carolinas Clean Energy Business Association," in the matter of Biennial Consolidated Carbon Plan and Integrated Resource Plans of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, Pursuant to N.C.G.S. § 62-110.9 and§ 62-110.l(c), May 28, 2024.
- Before the FERC, Docket No. EC23-74-000, *Independent Monitoring Report*, report prepared for Vistra Corp., April 30, 2024 (with J. Higham).
- Before the FERC, Docket No. ER23-2977-000, "Written Testimony of Dr. Kathleen Spees, Samuel A. Newell, and Dr. Linquan Bai" on behalf of Midcontinent Independent System Operator, Inc., regarding the reliability-based demand curve, September 28, 2023.
- Before the FERC, Docket No. ER22-2984-000, "Answering Affidavit of Dr. Samuel A. Newell, Kathleen Spees, and John M. Hagerty on Behalf of PJM Interconnection, L.L.C.," regarding periodic review of variable resource requirement curve shape and key parameters, November 8, 2022.
- Before the FERC, Docket No. ER22-2984-000, "Affidavit of Kathleen Spees and Dr. Samuel A. Newell on Behalf of PJM Interconnection, L.L.C.," regarding periodic review of variable resource requirement curve shape and key parameters, September 30, 2022.
- Before the FERC, Docket No. ER22-2984-000, "Affidavit of Samuel A. Newell, John M. Hagerty, and Sang H. Gang on Behalf of PJM Interconnection, L.L.C.," regarding the administrative Cost of New Entry parameter, representing the cost of building a generation plant for use in PJM's capacity market, September 30, 2022.
- Before the FERC, Docket No. ER22-2984-000, "Affidavit of Samuel A. Newell, James A. Read Jr., and Sang H. Gang on Behalf of PJM Interconnection, L.L.C.," regarding the use of forward-looking data to estimate energy and ancillary services revenues for the purposes of determining capacity market parameters, September 30, 2022.
- Before the California Senate Committee on Energy, Utilities and Communications, Subcommittee on Clean Energy Future, hearing on "Clean reliability: What does California need to ensure grid reliability while reducing fossil fuels?," live, videographic testimony on "Near-

Term Resource Adequacy Benefits of Retaining Diablo Canyon" for Policy Impact on behalf of Carbon Free California, August 9, 2022.

- Before the Texas State Energy Plan Advisory Committee to the Governor and Legislature (on invitation by the Committee), oral testimony on market design and policy options for supporting resource adequacy in ERCOT, June 28, 2022.
- Before the FERC, Docket No. AD21-10-000, Post-technical Conference Comments and Testimony of Dr. Kathleen Spees and Samuel A. Newell on behalf of the New York State Energy Research and Development Authority, "Modernizing Electricity Market Design – Efficiently Managing Net Load Variability in High-Renewable Systems: Designing Ramping Products to Attract and Leverage Flexible Resources," February 4, 2022.
- Before the FERC, Docket No. ER21-2582-000, Written Testimony of Dr. Kathleen Spees and Samuel A. Newell on behalf of the Natural Resource Defense Council, the Sustainable FERC Project, Earthjustice, Sierra Club, and Union of Concerned Scientists, "Economic Impacts of the Expansive Minimum Offer Price Rule within the PJM Capacity Market," August 20, 2021.
- Before the FERC, Docket No. EL21-7-000, Written Testimony of Dr. Kathleen Spees and Samuel A. Newell on behalf of the Natural Resource Defense Council, the Sustainable FERC Project, Earthjustice, Sierra Club, American Wind Energy Association, Alliance for Clean Energy New York, and Advanced Energy Economy, regarding the economic impacts of buyer-side mitigation in the NYISO capacity market, November 18, 2020.
- Before the NY Public Service Commission, Case 19-T-0684, "Rebuttal Testimony of Samuel A. Newell on Behalf of New York Transco LLC," in response to the direct testimony of Cricket Valley Energy Center, LLC and Guidehouse Inc. regarding the economic benefits of Transco's proposed "Segment B" transmission project, September 30, 2020.
- Before the FERC, Docket Nos. EL19-58 and ER19-1486, "Supplemental Affidavit of Samuel A. Newell and James A. Read Jr. on Behalf of PJM Interconnection, L.L.C.," regarding the use of forward-looking data to estimate energy and ancillary services revenues for the purposes of determining capacity market parameters, September 17, 2020.
- Before the FERC, Docket Nos. EL19-58 and ER19-1486, "Affidavit of Samuel A. Newell, James A. Read Jr., and Sang H. Gang on Behalf of PJM Interconnection, L.L.C.," regarding the use of forward-looking data to estimate energy and ancillary services revenues for the purposes of determining capacity market parameters, August 5, 2020.
- Before the FERC, Docket Nos. EL16-49, ER18-1314-000, ER18-1314-001, EL18-178-000 (consolidated), "Supplemental Affidavit of Samuel A. Newell, John M. Hagerty and Sang H. Gang

on Behalf of PJM Interconnection, L.L.C.," regarding the expansion of the Minimum Offer Price Rule in its forward capacity market, March 23, 2020.

- Before the FERC, Docket Nos. EL16-49, ER18-1314-000, ER18-1314-001, EL18-178-000 (consolidated), "Affidavit of Samuel A. Newell, John M. Hagerty and Sang H. Gang on Behalf of PJM Interconnection, L.L.C.," regarding the expansion of the Minimum Offer Price Rule in its forward capacity market, March 17, 2020.
- Before the Indiana General Assembly 21st Century Energy Policy Development Task Force, "Electricity Transmission Basics," oral testimony on behalf of the Indiana Energy Association, October 17, 2019.
- Before the American Arbitration Association, International Centre for Dispute Resolution, co-authored confidential expert report for an international engineering, procurement, and construction (EPC) contractor to estimate the fair market value of a power plant at a future date based on projected cash flows and comparables, November 27, 2018.
- Before the FERC, Docket No. ER19-105-000, Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters, "Affidavit of Samuel A. Newell, John M. Hagerty, and Sang H. Gang on Behalf of PJM Interconnection, L.L.C.," regarding the Cost of New Entry, accompanied by report, *PJM Cost of New Entry Combustion Turbines and Combined-Cycle Plants*, June 1, 2022, online date, October 12, 2018.
- Before the FERC, Docket No. ER19-105-000, Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters, "Affidavit of Dr. Samuel A. Newell and David Luke Oates on behalf of PJM Interconnection, L.L.C," regarding the Variable Resource Requirement Curve Shape, accompanied by report, *Fourth Review of PJM's Variable Resource Requirement Curve*, October 12, 2018.
- Before the FERC, Docket Nos. EL16-49-000, ER18-1314-000, ER18-1314-001, EL18-178-000 (consolidated), "Affidavit of Kathleen Spees and Samuel A. Newell Regarding the Need for a Self-Supply Exemption from Minimum Offer Price and Other Policy Supported Resource Rules on behalf of Dominion Energy Services, Inc. and Virginia Electric and Power Company, October 2, 2018.
- Before the FERC, Docket Nos. EL17-32-000 and EL17-36-000, Prefiled Comments of Samuel A. Newell, Dr. Kathleen Spees, and Yingxia Yang on behalf of the Natural Resources Defense Council: "Opportunities to More Efficiently Meet Seasonal Capacity Needs in PJM," April 15, 2018; presented oral testimony on the Seasonality Panel at FERC's Seasonal Capacity Technical Conference on April 24, 2018.

- Before the FERC, Docket No. EL18-34-000, Samuel A. Newell, Pablo A. Ruiz, and Rebecca C. Carroll, "Evaluation of PJM's Fast-Start Pricing Proposal," prepared for NextEra Energy Resources and attached to *Reply Brief of Joint Commenters*, March 14, 2018.
- Before the US District Court of Maine, in "Fed. Energy Regulatory Comm'n v. Silkman" (1:16-cv-00205-JAW), submitted "Expert Report of Samuel A. Newell" on behalf of the FERC Office of Enforcement, January 29, 2018, and "Rebuttal Report of Samuel A. Newell," March 15, 2018.
- Before the New Hampshire Site Evaluation Committee, Docket No. 2015-06, written and oral testimony and cross examination on the electricity market impacts of the proposed Northern Pass Transmission Project, October 26-27, 2017.
- Before the FERC, Docket No. AD17-11-000, Prefiled Comments of Samuel A. Newell regarding "Reconciling Wholesale Competitive Markets with State Polices," April 25, 2017; and oral testimony on Industry Expert Panel at the Technical Conference on May 2, 2017.
- Before the New Hampshire Site Evaluation Committee, Docket No. 2015-06, Prefiled Supplemental Testimony of Samuel Newell and Jurgen Weiss on behalf of the New Hampshire Counsel for the Public, with attached report, "Electricity Market Impacts of the Proposed Northern Pass Transmission Project--Supplemental Report," April 17, 2017.
- Before the FERC, Docket No. ER17-284-000, filed "Response of Dr. Samuel A. Newell, Dr. Kathleen Spees, and Dr. David Luke Oates on behalf of Midcontinent Independent System Operator Regarding the Competitive Retail Solution," January 13, 2017.
- Before the New Hampshire Site Evaluation Committee, Docket No. 2015-06, Prefiled Direct Testimony of Samuel Newell and Jurgen Weiss on behalf of the New Hampshire Counsel for the Public, with attached report, "Electricity Market Impacts of the Proposed Northern Pass Transmission Project," December 30, 2016.
- Before the FERC, Docket No. ER17-284-000, filed "Testimony of Dr. Samuel A. Newell, Dr. Kathleen Spees, and Dr. David Luke Oates on behalf of Midcontinent Independent System Operator Regarding the Competitive Retail Solution," November 1, 2016.
- "Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades," Appendix 1 to Comparative Evaluation of Alternating Current Transmission Upgrade Alternatives, Trial Staff Final Report, *Proceeding on Motion of the Commission to Examine Alternating Current Transmission Upgrades*, New York State Department of Public Service, Matter No. 12-02457, Case No. 12-T-0502, September 22, 2015. Presented to NYISO and DPS Staff at the Technical Conference, Albany, NY, October 8, 2015.

- Before the Maine Public Utilities Commission, Docket No. 2014-00071, filed "Testimony of Dr. Samuel A. Newell and Matthew P. O'Loughlin on Behalf of the Maine Office of the Public Advocate, Comments on LEI's June 2015 Report and Recommendations for a Regional Analysis," November 18, 2015.
- Before the FERC, Docket No. ER14-2940-000, filed "Response of Dr. Samuel A. Newell and Dr. Kathleen Spees on Behalf of PJM Interconnection, LLC Regarding Variable Resource Requirement Curve," for use in PJM's capacity market, November 5, 2014.
- Before the FERC, Docket No. ER15-68-000, filed "Affidavit of Dr. Samuel A. Newell on behalf of PJM Interconnection, LLC," regarding the Cost of New Entry for use in PJM's Minimum Offer Price Rule, October 9, 2014.
- Before the Texas House of Representatives Environmental Regulation Committee, Hearing on the Environmental Protection Agency's Newly Proposed Clean Power Plan and Potential Impact on Texas, invited by Committee Chair to testify orally on "EPA's Clean Power Plan: Basics of the Rule, and Implications for Texas," Austin, TX, September 29, 2014.
- Before the FERC, Docket No. ER14-2940-000, filed "Affidavit of Dr. Samuel A. Newell and Mr. Christopher D. Ungate on Behalf of PJM Interconnection, LLC," regarding the Cost of New Entry for use in PJM's capacity market, September 25, 2014.
- Before the FERC, Docket No. ER14-2940-000, filed "Affidavit of Dr. Samuel A. Newell and Dr. Kathleen Spees on Behalf of PJM Interconnection, LLC Regarding Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters," September 25, 2014.
- Before the Public Utilities Commission of the State of Colorado, Proceeding No. 13F-0145E, "Answer Testimony and Exhibits of Dr. Samuel A. Newell on Behalf of Tri-State Generation and Transmission Association, Inc.," regarding an analysis of complaining parties' responses to Tri-State Generation and Transmission Association, Inc.'s Third Set of Data Requests, Interrogatory, September 10, 2014.
- Before the Maine Public Utilities Commission, Docket No. 2014-00071, "Testimony of Dr. Samuel A. Newell and Matthew P. O'Loughlin on Behalf of the Maine Office of the Public Advocate, Analysis of the Maine Energy Cost Reduction Act in New England Gas and Electricity Markets," July 11, 2014.
- Before the FERC, Docket No. ER14-1639-000, filed "Testimony of Dr. Samuel A. Newell and Dr. Kathleen Spees on behalf of ISO New England Inc. Regarding a Forward Capacity Market Demand Curve," April 1, 2014.

- Before the FERC, Docket No. ER14-1639-000, filed "Testimony of Dr. Samuel A. Newell and Mr. Christopher D. Ungate on Behalf of ISO New England Inc. Regarding the Net Cost of New Entry for The Forward Capacity Market Demand Curve," April 1, 2014.
- Before the FERC, Docket No. ER14-616-000, filed "Affidavit of Dr. Samuel A. Newell on Behalf of ISO New England Inc.," and accompanying "2013 Offer Review Trigger Prices Study," regarding the Minimum Offer Price Rule new capacity resources in capacity auctions, December 13, 2013.
- Before the American Arbitration Association, provided expert testimony (deposition, written report, and oral testimony at hearing) in a dispute involving the acquisition of a demand response company, July-November, 2013. (Non-public.)
- Before the Public Utility Commission of Texas, at a workshop on Project No. 40000, presented "Report On ORDC B+ Economic Equilibrium Planning Reserve Margin Estimates Prepared By The Brattle Group," on behalf of The Electric Reliability Council of Texas (ERCOT), June 25, 2013. Subsequently filed additional comments, "Additional ORDC B+ Economic Equilibrium Planning Reserve Margin Estimates," July 29, 2013.
- Before the FERC, Docket No. ER13-535-000, filed "Affidavit of Dr. Samuel A. Newell on Behalf of the 'Competitive Markets Coalition' Group Of Generating Companies," supporting PJM's proposed tariff revisions to change certain terms regarding the Minimum Offer Price Rule in the Reliability Pricing Model, December 28, 2012.
- Before the FERC, Docket No. ER12-513-000, filed "Affidavit of Dr. Samuel A. Newell on Behalf of PJM Interconnection, LLC," in support of PJM's Settlement Agreement regarding the Cost of New Entry for use in PJM's capacity market, November 21, 2012.
- Before the Texas House of Representatives State Affairs Committee, Hearing on the issue of resource adequacy in the Texas electricity market, testified orally on "The Resource Adequacy Challenge in ERCOT," on behalf of The Electric Reliability Council of Texas, October 24, 2012.
- Before The Public Utility Commission of Texas, at a workshop on Project No. 40480, presented "Resource Adequacy in ERCOT: 'Composite' Policy Options," and "Estimate of DR Potential in ERCOT" on behalf of The Electric Reliability Council of Texas (ERCOT), October 25, 2012.
- Before The Public Utility Commission of Texas workshop on Project No. 40480, presented "ERCOT Investment Incentives and Resource Adequacy," September 6, 2012.
- Before The Public Utility Commission of Texas workshop on Project No. 40480, presented "Summary of Brattle's Study on ERCOT Investment Incentives and Resource Adequacy," July 27, 2012.

- Before the FERC, Docket No. ER12-___-000, Affidavit of Samuel A. Newell on Behalf of SIG Energy, LLLP, March 29, 2012, Confidential Exhibit A in Complaint of Sig Energy, LLLP, SIG Energy, LLLP v. California Independent System Operator Corporation, Docket No. EL 12-___-000, filed April 4, 2012 (public version, confidential information removed).
- Before the FERC, Docket No. ER12-13-000, filed "Response of Dr. Samuel A. Newell and Dr. Kathleen Spees on Behalf of PJM Interconnection, LLC," regarding the Cost of New Entry for use in PJM's capacity market, January 13, 2012.
- Before the FERC, Docket No. ER12-13-000, Affidavit of Samuel A. Newell on Behalf of PJM Interconnection, LLC, regarding the Cost of New Entry Estimates for Delivery Year 2015/16 in PJM's Reliability Pricing Model, December 1, 2011.
- Before the FERC, Docket Nos. ER11-4069 and ER11-4070, Direct Testimony of Johannes Pfeifenberger and Samuel Newell on behalf of the RITELine Companies, regarding the public policy, congestion relief, and economic benefits of the RITELine Transmission Project, July 18, 2011.
- Before the FERC, Docket No. No. EL11-13-000, Direct Testimony of Johannes Pfeifenberger and Samuel Newell on behalf of The AWC Companies regarding the public policy, reliability, congestion relief, and economic benefits of the Atlantic Wind Connection Project, filed December 20, 2010.
- "Economic Evaluation of Alternative Demand Response Compensation Options," whitepaper filed by ISO-NE in its comments on FERC's Supplemental Notice of Proposed Rulemaking in Docket No. RM10-17-000, October 13, 2010 (with K. Madjarov).
- Before the FERC, Docket No. RM10-17-000, Filed Comments regarding: Supplemental Notice of Proposed Rulemaking and September 13, 2010 Technical Conference, October 5, 2010 (with K. Spees and P. Hanser).
- Before the FERC, Docket No. RM10-17-000, Filed Comments regarding Notice of Proposed Rulemaking regarding wholesale compensation of demand response, May 13, 2010 (with K. Spees and P. Hanser).
- Before the Connecticut Department of Public Utility Control, provided oral testimony to support the 2010 "Integrated Resource Plan for Connecticut" (see below), June 2010.
- 2010 "Integrated Resource Plan for Connecticut," report co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Energy Advisory Board, January 4, 2010. Presented to the Board January 8, 2010.

- "Dynamic Pricing: Potential Wholesale Market Benefits in New York State," lead authors: Samuel Newell and Dr. Ahmad Faruqui at The Brattle Group, with contributors Michael Swider, Christopher Brown, Donna Pratt, Arvind Jaggi and Randy Bowers at the New York Independent System Operator, submitted as "Supplemental Comments of the NYISO Inc. on the Proposed Framework for the Benefit-Cost Analysis of Advanced Metering Infrastructure," in State of New York Public Service Commission Case 09-M-0074, December 17, 2009.
- Before the Connecticut Department of Public Utility Control, provided oral testimony to support the 2009 "Integrated Resource Plan for Connecticut," June 30, 2009.
- 2009 "Integrated Resource Plan for Connecticut," report co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Energy Advisory Board, January 1, 2009.
- "Informational Filing of the Internal Market Monitoring Unit's Report Analyzing the Operations and Effectiveness of the Forward Capacity Market," prepared by Dave LaPlante and Hung-po Chao of ISO-NE with Samuel A. Newell, Dr. Metin Celebi, and Attila Hajos, filed with FERC on June 5, 2009, under Docket No. ER09-1282-000.
- Before the Connecticut Department of Public Utility Control, provided oral testimony to support the 2008 "Integrated Resource Plan for Connecticut" and "Supplemental Reports," September 22, 2008.
- "Integrated Resource Plan for Connecticut," co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Energy Advisory Board; co-authored with M. Chupka, A. Faruqui, and D. Murphy, January 2, 2008. Supplemental Report co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Department of Utility Control; co-authored with M. Chupka, August 1, 2008.
- "Quantifying Customer Benefits from Reductions in Critical Peak Loads from PHI's Proposed Demand-Side Management Programs," whitepaper by Samuel A. Newell and Dr. Ahmad Faruqui filed by Pepco Holdings, Inc. with the Public Utility Commissions of Delaware (Docket No. 07-28, 9/27/2007), Maryland (Case No. 9111, filed 12/21/07), New Jersey (BPU Docket No. EO07110881, filed 11/19/07), and Washington, DC (Formal Case No. 1056, filed 10/1/07). Presented orally to the Public Utility Commission of Delaware, September 5, 2007.
- Before the Public Service Commission of Wisconsin, Docket 137-CE-149, "Planning Analysis of the Paddock-Rockdale Project," report by American Transmission Company regarding transmission cost-benefit analysis, April 5, 2007 (with J.P. Pfeifenberger and others).

- Prepared Supplemental Testimony on Behalf of the Michigan Utilities before the FERC, Docket No. ER04-718-000 et al., regarding Financial Impact of ComEd's and AEP's RTO Choices, December 21, 2004 (with J. P. Pfeifenberger).
- Prepared Direct and Answering Testimony on Behalf of the Michigan-Wisconsin Utilities before the FERC, Docket No. ER04-375-002 et al., regarding Financial Impact of ComEd's and AEP's RTO Choices on Michigan and Wisconsin, September 15, 2004 (with J.P. Pfeifenberger).
- Declaration on Behalf of the Michigan-Wisconsin Utilities before the FERC, Docket No. ER04-375-002 et al., regarding Financial Impact of ComEd's and AEP's RTO Choices on Michigan and Wisconsin, August 13, 2004 (with J.P. Pfeifenberger).

REPORTS & ARTICLES

- *A Wide Array of Resources Is Needed to Meet Growing US Energy Demand*, report prepared for ConservAmerica, February 2025 (with W. Chang, P. Vincent, and S. Willet).
- *ERCOT CONE for 2026*, report prepared for ERCOT, June 10, 2024 (with A. Thompson, R. Janakiraman, S. Gang, J. Jungé, H. Lee, and P. Nair).
- *Capacity Resource Accreditation for New England's Clean Energy Transition: Report 1*: *Foundations of Resource Accreditation*, report prepared for Massachusetts Attorney General's Office June 2022 (with K. Spees and J. Hingham).
- *Capacity Resource Accreditation for New England's Clean Energy Transition: Report 2*: *Options for New England*, report prepared for Massachusetts Attorney General's Office June 2022 (with K. Spees and J. Hingham).
- *Offshore Wind Transmission: An Analysis of Options for New York*, report prepared for Anbaric, August 2020 (with J. Pfeifenberger, W. Graf, and K. Spokas).
- *Singapore Foreward Capacity Market—FCM Design Proposal (Third Consultation Paper)*, prepared for the Singapore Energy Market Authority, May 2020 (with J. Chang and W. Graf). Followed draft proposals in first and second Consultation papers in May 2019 and Dec 2019.
- *Quantitative Analysis of Resource Adequacy Structures*, report prepared for NYSERDA and NYSDPS, July 1, 2020 (with K. Spees, J. Imon Pedtke, and M. Tracy). Update to presentation from July 1, 2020.
- *New York's Evolution to a Zero Emission Power System: Modeling Operations and Investment Through 2040 Including Alternative Scenarios*, report prepared for NYISO Stakeholders, June 22,

2020 (with R. Lueken, J. Weiss, S. Crocker Ross, and J. Moraski). Update to presentation from May 18, 2020.

- *Qualitative Analysis of Resource Adequacy Structures for New York*, report prepared for NYSERDA and NYSDPS, May 19, 2020 (with K. Spees and J. Imon Pedtke).
- *Offshore Transmission in New England: The Benefits of a Better-Planned Grid*, report prepared for Anbaric, May 2020 (with J. Pfeifenberger and W. Graf).
- *Implementing Recommended Improvements to Market Power Mitigation in the WEM*, report prepared for Energy Policy WA in Western Australia, April 2020 (with T. Brown).
- *Gross Avoidable Cost Rates for Existing Generation and Net Cost of New Entry for New Energy Efficiency*, report prepared for PJM, March 17, 2020 (with M. Hagerty, S. Sergici, E. Cohen, S. Gang, J. Wroble, and P. Daou).
- "Forward Clean Energy Markets: A New Solution to State-RTO Conflicts," *Utility Dive*, January 27, 2020 (with K. Spees and J. Pfeifenberger.)
- *How States, Cities, and Customers Can Harness Competitive Markets to Meet Ambitious Carbon Goals: Through a Forward Market for Clean Energy Attributes: Expanded Report Including a Detailed Market Design Proposal*, report prepared for NRG, September 2019 (with K. Spees, W. Graf, and E. Shorin).*International Review of Demand Response Mechanisms in Wholesale Markets*, report for the Australian Energy Market Commission, June 2019 (with T. Brown, K. Spees, and C. Wang).
- *Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region, 2018 Update, Final Draft*, prepared for the Electric Reliability Council of Texas, December 20, 2018 (with R. Carroll, A. Kaluzhny, K. Spees, K. Carden, N. Wintermantel, and A. Krasny).
- *Harmonizing Environmental Policies with Competitive Markets: Using Wholesale Power Markets to Meet State and Customer Demand for a Cleaner Electricity Grid More Cost Effectively*, discussion paper, July 2018 (with K. Spees, J. Pfeifenberger, and J. Chang).
- *Fourth Review of PJM's Variable Resource Requirement Curve*, report prepared for PJM Interconnection LLC for submission to FERC and PJM stakeholders, April 19, 2018 (with J. Pfeifenberger, K. Spees, and others).
- *PJM Cost of New Entry Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date*, report prepared for PJM Interconnection LLC for submission to FERC and PJM stakeholders, April 19, 2018 (with J. Michael Hagerty, J. Pfeifenberger, S. Gang of Sargent & Lundy, and others).

- *Evaluation of the DOE's Proposed Grid Resiliency Pricing Rule*, whitepaper prepared for NextEra Energy Resources, October 23, 2017 (with M. Celebi, J. Chang, M. Chupka, and I. Shavel).
- *Near Term Reliability Auctions in the NEM: Lessons from International Jurisdictions*, report prepared for the Australian Energy Market Operator, August 23, 2017 (with K. Spees, D.L. Oates, T. Brown, N. Lessem, D. Jang, and J. Imon Pedtke).
- *Pricing Carbon into NYISO's Wholesale Energy Market to Support New York's Decarbonization Goals*, whitepaper prepared for the New York Independent System Operator, August 10, 2017 (with R. Lueken, J. Weiss, K. Spees, P. Donohoo-Vallett, and T. Lee).
- "How wholesale power markets and state environmental Policies can work together," *Utility Dive*, July 10, 2017 (with J. Pfeifenberger, J. Chang, and K. Spees).
- *Market Power Mitigation Mechanisms for the Wholesale Electricity Market in Western Australia*, whitepaper prepared for the Public Utilities Office in the Government of W. Australia's Department of Finance, September 1, 2016 (with T. Brown, W. Graf, J. Reitzes, H. Trewn, and K. Van Horn).
- *Western Australia's Transition to a Competitive Capacity Auction*, report prepared for Enernoc, January 29, 2016 (with K. Spees and C. McIntyre).
- *Cost-Benefit Analysis of ERCOT's Future Ancillary Services (FAS) Proposal*, report prepared for ERCOT, November 2015 (with R. Carroll, P. Ruiz, and W. Gorman).
- *Enhancing the Efficiency of Resource Adequacy Planning and Procurements in the Midcontinent ISO Footprint—Options for MISO, Utilities, and States*, report prepared for NRG, November 2015 (with K. Spees and R. Lueken).
- *International Review of Demand Response Mechanisms*, report prepared for Australian Energy Market Commission, October2015 (with T. Brown, K. Spees, and D.L. Oates).
- *Resource Adequacy in Western Australia — Alternatives to the Reserves Capacity Mechanism*, report prepared for EnerNOC, Inc., August 2014 (with K. Spees).
- *Third Triennial Review of PJM's Variable Resource Requirement Curve*, report prepared for PJM Interconnection, LLC, May 15, 2014 (with J. Pfeifenberger, K. Spees, A. Murray, and I. Karkatsouli).
- *Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM*, report prepared for PJM Interconnection, LLC, May 15, 2014 (with M. Hagerty, K. Spees, J. Pfeifenberger, Q. Liao, and with C. Ungate and J. Wroble at Sargent & Lundy).

- *Developing a Market Vision for MISO: Supporting a Reliable and Efficient Electricity System in the Midcontinent*, foundational report prepared for Midcontinent Independent System Operator, Inc., January 27, 2014 (with K. Spees and N. Powers).
- *Estimating the Economically Optimal Reserve Margin in ERCOT*, report prepared for the Public Utilities Commission of Texas, January 2014 (with J. Pfeifenberger, K. Spees, and I. Karkatsouli).
- "Capacity Markets: Lessons Learned from the First Decade," article, *Economics of Energy & Environmental Policy*. Vol. 2, No. 2, Fall 2013 (with J. Pfeifenberger and K. Spees).
- *ERCOT Investment Incentives and Resource Adequacy*, report prepared for the Electric Reliability Council of Texas, June 1, 2012 (with K. Spees, J. Pfeifenberger, R. Mudge, M. DeLucia, and R. Carlton).
- "Trusting Capacity Markets: does the lack of long-term pricing undermine the financing of new power plants?" *Public Utilities Fortnightly* article, December 2011 (with J. Pfeifenberger).
- *Second Performance Assessment of PJM's Reliability Pricing Model: Market Results 2007/08 through 2014/15*, report prepared for PJM Interconnection LLC, August 26, 2011 (with J. Pfeifenberger, K. Spees).
- *Cost of New Entry Estimates for Combustion-Turbine and Combined-Cycle Plants in PJM*, report prepared for PJM Interconnection LLC, August 24, 2011 (with J. Pfeifenberger, K. Spees, and others).
- "Fostering economic demand response in the Midwest ISO," *Energy* 35 (2010) 1544–1552 (with A. Faruqui, A. Hajos, and R.M. Hledik).
- "DR Distortion: Are Subsidies the Best Way to Achieve Smart Grid Goals?" *Public Utilities Fortnightly*, November 2010.
- *Midwest ISO's Resource Adequacy Construct: An Evaluation of Market Design Elements*, report prepared for MISO, January 2010 (with K. Spees and A. Hajos).
- *Demand Response in the Midwest ISO: An Evaluation of Wholesale Market Design*, report prepared for MISO, January 2010 (with A. Hajos).
- *Cost-Benefit Analysis of Replacing the NYISO's Existing ICAP Market with a Forward Capacity Market*, whitepaper for the NYISO and stakeholders, June 15, 2009 (with A. Bhattacharyya and K. Madjarov).
- *Fostering Economic Demand Response in the Midwest ISO*, whitepaper written for MISO, December 30, 2008 (with R. Earle and A. Faruqui).

- *Review of PJM's Reliability Pricing Model (RPM)*, report prepared for PJM Interconnection LLC for submission to FERC and PJM stakeholders, June 30, 2008 (with J. Pfeifenberger and others).
- "Reviving Integrated Resource Planning for Electric Utilities: New Challenges and Innovative Approaches," *Energy*, Vol. 1, 2008, newsletter, The Brattle Group (with M. Chupka and D. Murphy).
- *Enhancing Midwest ISO's Market Rules to Advance Demand Response*, report written for MISO, March 12, 2008 (with R. Earle).
- "The Power of Five Percent," article, *The Electricity Journal*, October 2007 (with A. Faruqui, R. Hledik, and J. Pfeifenberger).
- *Quantifying Customer Benefits from Reductions in Critical Peak Loads from PHI's Proposed Demand-Side Management Programs*, prepared for Pepco Holdings, Inc., September 21, 2007 (with A. Faruqui).
- *Review of PJM's Market Power Mitigation Practices in Comparison to Other Organized Electricity Markets*, report prepared for PJM Interconnection LLC, September 14, 2007 (with P. Fox-Penner, J. Pfeifenberger, J. Reitzes, and others).
- "Valuing Demand-Response Benefits in Eastern PJM," *Public Utilities Fortnightly*, March 2007 (with J. Pfeifenberger and F. Felder).
- *Quantifying Demand Response Benefits in PJM*, report prepared for PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative, January 29, 2007 (with F. Felder).
- "Modeling Power Markets: Uses and Abuses of Locational Market Simulation Models," *Energy*, Vol. 2, 2006, The Brattle Group (with J. Pfeifenberger).
- "Innovative Regulatory Models to Address Environmental Compliance Costs in the Utility Industry," October 2005 Newsletter, American Bar Association, Section on Environment, Energy, and Resources: Vol. 3 No. 1 (with J. Pfeifenberger).

PRESENTATIONS & SPEAKING ENGAGEMENTS

- "Planning Future Load Growth," panelist at NJBPU Technical Conference, August 5, 2025.
- "Meeting Soaring Demand More Quickly…While Mitigating Increases in Rates and Emissions," presented at the Energy Bar Association Northeast Chapter Annual Meeting, June 18, 2025.
- "Avoiding Attrition of Solar PV," presented to NCUC Carolinas Resource Plan Technical Conference on behalf of the Carolinas Clean Energy Business Association, June 17, 2024.
- "Renewable Energy Economics: Updated on Development Fundamentals," presented at the Institute for Energy Law 2024 Renewables Conference, Houston, TX, April 25, 2024.
- "ERCOT Resource Adequacy: Reliability Standard and Market Design Implications," panelist at GCPA 38th Annual Fall Conference, Austin, TX, October 3, 2023.
- "Priorities for Reforming Resource Accreditation and the Resource Adequacy Framework in New England," presented to NEPOOL Markets Committee, September 14, 2022.
- "Observations and Implications of the 2021 Texas Freeze," presented to Power Markets Today webinar on the February 2021 ERCOT electricity failure, April 14, 2021.
- "Offshore Wind Transmission: An Analysis of Options for New York," presented at LCV Virtual Policy Forum, August 6, 2020 (with J. Pfeifenberger, W. Graf, and K. Spokas).
- "Possible Paths Forward from MOPR," presented to Power Markets Today webinar on "Capacity Market Alternatives for States," July 15, 2020.
- "Considerations for Meeting Sub-Annual Needs, and Resource Accreditation across RTOs," presented to MISO Resource Adequacy Subcommittee, July 8, 2020 (with J. Pfeifenberger, M. Hagerty, and W. Graf).
- "New York's Evolution to a Zero Emission Power System—Modeling Operations and Investment through 2040 Including Alternative Scenarios," presented to NYISO Stakeholders, June 22, 2020 (with R. Lueken, J. Weiss, S. Ross, and J. Moraski).
- "Singapore Foreward Capacity Market Design—Industry Briefing Sessions," presented via video to Singapore electricity market stakeholders, June 5 & 9, 2020 (with W. Graf).
- "Industry Changes in Resource Adequacy Requirements," presented to MISO Resource Adequacy Subcommittee, May 6, 2020 (with J. Pfeifenberger, M. Hagerty, and W. Graf).
- "NYISO Grid in Transition Study: Detailed Assumptions and Modeling Description," presented to NYISO Stakeholders, March 30, 2020 (with R. Lueken, J. Weiss, J. Moraski, and S. Ross).

- "Electricity Market Designs to Achieve and Accommodate Deep Decarbonization," presented to Advanced Energy Economy (AEE) video conference, "ISO-NE in 2050: Getting To An Advanced Energy Future In New England," March 18, 2020.
- "U.S. Offshore Wind Generation, Grid Constraints, and Transmission Needs," presented at Offshore Wind Transmission, USA Conference, September 18, 2019 (with J. Pfeifenberger and K. Spokas).
- "Pollution Pricing in the Power Sector: Market-Friendly Tools for Incorporating Public Policy," presented to GCPA Spring Conference, Houston, TX, April 16, 2019.
- "The Transformation of the Power Sector to Clean Energy: Economic and Reliability Challenges," keynote address to the Power Engineers 4th Annual Power Symposium, Weehawken, NJ, April 4, 2019.
- "Market Design for Winter Energy Security in New England: Further Discussion of Options," presented to The New England Power Pool Markets Committee on behalf of NextEra Energy Resources, Westborough, MA, February 6, 2019 (with D.L. Oates and P. Ruiz).
- "Market Design for Winter Energy Security in New England: Discussion of Options," presented to The New England Power Pool Markets Committee on behalf of NextEra Energy Resources, Westborough, MA, January 9, 2019 (with D.L. Oates).
- "Market Equilibrium Reserve Margin in ERCOT," presented to Power Markets Today webinar, "A Post Summer Check-in of ERCOT's Market," October 31, 2018.
- "Carbon Pricing in NYISO's Wholesale Energy Market, and Applicability to Multi-State RTO markets," presented to Raab Policy Roundtable, May 23, 2018; presented to the Energy Bar Association, 2018 EBA Energizer: Pricing Carbon in Energy Markets, June 5, 2018; presented to Bank of America Merrill Lynch, June 25, 2018.
- "Reconciling Resilience Services with Current Market Design," presented to RFF/R-Street Conference on "Economic Approaches to Understanding and Addressing Resilience in the Bulk Power System," Washington, DC, May 30, 2018.
- "System Flexibility and Renewable Energy Integration: Overview of Market Design Approaches," presented to Texas-Germany Bilateral Dialogue on Challenges and Opportunities in the Electricity Market, Austin, TX, February 26, 2018.
- "Natural Gas Reliability: Understanding Fact from Fiction," panelist at the NARUC Winter Policy Summit presented to The Committee on Gas, Washington, D.C., February 13, 2018 (with A. Thapa, M. Witkin, and R. Wong).

- "Carbon Pricing in Wholesale Markets: Takeaways from NYISO Carbon Charge Study," presented to Harvard Electric Policy Group, October 12, 2017.
- "Pricing Carbon into NYISO's Wholesale Energy Market: Study Overview and Summary of Findings," presented to NYISO Business Issues Committee, September 12, 2017.
- "Carbon Adders in Wholesale Power Markets—Preventing Leakage," panelist at Resources for the Future's workshop on carbon pricing in wholesale markets, Washington, D.C., August 2, 2017.
- "Market-Based Approaches to Support States' Decarbonization Objectives," panelist at Independent Power Producers of New York (IPPNY) 2017 Spring Conference, Albany, NY, May 10, 2017.
- "ERCOT's Future: A Look at the Market Using Recent History as a Guide," panelist at the Gulf Coast Power Association's Fall Conference, Austin, TX, October 4, 2016.
- "The Future of Wholesale Electricity Market Design," presented to Energy Bar Association 2016 Annual Meeting & Conference, Washington, DC, June 8, 2016.
- "Performance Initiatives and Fuel Assurance—What Price Mitigation?" presented to Northeast Energy Summit 2015 Panel Discussion, Boston, MA, October 27, 2015.
- "PJM Capacity Auction Results and Market Fundamentals," presented to Bloomberg Analyst Briefing Webinar, September 18, 2015 (with J. Pfeifenberger and D.L. Oates).
- "Energy and Capacity Market Designs: Incentives to Invest and Perform," presented to EUCI Conference, Cambridge, MA, September 1, 2015.
- "Electric Infrastructure Needs to Support Bulk Power Reliability," presented to GEMI Symposium: Reliability and Security across the Energy Value Chain, The University of Houston, Houston, TX, March 11, 2015.
- Before the Arizona Corporation Commission, Commission Workshop on Integrated Resource Planning, Docket No. E-00000V-13-0070, presented "Perspectives on the IRP Process: How to get the most out of IRP through a collaborative process, broad consideration of resource strategies and uncertainties, and validation or improvement through market solicitations," Phoenix, AZ, February 26, 2015.
- "Resource Adequacy in Western Australia—Alternatives to the Reserve Capacity Mechanism (RCM)," presented to The Australian Institute of Energy, Perth, WA, October 9, 2014.
- "Customer Participation in the Market," panelist on demand response at Gulf Coast Power Association Fall Conference, Austin, TX, September 30, 2014.

- "Market Changes to Promote Fuel Adequacy—Capacity Market to Promote Fuel Adequacy," presented to INFOCAST- Northeast Energy Summit 2014 Panel Discussion, Boston, MA, September 17, 2014.
- "EPA's Clean Power Plan: Basics and Implications of the Proposed CO_2 Emissions Standard on Existing Fossil Units under CAA Section 111(d)," presented to Goldman Sachs Power, Utilities, MLP and Pipeline Conference, New York, NY, August 12, 2014.
- "Capacity Markets: Lessons for New England from the First Decade," presented to Restructuring Roundtable Capacity (and Energy) Market Design in New England, Boston, MA, February 28, 2014.
- "The State of Things: Resource Adequacy in ERCOT," presented to INFOCAST – ERCOT Market Summit 2014 Panel Discussion, Austin, TX, February 24-26, 2014.
- "Resource Adequacy in ERCOT," presented to FERC/NARUC Collaborative Winter Meeting in Washington, D.C., February 9, 2014.
- "Electricity Supply Risks and Opportunities by Region," presentation and panel discussion at Power-Gen International 2013 Conference, Orlando, FL, November 13, 2013.
- "Get Ready for Much Spikier Energy Prices—The Under-Appreciated Market Impacts of Displacing Generation with Demand Response," presented to the Cadwalader Energy Investor Conference, New York, NY, February 7, 2013 (with K. Spees).
- "The Resource Adequacy Challenge in ERCOT," presented to The Texas Public Policy Foundation's 11th Annual Policy Orientation for legislators, Austin, TX, January 11, 2013.
- "Resource Adequacy in ERCOT: the Best Market Design Depends on Reliability Objectives," presented to the Harvard Electricity Policy Group conference, Washington, D.C., December 6, 2012.
- "Resource Adequacy in ERCOT," presented to the Gulf Coast Power Association Fall Conference, Austin, TX, October 2, 2012.
- "Texas Resource Adequacy," presented to Power Across Texas, Austin, TX, September 21, 2012.
- "Resource Adequacy and Demand Response in ERCOT," presented to the Center for the Commercialization of Electric Technologies (CCET) Summer Board Meeting, Austin, TX, August 8, 2012.
- "Summary of Brattle's Study on 'ERCOT Investment Incentives and Resource Adequacy'," presented to the Texas Industrial Energy Consumers annual meeting, Austin, TX, July 18, 2012.

- “Market-Based Approaches to Achieving Resource Adequacy,” presentation to Energy Bar Association Northeast Chapter Annual Meeting, Philadelphia, PA, June 6, 2012.
- “Fundamentals of Western Markets: Panel Discussion,” WSPP’s Joint EC/OC Meeting, La Costa Resort, Carlsbad, CA, February 26, 2012 (with J. Weiss).
- “Integrated Resource Planning in Restructured States,” presentation at EUCI conference on “Supply and Demand-Side Resource Planning in ISO/RTO Market Regimes,” White Plains, NY, October 17, 2011.
- “Demand Response Gets Market Prices: Now What?” NRRI teleseminar panelist, June 9, 2011.
- Before the PJM Board of Directors and senior level representatives at PJM’s General Session, panel member serving as an expert in demand response on behalf of Pepco Holdings, Inc., December 22, 2007.
- “Resource Adequacy in New England: Interactions with RPS and RGGI,” Energy in the Northeast Law Seminars International Conference, Boston, MA, October 18, 2007.
- “Corporate Responsibility to Stakeholders and Criteria for Assessing Resource Options in Light of Environmental Concerns,” Bonbright Electric & Natural Gas 2007 Conference, Atlanta, GA, October 3, 2007.
- “Evaluating the Economic Benefits of Transmission Investments,” EUCI’s Cost-Effective Transmission Technology Conference, Nashville, TN, May 3, 2007 (with J. Pfeifenberger, presenter).
- “Quantifying Demand Response Benefits in PJM,” PowerPoint presentation to the Mid-Atlantic Distributed Resources Initiative (MADRI) Executive Committee on January 13, 2007, to the MADRI Working Group on February 6, 2007, as Webinar to the U.S. Demand Response Coordinating Council, and to the Pennsylvania Public Utility Commission staff April 27, 2007.
- “Who Will Pay for Transmission,” CERA Expert Interview, Cambridge, MA, January 15, 2004.
- “Reliability Lessons from the Blackout; Transmission Needs in the Southwest,” presented at the Transmission Management, Reliability, and Siting Workshop sponsored by Salt River Project and the University of Arizona, Phoenix, AZ, December 4, 2003.
- “Application of the ‘Beneficiary Pays’ Concept,” presented at the CERA Executive Retreat, Montreal, Canada, September 17, 2003.

Dr. Andrew W. Thompson

ENERGY ASSOCIATE

Boston/Madrid

Mobile +34.66.663.91.97
Office +34.91.048.71.00

andrew.thompson@brattle.com

Dr. Thompson is an energy economist with a background in electrical engineering and expertise in wholesale electricity market design, regulatory economics, and policy analysis of network industries, particularly in the energy sector.

His work focuses on:

- Wholesale electricity market design and reform
- Capacity market/auction design and resource adequacy
- Integration of emerging energy technologies
- Energy market regulation
- The hydrogen economy
- Energy finance, cost of capital estimation, and utility rate cases
- Energy asset evaluation and economic damages assessments for renewable generation, transmission, and storage assets

Dr. Thompson has supported clients and diverse stakeholder groups – including electricity system operators, energy regulators, governments, clean energy advocacy groups, market participants, institutional investors, and utilities – in several international jurisdictions. This includes PJM, CAISO, ERCOT, NYISO, ISO-NE, the Non-ISO/RTO United States, Ontario, Alberta, the United Kingdom, Spain, Colombia, Saudi Arabia, Australia, and New Zealand.

He has published thought leadership on energy policy and market reforms to integrate emerging resources (renewables, battery storage, long-duration energy storage, distributed energy resources, and flexible load); the regulation of the energy sector; the hydrogen economy; and the economic implications of lithium-ion battery degradation for energy storage and electric vehicle technologies.

AREAS OF EXPERTISE

- Electricity Wholesale Markets & Planning
- Regulatory Economics, Finance & Rates

EDUCATION

- **Université Paris-Saclay (Paris, France)**
  PhD in Economics
- **Universidad Pontificia Comillas (Madrid, Spain)**
  MS in Energy Economics
- **Delft University of Technology (Delft, The Netherlands)**
  MSc in Engineering and Policy Analysis
- **Rowan University (New Jersey, USA)**
  BSc in Electrical and Computer Engineering

PROFESSIONAL EXPERIENCE

- **The Brattle Group (2020–Present)**
  Energy Associate
- **University of California Berkeley/Lawrence Berkeley National Laboratory (2017–2019)**
  Visiting Researcher
- **US Department of Energy: ARPE-E (2018)**
  Technology-to-Market Scholar
- **Institut Vedecom (2016–2018)**
  Electric Vehicle and Battery Storage Researcher
- **Spanish and Portuguese Energy Market Operator (OMIE) (2014–2015)**
  Energy Analyst

SELECTED CONSULTING EXPERIENCE

WHOLESALE ELECTRICITY MARKET DESIGN AND REFORM

- **Energy Storage Wholesale Market Reforms Roadmap:** For the American Clean Power Association (ACP) analyzed and developed a comprehensive roadmap for near-term wholesale market reforms needed to better integrate and enable energy storage resources, with a particular focus on implementing reform efforts in PJM, MISO, and NYISO.
- **IESO Future Market Reforms Initiatives**: For the Ontario Independent Electricity System Operator (IESO) conducted a benefits assessment of near-term, mid-term, and long-term market reform initiatives.
- **AESO Market Pathways Initiative**: For the Alberta Electric System Operator (AESO) and the Executive Working Group (EWG), provided support for various inquiries into energy market enhancements as part of the Market Pathways initiative that aims to inform the future evolution of Alberta's electricity market design.

- **ERCOT CONE for 2026 Study:** For the Electric Reliability Council of Texas (ERCOT) developed an updated estimate of the Cost of New Entry (CONE) for use in setting the Peaker Net Margin (PNM) threshold, evaluating the cost of proposed reliability standards, analyzing the Market Equilibrium Reserve Margin (MERM) and Economically Optimal Reserve Margin (EORM), and potentially setting demand curves for a Performance Credit Mechanism (PCM). Developed updated model to calculate CONE accounting for fixed and variable costs, lifetime estimates, financial parameters, and levelization of future net revenue requirements.
- **South Carolina Wholesale Energy Market Reforms Study:** For the South Carolina State Legislature, conducted a comprehensive assessment of potential benefits and risks from competitive reforms to the state's electricity sector and regulatory model. Examined potential reforms to join or integrate with a regional transmission organization, introduce competition into resource planning, and pursue partial or full retail choice.
- **US Bulk System Reliability for Tomorrow's Grid**: For the Center for Applied Environmental Law and Policy (CAELP), co-authored a report submitted to the US EPA as public comments of the New Source Performance Standards for greenhouse gas emissions. The report outlines current and emerging reliability impacts on the bulk power system due to recent and projected changes in the energy sector and explains the suite of solutions grid operators have at their disposal to ensure reliability is maintained throughout the ongoing energy transition.
- **Generation Interconnection Reform**: For Hydro Quebec, provided a summary of ongoing generation interconnection reform processes and identified best practices in North America.
- **IESO Wholesale Market Participation Model Design for DERs:** Provided expert support to IESO staff for proposed changes to wholesale market participation models and rules to better enable DER and hybrid resource integration.
- **Costs of Decarbonizing the US Electricity Sector**: For the American Council on Renewable Energy (ACORE), a renewable energy advocacy group, evaluated costs to decarbonize the US electricity sector under alternative proposals to extend and expand renewable energy tax credits in 2021. Simulated investment, costs, prices, and emissions nationally to 2050 using gridSIM, Brattle's capacity expansion model. Informed client's policy position.

CAPACITY MARKET/AUCTION DESIGN AND RESOURCE ADEQUACY

- **PJM Quadrennial Review of Capacity Market Design and Demand Curve Parameters:** For PJM, conducted periodic reviews of PJM's Reliability Pricing Model. Analyzed market functioning for resource adequacy, including uncertainty and volatility of prices, net cost of new entry (CONE) parameters, impacts of administrative parameters and regulatory uncertainties, locational mechanisms, demand curve shape, incremental auction procedures, and other market mechanisms. Developed a probabilistic simulation model evaluating the price volatility and reliability implications of alternative demand curve shapes and recommended a revised demand curve shape. Assisted expert support to stakeholder proceedings and testimony submitted before the Federal Energy Regulatory Commission.

- **PJM Development of Gross Avoidable Cost Rates:** For PJM, developed Avoidable Cost Rates (ACRs) for existing resource types for use in the Minimum Offer Price Rule (MOPR) and in Market Seller Offer Cap (MSOC). Contributed to submitted testimonies before FERC.
- **Ontario Capacity Auction Design:** Provided expert support to IESO staff in support of a new capacity auction design and enhancements. Delivered detailed reports describing options, tradeoffs, and lessons learned on every aspect of capacity auction design. Developed analysis and design proposals for the capacity market demand curve, capacity accreditation methodologies, and penalty mechanism design. Supported IESO stakeholder engagement efforts and presented analyses of design alternatives in public forums.
- **Assessment of Resource Adequacy Alternatives:** For a market operator, assessed potential alternative resource adequacy options including a centralized capacity market with single and bi-furcated pricing, a residual market, a bilateral market, and alternative capacity hedging strategies that could be pursued for end-customers.
- **Capacity Market Overview Study**: For a major renewable investment company, presented an overview of US and international capacity markets and resource adequacy mechanisms.
- **Capacity Accreditation Approaches for Hybrid Resources**: For a major renewable investment company, presented an assessment of current approaches to capacity accreditation using Effective Load Carrying Capability (ELCC) methods for evaluating hybrid resources.

INTEGRATION OF EMERGING ENERGY TECHNOLOGIES

- **Long-Duration Energy Storage (LDES) Technology Landscape:** For the Center for Climate and Energy Solutions (C2ES) provided expert support and research to an industry working group on the Long-duration Energy Storage (LDES) technology landscape. Assessed costs, technology readiness, and value proposition of Inter-day LDES (10-36 hrs) and Multi-day LDES (36+ hrs) technologies to address emerging system needs under deep decarbonization. Provided support on developing policy reforms to encourage greater LDES deployment at state and federal levels.
- **EPRI Long-Duration Energy Storage Working Group:** For the Electric Power Research Institute (EPRI) presented to an industry working group on the challenges associated with modeling LDES in capacity expansion models.
- **IESO (Ontario) Long-term Contract Design for Renewable, Storage, and Hybrid Resources:** Provided expert support to IESO staff for long/mid-term RFP contract design to procure energy, capacity, and environmental attributes from emerging resources including renewables, energy storage, and hybrid storage assets in Ontario.
- **NEOM Saudi Arabia Load Flexibility Integration Study:** Developed supporting analysis and a load flexibility roadmap to assist the public utility (ENOWA) in developing their load flexibility integration plan for various sources of large-scale electricity demand within NEOM.

ENERGY MARKET REGULATION

- **Recent Developments in International Rate of Return Methods**: For Energy Networks Australia (ENA), developed an updated overview of international rate of return methods for regulators in the US, Great Britain, New Zealand, Italy, and The Netherlands. This paper also provided a review of the Australian Energy Regulator's draft 2022 Rate of Return Instrument and recommend improvements as well as a comparison on a like-for-like basis of recent rate of return decision from each regulator.
- **International Approaches to Regulated Rates of Return**: For the Australian Energy Regulator (AER), researched international approaches to rate of return and WACC estimations across six countries: Australia, Italy, the Netherlands, New Zealand, the US, and the UK. This report reviewed and summarized international regulators' approaches to utility regulation and compared the rate of return approach of each regulator to that of the AER as part of the 2022 Rate of Return Instrument.

THE HYDROGEN ECONOMY

- **Future of Hydrogen in the Power Sector:** For the Environmental Defense Fund (EDF), developed an assessment of the potential role of hydrogen in a decarbonized power sector. Explained the nature of reliability needs in renewable power systems and assessed hydrogen technologies' ability to address system reliability, resiliency, and resource adequacy challenges.

ENERGY FINANCE, COST OF CAPITAL ESTIMATION, UTILITY RATE CASES

- **PacifiCorp Rate Case:** Supported Mr. John Tsoukalis' expert testimony before the Wyoming Public Service Commission regarding the reliability value of inter-state transmission, the risks and costs of operating the Bulk Electricity System (BES) in non-compliance with NERC standards, the economic impact of reliability events particularly to large industrial customers, and transmission cost allocation approaches in multi-state jurisdictions.
- **Alberta Utilities Commission Generic Cost of Capital (GCOC) Estimation**: Supported Dr. Bente Villadsen's expert testimony on the cost of equity and appropriate capital structure presented before the Alberta Utilities Commission (AUC).
- **Cost of Capital Estimation for North American Regulated Electric Utilities:** For several major North American regulated electric utilities, conducted financial and economic analyses to support expert testimony estimating allowed Return on Equity to inform upcoming rate case hearings before state utility commissions and the FERC.
- **Cost of Capital Estimation for North American Regulated Gas Utilities:** For several major North American regulated gas utilities, conducted financial and economic analyses to support expert testimony estimating allowed Return on Equity to inform upcoming rate case hearings before state utility commissions and the FERC.

ENERGY ASSET EVALUATION AND ECONOMIC DAMAGES ASSESSMENTS

- **HVDC Transmission Energy, Capacity, and Resource Adequacy Value:** For several major transmission companies, assessed the energy, capacity, and additional resource adequacy value of proposed inter-regional high-voltage DC (HVDC) transmission projects under various carbon price and future resource mix scenarios for due diligence processes.
- **PJM Battery Storage Asset Valuation and Damages**: For a major renewable energy developer, developed an economic damages estimation due to an alleged breach in contractual performance warranties of a battery storage asset in PJM Interconnection LLC.
- **Spanish Wind Asset Regulatory Impacts:** For a major renewable energy developer, contributed to expert report on the financial impact on wind assets of a mid-stream switch in the regulatory regime for Spanish renewables.
- **Spanish Solar PV Asset Valuation and Damages**: For a major renewable energy developer, contributed to litigation support and damages estimation of an international arbitration concerning the financial impact of a mid-stream switch in the regulatory regime for Spanish renewables. The damages estimate considers the valuation of both the reduction in remuneration and financial instruments related to the project financing.
- **Spanish Wind Asset Valuation and Damages**: For a major renewable energy developer, contributed to litigation support and damages estimation of an international arbitration concerning the financial impact of a mid-stream switch in the regulatory regime for Spanish renewables. The damages estimate considers the valuation of both the reduction in remuneration and financial instruments related to the project financing.
- **Spanish Concentrated Solar Power (CSP) Asset Valuation and Damages**: For a major renewable energy developer, contributed to litigation support and damages estimation of an international arbitration concerning the financial impact of a mid-stream switch in the regulatory regime for Spanish renewables. The damages estimate considers the valuation of both the reduction in remuneration and financial instruments related to the project financing.
- **Colombia Energy Investors Dispute**: For a group of investors in electricity companies, contributed to analysis for expert testimony regarding a dispute over dividend payments before the Bogotá Chamber of Commerce Arbitration Centre.

REPORTS, ARTICLES, & PUBLICATIONS

- "Sixth Review of PJM's Variable Resource Requirement Curve", with Kathleen Spees and Samuel A. Newell, prepared for PJM Interconnection, LLC (April 2025)
- "Brattle 2025 CONE Report for PJM", with Samuel A. Newell and Bin Zhou, prepared for PJM Interconnection, LLC (April 2025)
- "Energy Storage Market Design Roadmap", with Samuel A. Newell, Andrew Levitt, and Serena Patel, prepared for American Clean Power (April 2025)

- "LDES Scoping Report", with J. Michael Hagerty and Andrew Levitt, prepared for the Center for the Center for Climate and Energy Solutions (C2ES) (March 2024)
- "ERCOT CONE for 2026," with Samuel A. Newell, prepared for the Electric Reliability Council of Texas, Inc. (ERCOT) (June 2024)
- "Bulk System Reliability for Tomorrow's Grid," with Metin Celebi, Andrew Levitt, and Ragini Sreenath, prepared for prepared for the Center for Applied Environmental Law and Policy (CAELP) (December 2023)
- "Ontario's Experience with the Single Buyer Contracting Model", with Kathleen Spees, Andrew Levitt, and Xander Bartone, prepared for the Alberta Electric System Operator (AESO) and the Executive Working Group (EWG)(November 2023)
- "Assessment of Potential Market Reforms for South Carolina's Electricity Sector," with John H. Tsoukalis, Kathleen Spees, Johannes P. Pfeifenberger, Andrew Levitt, and Oleksandr Kuzura, prepared for the South Carolina General Assembly Electricity Market Reform Measures Committee (April 2023)
- "Gross Avoidable Costs for Existing Generation," with Samuel Newell, prepared for PJM Interconnection, L.L.C. (January 2023)
- "International Rate of Return Methods – Recent Developments," with Bente Villadsen and Toby Brown, prepared for Energy Networks Australia (September 2022)
- "Fifth Review of PJM's Variable Resource Requirement Curve," with Kathleen Spees and Samuel Newell, prepared for PJM Interconnection (April 2022)
- **"**Vehicle-to-Everything (V2X) Energy Services, Values Streams, and Regulatory Policy Implications," with Yannick Perez, *Energy Policy,* 137, Article 111136 (2020)
- "Economic implications of lithium-ion battery degradation for Vehicle-to-Grid (V2X) services," *The Journal of Power Sources*, 396, pp. 691–709 (2018)

PRESENTATIONS & SPEAKING ENGAGEMENTS

- "Evolving Resource Adequacy Approaches in North America", Presentation and panel discussions at the International Energy Agency (IEA) Expert Workshop on Power Market Design, (May 2025)
- Bank of America, US Power & Utilities Research Expert Presentation on PJM CONE Estimation, with Samuel Newell, Sang Gang, and Joshua Junge, (May, 2025)
- Jefferies, US Power, Utilities, & Clean Energy Research Expert Presentation on PJM Parameters, with Samuel Newell and Kathleen Spees, (May, 2025)
- UBS, Utilities and Power Equity Research Expert Presentation on PJM Parameters, with Samuel Newell and Kathleen Spees, (April, 2025)

- "Sixth Review of PJM's RPM VRR Curve Parameters: Final Recommendations," with Samuel Newell and Kathleen Spees, PJM Market Implementation Committee (April, 2025)
- "The Need for Mechanisms to Support Flexibility or Capacity" and "Aligning the Security of Supply and Decarbonization Targets", Panel Discussions at the 7th Capacity Mechanisms Forum: Ensuring the European Electricity Supply (October 2024)
- "Resource Adequacy Trends of the Energy Transition: Experience from North America," 7th Capacity Mechanisms Forum: Ensuring the European Electricity Supply (October 2024)
- "Modeling Storage Adequacy in Capacity Expansion Models," with Kate Peters, EPRI Long-Duration Energy Storage Working Group (July 2024)
- "Long-duration Energy Storage Scoping Report," with Andrew Levitt and Michael Hagerty, C2ES LDES Working Group, (March 2024)
- "Resource Adequacy Trends of the Energy Transition: Experience from North America," NTNU Energy Transition Week: Power Markets (March 2024)
- "Role of Hydrogen in a Decarbonized Future," with Josh Figueroa and Metin Celebi, Bank of America Global Research US Alternative Energy Hydrogen Conference (December 2023)
- "Discussion on Demand Curve Review," IESO Technical Session (October 2022)
- "PJM Market Implementation Committee Special Session: Quadrennial Review," with Kathleen Spees and Samuel Newell, PJM Interconnection (December 2021)
- "Vehicle-to-Everything (V2X) Energy Services," presented to Smart Charging Webinar hosted by Newcastle University in conjunction with The Alan Turing Institute, CESI and Supergen Energy Networks, (October 2020)
- "Vehicle-to-Everything (V2X) Energy Services," presented to the International Smart Grid Action Network (ISGAN), (April 2019)
- "Economic Feasibility of Wind Energy Participation in Secondary Reserves Markets," *Proceedings of the 1st Italian Association of Energy Economists (IAEE) Energy Symposium,* Milan, Italy (2016)
- "PV by-pass diode performance in landscape and portrait modalities," with Carlos Barreiro, Peter M. Jansson, and John L. Schmalzel, *37th IEEE Photovoltaic Specialists Conference* (2011)

TRADE PRESS & MEDIA COVERAGE

- E&E News, "Spain's big blackout: A cautionary tale for US grid managers", June 2025
- Utility Dive, "PJM, MISO, NYISO ripe for energy storage market reforms: Brattle/ACP", April 2025
- RTO Insider, "ACP Road Map Suggests Market Changes to Increase Storage Participation", April 2025

- Energy Storage News, "American Clean Power report recommends energy storage-friendly market reforms to US grid operators", April 2025
- PV Magazine: Energy Storage, "US call for better energy storage rules in wholesale markets", April 2025

PROFESSIONAL ASSOCIATIONS & MEMBERSHIPS

International Association for Energy Economics (IAEE)
Institute of Electrical and Electronics Engineers (IEEE) Power and Energy Society

LANGUAGES

- Spanish (fluent), French (conversational)

Bin Zhou

PRINCIPAL

Boston | +1.617.864.7900 | Bin.Zhou@brattle.com

Dr. Zhou is a valuation, corporate finance, and accounting expert with more than 25 years of consulting experience.

He specializes in the application of financial economics, management accounting, business organizations, and taxation principles to various consulting and litigation settings. Dr. Zhou's work has included projects spanning financial institutions, consumer goods, energy, pharmaceuticals and medical devices, technology, and utilities industries.

Dr. Zhou has supported testifying experts and led large engagement teams in many high-profile transfer pricing, bankruptcy, and M&A litigations. His work has been primarily focused on the economic analysis of transfer pricing disputes involving hard-to-value intangibles, the economic substance of complex transactions, solvency analysis and fraudulent conveyance claims, structured finance transactions, financial statement analyses, and damages.

His recent experience includes a couple of litigation and SEC investigation involving private investment in public equities (PIPEs), claim estimation in the Puerto Rico Electric Power Authority's Title III case, lost profits damages in an antitrust case against a large technology company, and two Delaware breach of fiducial duty class actions against large technology companies. He has also recently performed economic profitability analyses in several antitrust matters and has been involved in a special litigation committee investigation of a large acquisition in the software-as-a-service industry, international arbitration cases involving two publicly listed Korean companies, and intellectual property transfers in distressed companies.

AREAS OF EXPERTISE

- Accounting
- Bankruptcy & Restructuring
- Financial Institutions
- M&A Litigation
- Tax Controversy & Transfer Pricing
- Technology

EDUCATION

- **Brandeis University**
  PhD in International Economics and Finance, 1998
- **Washington State University**
  MA in Economics, 1994
- **Fudan University (China)**
  BA in Economics, 1991

PROFESSIONAL EXPERIENCE

- **The Brattle Group (1998–Present)**
  Principal (2013–Present)
  Senior Consultant (2003–2013)
  Associate (1998–2003)

EXPERT TESTIMONY AND TRIAL EXPERIENCE

- **Apportionment of mutual fund fees in a non-Federal tax dispute** | Submitted expert report (2025), trial testimony pending
- **PJM Interconnection, LLC proceeding on cost of new entry** | Federal Energy Regulatory Commission | Dockets nos. ER22, ER19-105-00, ER14-2940-000 | Affidavit (2022), Affidavit and Reply Affidavit (2018), Affidavit (2014) regarding the merchant generation cost of capital, all with Johannes P. Pfeifenberger
- **Alberta Electric System Operator proceeding** | Alberta Utilities Commission | Docket no. 23757 | Reply affidavit on merchant generation cost of capital, joint with Johannes P. Pfeifenberger (2019)
- **Estate dispute involving annuity valuation** | Submitted three expert reports and testified at trial (2014)

SELECTED CONSULTING EXPERIENCE

TRANSFER PRICING AND OTHER TAX CONTROVERSIES

- On behalf of an estate, Dr. Zhou supported a Brattle expert to estimate the fair market value of a large block of shares that were subject to various resale restrictions.

- In an ongoing transfer pricing dispute involving a large technology company, Dr. Zhou advised the taxpayer on a number of economic, marketing, and valuation issues (acquisition of a publicly traded company and buy-in transactions) involved in the case.
- In Western Digital's transfer pricing dispute against the IRS, on behalf of the taxpayer, Dr. Zhou supported a testifying expert in rebutting an opposing expert' valuation of the technology transfer and the profitability of intangible assets.
- In Facebook's transfer pricing dispute with the IRS (the client), Dr. Zhou supported an academic accounting expert to review Facebook's general ledgers and financial reporting for certain acquisitions and intercompany transfers.
- In a now settled transfer pricing dispute involving a U.S. electrical device manufacturer, Dr. Zhou led a support team to analyze the profit drivers for the taxpayer's sales of a small variety of low-priced high-volume products and evaluate the best transfer pricing method.
- In Coca-Cola's transfer pricing dispute with the IRS, Dr. Zhou led Brattle's consulting team to perform an independent functional analysis of the taxpayer's international operations and the value drivers of the industry, and to propose an arm's length prices for the transfer of the company's product and marketing intangibles.
- In the bankruptcy of Gawker Media (a now-defunct online media company), Dr. Zhou advised the bankruptcy trustee on the intercompany transfer pricing among the content creation, distribution, and sales functions.
- Brattle was retained by Boston Scientific / Guidant to value the allocation of intangibles between US and foreign entities and evaluate the best transfer pricing method. Dr. Zhou led the project team to support a transfer pricing testifying expert.
- In Eaton's successful challenge to an IRS adjustment involving two advance pricing agreement cancellations, Dr. Zhou led support teams for three outside and one in-house experts on issues ranging from managerial accounting, technology licensing, and transfer pricing methods. Dr. Zhou played an instrumental role in supporting a cost accounting expert on Eaton's managerial accounting and APA compliance.
- In Amazon's successful Tax Court petition involving its transfer pricing dispute with the IRS. Dr. Zhou supported an outside licensing expert on the structure of arm's-length licenses of marketing intangible property.
- On behalf of a number of US subsidiaries of a foreign-headquartered multinational corporation, Dr. Zhou led the project team to analyze the US subsidiaries' intercompany financing from a foreign affiliate, valuation of the businesses, and ability to service the debt.

- Dr. Zhou led a support supporting a large Canadian bank in a dispute with the Canada Revenue Agency over the proper allocation of a multi-billion dollar-securities class action settlement in the US. The Brattle team assessed the risk positions and risk-bearing abilities of each entity to the transactions implicating the Canadian bank.
- In Broadwood Investment Fund *et al.* v. U.S.A. (tax dispute involving distressed assets/debt), Dr. Zhou assisted a Brattle expert and two external experts analyzing the reasonable profitability of the taxpayers' investment in non-performing loan portfolios.
- Dr. Zhou worked on a tax dispute on behalf of AstraZeneca against the UK's Revenue and Customs. He supported Prof. Stewart Myers from MIT's Sloan School of Management to analyze whether the licensing agreements for several drugs between the UK parent and its Puerto Rican subsidiary were at arm's length.
- Dr. Zhou worked on a tax dispute with the IRS on behalf of Wells Fargo with respect to several of the bank's leasing transactions. He prepared evidence and analyses on the character, time pattern, and degree of risk borne by the buyer (lessor), the extent of defeasance, the choice of risk- and tax-adjusted discount rates for the municipal agencies (lessees), and the probability of their exercise of purchase option at the end of the lease.
- In a tax dispute between ExxonMobil and the Australian tax authority, Dr. Zhou led the project team to estimate the fair value of certain petroleum products at potential taxing points upstream of the actual sales.
- Dr. Zhou assisted counsel for GlaxoSmithKline in its tax litigation against the IRS involving valuation of intellectual property rights. He assisted in the development of a life-cycle model of a successful drug.
- In a dispute concerning the interest deduction claimed by HSBC Bank, Dr. Zhou analyzed whether the US branches of the UK bank maintained adequate capital and whether the borrowing and lending transactions between the affiliated parties were arm's-length.
- In several litigation matters between the IRS and US companies (AEP, Dow Chemical, and Xcel Energy) regarding the interest deduction of policy loans against the corporate-owned life insurance policy, Dr. Zhou consulted client counsel on the corporate finance issues of the insurance policies.

M&A LITIGATION, BANKRUPTCY, AND RESTRUCTURING

- Brattle was engaged by the independent directors of a publicly traded company to value the control premium of a large non-controlling block held by one of the company's co-CEOs. Dr. Zhou and other consultants at Brattle recommended a control premium based on recent dual-class reclassification transactions. The directors accepted our recommendation and repurchased the shares.

- Brattle was engaged as a financial advisor to Ambac on spin-off of its primary subsidiary and reorientation of business. Dr. Zhou was a member of the consulting team.
- In a Delaware appraisal litigation against an online gaming company, on behalf of the plaintiffs, Dr. Zhou led a Brattle team to analyze the split of M&A gains between the bidders and targets. The case settled.
- In Puerto Rico Electric Power Authority's bankruptcy proceeding, Dr. Zhou supported a Brattle expert to estimate the future cash flows expected to flow to the bondholders as of the bankruptcy petition date. The bankruptcy judge accepted the Brattle expert's model.
- In a Delaware breach of fiduciary litigation against a media company, Dr. Zhou supported a Brattle expert to calculate the damages arising from the company's multi-year stock buyback that allegedly led to a squeeze out. The case settled before the trial.
- In a Delaware breach of fiduciary litigation against Michael Dell, Dr. Zhou supports a Brattle expert to calculate the damages of a corporate transaction on the shareholders (the client). The case settled before the trial with a $1 billion cash settlement to the class.
- In a dispute involving an online travel reservation company (the client) and its lenders, Dr. Zhou led a Brattle team to analyze the impact of COVD-19 on industry, the company's pro forma financial reporting, and the impact of an intellectual property transfer on the platform company.
- In an international arbitration, Dr. Zhou supported an academic expert to analyze whether a corporate subsidiary had been effectively under the strategic and operational control of its parent to such an extent that it was appropriate to "pierce the corporate veil."
- In a dispute between J. Crew and some of its lenders (the client), Dr. Zhou supported a Brattle Principal to value the company before the transfer of J. Crew's brand intangibles to an affiliated company beyond the reach of the lenders.
- In a special litigation committee (SLC) investigation of whether a large publicly traded company overpaid in its acquisition of a related software-as-a-service target company, Dr. Zhou supported an academic expert to advise the SLC on various economic, industry, and valuation issues. He led the Brattle team to assist counsel for the SLC counsel in document review, witness interviews, SLC presentations, and mediation.
- In two international arbitration disputes against the Republic of Korea (the client), Dr. Zhou supports an affiliated expert to opine on the fair market value of several publicly-traded

companies within a large Korean chaebol, the merger ratio between two of them, and the claimants' trading strategies involving these companies.

- In the bankruptcy of Avaya (a telecom service provider), on behalf of a large equity investor, Dr. Zhou led a project team to analyze Avaya's patent portfolios, its competitive positions in the industry, and post-bankruptcy valuation. The case settled before the confirmation hearing.
- In Caesars Entertainment Operating Company's bankruptcy, Brattle was retained by Apollo Global Management to provide valuation and solvency analyses over 15 transactions between 2008 and 2014. The transactions involved the sale of gaming and lodging properties, intellectual property, and other related assets. Dr. Zhou supported an in-house expert. The case settled.
- In US Steel Canada's insolvency proceeding in Ontario, Dr. Zhou assisted an in-house expert to rebut assertions by the opposing parties that certain intercompany loans should be re-characterized as equity. The Court ruled in our client's favor.
- In Nortel's bankruptcy allocation and claims proceedings, Dr. Zhou supported an allocation expert and a transfer pricing expert on behalf of Nortel's UK pension fund. The key issue before the joint US and Canada courts is the allocation of Nortel's $7.3 billion liquidation proceedings, mostly from patents-related intangible assets, among Nortel's three primary bankruptcy estates (Canada, US, and EMEA). He led the Brattle team through all phases of the expert reports, deposition, and trial. The allocation decisions were issued in our client's favor.
- In Ambac's bankruptcy proceeding, Dr. Zhou assisted Ambac in its tax dispute with the IRS regarding the taxpayer's $700 million tax refund during the recent financial crisis. The dispute involves the appropriate taxation of credit derivatives, currently an unsettled area in tax policies and regulation. The case settled in our client's favor.
- In a confidential assignment involving a fraudulent conveyance action in Tribune's bankruptcy, The Brattle Group was retained as consulting experts to review several valuation and solvency analyses performed at the time of the transaction.
- In several suits against Ernst & Young brought by Refco's litigation trustee, Dr. Zhou advised counsel E&Y against allegations of breach of fiduciary duty. He performed forensic analysis of the financial institution's tax returns and workpapers of the audited financial statements. He also analyzed whether the alleged breach of fiduciary duty could have caused the brokerage's demise. The case was recently dismissed.
- In a number of litigations against Bank of America in Parmalat's bankruptcy, Dr. Zhou advised counsel for Bank of America regarding a number of structured finance transactions

it arranged for Parmalat's Latin American subsidiaries. He supported an outside academic expert to provide a coherent framework to examine a multinational enterprise's management of its financing strategy in the emerging markets. Against this framework, he analyzed various features of the financing and their overall impact on Parmalat's indebtedness.

- On behalf of Deutsche Bank, Dr. Zhou was extensively involved in a number of Enron-related securities and bankruptcy litigations. He supervised the project team to analyze Enron's off-balance-sheet debt, its sources and use of cash flows, and the related disclosure. He reviewed the transaction documents and journal entries for over a hundred special-purpose vehicle transactions, and led the project team to analyze the transactions' impact on Enron's key financial ratios and their impact on Enron's creditworthiness. He also supported testifying experts on economic and accounting issues of certain structured finance and tax transactions.
- In a bankruptcy proceeding, Dr. Zhou supported an academic expert to analyze whether a corporate subsidiary had been effectively under the strategic and operational control of its parent, to such an extent that it was appropriate to "pierce the corporate veil."
- For Global Crossing's Board of Directors, Dr. Zhou reviewed the business purposes of certain fiber optic capacity lease transactions, conducted forensic analysis of the associated accounting records, and reviewed SEC disclosure regarding its pro forma accounting. He also examined the market reaction to the company's various disclosures.

SECURITIES LITIGATION

- Dr. Zhou advised counsel for two investment funds under SEC investigation of trading profits in PIPEs (convertible bonds) on potential damages. The investigation was recently withdrawn.
- Dr. Zhou supported an academic expert on an Exchange Act §15 class action lawsuit against multiple investors in a PIPE transaction involving the issuance of convertible bonds during COVID.
- Dr. Zhou advised counsel in two DOJ criminal investigations involving alleged fraudulent financial disclosures of channel stuffing and issuances of convertible securities.
- Dr. Zhou advised plaintiff counsel in a class action against a master limited partnership over its public disclosure on maintenance capital expenditure, and damages to the class.
- Dr. Zhou assisted counsel for the Federal Deposit Insurance Corporation (FDIC) in a warrant and representation dispute between JP Morgan and the FDIC. He advised on the relevant accounting and disclosure issues.

- In a valuation dispute between Barclays and a mortgage company related to the repo financing of a multi-billion MBS-based derivative portfolio, Dr. Zhou supported a Brattle principal to mark to market the portfolio around August 2007 and quantify the impact of market illiquidity on the portfolio valuation.
- In an insurance dispute between a broker-dealer (client) and a large bank whose natural gas trader caused hundreds of million trading losses amid valuation irregularities, Dr. Zhou provided consulting support in tracing the losses to its various causes. The case was recently settled on favorable terms to our client.
- For a 10b(5) securities class action against MBIA, Dr. Zhou provided consulting support to the company's mediation and settlement discussions with the plaintiffs. He reviewed the company's mandatory and voluntary disclosures during the 2007/2008 financial crisis regarding its exposure to subprime collateralized debt obligation, estimated the but-for stock price under alternative disclosures, and calculated the potential damages to shareholders.
- In a criminal sentencing case against a bank executive who was found guilty of material misrepresentation, Dr. Zhou led the project team to analyze the bank's valuation analysis and accounting records for certain complex mortgage-related derivatives, and reviewed a third-party's analyses that led to the bank's financial restatements. He also evaluated the loss causation and estimated the damages caused by the executive's misconduct.
- In a shareholder class action lawsuit against Scottish Re, where plaintiffs sued the company over its failure to book and disclose a valuation allowance for deferred tax assets, Dr. Zhou analyzed several of the company's statutory reserve securitization transactions, which allegedly should have caused the company to recognize the valuation allowance earlier. He assisted counsel for the company to identify factual evidence to refute the connection between the securitization transactions and the decision to book the valuation allowance. The case is settled.

CONTRACT DISPUTES AND DAMAGES

- In an antitrust case against a large technology company, Dr. Zhou supported an outside expert to estimate lost profits damages to a start-up whose innovative service was eliminated by the large tech's alleged anti-competitive conduct.
- In a confidential FTC matter, Dr. Zhou supported a Brattle expert on the analysis of a healthcare provider's economic profits, sources of profits, and indicia of market power.
- On behalf of Trans Canada over the interpretation of a long-term power purchase contract clause governing whether "high impact, low probability" risks were compensated through a

risk premium in the contract price, Dr. Zhou examined the regulatory history in Alberta leading to the contractual arrangements, and assisted another Brattle Principal to interpret the contractual language. The arbitration panel ruled in favor of Trans Canada.

- In a hedge fund redemption and valuation dispute in late 2008 between an investor and the fund management, Dr. Zhou analyzed the fund management's internal net asset valuation (NAV) calculation, valuation discounts under FAS 157, and monthly performance reporting to the investors. The assets under management included thousands of illiquid structured finance products and real estate assets.
- Dr. Zhou assisted Prof. Stewart Myers from MIT Sloan School on an international arbitration matter regarding damages from the government's expropriation of ExxonMobil oil assets in Venezuela.
- In a hedge fund dispute between an equity investor and the fund management, Dr. Zhou analyzed the fund's investment in various structured finance products, financial leverage via repo transactions, portfolio risk management, compliance with the investment guideline, and performance reporting. He assisted counsel for the investor to amend the complaint.
- In a dispute over damages from a prematurely terminated long-term power tolling contract, Dr. Zhou assisted the testifying experts to present evidence on why calculating the present value of those damages required the use of two distinct discount rates: one (a low rate) for the revenues lost under the low-risk terminated contract and another, much higher rate, for the valuation of the replacement revenues in the risky, short-term wholesale power markets. Our position was adopted by the arbitration panel.
- For a major US cable TV company, Dr. Zhou analyzed two complex corporate transactions each worth hundreds of millions dollars. Both transactions consist of revenue contribution and subsequent transfer of corporate ownership between two affiliated entities (each with a separate tracking stock on the market) at the time. Dr. Zhou investigated the fairness of the terms and conditions of overall transactions.
- Dr. Zhou worked on several Winstar cases, breach-of-contract lawsuits against the US government arising from the savings and loan crisis in the late 1980s. He built pro forma financial models and analyzed thrift financial data, operations, funding, and capital adequacy standards. He supported two experts estimating damages under reliance, restitution, lost profits / expectancy, and mitigation theories.

RISK ANALYSIS AND VALUATION

- In an estate dispute, Dr. Zhou opined on the reasonableness of an over-funded variable annuity in replicating the payoffs under a fixed annuity and estimated the cost savings.

- For a large oil pipeline project in Canada, Dr. Zhou led a project team to analyze the risks and returns of the investment under various scenarios, evaluated the distribution of project's internal rate of returns, and advised the company on regulatory filings before the National Energy Board.
- Dr. Zhou analyzed economic reasonableness of Chicago Clean Energy's cost of equity and capital costs, and presented results to Illinois Commerce Commission.
- For an online gaming company during its settlement negotiation with the Department of Justice, Dr. Zhou reviewed a third-party analysis of the gaming company's ability to pay fines.
- In a merger & acquisition litigation, Dr. Zhou analyzed the transaction premium for a proposed merger of two large US utility companies.
- Dr. Zhou recently valued a privately-owned C-Corp that owns, among others, general partnership (GP) interest of a publicly traded energy master limited partnership (MLP), and equity interest in a gas storage joint venture.
- In anticipation of a fraudulent conveyance action involving a large leveraged buyout transaction during the financial crisis, Dr. Zhou led the project team to review several valuation and solvency analyses performed at the time of the transaction.
- For an electricity user consortium in New England considering electricity contract renewal v. generation asset purchase, Dr. Zhou presented market evidence on energy and capacity price forecasts, funding costs, and operational efficiency. He analyzed differences in cash flows under multiple market scenarios to inform considerations of risk.
- For an offshore wind developer proposing to build a 350 MW project off the coast of New Jersey, Dr. Zhou developed a detailed financial model of project funding, operation, and cash distributions to various types of investors (including production tax credit, and the FLIP tax structure), and the pro forma financial statements were used in an application to the state of New Jersey for project grants.
- Dr. Zhou provided due diligence support on regulatory and valuation matters to an Asian sovereign wealth fund in its investment in OnCor energy. On regulatory issues, he analyzed tax treatment of an LLC organization form, allowed rates of return, and investment recovery mechanism. On valuation issues, he reviewed the utility's pro forma financial statements and prepared valuation summaries under various market conditions and regulatory policy changes.
- For Peoples Gas in Chicago, Dr. Zhou reviewed its risk management strategies, recommended hedging policies based on volatility forecasts estimated from NYMEX gas

options, and developed proto-type hedging simulation models and performance monitoring metrics.

- For CenterPoint Energy's stranded cost recovery proceeding, Dr. Zhou analyzed whether the market valuation of Texas Genco, CenterPoint's majority-owned subsidiary at the time, reflected the fair value of the generation assets, and whether the company's conservative corporate finance policy and ownership structure at the time enhanced the enterprise value.
- Dr. Zhou worked on several cost of capital cases for both regulated and unregulated businesses. For a major US utility company, Dr. Zhou developed a methodology for estimating cost of capital for different types of electricity generation plants, based on their respective fuel inputs, geographic locations, and operating leverage.
- In various projects, Dr. Zhou developed financial models (discounted cash flow models and real option pricing models) to estimate the value of a project, investment hurdle rate, and asset retirement and replacement decisions. The industries include utilities, energy, and telecommunication.
- In various projects, Dr. Zhou developed valuation frameworks to value tax-favored investment vehicles. They include partnerships, S-Corp., municipalities, MLPs, and life insurance products.

MISCELLANEOUS

- In US Airways v Sabre, Dr. Zhou supported a Brattle expert on the analysis of Sabre Travel Network's economic profits, sources of profits, and indicia of market power.
- In Epic v. Apple, Dr. Zhou analyzed Apple App business's economic profits against a large sample of high-tech companies.
- In MetWest's excessive advisory fee litigation, Dr. Zhou supported a cost accounting expert to analyze the appropriateness of fees charged to mutual fund investors for investment management and related services. He advised the fund advisor and its outside counsel on the relevant measures of profitability, and reviewed and tested the sensitivity of cost allocations to the funds.
- For a US telecom company, Dr. Zhou analyzed the economic impact of a tax-favored dividend repatriation policy on the US economy.
- For a major investor of US wind farms and wind turbine manufacturers, Dr. Zhou and a team of Brattle consultants analyzed the economic impact of the extension of US production tax credit program.

- In an intellectual property infringement case, Dr. Zhou supported a Brattle testifying expert to estimate lost profit damages. He analyzed intra-company financial data for the infringed to estimate the marginal cost and transfer pricing of intermediate products.
- Dr. Zhou coauthored a white paper on behalf of a coalition for competitive insurance rates analyzing the impact on the US property and casualty insurance market of a tax on offshore affiliate reinsurance.
- For a Denmark company with operations in Venezuela, Dr. Zhou reviewed and recommended improvement to the local unit's foreign exchange hedging strategy.
- For a major US telecom company, Dr. Zhou supported two MIT Sloan School professors advising the telecom company about its market penetration strategy in emerging markets and business alliance strategy with local business groups.

ARTICLES & PUBLICATIONS

- "The Proper Measure of Profits for Assessing Market Power," joint with Michael Cragg, Patrick Holder, and David Hutchings, *Antitrust*, Volume 37, No. 2 (Spring 2023)
- "The Social and Economic Contributions of the Life Insurance Industry: An Update," with Michael Cragg and Sarah Hamilton, prepared for MetLife Inc. (2020)
- "How To Assess Accounting Materiality Amid Economic Crisis," with Adrienna Huffman and Chi Cheng, *Law360* (May 8, 2020)
- "Examining the Role of Market Price in Appraisal" Parts 1 and 2, with Dirk Hackbarth, *Law360* (September 10 and 11, 2018)
- "The Social and Economic Contributions of the Life Insurance Industry: An Update," with David Cummins, Michael Cragg, and Jehan deFonseka, prepared for MetLife Inc. (2018)
- "Effects of New Tax Law on Capital Structure and Cost of Capital," with Dirk Hackbarth, *Tax Notes* (March 12, 2018)
- "Evaluating the Impact of an Offshore Reinsurance Tax," with Michael Cragg, Jehan deFonseka, and Lawrence Powell, *Tax Notes* (February 9, 2017)
- "The Impact of Offshore Affiliate Reinsurance Tax Proposals on the U.S. Insurance Market: An Updated Economic Analysis," with Michael Cragg, Jehan deFonseka, and Lawrence Powell, prepared for the Association of Bermuda Insurers and Reinsurers (January 23, 2017)
- "The Social and Economic Contributions of the Life Insurance Industry," with David Cummins, Michael Cragg, and Jehan deFonseka, prepared for MetLife Inc. (2016)

- “The Interaction of Managerial and Tax Transfer Pricing,” with Shannon Anderson, Rand Ghayad, and Michael Cragg, *Bloomberg BNA Transfer Pricing Report*, Vol. 24, No. 2 (2016)
- “The Implications of Transfer Pricing in Bankruptcy,” with Steven Felgran, *Bloomberg BNA Transfer Pricing Report*, Vol. 24, No. 17 (2015)
- “Statistical review of U.S. macronutrient consumption data, 1965-2011: Americans have been following dietary guidelines, coincident with the rise in obesity,” with Evan Cohen, Michael I. Cragg, Jehan deFonseka, Melanie Rosenberg, and Adele Hite, *Nutrition*, Vol. 31, Issue 5, pp. 727–732. (May 2015)
- “Public Disclosure versus Confidentiality in Liquid Fuel Markets,” with Evan Cohen, Michael Cragg, and David Hutchings, prepared for Flint Hills Resources, LP and Marathon Petroleum Company LP (January 23, 2015)
- “Reducing Rate Shocks,” with A. Lawrence Kolbe and Philip Q Hanser, *Fortnightly Magazine* (June 2013)
- “Economic Considerations in Litigation against the Credit Rating Agencies,” with Pavitra Kumar, The Brattle Group, Inc. (April 2012)
- “State Regulatory Hurdles to Utility Environmental Compliance,” with Phil Hanser and Metin Celebi, *The Electricity Journal* (April 2012)
- “Cost of New Entry Estimates for Combustion Turbine and Combined-Cycle Plants in PJM,” with Kathleen Spees, Samuel A. Newell, Robert Carlton, and Johannes P. Pfeifenberger, et al. (2011)
- “Defining Market Manipulation in a Post-REMIT World,” Brattle Discussion Paper, with Shaun Ledgerwood, Dan Harris, and Pinar Bagci (2011)
- “Risk-Adjusted Damages Calculation in Breach of Contract Disputes: A Case Study,” with Frank C. Graves, Melvin Brosterman, and Quinlan Murphy, *Journal of Business Valuation and Economic Loss Analysis* (2010)
- “The Impact on the U.S. Insurance Market of H.R. 3424 on Offshore Affiliate Reinsurance: An Updated Economic Analysis,” with Michael I. Cragg and J. David Cummins, The Brattle Group, Inc. (July 8, 2010)
- “Litigation Facing the Private Equity Industry,” *Finance*, No. 1 (2009)
- “The Impact on the U.S. Insurance Market of a Tax on Offshore Affiliate Reinsurance: An Economic Analysis,” with Michael I. Cragg and J. David Cummins, The Brattle Group, Inc. (May 1, 2009)

- "Cost of Capital Estimation for Unregulated Generation: Methodology and Estimates," The Brattle Group, Inc. (May 22–23, 2001)
- "New Advances in Capital Budgeting for Generation Assets: Survey and Interpretation," Electricity Power and Research Institute Fall Seminar (November 14, 2000)

PRESENTATIONS & SPEAKING ENGAGEMENTS

- TP Debate (Participant), "There is a material role for economic analysis in the application of Pillar Two," NABE Transfer Pricing Symposium (July 2024)
- TP Debate (Moderator), "Machine Learning will soon represent a viable option for conducting CPM searches in a manner that is both reliable and consistent with eh 482 regulations," NABE Transfer Pricing Symposium (July 2023)
- "Fraudulent Transfers: Cases, Trends and Updates in the 2019 Minefield," The Knowledge Group Webinar, January 16 (2019)
- Presentation to Joint Task Force on M&A Litigation, ABA Business Law Section Meeting, Austin, TX (September 15, 2018)
- "Tax Cuts and Jobs Act: Transfer Pricing Implications for Financial Transactions and Financial Services Companies" (panelist), NABE Transfer Pricing Symposium (July 2018)
- "OECD Country-by-Country Data Submissions — A Potential for Misapplication of Big Data" (moderator), ABA Tax 2016 Joint Fall Meeting, Boston, MA (2016)
- "Infrastructure and Rate Structure: Lessening the Shock," with Larry Kolbe and Phil Hanser, 2012 NASUCA Annual Meeting, Baltimore, MD (November 2012)
- "Control Premiums / Minority Discounts --- Recent Cases and Economic Evidence," at The Knowledge Congress webcast series *Business Valuation Trends Explored in 2012 LIVE Webcast* (October 2012)
- EUCI Workshops on Utility Financial Accounting, co-taught by Bente Villadsen and Bin Zhou, October 2012 (Denver), May 2012 (Atlanta), and February 2012 (Chicago) (one and half days each)
- "U.S. Tax Implications of Wind Power Business," presented at U.S.-China Wind Summit 2011 (December 2011)
- "U.S. Renewable Energy and Transmission Regulation and Investment Opportunities," with Judy Chang, presented to State Grid Corporation of China (Beijing) (September 2011)

- "Economics of Supervisory Goodwill," with Stewart C. Myers, presented at MIT Sloan School of Management, The Brattle Group, Inc. (March 17, 2003)

LANGUAGES

- Chinese (native)

JOSHUA C. JUNGE

Principal Energy Consultant

Sargent & Lundy Consulting Group

Education

- BS Mechanical Engineering—University of Illinois Urbana-Champaign—2011

Registrations

Professional Engineer (Illinois, Texas)

Proficiencies

- Capital and Operating Cost Estimation
- Mechanical Systems Engineering, Design, and Equipment Specification
- Reciprocating Engines (RICE)
- Heat Recovery Steam Generators
- Combustion and Steam Turbine Generating Systems
- Air Quality and Emissions Control Systems including ACI, DSI, SCR, and CCUS
- Battery Energy Storage Systems (BESS)
- Onshore Wind and Solar Photovoltaic (PV)
- Hydrogen Generation, Storage, Transmission, and Utilization
- Due Diligence and Lender's Advisory Services

Responsibilities

Josh leads many of Sargent & Lundy's projects involving cost and performance studies for public and private clients to inform resource modeling and planning efforts. His work includes evaluation of new and alternative power generation and storage technologies, supporting clients with project due diligence, technical reviews, feasibility studies, cost estimation, financial analysis, and execution of projects in the utility power sector. Josh chartered and presently manages Sargent & Lundy's Data Center Services Community of Practice focused on the technical and economic nuances of designing power solutions to reliably serve data center loads while addressing their unique operational challenges. Josh assembled and led a team in Sargent & Lundy's artificial intelligence enterprise integration pilots and oversees cross-functional initiatives to implement automation, drive benchmark data restructuring, and develop agentic solutions that leverage AI across multiple internal processes.

Sargent & Lundy Experience

As a Principal Energy Consultant, Josh leads cost and performance studies and economic assessments across conventional generation and energy storage technologies, informing resource planning, market design reviews, and investor diligence based on a foundation of detailed engineering and field experience. His recent work includes leading and contributing to cost-of-new-entry studies for regional wholesale power markets, developing technical specifications and capital and operating cost estimates for combustion turbines, combined-cycle plants, reciprocating engines, and multiple storage technologies, and drafting technical language supporting regulatory filings. He supports utilities and public-sector analyses by producing technology cost/performance inputs for integrated resource planning and long-horizon national energy modeling and brings prior owner's engineer and engineer-of-record experience on large capital projects to deliver thorough and grounded techno-economic assessments. Joshua has been a licensed professional engineer since 2015 and maintains active licenses in Illinois and Texas.

Cost and Performance Experience

PJM | 2021–2025

- 2024-2025 | Cost of New Entry (CONE) Quadrennial Review
- Collaborated with the Brattle Group for the cost of new entry (CONE) study and review of PJM's Variable Resource Requirement (VRR) curve. Prepared technical specifications, capital, and operating cost estimates for combustion turbine, combined cycle, and battery energy storage representative technologies for new entry into PJM markets.
- 2024 | Cost of New Entry (CONE) Escalation Review
- Collaborated with the Brattle Group for review of the escalation methodology used to update the cost of new entry (CONE) values from PJM's 2022 Quadrennial Review. Reviewed applicable indices from the U.S. Bureau of Labor Statistics to review cost escalation for the turbines, materials, and labor components of the capital cost components of the CONE for each of the PJM locational deliverability areas.
- 2022 | Demand Curve Reset
- Collaborated with The Brattle Group to analyze the gross avoidable costs rates (ACRs) for several types of existing generation including single-unit nuclear, multi-unit nuclear, coal, gas-fired combined-cycle, gas-fired combustion turbines, onshore wind, utility-scale solar PV, and steam oil and gas generators.

- 2021-2022 | Cost of New Entry (CONE) Study
- Collaborated with the Brattle Group for cost of new entry (CONE) study and review of PJM's Variable Resource Requirement (VRR) curve. Prepared technical specifications, capital, and operating cost estimates for combustion turbine and combined cycle representative technologies for new entry into PJM markets.

Hydro-Québec | 2024–2025

- 2024-2025 | Cost of New Entry (CONE) Study
- Collaborated with The Brattle Group for cost of new entry (CONE) study for Hydro-Quebec. Led a techno-economic assessment for Hydro-Québec to identify and select four commercially available, ≤5-year-deployable low-carbon firm capacity options to meet winter peak demand. Delivered market benchmarking for resources to produce Québec-specific estimates covering EPC scope, lifecycle/decommissioning, construction schedules and cash-flow phasing, development and O&M (including full fuel logistics), performance parameters, and 2025–2040 cost trajectories. Delivered an Excel model to calculate annualized cost/levelized cost of capacity under multiple regulatory, tax, and financing assumptions with sensitivity analyses; assessed value from ancillary services and energy arbitrage; and produced a detailed technical report with a public-facing summary to support investment decisions.

ERCOT | 2023–2024

- 2024 | Cost of New Entry (CONE) Study
- Collaborated with The Brattle Group for cost of new entry (CONE) study for ERCOT. Prepared technical specifications, capital, and operating cost estimates for combustion turbine, solar PV, and battery energy storage representative technologies with regional cost and performance considerations unique to the ERCOT market.

Entergy | 2022-2024

- 2022-2024 | Cost and Performance Studies
- Prepared technical specifications, capital, and operating cost estimates for a variety of combustion turbine, combined cycle, and reciprocating engine representative technologies for hypothetical developments in the Entergy service areas in support of Entergy's 2022, 2023, and 2024 Integrated Resource Planning.

EIA | 2023

- 2023 | Cost and Performance of New Generation

- Prepared technical specifications, capital, and operating cost estimates for several types of existing generation including multi-unit nuclear, small modular reactor nuclear, coal, gas-fired combined-cycle, gas-fired combustion turbines, onshore wind, offshore wind, utility-scale solar PV, geothermal, hydroelectric, and bio-energy systems. Cost and performance estimates were developed for each technology to inform inputs to the EIA's Electricity Market Module used in their National Energy Modeling System (NEMS). Final report published with the EIA's Annual Energy Outlook 2025 reference resources.

IESO | 2021–2022

- 2022 | Cost and Performance Study
- Prepared technical specifications, capital, and operating cost estimates for combustion turbine, combined cycle, combined heat & power, and reciprocating engine representative technologies for new entry into IESO markets.

NYISO | 2021

- 2021 | Buyer Side Mitigation Review
- Performed buyer-side mitigation review of solar and battery energy storage projects bid into the NYISO market.

Other Experience

Confidential Data Center Developer Client | 2025–Present

- 2025–Present | Cost and Performance Technology Matrix and Power Block Analysis
- Led development of a comparative cost and performance screening matrix, framing eight configurations across RICE and aeroderivative combustion turbines (CTs) and normalizing outputs for capacity, heat rate/efficiency, fuel pressure and compression needs, emissions controls, and indicative lead-time assumptions
- Managed fatal flaw assessment, reliability, availability, and maintainability (RAM) analyses, environmental and permitting studies, and developed conceptual general arrangement, single-line diagrams, EPC schedules,

DOE Loan Programs Office | 2021–Present

- 2023–Present | Due Diligence for Confidential Virtual Power Plant Project
- Performed independent engineer due diligence including technical review of loan program applicant's technology offerings including commercial thermal energy storage systems and distributed resource aggregation software.

- 2022–Present | Due Diligence for Confidential Virtual Power Plant Project
  - Performed independent engineer due diligence including technical review of loan program applicant's technology offerings including residential solar PV, battery energy storage, and distributed resource aggregation software.
  - Ongoing technical performance monitoring support to ensure progress milestones are kept per the terms of loan guarantee agreement.
- 2022 | Decarbonization Study for the US Power Sector
  - Performed a technical review of existing and nascent power generation and storage technologies in the U.S. power sector.
  - Performed capacity expansion and production cost modeling, iterating for resource adequacy and grid congestion, and evaluations of multiple decarbonization scenarios.
- 2021| Project Readiness – From Pilot to Deployment Report
- Analyzed Technology Readiness Levels and key hurdles between developmental phases, including case studies of successful and unsuccessful projects at different phases of development and identification of key factors to successful private and publicly funded partnership projects

Competitive Power Ventures | 2022–Present

- 2022–Present | Independent Engineering Due Diligence for PV and Onshore Wind Facilities
- Independent Engineering review of project design and commercial documentation for multiple solar PV and onshore wind power generation facilities.
- Managed the full scope of diligence efforts including detailed design reviews and construction monitoring for the duration of the project through commercial operation.

Puerto Rico Electric Power Authority | 2020–2021

- 2020–2021 | Independent Engineering Due Diligence for Combustion Turbine and Combined Cycle Facilities
- Independent Engineering review of Puerto Rico's major combustion turbine and thermal power generation facilities

El Paso Electric Company | 2019–2021

- 2019–2021 | Newman 6 – GT5 Simple Cycle Balance of Plant Engineering
- Prepared technical specifications for plant utilities and process systems, including service/fire water storage tank, fuel gas conditioning equipment, compressed air system, pre-engineered

buildings, fire protection pumps and enclosure, wastewater recycling system, horizontal water pumps, aqueous ammonia storage and forwarding system, and air-cooled heat exchangers.

- 2019–2021 | Newman 6 – GT5 Simple Cycle Owners Engineering Support
    - Vendor Drawing Review of Equipment OEM Submittals

Eastern Generation, LLC | 2018–2021

- 2018–2021 | Covert Generating Station SCR Upgrade EPC
- Developed the EPC contract for selective catalytic system and performed detailed engineering and design for aqueous ammonia storage and forwarding system
- Performed detailed engineering study and specification for drum level transmitter Relocation and Replacement
- 2019–2021 | Astoria Generating Station Owner's Engineer Support for ULSD Storage Tank EPC

Tucson Electric Company | 2019–2021

- 2019–2021 | Oso Grande Wind Farm O&M Building EPC
- Developed site general arrangements, pre-engineered building specifications, and reviewed technical documentation from vendors for the wind farm operations and maintenance facility

Cleco Corporation | 2016–2019

- 2016–2019 | St Mary's Clean Energy Center Waste Heat Recovery Steam Generator
- Prepared specifications for power island equipment supply, installation contractor scope, boiler and pipe cleaning services, heat tracing, and performance testing, and managed BOP equipment procurement

NRG Energy, Inc. | 2012–2016

- 2012–2014 | Big Cajun II Generating Station Selective Non-Catalytic Reduction System
    - Engineering, Procurement, and Construction Specification for new SNCR system
- 2013–2014 | Big Cajun II Generating Station Electrostatic Precipitator Upgrade
    - Owner's Engineer for ESP Upgrade EPC
- 2014–2016 | Big Cajun II Generating Station Dry Sorbent & Activated Carbon Injection Systems
- Prepared procurement and installation specifications for Dry Sorbent Injection (DSI) and Activated Carbon Injection (ACI) systems at the Big Cajun II Generating Station, and provided on-site construction and commissioning support

GenOn Energy, Inc. | 2011–2012

- 2011–2012 | Conemaugh Generating Station Selective Catalytic Reduction System EPC
- Prepared EPC specification for new SCR system, engineering and procurement specifications for BOP equipment

Other Experience

Military Experience

United States Marine Corps | 2002–2007

Electro-Optical Ordinance Repair Technician, Platoon Sergeant

- 2003 | Completed Specialized Technical School in Aberdeen Proving Grounds, MD
- 2004 | Deployment to Ramadi, Iraq – Operation Iraqi Freedom
- 2006 | Deployment to Al Asad, Iraq – Operation Iraqi Freedom

Achievements

- Two Meritorious Promotions, Two Navy and Marine Corps Achievement Medals

Exhibit No. 2

2025 CONE Report

Brattle 2025 CONE Report for PJM

Informing Parameters for PJM's RPM Auctions for Delivery Year 2028/29 through 2031/32

PREPARED BY

The Brattle Group

Samuel A. Newell
Andrew W. Thompson
Bin Zhou
Nathan Felmus
Harsha Haribhaskar

Sargent and Lundy

Sang H. Gang
Joshua C. Junge
Hyojin Lee
Liam Tawelian

PREPARED FOR

PJM Interconnection, LLC

APRIL 9, 2025

Brattle

pjm

NOTICE

This report was prepared for PJM Interconnection, in accordance with The Brattle Group's engagement terms, and is intended to be read and used as a whole and not in parts. The report reflects the analyses and opinions of the authors and does not necessarily reflect those of The Brattle Group's clients or other consultants.

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Executive Summary

PJM Interconnection (PJM) retained consultants at The Brattle Group (Brattle) and Sargent & Lundy (S&L) to review key elements of the Reliability Pricing Model (RPM), as required periodically under PJM's Open Access Transmission Tariff ("OATT" or "tariff").[1] This report presents: (1) our analysis and selection of relevant resource types; (2) estimates of the Cost of New Entry (CONE) for the 2028/2029 commitment period and escalation methods for subsequent years through 2031/2032; (3) recommendations regarding the methodology for calculating the net energy and ancillary service (E&AS) revenue offset (E&AS Offset); and (4) our recommendations for the reference prices that will be used as an input to setting pricing parameters on the Variable Resource Requirement (VRR) curves. A separate, concurrently-released report the *Sixth Review of PJM's Variable Resource Requirement Curve* ("2025 PJM VRR Curve Report") presents our review of the VRR curve shape.[2]

BACKGROUND

The VRR curve is not a typical market demand curve expressing aggregate customer demand. It is set administratively with the aim to procure enough resources to meet resource adequacy requirements while providing reasonable price stability. To meet those and other related objectives defined herein, the administrative derivation identifies a reference price based on the long-run marginal cost of capacity, such that unconstrained economic entry can be expected to achieve the resource adequacy requirement on a long-run average basis. The curve slopes downward to the right from that reference point to procure more when capacity is plentiful and inexpensive, and upward to the left to procure less when capacity is scarce and expensive.

The Reference Price has historically been determined by: (1) selecting a reference resource that can economically enter the PJM market and determining its characteristics, capital costs and ongoing operating and maintenance costs; (2) estimating first-year all-in revenues needed for entry (CONE) given likely trajectories of future total revenues and E&AS offsets; and (3) then subtracting first-year E&AS to arrive at Net CONE. E&AS offsets are typically re-calculated by PJM

1 PJM Interconnection, LLC. (2024). PJM Open Access Transmission Tariff. Effective January 1, 2024. ("PJM Tariff"), Attachment DD, Section 5.10.a.iii.

2 Spees, et. al, Sixth Review of PJM's Variable Resource Requirement Curve, April 9, 2025.

shortly before setting the parameters for each auction. Resulting Net CONE estimates are also used to set default minimum offer prices for new resources in the infrequent cases where minimum offer pricing applies in RPM.

Historically, the concepts of Net CONE, the long-run marginal cost of capacity, and the reservation prices merchant entrants would require to enter, were considered one and the same, however current market circumstances have caused these to diverge as we explain herein.

CURRENT MARKET CONTEXT

Demand growth rates for electricity are rapidly accelerating in PJM, throughout the US, and in other parts of the world, driven by the growth of data centers, manufacturing, and some electrification. Developers, generation supply chains, and transmission planners were not prepared for this surprise growth rate and will be challenged to meet it.

The supply of gas-fired combustion turbines, transformers, and switch gear is scarce. Scarcity of these components, labor, and other inputs has driven the cost of new gas-fired generation plants 43%-46% higher than in the CONE study conducted 2.5 years ago after accounting for inflation. In these tight conditions, prices are not only high but subject to substantial uncertainty and rapidly evolving market conditions (e.g., up 15%-21% just since August 2024 after accounting for inflation). Supply shortages and volatile price premiums may last for several years until supply chains can develop sufficient capacity to support demand. Compounding that is the recent increases and ongoing fluctuations in tariffs—and this report does not even account for the major tariffs announced on April 2, 2025, just before printing.

Like the upstream supply chain, the generation project development pipeline in PJM was similarly unprepared. Following years of slow load growth and low capacity prices, the PJM footprint has only about 6 GW Installed Capacity (ICAP) of new gas-fired generation in the interconnection queue through 2030.[3] Furthermore, extended lead-times for scarce new equipment, permitting processes, and interconnection processes limit the pace of new supply entry of gas-fired generation plants, even if investors are motivated by available returns.

PJM's projected demand growth is 32 GW by 2030, while aging coal capacity continues to retire with 18 GW of coal plants projected to retire by 2030 (though some now will likely be retained

[3] 6 GW was in the queue as of late 2024. Recent developments may expand the pipeline.

or converted to natural gas under prevailing high prices).[4] These forecasts suggest that a large gap must be filled, and RPM will need to attract and retain large amounts of capacity in the next few years. Strong price signals from RPM should attract demand response (DR) and uprates to existing plants, investments to life-extend aging thermal resources, attract net imports, and make energy efficiency more cost effective. Many such resources can be added quickly and at a range of price points. Over 53 GW ICAP of battery energy storage systems (BESS) and other storage and 29 GW ICAP of hybrid BESS/renewable resources are in the queue with Commercial Online Dates (CODs) before June 2028. Yet the capacity values per kilowatt of BESS and hybrid resources are relatively low and uncertain compared to dispatchable thermal resources. For example, the 53 MW ICAP of storage in the queue translates to approximately 29 MW in Unforced Capacity (UCAP) value at current accreditations. Further, despite having experienced major cost declines over the past few years, BESS is still relatively costly per kW of accredited capacity.

To enter economically, a merchant BESS investor would need a high capacity price, likely even higher than level-nominal Net CONE considering the likelihood of lower prices in future years when the market returns to more normal conditions with new non-premium gas-fired capacity setting capacity prices. Pricing pressures and uncertainties are compounded by the current unstable tariff environment, although that also affects all other resource types to a lesser extent.

All of these pressures are additive to the conditions that already led to price increases in the 2025/26 auction and PJM's proposal to collar prices for the 2026/27 and 2027/28 auctions, in response to the Pennsylvania Governor's office 206 FERC Filing and expressed concern on the high capacity price impacts to consumers.[5] State agencies and customer interests are concerned about rate increases and affordability challenges after the 2025/26 auction cleared at prices of

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4 PJM forecasts approximately 31,600 MW of RTO summer peak demand growth between 2024 and 2030. See PJM, 2025 PJM Long-Term Load Forecast Report, January 24, 2025, Table B-1 . The retirement projection shows the projected retirements from 2025 through 2030 (inclusive) and comes from the February 2023 Energy Transition in PJM Report, see PJM, Energy Transition in PJM: Resource Retirements, Replacements & Risks, February 24, 2023, pg. 5.

5 The 2025/26 auction cleared at $269.92/MW-day for the RTO up from $29/MW-day in the 2024/25 BRA after a confluence of events that impacted the supply-demand balance with a VRR curve based on a CT plant. This was to be followed by the 2026/27 auction which would have featured a steeper VRR curve with a higher price cap set by CONE of a CC plant. Due to market conditions beyond the range of conditions tested for this curve design, PJM filed a 205 Filing before FERC to maintain the CT as the Reference Resource, which would have the effect of lowering the price cap for the 2026/27 VRR curve, and this was accepted by FERC in February 2025. In the meantime, the Commonwealth of Pennsylvania filed a 206 filing at FERC protesting the initial 2026/27 BRA clearing results, VRR curve, and auction impacts, then later agreed on a new proposal with PJM. The proposal was to employ a VRR curve with a temporary cap and floor intended to be in place for 2 years for the 2026/27 and 2027/28 auctions which PJM submitted in a 205 filing before FERC in February 2025. See 2025 PJM VRR Curve Report, Section II.B and Section II for more discussion.

approximately $270/MW-day, or $187/MW-day higher than the $83/MW-day average price over the prior 13 years.[6] Though the most recent BRA prices were high compared to recent history, they are not high compared to the long-run marginal cost of supply nor compared to the prices that might be needed over the next few years to attract incremental thermal or BESS resources.

It is in these challenging conditions that we conducted this study. Our approach considers a range of reference resources that may be available to meet resource adequacy needs, including both dispatchable thermal supply and BESS resources. We assess these resources' costs under current economic conditions and indicators of long-run conditions, and the implications for setting VRR curve parameters.

SELECTION OF REFERENCE RESOURCES

As in past reviews, we began by establishing objectives for the VRR curve and criteria for selecting an appropriate reference resource. Primary criteria for the reference resource are that it should be economically viable, as indicated by actual merchant entry and competitive costs; its CONE and E&AS offsets should be amenable to accurate estimation; and it should available at scale with similar costs. Another longstanding criterion is that it should be feasible to build within the three-year forward period of the BRA, although that is quite limiting under current conditions with extended development times for many resources.

As an updated approach compared to prior reviews, we do not recommend selecting a single reference resource. This is in part because the transitioning resource mix will likely see investments in many types of resources with complementary characteristics. Nor do we recommend setting reference prices based on a single set of assumptions, especially not under transient extreme conditions described above that exceed long-run expectations and typical fluctuations. Tying the reference price to a single resource and set of assumptions can also lead to large updates when these individual assumptions change. A more stable reference price that is more aligned with the long-run marginal cost of supply can be developed based on multiple technologies and a broader range of conditions that may apply over the review period and beyond.

Based on a screening analysis, we focused on three technologies: a natural gas-fired simple-cycle combustion turbine plant (CT), a natural gas-fired combined-cycle plant (CC), and a 4-hour BESS resource. None pass all selection criteria: CTs and CCs currently have high and fluctuating costs;

[6] The prices were viewed as a concern because they were higher than in recent years and because the magnitude of the net 15.5 GW tightening in the supply-demand balance came as a surprise to many stakeholders. See 2025 PJM VRR Curve Report, Section III for more detail.

both have longer lead times than the available time between the auction (in early 2026) and the 2028/29 and 2029/30 delivery years; CCs have much greater variability (even if not uncertainty) relative to CTs; and CTs have not been commercially demonstrated by large amounts of recent entry of actual projects in PJM. But BESS resources have not yet been built in PJM for capacity purposes, and projects built over the next several years will have relatively high costs and uncertain Net CONE, due to more complicated E&AS revenues, fluctuating supply costs, exposure to tariffs, and potential changes in tax credits. These uncertainties are greater for BESS than for CC and CT technologies, considering the lower Effective Load-Carrying Capacity (ELCC) for BESS which magnifies the effect of uncertainties on the net cost per kilowatt (kW) in ICAP when translated to UCAP terms.

We assess all of these imperfect reference resources under varying conditions, ultimately to inform a reference price and price cap for a VRR curve that can be robust to fluctuating market conditions, ranging from the very tight conditions anticipated for the 2028/29 delivery year, and perhaps more normalized conditions by 2031/32.

BOTTOM-UP ANALYSIS OF CAPITAL AND FIXED COSTS

Developing a bottom-up cost analysis requires specifying typical plant locations, technology choices, and plant configurations for each technology. Specifications were informed by actual projects and environmental requirements, as studied in our 2022 CONE Study for PJM plus observations of additional projects planned since then, then confirmed through consultation with stakeholders.

The CT specifications included a single simple-cycle GE 7HA.03 with 390 MW of capacity and a 9,150 British thermal units per kilowatt hour (Btu/kWh) higher heating value (HHV) heat rate at max summer capacity conditions. The CT also has selective catalytic reduction (SCR) and dual-fuel capability. The CC plant includes GE 7HA.03 turbines, SCR, dry cooling, and a firm gas transportation contract instead of dual-fuel capability.[7] The CC specifications are for a 1,282 MW plant with two trains of a single-shaft combined cycle plant, each with a single combustion turbine, heat recovery steam generator, and steam turbine (i.e., two “single-shaft 1×1s”) including 164 MW of duct-firing capacity. The CC has an HHV max summer heat rate of 6,315 Btu/kWh at full load without duct firing and 6,594 Btu/kWh with duct firing (and 7,804 Btu/kWh at minimum stable level of 33% of full load) at standard conditions. BESS specifications are for a 200 MW 4-hour battery with 26.09% initial oversizing and five capacity augmentations to

[7] These capacities and heat rates refer to an average over the four CONE Areas. Area-specific values reflecting local ambient conditions are provided within the report.

maintain charge capability and duration. Augmentations are planned for every three years starting in the fifth year of operation.

For CCs, CTs, and 4-hr BESS in each CONE Area, we conducted a comprehensive, bottom-up analysis of the capital costs to build the plant. This included: (1) the engineering, procurement, and construction (EPC) and owner-furnished equipment (OFE) costs based on January 2025 estimates using recent project financials and quotes from multiple original equipment manufacturers (OEMs); (2) current prevailing labor rates in each area and typical EPC contractor fees; and (3) non-EPC owner's costs, including project development, financing fees, gas and electric interconnection costs, and inventories. We separately estimate annual fixed operation and maintenance (O&M) costs, including labor, materials, property taxes, and insurance.

REVIEW OF E&AS METHODOLOGY

For technology-specific Net CONE calculations, PJM's forward-looking E&AS offset methodology remains reasonable, with minor refinements. Application of this forward methodology leads to indicative E&AS offset values that are much greater than in prior years because of tight market conditions with high spark spreads embedded in forward prices, especially for CCs. This is why we recommend also considering non-forward datapoints as part of a broader set of benchmarks of long-term values to inform the Reference Price, as discussed below.

For the PJM RTO-wide calculation, we recommend no longer conducting a virtual dispatch on a single set of synthetic energy and gas prices averaged across all Locational Deliverability Areas (LDAs), but rather conducting the E&AS and Net CONE analysis for each LDA as described below, then selecting the 33rd percentile among LDA Net CONE values. This represents the Net CONE for an entrant serving the RTO-wide need.[8]

LEVELIZED CONE AND NET CONE CALCULATIONS

As noted above, estimated capital and fixed costs are typically translated into first-year all-in revenues needed for entry (i.e., CONE) given likely trajectories of future total revenues and E&AS offsets, then first-year forward E&AS revenues are subtracted to arrive at Net CONE as an estimate of both a long-run marginal cost of capacity and a reservation price for entry. Current conditions cause reservation prices to diverge from long-run marginal costs, however, in two ways. First, current costs incorporate premium pricing on capital above long-run marginal costs with equilibrated supply chains. Second, the normal level-nominal calculation understates the

[8] In theory, the minimum could be more appropriate, but that may understate the cost if the minimum is driven by estimation errors or if siting opportunities are limited in that area.

reservation price an entrant would need if anticipating future downward reversion of market revenues as supply chains expand. We therefore present several alternative calculations that reflect distinct concepts for the Net CONE or Reference Price to inform VRR curve parameter recommendations: (1) *Level-Nominal CONE and Net CONE*, which is the traditional level-nominal calculation given premium current costs and forward E&AS revenues; (2) *Long-Run Net CONE Estimates*, which provide indicators of long-run marginal costs absent current premium pricing; and (3) *Short-Term Reservation Prices*, which reflect the first-year or short-term clearing price for capacity needed to attract current entrants considering both of the above.

Concept 1: Level-Nominal CONE and Net CONE

Estimated capital costs are translated into the level-nominal net revenues the resource owner would need to earn an adequate return on and of capital, assuming a 20-year economic life with real all-in net revenues declining at the rate of inflation. This calculation also involves a cost of capital. We estimate an after-tax weighted-average cost of capital (ATWACC) of 9.5% for a merchant generation investment, based on analysis of publicly-traded merchant generation companies and other reference points. While the CONE calculation only depends on the ATWACC and not on the individual components, we do present self-consistent financial parameters based on our analysis of comparable companies. The 9.5% ATWACC thus corresponds to a return on equity of 16.0%, a 5.8% cost of debt, and a 55/45 debt-to-equity capital structure with an effective combined state and federal tax rate of 27.7%.[9] This ATWACC is higher than in the prior

[9] 5.8% × 55% × (1 − 27.7%) + 16.0% × 45% = 9.5%. The tax rate of 27.7% is a combined federal-state tax rate, where state taxes are deductible for federal taxes (= 8.5% + (1 − 8.5%) × 21%). Note that the ATWACC applied to the four CONE Areas varies slightly with applicable state income tax rates, as discussed in later sections.

Quadrennial Review primarily because of an increase in interest rates. Table ES-1 below shows the resulting 2028/29 CONE estimates for all three technologies and all five CONE Areas.

TABLE ES-1: CONE ESTIMATES
(NOMINAL$ FOR JUNE 2028 ONLINE YEAR)

CONE Area	Technology	Overnight Capital Cost	Capital Charge Rate	Year 1 Capital Recovery	Levelized Fixed O&M	Gross CONE ICAP
		[A]	[B]	[C]	[D]	[E]
Nominal$ for 2028 Online Year		$/kW	%/year	$/MW-day	$/MW-day	$/MW-day
1. EMAAC	Gas CT	$1,395	16.0%	$611	$59	**$670**
	Gas CC	$1,517	17.0%	$705	$112	**$816**
	BESS 4-hr	$1,832	9.6%	$483	$197	**$680**
2. SWMAAC	Gas CT	$1,339	15.9%	$585	$91	**$676**
	Gas CC	$1,411	16.9%	$653	$166	**$819**
	BESS 4-hr	$1,753	9.6%	$463	$208	**$671**
3. Rest of RTO	Gas CT	$1,361	15.9%	$593	$69	**$663**
	Gas CC	$1,419	16.9%	$656	$157	**$813**
	BESS 4-hr	$1,750	9.6%	$462	$191	**$652**
4. WMAAC	Gas CT	$1,390	15.9%	$606	$58	**$664**
	Gas CC	$1,476	16.9%	$682	$132	**$814**
	BESS 4-hr	$1,784	9.6%	$471	$196	**$667**
5. COMED	Gas CT	$1,495	17.8%	$730	$58	**$789**
	Gas CC	$1,649	18.8%	$849	$105	**$953**
	BESS 4-hr	$1,980	9.6%	$521	$204	**$726**

Sources and Notes:
[A], [B], [D]: Outputs from CONE Model.
[C]: [A] x [B] x (1000 / 365).
[E]: [C] + [D].

Focusing on representative CONE Area 3, the Gross CONE estimates for CCs and CTs exceed those from the 2022 Quadrennial Review by 44% and 47% respectively in real terms. The CC CONE from the prior Review was $566/MW-day ICAP in 2028 dollars. Higher equipment costs net of greater economies of scale with the new GE 7HA.03 turbines added $80/MW-day; a higher capital charge rate accounting for extended construction periods, higher cost of capital, and loss of bonus depreciation added $140/MW-day; and higher fixed O&M that relates to capital costs and higher firm gas transportation costs added $28/MW-day, for a total current CC CONE of $813/MW-day, an increase of 44%. The CONE for CTs increased by 47% in real terms, a slightly higher percentage due to the higher-cost combustion turbines with dual-fuel capability accounting for a larger share of capital costs but with a partial offsetting cost reduction since they avoid buying natural gas under firm fuel arrangements. BESS CONE estimates are now 11% lower than in the 2022 Review, primarily because the currently available 30% ITC more than offsets the higher cost of capital and modest increase in capital costs which are predominately due to current tariffs.[10] Yet BESS still has higher Net CONE than the other technologies in most areas.

Estimating a current level-nominal value for Net CONE involves subtracting forward E&AS offsets from the CONE estimates above. Forward E&AS offsets are currently substantially above historical levels, presumably due to the impact of much tighter reserve margins on spark spreads. The results are reported in Table ES-2 below. Overall, these Level-Nominal Net CONE estimates provide a somewhat higher-end estimate of the likely long-run marginal cost of supply, considering that they incorporate temporary cost premiums and extended construction timelines that will moderate over time and potentially toward the end of the Review period.

Concept 2: Long-Run Net CONE Estimates

More normalized long-run costs can be derived from the 2022 CONE Study, prior to current turbine scarcity. We thus assume 2022-vintage costs per kW for major equipment and other EPC costs, adjusted for inflation; and update the non-EPC costs and cost of capital to the same as in our current level-nominal calculations above to arrive at "long-term CONE" estimates. For indicative E&AS Offsets, we show the same current forward values as above ("Forward E&AS") and, alternatively, a 10-year average of E&AS revenues ("10-yr Average E&AS"). The forward approach likely overstates long-term E&AS and the 10-yr average approach likely understates long-term E&AS, so we consider both.

Another indicator of long-run Net CONE can be derived from clearing prices that sufficed to attract new generation in the past, often referred to as empirical Net CONE. For the delivery periods 2014/15 to 2022/23, when plentiful new generation (almost entirely CCs) entered, we derived a comparable estimate of empirical Net CONE by averaging the historical clearing prices, adjusted for inflation, increasing the cost of capital to current conditions, and adjusting to account for the current accreditation approach (i.e., multiplied by old UCAP ratings divided by current ELCCs). The resulting "Adjusted Empirical Net CONE" is $241/MW-day in 2028 dollars. This measure does not necessarily incorporate all factors that may affect current costs of building new supply, but it provides a useful benchmark to inform what supply costs might be after removing the temporary pricing premiums affecting supply entry. Overall, we interpret these

10 BESS capital costs have actually decreased substantially since the 2022 PJM CONE Study but are slightly higher when including prevailing tariffs for batteries.

long-run costs as a lower-end estimate of the most relevant long-run marginal cost of supply, and a relevant indicator of supply costs that could prevail toward the end of the relevant review period or whenever present tight supply conditions moderate.

TABLE ES-2: INDICATIVE NET CONE FOR CURRENT LEVEL-NOMINAL CONE ESTIMATES AND OTHER BENCHMARKS (RTO, NOMINAL$ FOR JUNE 2028 ONLINE YEAR)

Nominal$ for 2028 Online Year	Overnight Capital Cost [A] $/kW See notes	Capital Charge Rate [B] %/year See notes	Year 1 Capital Recovery [C] $/MW-day See notes	Levelized Fixed O&M [D] $/MW-day See notes	Gross CONE ICAP [E] $/MW-day [C] + [D]	E&AS Offset [F] $/MW-day See notes	Net CONE ICAP [G] $/MW-day [E] - [F]	ELCC [H] % See notes	Net CONE UCAP [I] $/MW-day [G] / [H]
Current Level-Nominal CONE with Forward EAS									
CT	$1,361	15.9%	$593	$69	**$663**	$241	$422	79%	**$534**
CC	$1,419	16.9%	$656	$157	**$813**	$506	$308	81%	**$380**
BESS 4-hr	$1,750	9.6%	$462	$191	**$652**	$244	$409	65%	**$629**
Other Benchmarks									
LTCT and Forward E&AS	$1,053	13.5%	$388	$69	**$457**	$241	$217	79%	**$274**
LTCC and Forward E&AS	$1,263	14.4%	$497	$157	**$655**	$506	$149	81%	**$184**
LTCT and 10-yr Avg. E&AS	$1,053	13.5%	$388	$69	**$457**	$207	$251	79%	**$317**
LTCC and 10-yr Avg. E&AS	$1,263	14.4%	$497	$157	**$655**	$374	$281	81%	**$346**
LTCC, 15-yr life and Forward E&AS	$1,263	16.2%	$560	$157	**$717**	$506	$212	81%	**$261**
CC, 15-yr life	$1,419	19.0%	$738	$154	**$892**	$506	$386	81%	**$477**
BESS 4-hr, Without 30% ITC	$1,750	13.0%	$621	$191	**$812**	$244	$569	65%	**$875**
Adjusted Empirical Net CONE 14/15 to 22/23	-	-	-	-	**-**	-	-	-	**$241**

Sources and Notes: "LTCT" and "LTCC" refer to long-term CT CONE and long-term CC CONE respectively.
[A], [B], [D]: Outputs from CONE Model for CONE Area 3.
[C]: [A] x [B] x 1000/365.
[F]: Forward E&AS provided by PJM staff for DEOK LDA. 10-yr Avg E&AS calculated from DEOK net revenues for delivery years 2017/2018 – 2023/24 from Monitoring Analytics, State of the Market Report for PJM, March 14, 2024, pp. 399-400; Net revenues for delivery years 2024/25-2026/27 from PJM, Default New Entry MOPR Offer Prices, Accessed March 6, 2025. See Appendix A.
[H]: Provided by PJM staff.

Concept 3: Short-Term Reservation Prices

The third concept that we consider is the short-term reservation price at which investors would be willing to enter in the 2028/29 auction, if we assume that they face temporarily high prices due to current high costs to build but they expect lower-cost resources to set market clearing prices over the long term. To estimate these short-term reservation prices, we assume the new entrants consider how much higher than level-nominal CONE all-in market prices would have to be for 1, 3, or 5 years of shortage conditions to achieve a net present value (NPV) of zero, assuming revenues thereafter revert to a long-run equilibrium. For CCs and CTs, we assume the remainder of their 20-year economic lives they earn "long-run CONE" for their own technologies from above, constant in nominal terms. For BESS, we assume they thereafter earn $471/MW-day

ICAP, again constant nominally.[11] The resulting short-term reservation price estimates are impressively high under these assumptions, as summarized in Table ES-3 below.

TABLE ES-3: SHORT-TERM RESERVATION PRICES (RTO, NOMINAL$ FOR JUNE 2028 ONLINE YEAR)

	Current Level-Nominal CONE (ICAP)	Long-run CONE (ICAP)	Front Loaded CONE (ICAP)			Forward E&AS (ICAP)	ELCC	Short-Term Reservation Price (UCAP)			Current Level-Nominal Net CONE (UCAP)
	[A] $/MW-day	[B] $/MW-day	[C] $/MW-day			[D] $/MW-day	[E] %	[F] $/MW-day			[G] $/MW-day
			1-yr	3-yr	5-yr			1-yr	3-yr	5-yr	
CT	$663	$457	$2,436	$1,178	$928	$241	79%	$2,779	$1,186	$870	$534
CC	$813	$655	$2,183	$1,211	$1,018	$506	81%	$2,070	$871	$633	$380
BESS	$652	$471	$2,219	$1,108	$887	$244	65%	$3,040	$1,329	$990	$629

Sources and Notes:
[A]: Current Level-Nominal CONE value from CONE model for RTO.
[B]: for CT and CC, long-run CONE from Table ES-2. For BESS, long-run CONE assumed to be back calculated from the $350/MW-day UCAP long-run Net CONE from Figure ES-1. $471 CONE ICAP = $350 Net CONE UCAP × 65% ELCC + $244 Forward E&AS ICAP for BESS.
[C]: Output from CONE model, reservation price analysis.
[D], [E]: Provided by PJM staff.
[F]: ([C] – [D]) / [E].
[G]: ([A] – [D]) / [E].

These indicative short-term reservation prices are greatly dependent on the assumed duration over which high prices could prevail, but they illustrate the range of prices that investors might require in order to enter without any expectations of high prices continuing. These estimates illustrate an extreme, but not implausible, scenario in which much higher VRR curve prices might be needed to attract new supply entry through RPM's single-year commitments. If we further assume that BESS would be the primary available new supply for the next few years while gas-fired generation additions are limited, the Reference Price might have to be $1,300/MW-day, assuming investors expect just 3 years of high prices which later normalize to long-run prices. Further, if the VRR curve price cap is 1.5 to 1.75 times that, the price could rise to nearly $2,300/MW-day in scarcity, or nearly 10 times what they were in the 2025/26 auction that transacted $15 billion. This exercise illustrates the challenge that the cost of attracting supply now has the potential to be greatly inflated if that supply is secured under one-year

[11] The $471/MW-day is estimated as 0.65 ELCC × ($350/MW-day assumed long-run capacity price in UCAP terms, corresponding to our proposed RTO Reference Price) *plus* $244/MW-day ICAP assuming continuation of current forward E&AS with suggested changes to BESS virtual dispatch.

commitments, compared to the prices that would be needed over the long term and compared to prices that would be needed under a more typical conditions where prices and revenues are expected to remain flat or increase over time.

We do not recommend the short-term reservation prices as a basis for the VRR curve Reference Price, since doing so would introduce the risks of excess price volatility; expose customers to the potential for extreme high costs in the event of price cap events; and because these short-term reservation prices substantially exceed the prices and price cap needed to attract supply over the long run. Even so, this exercise illustrates why there is a material risk that RPM prices available under one-year commitments may be insufficient to attract new entry in one or more of the upcoming auctions. In the companion 2025 PJM VRR Curve Report, we assess options for managing these conditions through either tolerating temporary reliability shortfalls or pursuing a backstop competitive procurement to fill the gap.

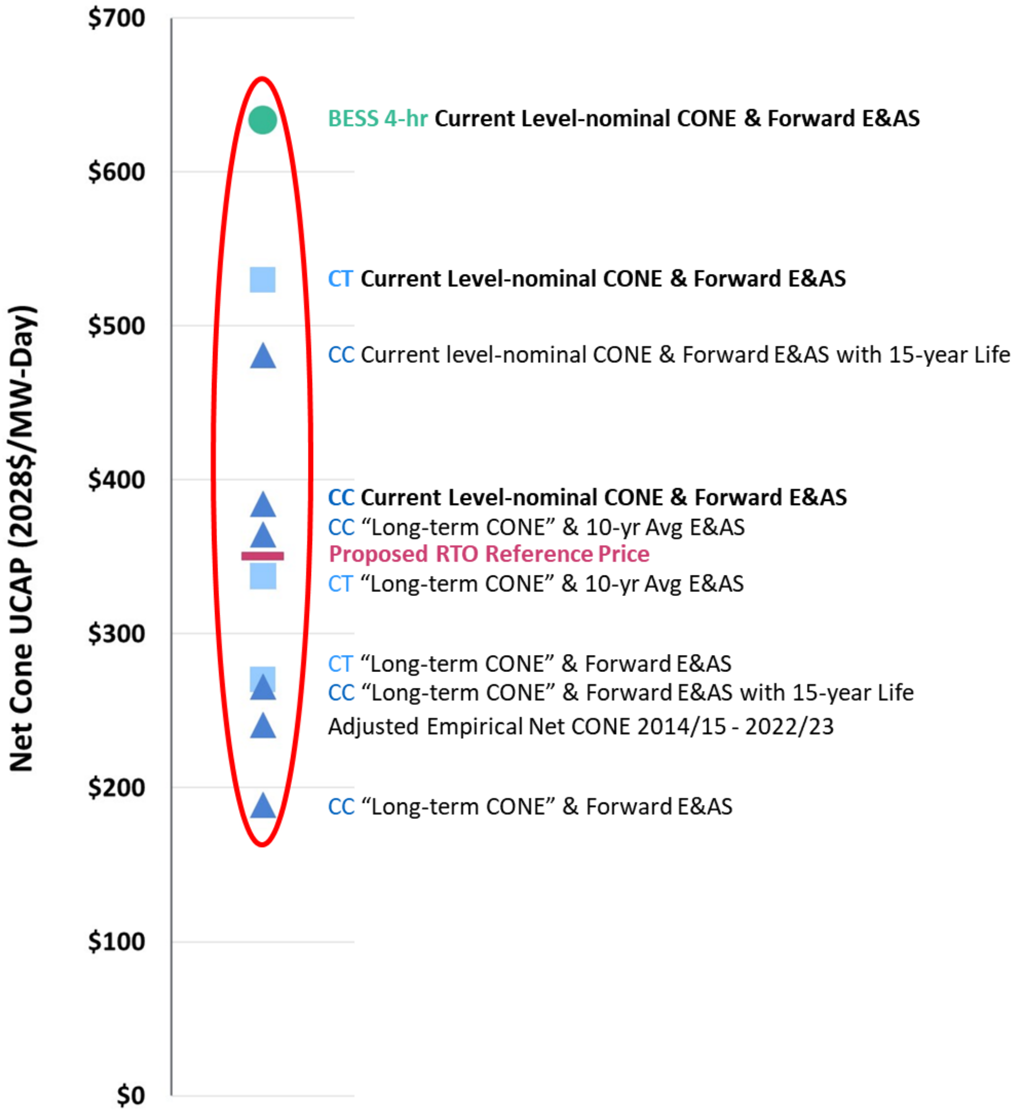
RECOMMENDED REFERENCE PRICE FOR VRR CURVES

We recommend setting the Reference Price based on an estimate of the long-run marginal cost, in order to support the established VRR curve primary objectives of maintaining 1-in-10 loss of load expectation (LOLE) on a long-run average basis while limiting volatility such as extreme price spikes. That might suggest deriving the Reference Price from only the long-term equilibrium estimates presented above. However, given the imperfect nature of those indicators and the need to elevate the curve a reasonable amount to address current conditions, we also consider the high Current Level-Nominal Net CONE. The full set of relevant benchmarks is presented graphically below.

Consideration of that full set points to a central value at $350/MW-day UCAP, as shown in Figure ES-1.[12] This proposed RTO Reference Price is lower than current estimates of level-nominal technology costs that incorporate temporary cost premiums (Concept 1 above), and higher than the indictors of long-run marginal cost (Concept 2 above). This mid-point estimate of Reference Price is further informed by multiple technologies (primarily the CC and CT resources) and by a range of scenario analyses that may influence costs over the study period. Though the uncertainty range affecting the Reference Price is relatively large, we believe the uncertainties are approximately balanced.

[12] With the exception of the “BESS without ITC benchmark”, given that the ITC is still prevailing law at the time of publishing.

FIGURE ES-1: INDICATIVE NET CONE FOR CURRENT LEVEL-NOMINAL CONE ESTIMATES AND LONG-TERM BENCHMARKS (RTO, $/MW-DAY UCAP, NOMINAL$ FOR JUNE 2028 ONLINE YEAR)



Sources and Notes: "Long-term CONE" reflects escalated 2022 OFE/EPC costs with current Non-EPC costs and fixed O&M. Forward E&AS and 10-yr Avg E&AS from Appendix A.

This proposed value is clearly surrounded by judgment and uncertainty. Attaching a heavier weight to some reference points than others could change the value by plus or minus $100/MW-day or more, which is our estimate of the uncertainty range in Net CONE under present conditions. We incorporate this uncertainty range in Reference Prices in evaluating the robustness of alternative VRR Curve shapes and price caps in the 2025 PJM VRR Curve Report.

REFERENCE PRICES IN LOCATIONAL DELIVERABILITY AREAS

Reference prices for the LDAs can be derived using a comparable approach to the RTO. For each benchmark and each LDA, Net CONE is calculated; then for each benchmark and each CONE Area (EMAAC, SWMAAC, Rest of RTO, WMAAC, ComEd) and MAAC, calculate the 33rd percentile from all the constituent LDAs. Finally, for each CONE Area, the Reference Price is the median from among all benchmarks (except for the BESS-without-ITC benchmark) rounded to the nearest $25/MW-day increment. If the resulting CONE Area Reference Price is at or above the RTO Reference Price, it receives the CONE Area Reference Price, otherwise the CONE Area receives the RTO Reference Price. The individual LDAs' Reference Prices are set equal to that of the immediate parent CONE Area, since variation within each CONE Area is relatively low in most cases.

This results in a Reference Price in UCAP terms of $350/MW-day for the RTO, $600/MW-day for all LDAs in CONE Area 1 (EMAAC), $350/MW-day for all LDAs in CONE Area 2 (SWMAAC), $350/MW-day for all LDAs in CONE Area 3 (Rest of RTO), and $425/MW-day for all LDAs in CONE Area 4 (WMAAC). Additionally, we provide a Reference Price for MAAC which is comprised of the LDAs for EMAAC, SWMAAC, and WMAAC of $425/MW-day based on the same approach. ComEd is unique since it is a single-LDA CONE Area and current environmental laws greatly impact the Net CONE estimates for gas-fired technologies due to the truncated economic lives. In each future year during the review period, economic lives for gas-fired resources would be further truncated which would cause their Net CONEs to be expected to remain above a BESS Net CONE, therefore we recommend a $725/MW-day Reference Price for ComEd equivalent to the current level-nominal BESS Net CONE estimate for ComEd, rounded.

ANNUAL UPDATES TO REFERENCE PRICES

Since the recommended Reference Price does not express the net cost of entry at a snapshot in time but a long-term view, it does not need to be updated annually for temporary changes in costs and revenues. We therefore propose to hold the Reference Price constant in real terms between Quadrennial Reviews by indexing to the Consumer Price Index (CPI), other than scaling to changes in fleet-wide average accreditation factors.[13] This should help stabilize capacity price signals, supporting investment.

[13] Specifically, we propose the "Consumer Price Index for All Urban Consumers (CPI-U) for the U.S. City Average for All Items, 1982-84=100" as reported by the U.S. Bureau of Labor Statistics (BLS), since this is the broadest, most comprehensive CPI. See U.S. BLS, Consumer Price Index for All Urban Consumers (CPI-U).

I. Introduction

A. Study Objective and Scope

In accordance with the tariff, PJM determines Net CONE for a representative Reference Technology just prior to the forward BRA, which has historically been either a CT or CC in each of the five CONE Areas. Gross CONE values have been determined through periodic CONE studies such as this one, with escalation rates applied in the intervening years. Shortly before each BRA, PJM estimates an E&AS Offset for each zone, then calculates a relevant Net CONE value to use in each locational VRR curve being represented in the auction. PJM also estimates Net CONE for a variety of technologies in order to develop offer price screens under the Minimum Offer Price Rule (MOPR) for new generation offering capacity into RPM.

PJM Interconnection (PJM) retained consultants at The Brattle Group (Brattle) and Sargent & Lundy (S&L) for this Sixth Quadrennial Review. Per the PJM tariff, the scope of the Quadrennial Review is to review the Variable Resource Requirement (VRR) Curve and its parameters, including the Cost of New Entry (CONE) and the Energy and Ancillary Services (E&AS) Offset Methodology.[14] Our concurrently-issued report, the *Sixth Review of PJM's Variable Resource Requirement Curve* ("2025 PJM VRR Curve Report"), addresses the review and design of the VRR curve.[15] This report:

- Develops bottom-up CONE estimates for competitive merchant developers of a new gas-fired simple-cycle combustion turbine plants (CT), a gas-fired combined-cycle plant (CC), and a battery energy storage system (BESS) at representative sites in each of the five CONE Areas for the 2028/29 Base Residual Auction (BRA);
- Reviews the E&AS offset methodology; and
- Recommends a Reference Price informed by Net CONE of the three technology types under a range of conditions indicating the price at which developers would be willing to add capacity

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[14] PJM Interconnection, LLC. (2024). PJM Open Access Transmission Tariff. Effective January 1, 2024. ("PJM Tariff"), Attachment DD, Section 5.10.a.iii.

[15] Spees, et. al, Sixth Review of PJM's Variable Resource Requirement Curve ("2025 PJM VRR Curve Report"), April 10, 2025.

in long-run equilibrium conditions; and recommends a method for updating the Reference Price annually.

CONE has historically been estimated by quantifying a reference resource's capital and fixed costs, then levelized nominally into first-year all-in revenues needed for entry (CONE). Net CONE is calculated by then subtracting the resource's first-year forward E&AS revenues from the CONE. This estimate has been taken to represent both a long-run marginal cost of capacity and a reservation price for entry. Current conditions cause reservation prices to diverge from long-run marginal costs, however, in two ways. First, current costs incorporate extended construction timeframes and premium pricing on capital above long-run marginal costs with equilibrated supply chains. Second, the normal level-nominal calculation understates the reservation price an entrant would need if anticipating a future downward reversion of market revenues as supply chains expand. We therefore present several alternative calculations to inform VRR curve parameter recommendations: (1) the traditional level-nominal calculation given current (premium) costs and forward E&AS revenues; (2) indicators of long-run marginal costs absent current premium pricing; and (3) a short-term reservation price for current entrants considering both of the above.

In this review, we propose a VRR curve Reference Price informed by several of the benchmarks described above instead of a single reference resource's Net CONE under a single, current snapshot of market conditions. Since this Reference Price reflects a long-term view, it would be updated annually using a simple inflation adjustment rather than more complicated indexes and updated E&AS analyses, as in the past. This approach should help to avoid extreme swings in pricing parameters and clearing prices, which should help stabilize the performance of RPM.

This review, like other Quadrennial Reviews, also informs review thresholds under the Minimum Offer Price Rule (MOPR). For that purpose, the Net CONE estimates for individual technologies are needed, with more traditional annual updates as described in Section IX.B.

This CONE Report presents our research and empirical analysis to inform our recommendations. It highlights where judgments must be made in specifying resource characteristics and translating their estimated costs into levelized revenue requirements and Net CONE values. In such cases, we discuss the trade-offs and provide our own recommendations for best meeting RPM's objectives to inform PJM's decisions in setting future VRR curves. We provide not only our best estimate of the Reference Price informed by Net CONE (defined as the long-run marginal cost of supply), but also the range of uncertainty in this estimate, a key consideration in designing the VRR curve, as also discussed in the 2025 PJM VRR Curve Report.

B. Analytical Approach

Our starting point is to identify the most appropriate candidate resource types to inform the Reference Price for the VRR curve. As discussed in Section II, we identified criteria for selecting the candidate resources then evaluated a broad range of resource types against those criteria in an initial screening analysis. The results of the screening analysis narrowed the choices down to a CC, a CT, and BESS.

For each of the three identified resources, we estimated CONE for the five CONE Areas, starting with a characterization of plant configurations, detailed specifications, and locations where developers are most likely to build. We identified specific plant and site characteristics based on: (1) our analysis of recently developed plants; (2) our analysis of technologies, regulations, and infrastructure; and (3) our experience from previous CONE analyses. We developed comprehensive, bottom-up cost estimates of building and maintaining a CC, CT, and BESS in each of the five CONE Areas.

S&L estimated **plant-proper capital costs**, including all equipment, materials, and labor costs, as well as engineering, procurement, and construction (EPC) contracting costs. Cost estimates are founded on a complete plant design relying on S&L's proprietary database of actual projects and experience in developing similar projects.

S&L and Brattle then estimated the **owner's capital costs**, including OFE, gas and electric interconnection, development and startup costs, land, fuel and non-fuel inventories, and financing fees. Cost estimates are derived from S&L's proprietary data and additional analysis of other data sources for each component.

We further estimated **annual fixed and variable operation and maintenance (O&M) costs**, including labor, materials, property tax, insurance, asset management costs, and interest on working capital.

Next, we translated the total up-front capital and fixed O&M costs of the plant into a levelized estimate of the plant's revenue requirement, or CONE. CONE depends on the estimated capital and fixed O&M costs of the plant, the estimated cost of capital consistent with the project's risk, the assumed economic life of the asset, and the assumed revenue recovery trajectory or levelization approach, such as the level-nominal method used for most calculations herein.

The Brattle and S&L authors collaborated on this study and report. The specification of plant characteristics was jointly developed by both teams, with S&L taking primary responsibility for developing the plant proper capital, plant O&M and major maintenance costs, and the Brattle authors taking responsibility for various owner's costs and fixed O&M costs, and for translating the cost estimates into the CONE values.

II. Screening Analysis for Candidate Resources

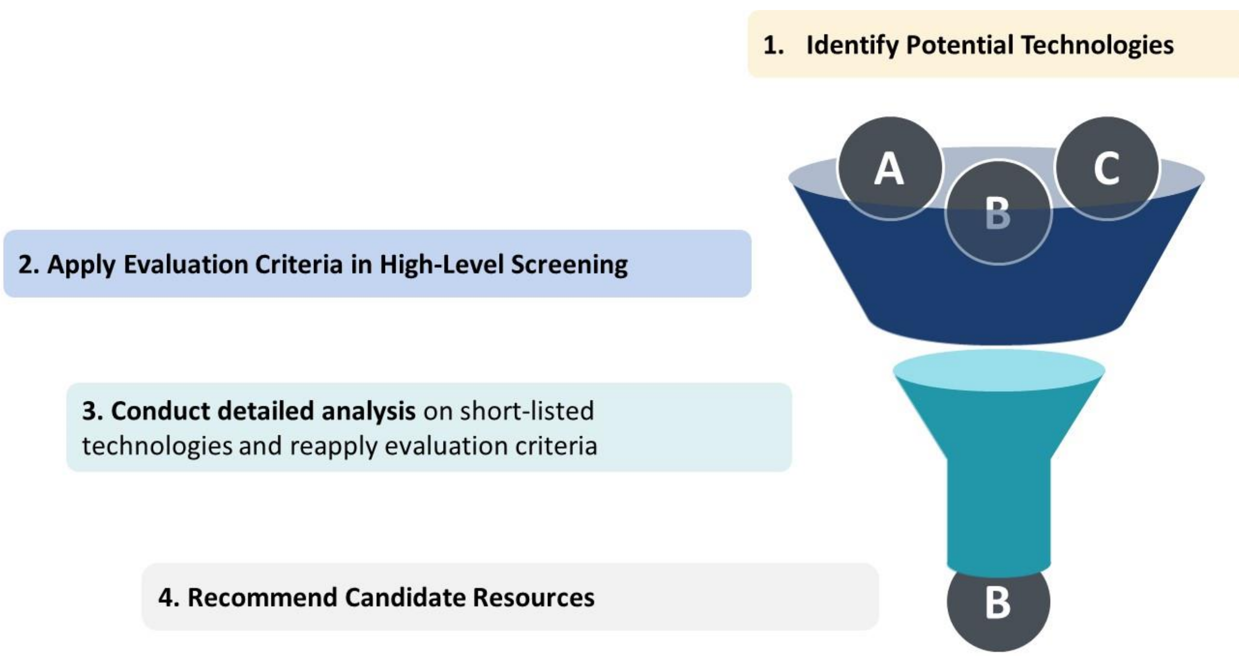
The purpose of selecting candidate resources and developing administrative Net CONE estimates is to set a VRR curve that aims to procure sufficient capacity resources to ensure resource adequacy. Under current market and industry conditions, gas-fired turbines might not be available for the first delivery year (too little time to develop before auctions that are not 3-years ahead). Even thereafter, there could be a period where a different technology is needed to meet unprecedented high demand due to scarcity of thermal dispatchable resources driven by constrained supply chains or by environmental policies discouraging entry in some locations. The administrative Reference Price does not determine capacity prices; long-run prices primarily depend on the supply curve. Still, as the Reference Price in our recommended VRR curve is informed by Net CONE, we aim to estimate Net CONE as accurately as possible, which begins with an assessment of candidate resources.

PJM has historically used a single reference resource to estimate Net CONE, which has typically been a CT. In this Quadrennial Review, we were asked to evaluate a range of resource types that reasonably reflect costs that suppliers need to recover to be willing to enter with significant volumes of capacity in the RPM. In our screening, we considered a range of other technologies in addition to gas-fired CTs and CCs, including non-fossil fired generation technologies such as 4, 6, 8, and 10-hour BESS, utility-scale solar photovoltaic (PV), onshore wind, PV+BESS hybrids, and emerging resources; as well as uprates and conversions of existing facilities and demand response. All candidates were evaluated against a set of selection criteria.

A. Process for Selecting Resources

As in the 2022, 2018, and 2014 PJM CONE Studies, we selected the candidate resources via a multi-stage process described in this section and illustrated below in Figure 2.[16] First, we identified a broad range of potential technologies; second, we applied PJM's selection criteria to those technologies in a high-level screening analysis; third, we conducted detailed analysis on the resulting short list; and finally, we applied the selection criteria again and recommended the final candidate resources to proceed to a full bottom-up estimate of their CONE.

FIGURE 2: REFERENCE RESOURCE SELECTION PROCESS



In consultation with PJM and its stakeholders, we updated the reference resource selection criteria used in the 2022 PJM CONE Study and adopted by PJM. The foundational objective of the selection criteria is to identify resource types that best support the RPM's broader objective of procuring enough capacity to meet resource adequacy goals while reflecting trends in market entry and effectively capturing projected costs of the future resource mix. The updated selection criteria we applied are summarized in Figure 3.

16 Newell et.al., PJM CONE 2026/2027 Report, April 21, 2022, ("2022 PJM CONE Study"); Newell et.al., PJM Cost of New Entry, Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date, April 19, 2018 ("2018 PJM CONE Study"); Newell et.al., Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM, May 15, 2014, ("2014 PJM CONE Study")

FIGURE 3: CRITERIA FOR SELECTING CANDIDATE RESOURCES

1. **Economic viability**
   - Demonstrated by recent/planned merchant entry
   - Not having a Net CONE much higher than other reasonable candidates
2. **Feasibility to build at scale by delivery year**
3. **Compliance with all regulations and can operate as needed**
4. **Ability to accurately assess Net CONE**
   - Capital and operating costs demonstrated from commercial experience
   - Costs are uniform when scaled, rather than increasing steeply as best sites are exhausted
   - Long-term net revenues can be projected well enough to calculate a first-year revenue requirement (CONE), considering possible future technology/market/system/regulatory conditions
   - Not largely dependent on difficult-to-forecast revenues (Ancillary Services, Renewable Energy Credits)
   - Has high ELCC, else cost and E&AS uncertainties (per kW ICAP) are amplified per kW UCAP
5. **Stable reliability contribution for each/all of the 4 delivery years** to limit unpredictability of Net CONE

We explain each of the selection criteria in order:

- **Economic viability**: First, technologies should have successful recent merchant entrants without a substantially higher Net CONE than other reasonable candidates. Otherwise, constructing the VRR curve based on uneconomic sources of capacity would unnecessarily shift the VRR curve upward (like a shift outward) and procure more capacity than needed, at the quantity where the true Net CONE of economic resources intersects the VRR curve. Resources that are economic should exhibit actual merchant development and reasonable estimates of Net CONE and they should not be subject to factors that will likely render them uneconomic over the next several auctions governed by this Quadrennial Review.
- **Feasibility**: Plants should ideally be able to be built at scale by the delivery year so that the BRA clearing price can attract projects when economically desirable.
- **Compliance with all regulations:** The technology should also be able to comply with all relevant regulations and operate as needed. As discussed later in this section, stringent environmental regulations may limit or alter certain plants' ability to operate as planned.
- **Ability to assess Net CONE accurately:** For the Net CONE estimate to be as accurate as possible, the technology must have substantial commercial experience such that both costs and revenues will not be difficult to assess. In addition, potential sites should be plentiful so that costs uniformly scale as more plants are built. If sites are scarce, the technology would be subject to rapid increases in costs as the best sites are exhausted. The long-term net revenues should be able to be projected well enough to calculate a first-year revenue requirement, and non-capacity revenues should be reasonably forecastable. The resource

must also have a high Effective Load Carrying Capability (ELCC). A low ELCC would mean that any uncertainties in cost and revenue estimates per kilowatt (kW) of Installed Capacity (ICAP) would have an amplified effect on the estimated cost per kW of Unforced Capacity (UCAP).

- **Stable reliability contribution**: Finally, to limit unpredictability of Net CONE, the technology must make a stable reliability contribution for each of the four delivery years under assessment. If the resource's ELCC is expected to vary significantly, then the Net CONE per kW of UCAP will be highly uncertain year-to-year.

B. Evaluation of Candidates Against Selection Criteria

We began by examining a wide range of 10 technologies, including gas-fired CTs and CCs, BESS hybrid PV+BESS, utility-scale PV, onshore wind, demand response, uprates/conversions, and emerging technologies. Five technologies were eliminated by the initial high-level screening:

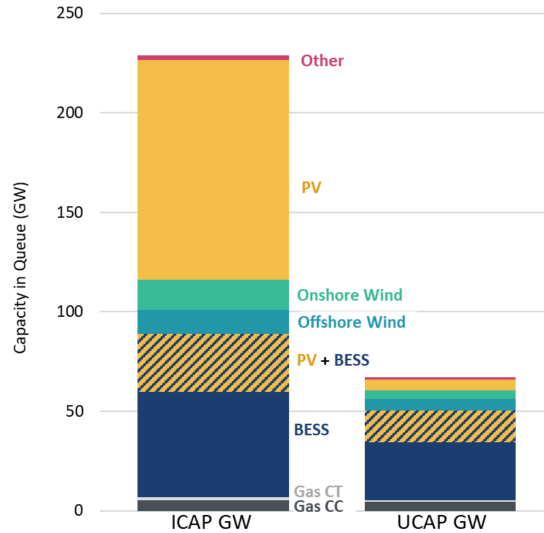
- Onshore Wind, Utility-Scale PV: Eliminated due to uncertain Renewable Energy Credit (REC) values amplified by low expected reliability contributions.
- Demand Response, Uprates/Conversions: Eliminated due to difficulty to accurately estimate Net CONE, as costs are idiosyncratic and not scalable.
- Emerging Technologies: Eliminated because they are infeasible to build by the delivery year and Net CONE would be difficult to assess due to their limited operational history.

The five candidate technologies without immediate concerns included: CC, CT, 4-hour BESS, 6/8/10-hour BESS, and a hybrid Solar PV + 4-hour BESS. Each of the five technologies remaining from the initial screen were carefully examined based on the selection criteria.

As part of this stage, we examined projects in PJM's interconnection queue for projects with a Commercial Online Date (COD) before the 2028/29 delivery year. As shown below in Figure 4, non-emitting resources, specifically PV and storage, represent most projects in the queue however, many have low ELCCs so their UCAP values are considerably smaller than their ICAP values.

FIGURE 4: SUMMARY OF PJM INTERCONNECTION QUEUE (THROUGH 2028/29 DELIVERY YEAR)

Technology	ICAP (GW)	ELCC (%)	UCAP (GW)
	[A]	[B]	[C]: [A] × [B]
Gas CC	5	81%	4
Gas CT	1	66%	1
Solar	111	5%	6
Storage	53	55%	29
PV+BESS	29	TBD	TBD
Onshore Wind	15	28%	4
Offshore Wind	12	47%	6
Other	2	Varies	1



Sources and Notes: Summarized data includes all projects active in the queue with a COD prior to June 1, 2028.
[A]: PJM, Serial Service Request Status, October 2024.
[B]: PJM, Supplementary Information about ELCC Class Ratings calculated for DY 2027/28–DY 2034/35, August 6, 2024, p. 3.

While CC and CT facilities are fewer MW in ICAP terms, their ELCCs are high so gas-fired generation represents a larger proportion of the queue in UCAP terms relative to their ICAP values than the non-dispatchable resources, meaning that non-dispatchable resources must be built at much higher ICAP volumes to achieve similar UCAP volumes. Moreover, gas projects are more likely to reach COD due to their established economics and operational history in PJM. Table 4 shows both recently constructed and queued gas-fired capacity as of late 2024, with nearly all projects at the engineering and procurement, construction, or operation stage.

TABLE 4: GAS-FIRED PLANTS IN DEVELOPMENT IN PJM
(MW ICAP, THROUGH 2028/29 DELIVERY YEAR)

Project Name	Target COD	State	Queue Status	LDA	Ownership	ICAP (MW)
New Build Gas-Fired Total						**5,441**
Gas CC Total						**4,740**
Glen Falls 138kV	03/31/2028	WV	Engineering and Procurement	APS	IPP (GE subsidiary)	550
Sullivan 345kV #1	06/01/2025	IN	Engineering and Procurement	AEP	IPP (Invenergy)	575
Sullivan 345kV #2	06/01/2025	IN	Engineering and Procurement	AEP	IPP (Invenergy)	575
Highland-Hanna 345kV	08/12/2025	OH	Under Construction	ATSI	IPP (Clean Energy Future)	940
Belmont-Flint Run 500 kV	07/01/2026	WV	Active	APS	IPP (Competitive Power Ventures)	2,100
Gas CT Total						**569**
Chesterfield 230 kV	06/01/2023	VA	Active	Dominion	Regulated Utility (Dominion)	569
Gas Other Total						**132**
Paulsboro 69 kV	02/25/2021	NJ	Active	AEC	Unknown	20
Paulsboro 69 kV II	09/01/2022	NJ	Active	AEC	Unknown	58
Double Toll Gate - Strasbu	01/01/2022	VA	Active	APS	Unknown	14
Price Hill - Pruntytown 138	06/01/2024	WV	Active	APS	Unknown	40
Coal to Gas Conversion Total						**750**
Osage 138 kV	04/01/2022	WV	Active	APS	IPP (Vicinity Energy)	50
Rockport 765 kV	05/31/2026	IN	Active	AEP	Regulated Utility (AEP)	700
Existing Facility Uprates Total						**1,437**
Gas CC						725
Gas CT						703
Gas Other						9
Total Gas-Fired Capacity in Queue						**7,628**

Sources and Notes: Project ICAP values retrieved from PJM, Serial Service Request Status, October 2024. The Chesterfield 230 kV CT facility (total of 1,138 MW) is shown here but the 569 MW portion with target COD of 12/31/2029 is excluded from the total here due to a projected COD after the June 1 start of the 2028/29 DY.

It is important to note that policy and market developments since this screening analysis was conducted have bearing on the future of projects in PJM. Supply chains continue to tighten and major equipment such as turbines have become increasingly scarce. This has increased development timelines for gas-fired resources such that new build projects that have not already begun development will have difficulty to achieve operation by the delivery year. As such, other resources may be required to fill this gap in the near-term with either BESS or PV+BESS hybrids. However, if federal tax credits in the Inflation Reduction Act (IRA), specifically the Investment Tax Credit (ITC) and Production Tax Credit (PTC) expire or are repealed, non-emitting resources such as BESS and PV would become significantly less economic to build.

C. Results of Screening Analysis

After the second stage of screening, we selected three final reference technologies: gas CT, gas CC, and 4-hour BESS which offered the best combination of selection criteria, although none of them were perfect across every category. The CT and the CC fulfill most of the selection criteria, as they have long operational histories in PJM, have high ELCC values, and will provide a stable reliability contribution. However, the limited number of gas projects in the queue indicates that a CONE estimate based on only gas projects will not be sufficiently forward-looking.

Thus, while the 4-hour BESS has a lower ELCC value and more limited operational history than gas-fired technologies, it is included because of its prevalent development pipeline and greater probability to be built in time for 2028/29 due to shorter construction timelines and less uncertainty around permitting due to environmental policies. Among non-emitting resources, the uncertainty in estimating a 4-hr BESS Net CONE is less than for longer-duration storage and hybrid PV-BESS.

We continue to uphold our position from the 2022 PJM CONE Study that relying on the clearing price at which new capacity has been willing to enter in recent past auctions would not be advisable. Although historical data offer a valuable reference for Net CONE, this Adjusted Empirical Net CONE alone is unreliable due to its backward-looking orientation and the unclear relationship between clearing prices and the amount entrants would actually need to recover their costs.

III. CONE Calculation Overview

A. CONE Components

CONE is calculated as the levelized net revenues a resource owner would require to be willing to enter the market. It is a function of a plant's installed costs, fixed O&M costs, the shape and timeframe of its projected future net revenue trajectory, and the risk-appropriate cost of capital (CoC). Although all of these factors are incorporated into a spreadsheet model that accounts for taxes, depreciation, and many factors changing over time, the essence of the calculation can be expressed through the following formula:

FIGURE 5: GROSS CONE EQUATION

$$\underbrace{\text{Gross CONE}}_{\text{Owner's Required Levelized Revenues}} = \underbrace{\text{Overnight Capital Cost x Capital Charge Rate}}_{\text{Investors' Levelized Capital Recovery}} + \underbrace{\text{Levelized Fixed O\&M}}_{\text{Annualized O\&M Costs}}$$

Owner's Required Levelized Revenues

Investors' Levelized Capital Recovery: Dependent on capital costs, levelization method, length of project development period, taxes, and cost of capital

Annualized O&M Costs: Dependent on size and trajectory of fixed operating costs + levelization approach

A plant's overnight capital costs represent the total nominal capital costs, exclusive of capital carrying costs during construction, that will be incurred throughout its project development period. The capital charge rate (CCR) expresses the fraction of overnight capital costs that must be recovered each year to earn their cost of capital. It is derived from the spreadsheet model accounting for the cost of capital, the carrying costs of capital during project development, annual income taxes net of depreciation, the levelization method, and the assumed economic life. Finally, the levelized fixed O&M costs are the plant's annualized fixed O&M costs after applying the revenue levelization approach discussed below. The annual revenue requirement, or Gross CONE, is thus the sum of the levelized capital recovery and the levelized fixed O&M costs.

B. Levelization Approach and Economic Life

Translating investment costs into levelized annual costs for the purpose of setting annual capacity price benchmarks requires an assumption about how net revenues are received over an assumed economic life. Levelization is the method of translating investment and annual fixed costs into first-year annualized costs that reflect expectations for capital recovery over the entire economic life, such that the investment has an NPV of 0. When determining the levelization approach, we consider the drivers of long-term cost recovery and long-term trends in power plant equipment costs and how they can impact the future economics of a plant built for the 2028/29 delivery year.

For the economic life, we recommend maintaining the prior assumption of a 20-year economic life for gas-fired resources from the 2022 PJM CONE Study. Although new natural gas-fired plants can physically operate for 30 years or longer, developers commonly express a preference to recover capital within 20 years in the current and projected policy environment. For the 4-hr BESS we recommend changing from a 15-year life from the 2022 PJM CONE Study to a 20-year life based on S&L's experience with recent power purchase agreement (PPA) term lengths and developers' financial models which have extended BESS asset economic lifetimes relative to the last Quadrennial Review. Assuming that a plant will receive a steady stream of revenues that terminates after an assumed 20-year life is a modeling simplification used to calculate a

Reference Price that reflects the marginal cost of capacity in long-run equilibrium conditions. Our concurrent 2025 PJM VRR Curve Report tests the robustness of the recommended VRR curve for an uncertainty range in the Reference Price that encompasses different assumptions on cost recovery.

For the levelization method, we follow the level-nominal approach already established in prior reviews. However, Section I.C presents an alternative calculation of a short-term reservation price with much more front-loaded revenue requirements corresponding to expectations of current shortage conditions normalizing after 1, 3, or 5 years.

C. ATWACC and Financial Inputs

An appropriate discount rate is needed for translating uncertain future cash flows into present values and deriving the CONE value that makes the project NPV zero. It is standard practice to discount future all-equity cash flows (*i.e.*, without deducted interest payments) using an ATWACC.[17] We developed our recommended cost of capital by an independent estimation of the ATWACC for publicly traded merchant generation companies or independent power producers (IPPs), supplemented by additional market evidence from merger and acquisition (M&A) transactions. These market- and transaction-based data are the most direct, reliable, transparent, and verifiable evidence on the cost of capital of companies in the merchant generation business. They reflect not only the capital providers' required compensation for the risks, but also the borrowers' willingness to bear these risks.

Based on our empirical analysis as of February 28, 2025, we recommend 9.5% as the appropriate ATWACC to set the CONE price for a new merchant plant that will commence operation by June 2028. Consistent with this ATWACC determination, we recommend the following specific components for a new merchant plant: a capital structure of 55/45 debt-equity ratio, a cost of debt of 5.8%, a combined federal and state tax rate of 27.7%, and a cost of equity of 16.0%.[18] It is important to emphasize that the exact capital structure and corresponding cost of debt and

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[17] The ATWACC is so-named because it accounts for both the cost of equity and the cost of debt, net of the tax deductibility of interest payments on debt, with the weights corresponding to the debt-equity ratio in the capital structure. Cash flows to which the ATWACC is applied must include revenues, costs, and taxes on income net of depreciation (but not accounting for interest payments or their deductibility, since that is incorporated into the ATWACC itself).

[18] $5.8\% \times 55\% \times (1 - 27.7\%) + 16.0\% \times 45\% = 9.5\%$. The tax rate of 27.7% is a combined federal-state tax rate, where state taxes are deductible for federal taxes ($= 8.5\% + (1 - 8.5\%) \times 21\%$). Note that the ATWACC applied to the four CONE Areas varies slightly with applicable state income tax rates, as discussed in the next section.

return on equity (ROE) do not significantly affect the CONE calculation as long as they amount to the empirically based 9.5% ATWACC.[19] This is because the CONE value is determined by the 9.5% ATWACC, not by the ATWACC components. Nonetheless, we use market observations and judgements to select a set of self-consistent components of the ATWACC.

The rest of this section further describes our approach to developing the recommended ATWACC. First, we perform an independent cost of capital analysis for US IPPs. Second, we discuss how we adjust the discount rates used in M&As for the changes in the risk-free rate. Finally, we discuss how considerations of the specific dynamics of PJM markets affect cost of capital recommendations.

ATWACC for Publicly Traded Companies as of February 28, 2025: We estimated ATWACC using the following standard techniques, with the base-case results summarized in Table 5 and charted with sensitivities in Figure 7.

TABLE 5: BASE CASE ATWACC-2025

Company	S&P Credit Rating [1]	Market Capitalization [2]	Long Term Debt [3]	Beta [4]	CAPM Cost of Equity [5]	Equity Ratio [6]	Cost of Debt [7]	ATWACC [8]
Comparable Companies for CONE Analysis - 2025								
AES Corp	BBB-	$7,496	$25,431	1.15	13.1%	28%	5.6%	6.6%
NRG Energy	BB	$21,137	$9,929	1.15	13.1%	54%	5.9%	9.1%
Vistra Corp	BB+	$53,248	$15,418	1.15	13.1%	55%	5.8%	9.1%
Additional Company Considered But Not Included in Sample								
Constellation Energy	BBB+	$93,094	$7,384	1.10	12.8%	85%	5.3%	11.5%

Sources and Notes:
[1]: S&P Research Insight.
[2]: Bloomberg as of 2/28/2025, millions USD.
[3]: Bloomberg as of 12/31/2024, millions USD.
[4]: 5-year weekly betas from Value Line.
[5]: RFR (4.72%) + [4] × MERP (7.31%).
[6]: Equity as a percentage of total firm value, averaged over a 3-year period.
[7]: Computed cost of debt based on each company's S&P credit rating.
[8]: [5] × [6] + [7] × (1 − [6]) × (1 − 27.2%).

Base-case estimates are derived from three publicly traded companies with significant portfolios of natural-gas-fueled merchant generation. The sample ATWACC ranges from 6.6% for Applied Energy Services Corp. ("AES") to 9.1% for both NRG Energy Inc. ("NRG") and Vistra Corp. ("Vistra"

[19] Finance theory posits that, over a reasonable range, capital structure does not affect the cost of capital: for a given project or business, greater leverage will increase the cost of debt and cost of equity such that the ATWACC would remain the same.

or "VST"). As discussed below, we do not consider Constellation Energy ("CEG") a comparable company for the typical electricity generator in the PJM market. Nonetheless, we present CEG's results in this section to be consistent with Brattle's May 2024 Update.[20]

Additional details about the sample and key inputs are discussed next.

Sample: In our 2022 PJM CONE Study, we chose three sample companies: NRG, Vistra, and AES. As discussed in our previous analysis, since 2018, none of the publicly traded IPPs companies are natural gas fueled pure-play generation companies.[21] In Brattle's May 2024 ATWACC Update, we proposed to include CEG in our sample, but cautioned that CEG's ATWACC, about 11%—around 3% higher than ATWACCs from the other three companies—should not be used to set our recommended ATWACC.[22] We pointed out two factors contributing to CEG's higher ATWACC.[23] First, CEG's nuclear generation fleet has higher fixed costs than gas-fired plants, hence higher operating leverage. All else equal, companies with higher operating leverage tend to have higher cost of capital.[24] Second, CEG is a newly independent company with an equity/value ratio significantly above the range of its industry peers (about 83% in May 2024 v. 34%–51% for the other three companies).[25] All else equal, companies with higher equity ratios tend to have higher ATWACC. In our May 2024 ATWACC Update, we gave some weight to CEG's higher ATWACC and proposed 10% as the ATWACC for the CONE analysis, although this analysis was ultimately not used by PJM.

We give no weight to CEG in our current ATWACC analysis due to two most recent developments that make CEG a poor comparable company for a natural-gas-fueled developer in the PJM market. First, since March 2024, several leading technology companies have entered into agreements to

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[20] We also do not consider Talen Energy in our sample. Talen went public in the over-the-counter market in June 2023 and then migrated to NASDAQ in July 2024. In addition to a short trading history at a major stock exchange, Talen is also primarily a nuclear-powered generator via its holding of Susquehanna Steam Electric Station.

[21] For example, in March 2023, NRG acquired Vivint Smart Home in its bid to become a leader in the emerging convergence of energy and smart automation in the home and business. NRG, "NRG Completes Acquisition of Vivint Smart Home, Inc., Creating the Leading Essential Home Services Platform," March 10, 2023.

[22] The Brattle Group, "May 2024 ATWACC and Annual Automatic Update Methodology," at p. 4.

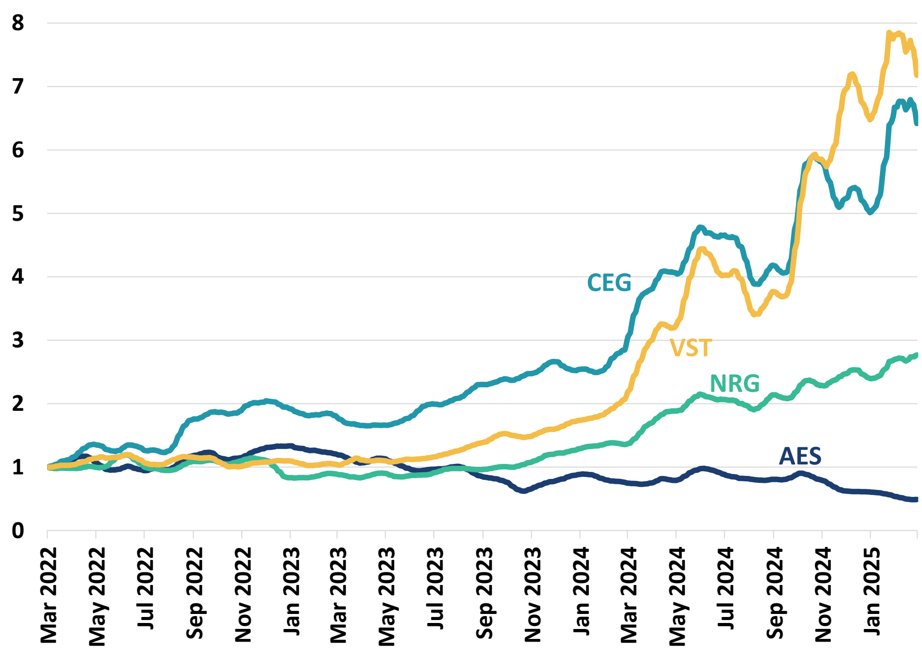
[23] The Brattle Group, "May 2024 ATWACC and Annual Automatic Update Methodology," at p. 9.

[24] See, *e.g.*, Richard A. Brealey, Stewart C. Myers, and Franklin Allen, "Principles of Corporate Finance," 11th edition, at p. 227 ("A production facility with high fixed costs, relative to variable costs, is said to have high operating leverage. High operating leverage means a high asset beta [a measure of the project's ATWACC].")

[25] In 2022, Exelon Corporation's electricity generation subsidiary, Constellation Energy, was spun off from Exelon to become a publicly listed company. Constellation Energy, "Investor FAQs," Accessed May 29, 2024.

buy electricity from clean fuel, such as nuclear power, for new data centers.[26] These agreements caused stock prices of IPPs, especially CEG and Vistra to increase substantially as shown in Figure 6. As of December 2024, according to its SEC Form 10-K, CEG's nuclear fleet accounted for 70% of its generation capacity and 87% of its energy supply.[27] Second, CEG announced in January 2025 that it would acquire Calpine Corp. ("Calpine").[28] Companies participating in M&As are typically excluded from the cost of capital estimation, because their stock prices tend to be influenced more by deal-specific news than business fundamentals as a standalone company would.

FIGURE 6: PRICE APPRECIATION OF IPP STOCK PRICES (2022–2025) (INDEXED TO MARCH 1, 2022)



Sources and Notes: Stock prices from Bloomberg as of March 13, 2025.

As shown in Figure 6, Vistra also experienced a significant stock price increase in 2024 and 2025. Among other reasons, the closing of its Energy Harbor acquisition in March 2024, primarily a large privately-held nuclear generator, positioned Vistra well for the subsequent surge in demand for

[26] For example, in March 2024, Amazon acquired Talen Energy's 960MW Cumulus data center adjacent to the Susquehanna nuclear power station in Pennsylvania for $650 million (Talen Energy sells Pa. datacenter campus to Amazon Web Services for $650M | S&P Global). Microsoft announced in September 2024 a 20-year PPA with CEG. Under this agreement, Microsoft will source carbon-free energy from the planned Crane Clean Energy Center, which involves restarting Unit 1 of the Three Mile Island nuclear facility in Pennsylvania (Constellation to Launch Crane Clean Energy Center, Restoring Jobs and Carbon-Free Power to The Grid).

[27] SEC Form 10-K, pp. 7–8 (Form 10-K for Constellation Energy Corp filed 02/18/2025).

[28] Constellation to Acquire Calpine; Creates America's Leading Producer of Clean and Reliable Energy to Meet Growing Demand for Customers and Communities, January 10, 2025.

clean energy for data centers, and contributed to its price appreciation.[29] After the acquisition, nuclear capacity accounted for 16% of Vistra's generation capacity and 24% of the electricity generation.[30] Since nuclear is not the largest fuel source for Vistra, however, we keep Vistra in our sample.

Cost of Equity (CoE): We estimate the CoE of the sample companies using the Capital Asset Pricing Model (CAPM). As shown in column [5] of Table 5, the resulting return on equity ranges from 12.8%–13.1% for the companies included in the analysis. The ROE for each company is derived as the risk-free rate plus a risk premium given by the expected risk premium of the overall market times the company's "beta." The "beta" describes each company stock's historical correlation with the overall market, where the "market" is taken to be the S&P 500 index.

Each of these inputs is discussed below:

- Market Risk Premium: we estimated the expected risk premium of the market to be 7.31% based on the long-term average of values provided by Kroll, *fka* Duff and Phelps.[31]
- Risk-free Rate: we use a risk-free rate of 4.72%, based on a 15-day average of 20-year US treasuries as of February 28, 2025.
- Betas: we use betas reported by Value Line in our base case. In addition, as a sensitivity, we estimate the betas for the sample companies using 3-year weekly stock returns on Wednesdays ending February 26, 2025. These betas are reported in Table 6.

[29] The transaction was first announced in March 2023.

[30] SEC Form 10-K (Form 10-K for Vistra Corp filed 02/28/2025), at pp. 2 and 63.

[31] Kroll Cost of Capital Navigator 2025, as of December 2024 (arithmetic average of excess market returns over 20-year risk-free rate from 1926–2024).

TABLE 6: BETAS

Company Name	Value Line Beta (February 2025)	3 Year Weekly Beta (As of 2/26/2025)
[1]	[2]	[3]
Comparable Companies for CONE Analysis - 2025		
AES Corp.	1.15	1.03
NRG Energy	1.15	0.90
Vistra Corp.	1.15	1.15
Additional Company Considered But Not Included in Sample		
Constellation Energy	1.10	1.25

Cost of Debt (CoD): We estimate the cost of debt by the average bond yields corresponding to the unsecured senior credit ratings for each merchant generation company (issuer ratings) as well as each company's actual CoD (averages across long-term debt).[32] They are reported in Table 7. In the base-case estimation in Table 5, we use rating-based cost of debt, but in the sensitivity analysis we also use company-specific CoD (Figure 7 below).

TABLE 7: COST OF DEBT

Company	Credit Rating	Ratings-Based Cost of Debt	Company-Specific Cost of Debt
[1]	[2]	[3]	[4]
Comparable Companies for CONE Analysis - 2025			
AES Corp	BBB-	5.6%	7.1%
NRG Energy	BB	5.9%	5.6%
Vistra Corp	BB+	5.8%	6.2%
Additional Company Considered But Not Included in Sample			
Constellation Energy	BBB+	5.3%	5.8%

Debt/Equity Ratio: We estimate the debt and equity ratios as averages over the 3-year period between March 1, 2023 and February 28, 2025. More specifically, the February 28, 2025 debt and equity ratios are based on debt balances as of December 31, 2024 (the last reported annual

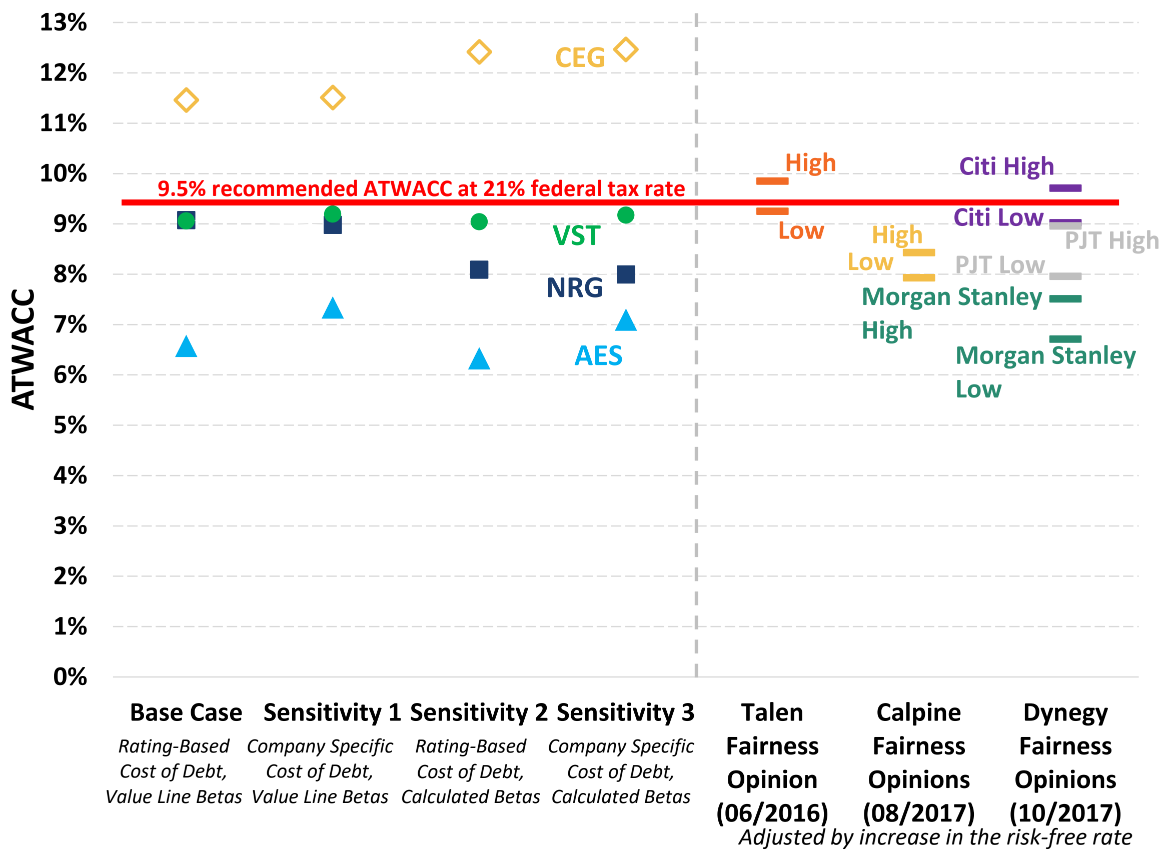
32 The rating-based average yields, based on a sample of similarly rated long-term (10 plus years) corporate bonds, are generally preferable to the company's actual CoD, which could be more influenced by company- and issue-specific factors, such as the issuers' competitive positions within the industry, and the debt issues' seniority, callability, availability of collateral. However, company-specific CoDs could carry real-time industry-wide credit information that the typically static credit ratings for a broad swath of industries are slow to incorporate.

numbers) and market capitalizations as of February 28, 2025. The equity ratios are shown in Table 5.

ATWACC Sensitivities: Figure 7 reports the ATWACC for the sample under alternative assumptions for the CoD and risk-free rate, along with the discount rates used in fairness opinions as additional reference points (discussed below):

- *Base Case* uses the inputs and results shown in Table 5 above (Value Line betas and rating-based CoD).
- *Sensitivity 1* uses Value Line betas and company-specific CoD.
- *Sensitivity 2* uses Brattle calculated betas and rating-based CoD.
- *Sensitivity 3* uses Brattle calculated betas and company-specific CoD.

FIGURE 7: SUMMARY OF ATWACC RANGES



For the Base Case and each sensitivity, the colored marks represent each of three US IPPs' ATWACCs. The highest ATWACC estimate is 9.2% for Vistra under Sensitivities 1 and 3. Two of NRG's ATWACC estimates are about or above 9.0%. As explained above, for consistency with the

May 2024 Update, we also present the results for CEG, but we do not use them as weights in our ATWACC recommendation.

Our analysis also considers the risk-free-rate-adjusted discount rates used in publicly disclosed fairness opinions for three M&As in the IPP industry (shown in the right-hand side of Figure 7). Talen's acquisition by Riverstone Holdings LLC announced on June 2, 2016; (2) Calpine's leveraged buyout by Energy Capital Partners announced on August 17, 2017; and (3) Dynegy's acquisition by Vistra announced on October 27, 2017. At the announcement time of those transactions, the prevailing risk-free rates were 2.84%, 3.04%, and 2.92%, respectively. We adjusted the range of discount rates used in each transaction by the increase in risk-free rates from the transaction dates to February 28, 2025. The upper bound of these adjusted discount rates is about 9.9%.

While there have been several more recent M&As involving electricity generation assets, the fairness opinions for those transactions were not publicly disclosed.[33] Therefore, we are unable to include them in our analysis. Given the long period of no new information, in our current recommendation of the ATWACC for the CONE analysis, we decide to give lower weight to these adjusted fairness opinion discount rates.

ATWACC for Merchant Generators in PJM Markets and the Recommended Components: The appropriate ATWACC for the PJM CONE Study should reflect the systematic financial market risks of a merchant generating project's future cash flows from participating in the PJM wholesale power market. As we have argued before, as a pure merchant project in PJM, the risks would be higher than for the average portfolio of independent power producers that have some long-term contracts in place.[34] Moreover, ATWACCs for the three companies in our sample likely under-estimate the ATWACC faced by a new entry plant in PJM because of these companies' business diversification away from the pure-play generation business. In the case of NRG and Vistra, they increasingly integrate their generation business with retail electricity supply, each serving as a partial hedge to the other and lowering the overall cost of capital for the combined operations. In the case of AES, its utility business and extensive international operations make it less sensitive to the US electricity generation market and thus puts a downward pressure on its ATWACC.

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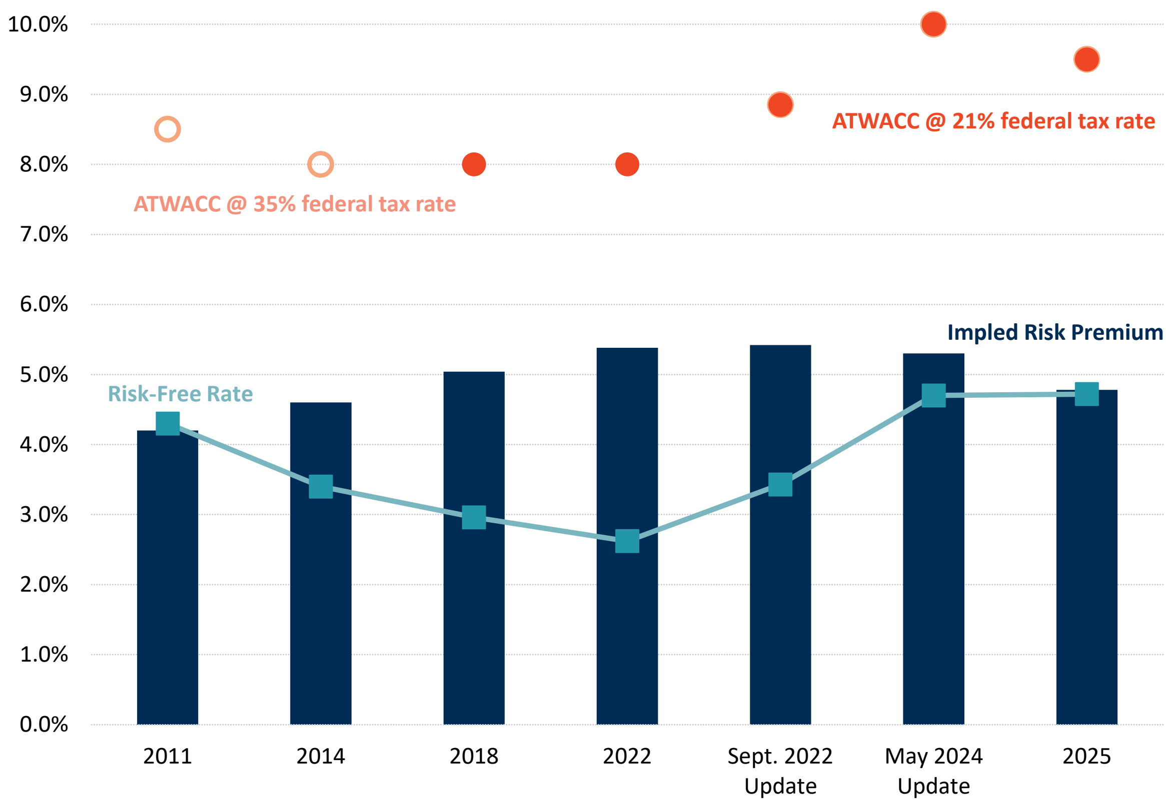
33 Recent M&As include (1) NRG's acquisition of Centrica's Direct Energy (retail, $3.625 bn) in January 2021; (2) CEG's acquisition of NRG's 44% interest in South Texas Project (nuclear plants, $1.75 bn) in November 2023; (3) Vistra's acquisition of Energy Harbor (nuclear fleet / retail, $3.4 bn) in March 2024; and (4) CEG's announced acquisition of Calpine in January 2025. Fairness opinion for NRG's acquisition of Vivint Smart Home ($2.8 bn) in March 2023 was publicly disclosed. But Vivint's business is home security, not power generation.

34 This is not to say that the reference merchant project would not arrange some medium-term financial hedging tools.

Based on the set of reference points shown in Figure 7 above, especially the upper bound of 9.2% for our independent analysis, and the recognition of PJM merchant generation risk that exceeds the average risk of the publicly traded generation companies, we believe that a 9.5% ATWACC is the most reasonable estimate for the purpose of estimating CONE.

As an additional point of reference, Figure 8 compares our current 9.5% recommendation and the implied risk premium against those from our four previous PJM CONE reports (2011, 2014, 2018, and 2022) and two updates (September 2022 and May 2024). The red dots represent the recommended ATWACC, the line is the prevailing risk-free rate, and the bars indicate the resulting implied risk premium (ATWACC - the risk-free rate).

FIGURE 8: COMPARISON OF ATWACC AND IMPLIED RISK PREMIUM



Relative to our May 2024 Update, the risk-free rate is about the same, but the lower ATWACC recommendation is due to our removal of CEG from the sample and lower weight given to the fairness opinion discount rates. Nonetheless, the implied risk premium 4.78% is within the range of the average implied risk premiums we recommended in the past.

IV. CONE Estimate for Natural Gas-Fired Simple-Cycle Combustion Turbines

A. Technical Specifications

Similar to the approach in the 2014, 2018, and 2022 PJM CONE studies, we assessed developers' revealed preferences for what is most feasible and economic in actual projects to determine the characteristics of the CT. Since technologies and environmental regulations continue to evolve, we supplemented our analysis with additional consideration of the underlying economics, regulations, infrastructure, and S&L's experience.

To determine the CT reference resource specifications, analysis from the 2022 PJM CONE Study was supplemented by reviewing the one additional gas-fired CT plant that has entered since 2022 shown in Table 4. The 2022 PJM CONE Study characterized all the recent CT plants either built or under construction by size, configuration, turbine type, cooling system, emissions controls, and fuel-firming to determine the most representative technical specifications.[35] For the specified locations within each CONE Area, S&L estimated the performance characteristics at a representative elevation and at a temperature and humidity that reflects peak conditions in the median year. Table 8 shows the elevation, temperature, and relative humidity assumptions for each CONE Area.

TABLE 8: ASSUMED AMBIENT CONDITIONS BY CONE AREA

CONE Area	Elevation ft	Max Summer Temperature °F	Relative Humidity %RH
EMAAC	330	92	55%
SWMAAC	150	96	44%
Rest of RTO	990	90	50%
WMAAC	1,200	91	49%
COMED	620	89	49%

Sources and Notes: Elevation estimated by S&L based on geography of specified area. Summer conditions developed by S&L based on data from the National Climatic Data Center's Engineering Weather dataset and 2021 American Society of Heating, Refrigerating, and Air-Conditioning Engineers (ASHRAE) Climatic Design Conditions.

[35] See 2022 PJM CONE Report, Section III.A for the CC and Section IV.A for the CT.

For ComEd, American Society of Heating, Refrigerating, and Air-Conditioning Engineers (ASHRAE) Technical Advisory Committee (TAC) 1% from Will County (Joliet and Lewis) are used.

Since the 2022 PJM CONE Study, PJM has adopted a new capacity accreditation approach based on the Marginal ELCC, which results in a substantial premium on the capacity value for dual-fuel CTs with dual fuel compared to CTs without. This, along with a net cost advantage compared to firm transportation, should favor dual fuel where possible. Notably, the one new CT plant in development shown in Table 4 is planning to install dual-fuel capability. This supports changing to a dual-fuel CT instead of the CT with firm gas from the 2022 PJM CONE Study.

Consistent with the 2022 PJM CONE Study, the GE 7HA turbine remains the preferred make and base model, owing to the industry's years of experience with the platform. However, based on conversations with S&L, developers, and the Independent Market Monitor (IMM), we have selected the 7HA.03 model over the 7HA.02 model used in the 2022 PJM CONE Study because of its improved performance at a lower cost per-kW which is making it an increasingly attractive option. It is thus most likely that plants which will be finished for the 2028/29 delivery year will feature 7HA.03 turbines, as observed in recently proposed projects. Table 9 below describes the technical specifications of the CT.

TABLE 9: CT TECHNICAL SPECIFICATIONS

Plant Characteristic	Specification
Turbine Model	GE 7HA.03 60HZ
Configuration	1 × 0
Cooling System	n/a
Power Augmentation	Evaporative Cooling; no inlet chillers
Net Summer ICAP (MW)	392 / 395 / 387 / 383 / 393*
Net Heat Rate (HHV in Btu/kWh)	9,166 / 9,161 / 9,141 / 9,149 / 9,133*
Environmental Controls	
CO Catalyst	Yes
Selective Catalytic Reduction (SCR)	Yes
Dual-Fuel Capability	Yes
Firm Gas Transportation Contract	No
Special Structural Requirements	No
Blackstart Capability	None
On-Site Gas Compression	None

Sources and Notes: *For EMAAC, SWMAAC, Rest of RTO, WMAAC, and ComEd, respectively.

To determine the location for the new ComEd CONE Area, we again followed the revealed preferences approach and analyzed which county contained most of the recent new-build capacity and uprates for CTs and CCs. This analysis led to Will County as the representative location for both the CT and CC, as shown in Table 10 below.

TABLE 10: ANALYSIS OF NEW-BUILD AND UPRATES FOR GAS-FIRED CT AND CC IN COMED CONE AREA (MW OF SUMMER NET CAPACITY INTERCONNECTION RIGHTS)

Technology:	Gas CC						Gas CT									
Build Type:	New Build			Uprate			New Build		Uprate							
County:	Will	Grundy	Lee	Will	Grundy	Lee	Lake	Lee	Kane	Will	Lake	Cook	Winnebago	Grundy	Lee	Du Page
Delivery Year																
2012-2013							495			54						
2013-2014									16	40		27				
2014-2015										56				13		
2015-2016			600													
2016-2017					20					20						
2017-2018					80											
2018-2019																
2019-2020															48	
2020-2021																
2021-2022										135	90					66
2022-2023	1,116												87			
2023-2024						24		314								30
2024-2025		1,150		120	93					46						
2025-2026										5						
Total 2012-2026	1,116	1,150	600	120	193	24	495	314	16	356	90	27	87	13	48	96

Sources and Notes: All numbers represent MWs of summer net Capacity Interconnection Rights (CIRs) received (for past years) or requested (for future years). Brattle analysis of PJM data from: PJM, Serial Service Request Status, October 2024.

The CT is assumed to have an economic life of 20 years in EMAAC, SWMAAC, Rest of RTO, and WMAAC. However, in ComEd, current Illinois law requires that all gas-fired generating plants permanently reduce carbon emissions to zero by January 1, 2045.[36] We assume this limits the economic life of a CT built in ComEd for the 2028/29 Delivery Year to 16.5 years.

B. Capital Costs

Capital costs are incurred during the plant's project development period and consist of equipment, physical infrastructure, initial financing, and other similar costs. Categories of costs are often described as owner-furnished equipment (OFE), engineering, procurement, and construction (EPC), and non-EPC owners' costs. OFE includes major pieces of equipment such as turbines and emissions control systems like the Selective Catalytic Reduction (SCR). EPC contractors facilitate construction by managing the offload, storage, and installation of the OFE, determining additional site design details, hiring labor, and procuring all other relevant materials

[36] Illinois General Assembly, Climate and Equitable Jobs Act (CEJA), Public Act 102-0662, 102nd session, September 15, 2021.

and equipment. Finally, non-EPC owners' costs include project development and startup costs, inventories, gas and electric interconnection, and financing costs.

All equipment and materials costs were estimated by S&L in January 2025 using proprietary data, vendor catalogs, quotes from equipment manufacturers, and other publications. Labor and materials costs are county-specific estimates for each CONE area. The dual-fuel CT plants are assumed to have enough liquid fuel storage and infrastructure on-site for three days of continuous operation. Dual-fuel capability requires the combustion turbines to have water injection nozzles to reduce NO_x emissions while firing liquid fuel. These modifications as well as the costs associated with fuel oil testing, commissioning, inventory, and the capital carrying charges on the additional capital costs contribute to the overall costs for dual-fuel capability. The methods used to calculate these costs are explained later in this section.

Based on the monthly project development capital drawdown schedule provided by S&L, we estimate the overnight capital costs for an online date of June 1, 2028 by escalating the January 2025 costs by inflation as described in more detail below. The "overnight capital costs" represent the total nominal capital costs, exclusive of interest and cost of equity during construction, that the project will incur throughout the project development period. The "installed costs" represent the present value of all cash flows during the period, including capital carrying costs during project development. Based on the technical specifications described above, the capital costs for a CT with an online date of June 1, 2028 are shown below in Table 11. Comparisons to costs from the 2022 PJM CONE Study are expressed in 2025 dollars to align them with the basis of our initial cost estimates. All costs presented in this section are expressed in ICAP terms unless specified otherwise.

TABLE 11: CAPITAL COSTS FOR A CT
(NOMINAL$ FOR JUNE 2028 ONLINE YEAR)

Capital Costs (in $millions)	Escalated Overnight Capital Costs: 06/2028				
Units	Nominal$	Nominal$	Nominal$	Nominal$	Nominal$
	EMAAC	SWMAAC	Rest of RTO	WMAAC	COMED
Net Summer Capacity (MW)	*392*	*395*	*387*	*383*	*393*
OFE+ EPC Costs	**$438**	**$420**	**$421**	**$427**	**$473**
Owner-Furnished Equipment (OFE)					
Gas Turbines	$159	$159	$159	$159	$159
SCR	$53	$53	$53	$53	$53
Sales Tax	$0	$0	$0	$0	$13
Engineering, Procurement, and Construction Costs (EPC)					
Equipment					
Other Equipment	$34	$34	$34	$34	$34
Construction Labor	$73	$60	$60	$65	$86
Other Labor	$28	$27	$27	$28	$29
Materials	$15	$15	$15	$15	$15
Sales Tax	$0	$0	$0	$0	$2
EPC Contractor Fee	$36	$35	$35	$35	$39
EPC Contingency	$40	$38	$38	$39	$43
Non-EPC Costs	**$109**	**$108**	**$105**	**$105**	**$114**
Project Development	$22	$21	$21	$21	$24
Mobilization and Start-Up	$4	$4	$4	$4	$5
Non-Fuel Inventories	$2	$2	$2	$2	$2
Net Start-Up Fuel Costs	-$1	$0	-$2	-$3	$1
Electrical Interconnection	$22	$22	$22	$22	$22
Gas Interconnection	$35	$35	$35	$35	$35
Land	$1	$1	$0	$1	$1
Fuel Inventories	$4	$4	$4	$4	$4
Owner's Contingency	$7	$7	$7	$7	$8
Financing Fees	$12	$11	$11	$11	$13
Total Overnight Capital Costs	**$547**	**$528**	**$526**	**$532**	**$587**
Overnight Capital Costs ($/kW)	**$1,395**	**$1,339**	**$1,361**	**$1,390**	**$1,495**
Installed Cost ($/kW)	**$1,715**	**$1,647**	**$1,674**	**$1,710**	**$1,837**

Sources and Notes: Net start-up costs in ComEd and land costs in Rest of RTO are non-zero but less than $500,000.

1. OFE and EPC Costs

a. Project Developer and Contract Arrangements

The scope of an EPC contract typically includes handling, storage, and installation of the OFE (including the gas turbines and major equipment), balance-of-plant engineering, procurement of other equipment, construction, commissioning, and delivery of a fully operational facility to meet certain performance guarantees. The contracting scheme for procuring professional EPC services in the US is typically implemented with a single contractor at a single, fixed, lump-sum price. A single contract reduces the owner's responsibility with construction coordination and reduces the potential for missed or duplicated scope compared to multiple contract schemes. The estimates and contractor fees herein reflect this contracting scheme.

b. Equipment, Materials, and Sales Tax

OFE is typically purchased by the plant owner through the EPC contractor. The owner and EPC contractor typically sign a fixed-price contract with equipment manufacturers early in the development process, effectively locking in the price of OFE and other equipment. The OFE costs shown reflect the total equipment cost including freight to site. Additional related costs including EPC handling costs, on-site storage and protection, equipment installation, and commissioning are included in the EPC's construction labor and other labor cost components. Due to the current tight market for turbines, combustion turbine costs which now represent 30% of total incurred overnight capital costs, have increased from $225/kW to $409/kW in 2025 dollars, or by 81% in real terms, since the 2022 PJM CONE Study. The rate of change has been rapid in these tight conditions. Since August 2024 alone, turbine costs have increased by 37% in real terms, from $298/kW to $409/kW in 2025 dollars.[37]

Materials include all construction materials associated with the EPC scope of work, material freight costs, and consumables during construction. This includes commodity-type materials such as concrete, formwork, rebar, wiring, cabling, raceways, instrumentation, steel, piping, fittings, specialties, and small valves. Material costs were estimated using S&L proprietary data, vendor catalogs, and publications. Estimates for the quantity of materials needed to construct simple- and combined-cycle plants are based on S&L's experience with similarly sized and configured facilities.

Other Equipment includes inside-the-fence balance-of-plant equipment required for interconnection and associated spare parts and special tools. This equipment includes (as applicable) air cooled condensers, auxiliary boilers, fuel gas conditioning equipment, pumps, fans, heat exchangers, compressors, tanks, water treatment systems, fire protection systems,

[37] Based on costs in CONE Area 3. Current costs are expressed pre-escalation, in 2025$. 2022 PJM CONE Affidavit turbine costs of $232/kW in 2026$ were deflated from June 2026 to January 2025 using the long-term inflation rate assumed in the 2022 PJM CONE Study. August 2024 comparison is based on preliminary CONE estimates published in November 2024, which were derived from S&L cost estimates as of August 2024. See Newell et. al., Sixth Review of PJM's RPM VRR Curve Parameters Preliminary Gross CONE and E&AS Methodology, November 26, 2024.

generator step-up transformers, and other engineered equipment required for operation of the plant. Equipment costs are based on S&L's proprietary database, professional experience, and continuous interaction with clients and vendors regarding equipment costs and budget estimates.

Sales Tax is applied under the same assumptions in the 2022 CONE Study for EMAAC, SWMAAC, Rest of RTO, and WMAAC.[38] However, ComEd estimates reflect the 6.25% sales tax on equipment in Illinois which does not have any provisions for tax exemptions for power plant equipment.[39]

c. Labor

Labor costs consist of both Construction Labor associated with the EPC scope of work and Other Labor, which includes engineering, procurement, logistics for non-OFE equipment, project services, construction management, field engineering, start-up, and commissioning services. As in the 2022 PJM CONE Study, the labor rates in this analysis do not reflect a specific assumption of whether union or non-union labor is utilized. Instead, S&L developed labor rates through a survey of the prevalent wages in each region, including both union and non-union labor. The labor costs are based on average labor rates weighted by the combination of trades required for each plant type. Increased competition for skilled labor in a tightening market has increased construction labor costs from $116/kW to $152/kW in 2025 dollars, or 30% in real terms, since the 2022 PJM CONE Study.[40]

d. EPC Contractor Fee and Contingency

The EPC Contractor Fee is added compensation and profit paid to an EPC contractor for coordination of engineering, procurement, project services, construction management, field engineering, and startup and commissioning. This fee is applied to all EPC costs as well as the OFE to account for the EPC costs associated with the tasks listed above once the equipment is turned over by the Owner to the EPC contractor. Based on S&L's proprietary project cost database and professional experience, the EPC Contractor Fee is 10% of OFE and EPC costs. Evidently, the tight market for qualified contractors has enabled EPCs to exact a premium for thermal power generation projects by continuing to charge fees equivalent to the same percentage on higher

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38 2022 PJM CONE Study, Section III.B.1.

39 Illinois General Assembly, 35 ILCS 105/305, Accessed January 30, 2025.

40 See footnote 37 above. The 2022 PJM CONE Affidavit Construction Labor costs are $120/kW in 2026$.

OFE and EPC costs. This results in an increase in the EPC contractor fee from $58/kW to $89/kW in 2025 dollars, a 55% increase in real terms, since the 2022 PJM CONE Study.[41]

The EPC Contingency covers undefined variables in both scope definition and pricing that are encountered during project implementation. Examples include nominal adjustments to material quantities in accordance with the final design, items clearly required by the initial design parameters that were overlooked in the original estimate detail, and pricing fluctuations for materials and non-OFE equipment. Based on S&L's proprietary project cost database and professional experience, the EPC Contingency is typically 10% of EPC and OFE costs, inclusive of the EPC contractor fee. Volatility in equipment and material pricing along with present labor shortages have caused EPC contractors to estimate contingencies equivalent to the typical percentage to higher EPC and OFE costs and thus increase the EPC contingency from $63/kW to $98/kW in 2025 dollars, or a 55% increase in real terms, since the 2022 PJM CONE Study.[42]

2. Non-EPC Costs

a. Project Development, Mobilization, and Start-Up

Project Development costs include development costs, oversight, and legal fees that are required prior to and generally through the early stages of the project timeline. These costs are typically 5% of the total OFE and EPC costs based on S&L's review of similar projects for which it has detailed information on actual owner's costs. Mobilization and Startup costs include costs incurred by the plant owner toward the completion of the plant, during testing, and initial stages of operation. This includes the training, commissioning, and testing by the staff that will operate the plant going forward. These costs are typically 1% of OFE and EPC costs based on S&L's review of similar projects.

b. Non-Fuel Inventories

Non-fuel inventories refer to the initial inventories of consumables and spare parts that are normally capitalized. Non-fuel inventories are typically 0.5% of OFE and EPC costs based on S&L's review of similar projects for which it has detailed information on actual owner's costs.

[41] See footnote 37 above. The 2022 PJM CONE Affidavit EPC Contractor Fee is $59/kW in 2026$.

[42] See footnote 37 above. The 2022 PJM CONE Affidavit EPC Contingency is $65/kW in 2026$.

c. Net Start-Up Fuel Costs

Before commencing full commercial operations, a new CT plant must undergo testing to ensure the plant is functioning and producing power correctly. This occurs in the months immediately before the online date and involves testing the turbine generators with both natural gas and fuel oil. S&L estimated the fuel consumption and energy production during testing based on typical schedule durations and testing protocols for plant startup and commissioning, as observed for actual projects. During this phase, a plant will purchase natural gas and fuel oil to use in testing but will also receive revenues for any energy produced during the tests. Net start-up costs are thus negative if the energy production credit received during testing is greater than the fuel costs incurred during testing. Additional details on net start-up fuel costs are presented in Appendix A.

d. Electric and Gas Interconnection

Electric interconnection costs were estimated using recent electric interconnection cost data provided by PJM. Electrical Interconnection costs fall into two categories: direct connection costs and network upgrade costs. Direct connection costs will be incurred by any new project connecting to the network and includes all necessary interconnection equipment such as generator lead and substation upgrades. Network upgrade costs may be incurred when improvements, such as replacing substation transformers, are required. Using the recent project data provided by PJM, we calculated a capacity-weighted average electrical interconnection cost of $55/kW (in 2025 dollars) for these projects. Appendix A provides additional details on the calculation of electrical interconnection costs. Due to increased intensity of network upgrades needed for further additions to the system combined with higher costs of materials including high-voltage transformers and cables, electrical interconnection costs have increased from $22/kW to $55/kW in 2025 dollars, 150% in real terms, since the 2022 PJM CONE Study.[43]

Gas interconnection costs represent the cost to construct a lateral pipeline connecting the plant to an existing gas pipeline. These costs were based on cost data for representative gas pipeline lateral projects. Similar to the 2022 PJM CONE Study, CT gas interconnection costs are assumed to consist of 5 miles of lateral pipeline, which resulted in a gas interconnection cost of $6.9 million/mile and $34.5 million total for the CT in nominal dollars for January 2025. This estimate is derived from a review of recent lateral projects in the Northeast and Midwest with pipe diameters of 12 to 16 inches, corresponding to the requirements for the 1×0 train CT. The gas interconnection costs are escalated to the midpoint of the project development period to

[43] See footnote 37 above. The 2022 PJM CONE Affidavit Electrical Interconnection Costs are $23/kW in 2026$.

produce the costs shown in Table 11. See Appendix A for more detail on the gas interconnection cost calculation based on historical project data, as well as escalation.

e. Land

The cost of land was derived current asking prices for vacant industrial land greater than 10 acres for sale in each county per CONE Area. 10 acres of land are required for the CT. The land costs are escalated to the midpoint of the project development period to produce the land costs shown in Table 11. See Appendix A for more detail.

f. Fuel Inventories

Unlike in the 2022 PJM CONE Study, the CT is assumed to have dual-fuel capability, or the ability to burn both natural gas and fuel oil. Fuel Inventories represent the capitalized cost of the fuel oil assuming a three-day supply of Ultra-low-sulfur diesel (USLD) will be purchased prior to operation. S&L estimated the volume of the fuel inventory required to fill the tank in gallons for each CONE Area, to which we apply an RTO-wide fuel oil price of $2.05/gallon to calculate the cost of procuring the fuel inventory. RTO-wide fuel oil prices for 2028 were provided by PJM based on forwards used in the E&AS offset calculations. For example, in Rest of RTO, S&L estimates that the CT requires a 3-day fuel inventory of 1.8 million gallons. This, multiplied by the RTO-wide fuel oil price, results in a fuel inventory cost of $3.6 million in 2025 dollars.[44]

g. Owners' Contingency

Owner's contingencies are needed to account for various unknown costs that are expected to arise due to a lack of complete project definition and engineering. Examples include permitting complications, greater than expected startup duration, etc. Based on S&L's review of recent projects, the owner's contingency is typically 8% of all other non-EPC costs, consistent with the 2022 PJM CONE Study.

h. Financing Fees

Financing fees are the cost of acquiring the debt financing, including associated financial advisory and legal fees. They are considered part of the plant overnight costs, whereas interest costs and equity costs during development are part of the total capital investment cost, or installed costs as described above. Financing fees are typically 4% of the OFE, EPC, and non-EPC costs based on

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[44] Numbers provided for representative CONE Area 3.

S&L's review of similar projects and are financed by debt using the same capital structure of 55% debt, 45% equity as discussed in Section III.C.

3. Escalation to 2028 Costs

Capital costs were escalated from S&L's January 2025 estimates to nominal dollars for a June 2028 online date. S&L developed monthly capital drawdown schedules over the project development period of 44 months for CTs based on a review of similar project timelines. The tight market for turbines and other major components has lengthened the project development period by 24 months since the 2022 PJM CONE Study. This means that a CT would need to have begun development on October 1, 2024 to have a planned COD of June 1, 2028. Unlike the 2022 PJM CONE Study, all costs are escalated at the rate of inflation based on the forecast inflation curve published by the Cleveland Federal Reserve Bank, rather than using different rates for individual line items. More detail on the capital drawdown schedule and inflation rates used for escalation is included in Appendix A.

Cost escalation results in nominal overnight capital costs for June 2028 which reflect the timing of the costs a developer accrues during the project development period. Costs were escalated using the following approaches:

- OFE and Major Equipment: As mentioned above OFE, the SCR system, and other major EPC equipment are typically purchased earlier in the project timeline. These are procured though a separate contract which has an associated payment schedule until the equipment delivery and represents a nominal cost that is locked-in at the time of the contract execution. Therefore, unlike prior CONE studies, these costs are escalated by inflation from their initial cost estimates (January 2025) to an Equipment Contract Lock-in Date at month 5 of the 44-month project development period (i.e., escalated to March 2025 for a June 2028 COD) for the CT.
- Net Start-up Fuel and Fuel Inventories: we do not escalate these costs since they are incurred in the few months before operation and are based on energy and fuel futures prices for June 2028.
- All other capital costs: we escalated at the rate of inflation from the initial cost estimates (January 2025) to the Project Development Midpoint, defined as when 50% of the capital cost has been incurred in the drawdown schedule. For the CT this occurs at month 15 of the 44-month project development period (i.e., escalated to January 2026 for a June 2028 COD). We escalate these costs to the Project Development Midpoint as a simplification to represent

expected nominal costs for line items whose costs can fluctuate over the project development period.

The capital drawdown schedule is used to calculate capital carrying costs during development and construction to arrive at a complete Installed Cost. The Installed Cost for each technology is calculated by first applying the monthly drawdown schedule to the nominal June 2028 overnight capital cost and then finding the present value of the cash flows as of the end of the project development period using the assumed cost of capital as the discount rate. By using the ATWACC to calculate the present value, the installed costs will include both the interest during construction from the debt-financed portion of the project and the cost of equity for the equity-financed portion.

C. Operations and Maintenance Costs

Once the plant enters commercial operation, the owners incur fixed O&M costs each year, including contracted maintenance services under a long-term service agreement (LTSA), property taxes, administrative expenses, insurance, fuel costs, and working capital financing. Annual fixed O&M costs increase CONE. Separately, we calculated variable O&M costs (including maintenance, consumables, and waste disposal costs) tied directly to unit operations to inform PJM's future E&AS margin calculations, but these do not factor into the CONE calculation.

Table 12 summarizes the fixed and variable O&M costs for a CT with an online date of June 2028 will incur in its first year as well as the levelized costs. The methods used to calculate the first-year and levelized fixed O&M costs are detailed below. Comparisons to costs from the 2022 PJM CONE Study are expressed in 2025 dollars to align them with the basis of our initial cost estimates. All costs presented in this section are expressed in ICAP terms unless specified otherwise.

TABLE 12: FIRST-YEAR AND LEVELIZED FIXED O&M COSTS FOR A CT (NOMINAL$ FOR JUNE 2028 ONLINE YEAR)

	Escalated O&M Costs: 06/2028				
Units	Nominal$	Nominal$	Nominal$	Nominal$	Nominal$
CONE Area	**EMAAC**	**SWMAAC**	**Rest of RTO**	**WMAAC**	**COMED**
Net Summer Capacity (MW)	*392*	*395*	*387*	*383*	*393*
Fixed First Year O&M ($ million/year)					
LTSA Fixed Payments	$0.5	$0.5	$0.5	$0.5	$0.5
Labor	$1.2	$1.3	$0.9	$1.0	$1.1
Maintenance and Minor Repairs	$0.5	$0.5	$0.5	$0.5	$0.5
Administrative and General	$0.3	$0.3	$0.3	$0.3	$0.3
Asset Management	$0.6	$0.7	$0.5	$0.5	$0.6
Property Taxes	$0.5	$6.7	$3.4	$0.6	$0.5
Insurance	$3.3	$3.2	$3.2	$3.2	$3.5
Interest on Working Capital	$0.2	$0.2	$0.2	$0.2	$0.2
Total Fixed First Year O&M ($ million/year)	**$7.0**	**$13.2**	**$9.2**	**$6.8**	**$7.2**
Total Fixed First Year O&M ($/kW-yr)	**$17.9**	**$33.5**	**$23.9**	**$17.7**	**$18.3**
Levelized Fixed O&M ($/kW-yr)	**$21.5**	**$33.2**	**$25.3**	**$21.2**	**$21.3**
Variable O&M					
Major Maintenance - Starts Based ($/Start)	$33,007	$33,007	$33,007	$33,007	$33,007
Consumables, Waste Disposal, Other VOM ($/MWh)	$1.1	$1.1	$1.0	$1.1	$1.1

1. Fixed Operations and Maintenance Costs

a. LTSA, Labor, Maintenance, and Administration

Labor, Maintenance and Minor repairs, and Administrative and General costs were estimated based on a variety of sources, including S&L's proprietary database on actual projects, vendor publications for equipment maintenance, and data from the Bureau of Labor Statistics.

Major maintenance is assumed to be completed through an LTSA with the original equipment manufacturer that specifies when to complete maintenance based on either fired-hours or starts. Consistent with past CONE studies and PJM market rules, the monthly payments specified in the LTSA are included as fixed O&M costs and the larger costs associated with run-time and starts are considered to be variable O&M.

b. Insurance and Asset Management

As in the 2022 PJM CONE Study, the insurance cost per year is assumed to be 0.6% of the plant's overnight capital cost. Asset management costs from typical costs incurred for fuel procurement, power marketing, energy management, and related services were estimated based on a sample of natural gas-fired plants in operation.

c. Property Tax

We maintained our bottom-up approach for estimating real and personal property taxes from the 2022 PJM CONE Study by researching tax regulations for the locations selected in each CONE Area and averaging the tax rates in areas that include multiple states. This method is explained in more detail in Appendix A, which also includes a summary of the tax rates in each CONE Area. The value of real property is assumed to escalate in future years in line with inflation, and the initial assessed value of the property is assumed to equal the plant's total capital cost (exclusive of real property). The assessed value of personal property is subject to depreciation in future years according to the law of each state.

d. Interest on Working Capital

During operation, plant owners also typically use a line of credit for working capital needs. Consistent with the 2022 PJM CONE Study, the working capital requirement during operation is assumed 0.5% of overnight capital costs, which is typical of similar projects. The yearly interest owed on the working capital account during operation is calculated by multiplying the working capital requirement by a short-term borrowing rate of 5.8%.[45]

2. Variable Operation and Maintenance Costs

Variable O&M costs are not used in calculating CONE, but they are inputs to the calculation of the E&AS revenue offset performed by PJM. With their lower expected capacity factor, the CTs are assumed to undergo major maintenance cycles tied to the factored starts of the unit, as opposed to the factored fired-hours maintenance cycles of the CCs. For this reason, the major maintenance cost component for the CTs is reported in "$/factored start" and not the $/MWh used for other consumables.

3. Escalation to 2028 Costs

Inflation rates affect our CONE estimates by forming the basis for projected increases in fixed O&M cost components over time. January 2025 O&M cost estimates were escalated from 2025 to nominal dollars for a June 2028 online date by the same real escalation rates used to escalate the overnight capital costs in Section IV.B. O&M costs are escalated based on the expected inflation assumptions described in Appendix A and are inflated to the middle of each year of operation.

[45] Short-term debt cost is the average of 3-month bond yield for companies with a BB credit rating as of February 19, 2025, from S&P Capital IQ.

D. CT CONE Estimates

The Gross CONE values shown below represent the total annual net revenues that a new CT resource would need to earn on average to recover its capital and fixed O&M costs, given reasonable expectations about future cost recovery over the plant's economic life. Table 13 summarizes the Gross CONE calculation, including capital costs, fixed O&M costs, and carrying costs in the form of the capital charge rate. The estimated level-nominal CONE for a CT ranges from $663/MW-day ICAP in Rest of RTO to $789/MW-day ICAP in ComEd. All costs presented in this section are expressed in ICAP terms unless specified otherwise.

TABLE 13: CONE CALCULATION FOR A CT
(NOMINAL$ FOR JUNE 2028 ONLINE YEAR IN ICAP TERMS)

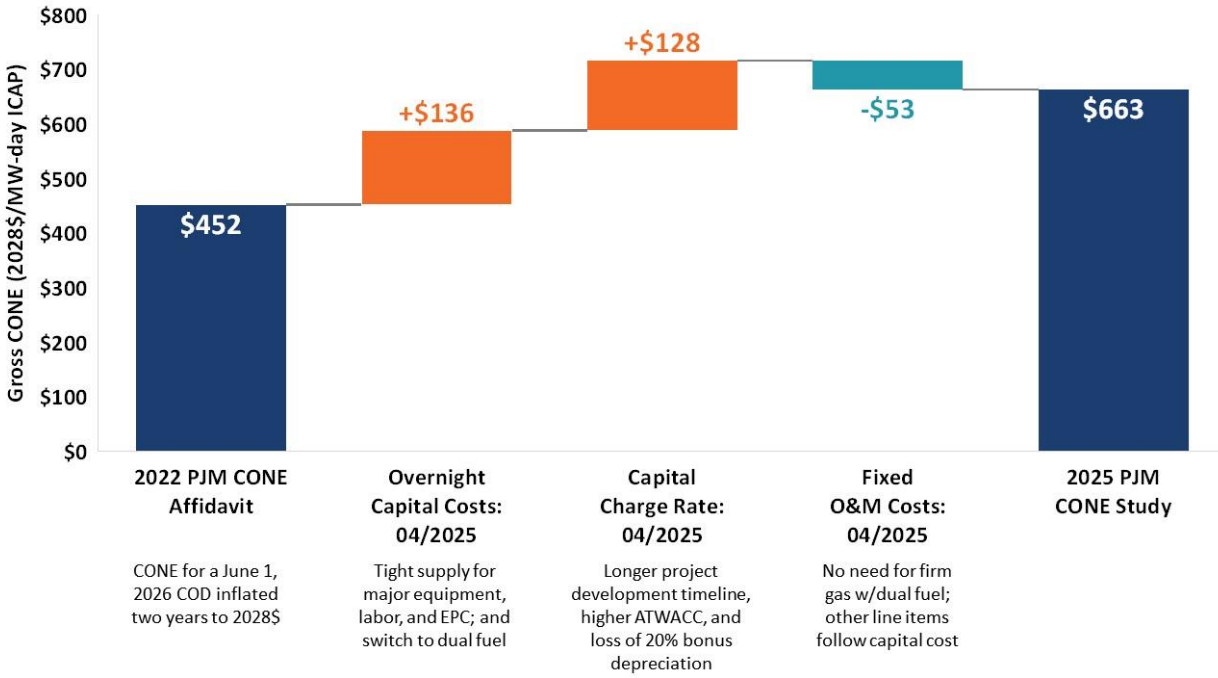
CONE Area				EMAAC	SWMAAC	Rest of RTO	WMAAC	COMED
Net Summer Capacity	MW	[1]		392	395	387	383	393
After-Tax WACC	%	[2]		9.5%	9.5%	9.5%	9.5%	9.5%
Capital Charge Rate	%	[3]		16.0%	15.9%	15.9%	15.9%	17.8%
Capital Costs								
Overnight Cost	Nominal $ million	[4]		$547	$528	$526	$532	$587
Overnight Cost	Nominal $/kW	[5]	[4] x 1000 / [1]	$1,395	$1,339	$1,361	$1,390	$1,495
Installed Cost	Nominal $ million	[6]		$672	$650	$647	$655	$721
Installed Cost	Nominal $/kW	[7]	[6] x 1000 / [1]	$1,715	$1,647	$1,674	$1,710	$1,837
Levelized Capital Cost	Nominal $/kW-yr	[8]	[5] x [3]	$223	$213	$217	$221	$266
O&M Costs								
First Year FOM	Nominal $ million/yr	[9]		$7	$13	$9	$7	$7
Levelized FOM	Nominal $/kW-yr	[10]		$21	$33	$25	$21	$21
Levelized CONE	**Nominal $/kW-yr**	**[11]**	**[8] + [10]**	**$244**	**$247**	**$242**	**$242**	**$288**
Levelized CONE	**Nominal $/MW-day**	**[12]**	**[11] x 1000/365**	**$670**	**$676**	**$663**	**$664**	**$789**

The 2028/29 CT CONE estimates for Rest of RTO are 47% higher in real terms compared in 2028$ than those calculated using the 2022 PJM CONE Affidavit model.[46] Major cost drivers include tightening markets for major equipment and labor, the resulting longer project timelines, a higher ATWACC, and more capital costs due to the switch to a dual-fuel CT. These effects are partially offset by the decrease in CONE from lower fixed O&M costs due to the switch from a firm fuel gas transportation contract to a dual-fuel configuration. Figure 9 below illustrates these

46 Based on the 2022 Rest of RTO CONE of $432/MW-day for a plant with a June 2026 COD, escalated two years at the long-term inflation rate assumed in the 2022 PJM CONE Study. CT CONE was calculated with the CONE model used in the 2022 PJM CONE Affidavit. See Samuel A. Newell, John M. Hagerty, and Sang H. Gang, "Affidavit of Samuel A. Newell, John M. Hagerty, and Sang H. Gang on Behalf of PJM Interconnection, L.L.C." ("2022 PJM CONE Affidavit") filed before the Federal Energy Regulatory Commission September 30, 2022, Docket No. ER22-2984-000.

drivers and the resulting changes in CONE. We present these in real terms by escalating the 2022 CT CONE estimate from 2026 to 2028 dollars.

FIGURE 9: DRIVERS OF INCREASED CT CONE (REST OF RTO, $/MW-DAY ICAP, NOMINAL$ FOR JUNE 2028 ONLINE YEAR)



V. CONE Estimate for Natural Gas-Fired Combined-Cycle Plants

A. Technical Specifications

We used the same approach discussed in Section IV.B for the CT to determine the technical specifications for the CC. This includes the assumption of a 20-year economic life in all CONE Areas except for ComEd, which has an economic life of 16.5 years due to CEJA. Consistent with the observations for the CT described in Section IV.A, the CC uses a GE 7HA.03 turbine rather than the smaller 7HA.02 used in the 2022 PJM CONE Study. The technical specifications for the CC shown in Table 14 are based on the assumptions discussed later in this section.

TABLE 14: CC TECHNICAL SPECIFICATIONS

Plant Characteristic	Specification
Turbine Model	GE 7HA.03 (CT), STF-A650 (ST)
Configuration	2 Trains of 1×1 Single Shaft
Cooling System	Dry Air-Cooled Condenser
Power Augmentation	Evaporative Cooling; no inlet chillers
Net Summer ICAP (MW)	
Without Duct Firing	1,125 / 1,127 / 1,112 / 1,100 / 1,129*
With Duct Firing	1,289 / 1,289 / 1,276 / 1,264 / 1,294*
Net Heat Rate (HHV in Btu/kWh)	
Without Duct Firing	6,318 / 6,345 / 6,303 / 6,314 / 6,294*
With Duct Firing	6,595 / 6,625 / 6,583 / 6,600 / 6,569*
Environmental Controls	
CO Catalyst	Yes
Selective Catalytic Reduction	Yes
Dual-Fuel Capability	No
Firm Gas Transportation Contract	Yes
Special Structural Requirements	No
Blackstart Capability	None
On-Site Gas Compression	None

Sources and Notes: *For EMAAC, SWMAAC, Rest of RTO, WMAAC, and ComEd, respectively.

B. Capital Costs

Capital costs for the CC were estimated using the same method as for the CT in Section IV.B, with a few exceptions described later in this section. Based on the technical specifications for the CC described above, the total capital costs for plants with an online date of June 1, 2028 are shown in Table 15. Comparisons to costs from the 2022 PJM CONE Study are expressed in 2025 dollars to align them with the basis of our initial cost estimates. All costs presented in this section are expressed in ICAP terms unless specified otherwise.

TABLE 15: CAPITAL COSTS FOR A CC
(NOMINAL$ FOR JUNE 2028 ONLINE YEAR)

Capital Costs (in $millions)	Escalated Overnight Capital Costs: 06/2028				
Units	Nominal$	Nominal$	Nominal$	Nominal$	Nominal$
	EMAAC	SWMAAC	Rest of RTO	WMAAC	COMED
Net Summer Capacity (MW)	*1,289*	*1,289*	*1,276*	*1,264*	*1,294*
OFE + EPC Costs	**$1,684**	**$1,555**	**$1,556**	**$1,608**	**$1,831**
Owner-Furnished Equipment (OFE)					
Gas Turbines	$296	$296	$296	$296	$296
HRSG / SCR	$120	$120	$120	$120	$120
Steam Turbines	$126	$126	$126	$126	$126
Sales Tax	$0	$0	$0	$0	$34
Engineering, Procurement, and Construction (EPC) Costs					
Equipment					
Condenser	$72	$72	$72	$72	$72
Other Equipment	$104	$104	$104	$104	$104
Construction Labor	$497	$395	$396	$437	$570
Other Labor	$75	$70	$70	$72	$78
Materials	$102	$102	$102	$102	$102
Sales Tax	$0	$0	$0	$0	$11
EPC Contractor Fee	$139	$128	$129	$133	$151
EPC Contingency	$153	$141	$141	$146	$166
Non-EPC Costs	**$273**	**$265**	**$255**	**$256**	**$302**
Project Development	$84	$78	$78	$80	$92
Mobilization and Start-Up	$17	$16	$16	$16	$18
Non-Fuel Inventories	$8	$8	$8	$8	$9
Emission Reduction Credits	$2	$2	$2	$2	$2
Net Start-Up Fuel Costs	-$25	-$21	-$26	-$31	-$12
Electrical Interconnection	$72	$72	$71	$70	$72
Gas Interconnection	$49	$49	$49	$49	$49
Land	$6	$6	$3	$6	$7
Owner's Contingency	$17	$17	$16	$16	$19
Financing Fees	$42	$39	$39	$40	$46
Total Overnight Capital Costs	**$1,956**	**$1,820**	**$1,811**	**$1,864**	**$2,133**
Overnight Capital Costs ($/kW)	**$1,517**	**$1,411**	**$1,419**	**$1,476**	**$1,649**
Installed Cost ($/kW)	**$1,929**	**$1,795**	**$1,806**	**$1,877**	**$2,096**

The following capital costs were estimated for the CC:

OFE AND EPC COSTS

- OFE: Estimated using the same method as for the CT described in Section IV.B.1. Due to the tight market for turbines and other major equipment paired with the current high-demand environment for dispatchable power, turbine costs, which now represent 16% of total overnight capital costs, have increased from $137/kW to $234/kW in 2025 dollars, 71% in real terms, since the 2022 PJM CONE Study. Since August 2024, turbine costs have increased by 28% from $183/kW to $234/kW in 2025 dollars.[47]

- Equipment: Estimated using the same method as for the CT described in Section IV.B.1.
- Construction and Other Labor: Estimated using the same method as for the CT described in Section IV.B.1. Increased competition for skilled labor in a tightening market has increased construction labor costs from $262/kW to $305/kW in 2025 dollars, 17% in real terms, since the 2022 PJM CONE Study.[48]
- Materials: Estimated using the same method as for the CT described in Section IV.B.1.
- Sales Tax: Calculated using the same method as for the CT described in Section IV.B.1.
- EPC Contractor Fee: Calculated as 10% of OFE and EPC costs, as with CTs as described in Section IV.B.1.

  EPC Contingency: Calculated as 10% of OFE and EPC costs, inclusive of the EPC contractor fee, as with CTs as described in Section IV.B.1.

NON-EPC COSTS

- Project Development: Calculated as 5% of OFE and EPC costs, as with CTs as described in Section IV.B.2.
- Mobilization and Start-up: Calculated as 1% of OFE and EPC costs, as with CTs as described in Section IV.B.2.
- Non-fuel Inventories: Calculated as 0.5% of OFE and EPC costs, as with CTs as described in Section IV.B.2.
- Emission Reduction Credits: Emission Reduction Credits (ERCs) must be obtained for new facilities located in non-attainment areas. ERCs may be required for projects located in the ozone transport region even if the specific location is in an area classified as "in attainment." ERCs must be obtained prior to the start of operation of the unit and are typically valid for the life of the project; thus, ERC costs are considered to be a one-time expense. ERCs are

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47 Based on costs in CONE Area 3. Current costs of $234/kW are pre-escalation and in 2025$. 2022 PJM CONE Affidavit turbine costs of $141/kW in 2026$ were deflated from June 2026 to January 2025 using the long-term inflation rate assumed in the 2022 PJM CONE Study. August 2024 comparison is based on November 2024 preliminary CONE estimates, which were derived from S&L cost estimates as of August 2024. See Newell et al, Sixth Review of PJM's RPM VRR Curve Parameters Preliminary Gross CONE and E&AS Methodology, November 26, 2024.

48 See footnote 47 above. 2022 PJM CONE Affidavit Construction Labor costs are $270/kW in 2026$.

determined based on the annual NO_x and volatile organic compounds (VOC) emissions of the facility and required offset ratio that depends on the specific plant location. Similar to our assumption from the 2022 PJM CONE study, we assumed a cost of $5,600/ton for all CONE Areas and an offset ratio of 1.15 for NO_x and VOC emissions, resulting in a one-time cost of $2.2 million (in 2025 dollars) prior to beginning operation of the CC plants. While ERC costs are likely to vary by project and by location, there is insufficient publicly available cost data to support a more refined cost estimate for each CONE Area.

ERCs are not included in our CONE estimate for CT plants, assuming they operate less and do not exceed the New Source Review (NSR) threshold. If they did need to buy ERCs, the costs would be even smaller than for CCs.

- Net Start-up Fuel Costs: Estimated using the same method as for the CT described in Section IV.B.2, although resulting in a net negative cost, or benefit for CCs, due to positive spark spreads captured in the wholesale market. More detail on this calculation is included in Appendix A.
- Electrical Interconnection: Estimated using the same method as for the CT described in Section IV.B.2. Electrical interconnection costs have increased from $22/kW to $55/kW in 2025 dollars, or 150% in real terms, since the 2022 PJM CONE Study.[49] More detail on this calculation is included in Appendix A.
- Gas Interconnection: Since the CC case includes two combustion turbines (one for each 1×1 train) as opposed to the 1×0 configuration for the CT, a larger pipeline is assumed to accommodate the greater volumetric flow. Based on S&L's experience with similar projects, CCs need a pipeline diameter between 20 and 24 inches. Using the methods described in Section IV.B.2, gas interconnection costs for the CC are $9.7 million/mile in 2025 dollars for a 5-mile lateral, inclusive of meter station costs. This results in a total gas interconnection cost of $48.4 million for the CC in 2025 dollars. The gas interconnection costs are escalated to the midpoint of the project development period to produce the costs shown in Table 15. See Appendix A for more detail on the gas interconnection cost calculation and escalation.
- Land: Similar to the CT, the cost of land was derived from current asking prices for vacant industrial land greater than 10 acres for sale in each county per CONE Area. 60 acres of land are required for the CC. The land costs are escalated to the midpoint of the project development period to produce the land costs shown in Table 15. See Appendix A for more detail.

[49] See footnote 47 above. 2022 PJM CONE Affidavit Electrical Interconnection costs are $23/kW in 2026$.

- Owner's Contingency: Calculated at 8% of all other non-EPC costs, as with CTs as described in Section IV.B.2.
- Financing Fees: Calculated as 4% of all other non-EPC costs, as with CTs as described in Section IV.B.2.

CAPITAL COST ESCALATION

The CC capital costs were escalated to nominal dollars for a June 2028 online date using the same methods as for the CT, which are described above in Section IV.B.3. S&L developed monthly capital drawdown schedules over the project development period of 50 months for CCs. The tight market for turbines and other major components has lengthened the project duration by 18 months since the 2022 PJM CONE Study. This means that a CC with a planned COD of June 1, 2028 would need to have begun development on April 1, 2024. The Equipment Contract Lock-in Date, like with the CT, is at month 5 of the project timeline which would be September 1, 2024. Since this is before our January 2025 cost estimates, OFE and Major Equipment costs are deescalated from January 2025 to September 2024 using the same inflation curve.

The CC does not have fuel inventories since it is not a dual-fuel unit but does have Net Start-up Fuel costs which are similarly not escalated like for the CT since they are estimated for June 2028. All other capital costs are escalated to the Project Development Midpoint (August 2025) for the CC using inflation. Escalations to the equipment price lock-in date and midpoint of the project development period are explained in further detail in Appendix A. The capital drawdown schedule is used to calculate capital carrying costs during development to arrive at a complete Installed Cost.

C. Operations and Maintenance Costs

Table 16 summarizes the fixed and variable O&M for CCs with an online date of June 1, 2028. Additional details on Plant Operation and Maintenance, Insurance and Asset Management Costs, Property Taxes, and Working Capital Financing can be found in the above Section IV.C.1. Unlike for CTs that have a lower expected capacity factor, the CC are assumed to undergo major maintenance cycles tied to the factored fired-hours maintenance cycles. Therefore, variable O&M costs are assumed to be directly proportional to plant generating output in $/MWh terms, consistent with past CONE studies. Comparisons to costs from the 2022 PJM CONE Study are expressed in 2025 dollars to align them with the basis of our initial cost estimates. All costs presented in this section are expressed in ICAP terms unless specified otherwise.

TABLE 16: FIRST-YEAR AND LEVELIZED FIXED O&M COSTS FOR A CC (NOMINAL$ FOR JUNE 2028 ONLINE YEAR)

	Escalated O&M Costs: 06/2028				
Units	Nominal$	Nominal$	Nominal$	Nominal$	Nominal$
CONE Area	**EMAAC**	**SWMAAC**	**Rest of RTO**	**WMAAC**	**COMED**
Net Summer Capacity (MW)	*1,289*	*1,289*	*1,276*	*1,264*	*1,294*
Fixed First Year O&M ($ million/year)					
LTSA Fixed Payments	$1.1	$1.1	$1.1	$1.1	$1.1
Labor	$5.3	$5.7	$3.9	$4.7	$5.1
Maintenance and Minor Repairs	$7.8	$8.0	$7.0	$7.5	$7.7
Administrative and General	$1.6	$1.6	$1.6	$1.6	$1.6
Asset Management	$1.7	$1.8	$1.2	$1.4	$1.6
Property Taxes	$3.3	$22.9	$12.6	$4.2	$3.1
Insurance	$11.7	$10.9	$10.9	$11.2	$12.8
Firm Gas Contract	$10.7	$20.4	$26.2	$18.7	$8.6
Interest on Working Capital	$0.6	$0.5	$0.5	$0.5	$0.6
Total Fixed First Year O&M ($ million/year)	**$44.0**	**$73.0**	**$65.1**	**$50.9**	**$42.3**
Total Fixed First Year O&M ($/kW-yr)	**$34.1**	**$56.6**	**$51.0**	**$40.3**	**$32.7**
Levelized Fixed O&M ($/kW-yr)	**$40.7**	**$60.5**	**$57.5**	**$48.1**	**$38.2**
Variable O&M ($/MWh)					
Major Maintenance - Hours Based	$1.9	$1.9	$1.9	$1.9	$1.9
Consumables, Waste Disposal, Other VOM	$0.8	$0.8	$0.8	$0.8	$0.8
Total Variable O&M ($/MWh)	**$2.6**	**$2.6**	**$2.7**	**$2.7**	**$2.6**

The following fixed O&M costs were estimated for the CC:

- LTSA Fixed Payments: Calculated using the same method as for the CT described in Section IV.C.1.
- Labor: Calculated using the same method as for the CT described in Section IV.C.1.
- Maintenance and Minor Repairs: Calculated using the same method as for the CT described in Section IV.C.1.
- Administrative and General: Calculated using the same method as for the CT described in Section IV.C.1.
- Asset Management: Calculated using the same method as for the CT described in Section IV.C.1.
- Property Taxes: Calculated using the same method as for the CT described in Section IV.C.1. Property tax costs have increased from $8.4/kW to $9.8/kW in 2025 dollars, or 17% in real terms, since the 2022 PJM CONE Study.[50] More detail on this calculation is included in Appendix A.

[50] See footnote 47 above. 2022 PJM CONE Affidavit property tax costs are $8.6/kW in 2026$.

- Insurance: Calculated as 0.6% of overnight capital costs per year, as with CTs as described in Section IV.C.1.
- Firm Gas Transportation Contract: Unlike the dual-fuel CT, the CC generally sign a firm gas transportation contract to secure its fuel supply, as established in the 2022 PJM CONE Study. Firm gas transportation service costs for the CC are again estimated based on rate schedules for pipelines servicing each CONE Area, assuming the CC will commit to procuring firm gas transportation on an annual basis. Firm gas costs, which represent 40% of first-year fixed O&M costs, have increased from $14/kW to $19/kW in 2025 dollars, or 35% in real terms, since the 2022 PJM CONE Study.[51] Additional details on calculating the cost of acquiring firm transportation service are included in Appendix A.
- Interest on Working Capital: Calculated using the same method as for the CT described in Section IV.C.1, maintaining the assumption that the working capital requirement during operation is 0.5% of overnight capital costs with a short-term debt rate of 5.8%.

Variable O&M costs are directly proportional to plant generating output, and include the SCR catalyst and ammonia, CO oxidation catalyst, water, and other chemicals and consumables. Variable O&M costs are expressed in $/MWh terms for the CC, consistent with past CONE studies.

The January 2025 O&M cost estimates were escalated to nominal dollars for a June 2028 online date by the same real escalation rates used to escalate the overnight capital costs in Section V.B. O&M costs are escalated based on the expected inflation assumptions described in Appendix A and are inflated to the middle of each year of operation.

D. CC CONE Estimates

The Gross CONE values shown below represent the total annual net revenues that a new CC resource would need to earn on average to recover its capital and fixed O&M costs, given reasonable expectations about future cost recovery over the plant's economic life. Table 17 summarizes the Gross CONE calculation, including capital costs, fixed O&M costs, and carrying costs in the form of the capital charge rate. The estimated level-nominal CONE for a CC ranges from $813/MW-day ICAP in Rest of RTO to $953/MW-day ICAP in ComEd. All costs presented in this section are expressed in ICAP terms unless specified otherwise.

[51] See footnote 47 above. 2022 PJM CONE Affidavit firm gas costs are $14/kW in 2026$.

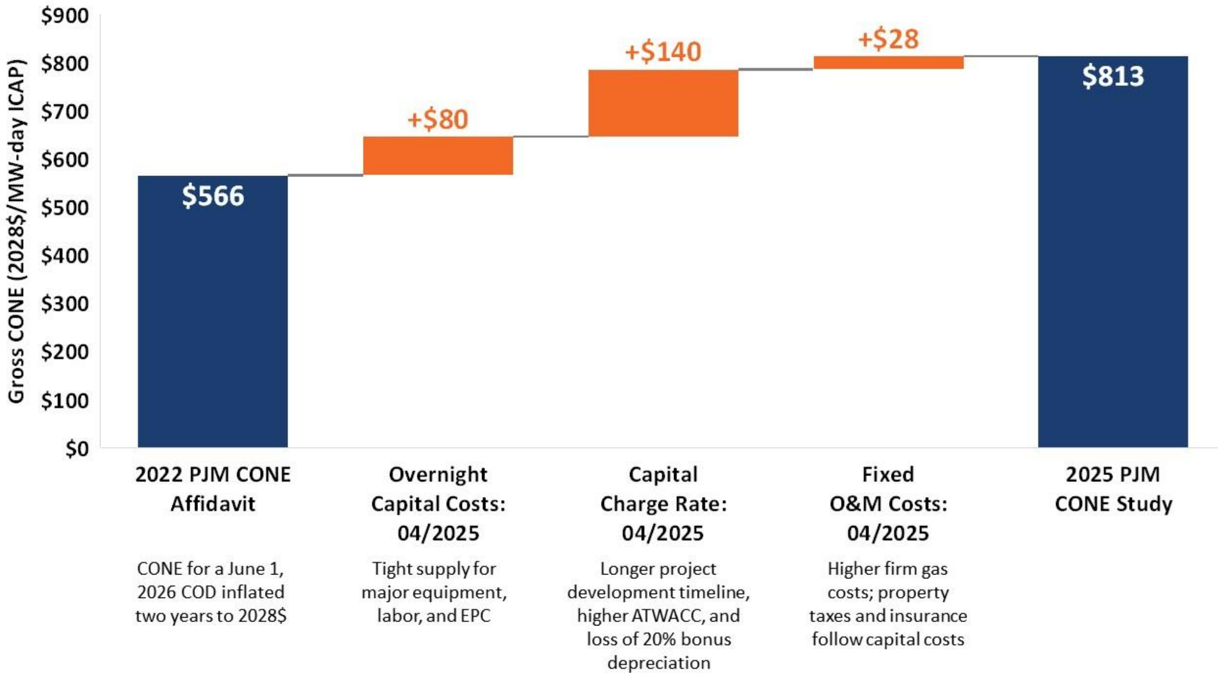
TABLE 17: CONE CALCULATION FOR A CC (NOMINAL$ FOR JUNE 2028 ONLINE YEAR IN ICAP TERMS)

CONE Area				EMAAC	SWMAAC	Rest of RTO	WMAAC	COMED
Net Summer Capacity	MW	[1]		1,289	1,289	1,276	1,264	1,294
After-Tax WACC	%	[2]		9.5%	9.5%	9.5%	9.5%	9.5%
Capital Charge Rate	%	[3]		17.0%	16.9%	16.9%	16.9%	18.8%
Capital Costs								
Overnight Cost	Nominal $ million	[4]		$1,956	$1,820	$1,811	$1,864	$2,133
Overnight Cost	Nominal $/kW	[5]	[4] x 1000 / [1]	$1,517	$1,411	$1,419	$1,476	$1,649
Installed Cost	Nominal $ million	[6]		$2,487	$2,314	$2,304	$2,372	$2,711
Installed Cost	Nominal $/kW	[7]	[6] x 1000 / [1]	$1,929	$1,795	$1,806	$1,877	$2,096
Levelized Capital Cost	Nominal $/kW-yr	[8]	[5] x [3]	$257	$238	$239	$249	$310
O&M Costs								
First Year FOM	Nominal $ million/yr	[9]		$44	$73	$65	$51	$43
Levelized FOM	Nominal $/kW-yr	[10]		$41	$61	$57	$48	$38
Levelized CONE	**Nominal $/kW-yr**	**[11]**	**[8] + [10]**	**$298**	**$299**	**$297**	**$297**	**$348**
Levelized CONE	**Nominal $/MW-day**	**[12]**	**[11] x 1000/365**	**$816**	**$819**	**$813**	**$814**	**$953**

The 2028/29 CC CONE estimates for Rest of RTO are 44% higher in real terms comparing in 2028$ than those calculated in the 2022 PJM CONE Affidavit.[52] Major cost drivers include tightening markets for major equipment and labor, the resulting longer project timelines, and a higher ATWACC. Figure 10 below illustrates these drivers and the resulting changes in CONE. We present these in real terms by escalating the 2022 CC CONE estimate from 2026 to 2028 dollars.

52 Based on the 2022 Rest of RTO CONE of $542/MW-day for a plant with a June 2026 COD, escalated two years at the long-term inflation rate assumed in the 2022 PJM CONE Study. See 2022 PJM CONE Affidavit.

FIGURE 10: DRIVERS OF INCREASED CC CONE
(REST OF RTO, $/MW-DAY ICAP, NOMINAL$ FOR JUNE 2028 ONLINE YEAR)



VI. CONE Estimate for 4-Hour Battery Storage Systems

A. Technical Specifications

The technical specifications for the 4-hour BESS were developed using a similar approach to the 2022 PJM CONE Study, resulting in the specifications listed in Table 18 below. The facility is sized for 200 MW at the point of interconnection (POI), based on a review of the capacity of battery storage facilities currently in the PJM interconnection queue, utilizing lithium-ion battery chemistry and a containerized installation.

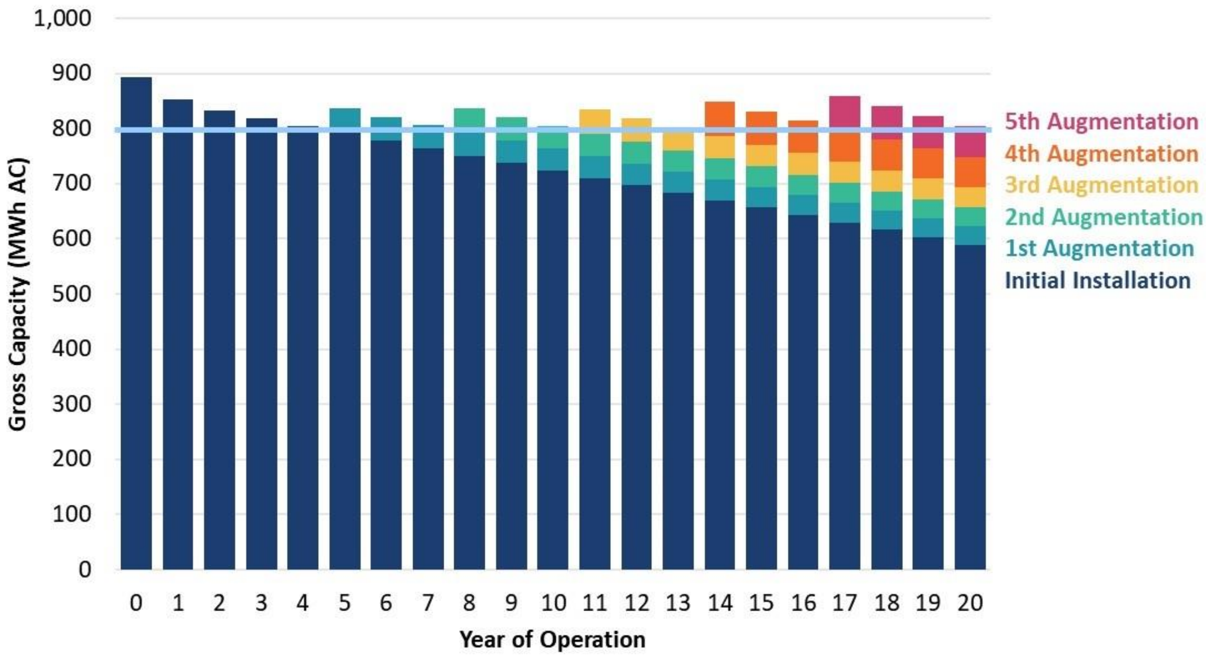
TABLE 18: BESS TECHNICAL SPECIFICATIONS

Plant Characteristic	Specification
Chemistry	Lithium-Ion
Installation Configuration	Containerized
Rated Output Power (at POI)	200 MW-ac
AC Losses	4.6%
Gross Inverter Output Requirement	210 MW-ac
Inverter Losses	1.6%
Capacity Degradation Loss (at first Augmentation)	10.28%
Minimum State of Charge	5.0%
Duration	4 Hours
Installed Energy Capacity	1,009 MWh-dc
Initial MWh Overbuild	26.09%
Annual Capacity Degradation	4.5% in Year 1, then 1.55% per year
Augmentations	Years 5, 8, 11, 14, and 17
Use Case	Daily Cycling
Economic Life	20 years
Salvage Value	$0

S&L estimates that BESS energy capacity (in MWh or duration at full power) degrades by 4.5% in the first year and 1.55% in subsequent years, assuming daily cycling and a 5% minimum state of charge. Developers are currently using a range of approaches to maintain sufficient capacity to provide the rated AC output at the POI over a four-hour period, including overbuilding the initial capacity and augmenting the capacity in future years. Overbuilding the initial capacity provides the developer greater cost certainty and reduces the frequency and costs of frequent augmentation events. On the other hand, a smaller overbuild defers capital expenditures to future augmentations and reduces the initial capital costs of the facility to potentially allow the owner to take advantage of declining module costs, depending on future cost trends.

As shown in Figure 11, to account for degradation of the energy capacity, this cost estimate assumes that the facility will include an initial 26% overbuild with augmentations planned for Years 5, 8, 11, 14, and 17. The augmentations also increase in size over time—the first three augmentations are sized at 45 MWh, whereas the last two are 62 MWh shown later in Figure 13. Based on S&L's recent project experience, developers are increasingly opting for a larger initial overbuild to maximize the benefit of the Investment Tax Credit (ITC) while planning for more frequent and larger augmentations later in the project's life to capture expected future real cost declines in batteries.

FIGURE 11: BESS ENERGY CAPACITY OVER 20-YEAR LIFE (REST OF RTO, MWH AC)



B. Capital Costs

Similar to the CT and the CC, we developed bottom-up estimates for capital costs for the BESS. BESS capital cost estimates were based on vendor quotes and S&L's internal datasets from ongoing and completed BESS projects of similar complexity and size. These datasets include detailed developer project models, EPC bid data, and executed contract values for BESS equipment. Due to the rapidly changing cost environment for BESS, estimates focused on capturing recent pricing in battery supply, using extensive up-to-date data from January and February 2025 for actual projects to come online over the next two years. For the EPC, development, and other costs required to execute the project, reference data was used in addition to parametric cost modeling, comprising data from similarly sized projects that were recently constructed or are currently in-development. EPC bids from unexecuted agreements were used to derive indicative escalation rates for certain components. We supplemented this by speaking with BESS developers and integrators to ground our estimates in most the recent cost data and tariff environment.

Based on the technical specifications for the BESS described above, the total capital costs for plants with an online date of June 1, 2028 are shown in Table 19. Comparisons to costs from the 2022 PJM CONE Study are expressed in 2025 dollars to align them with the basis of our initial cost estimates. All costs presented in this section are expressed in ICAP terms unless specified otherwise.

TABLE 19: CAPITAL COSTS FOR A BESS (NOMINAL$ FOR JUNE 2028 ONLINE YEAR)

Capital Costs (in $millions)	Escalated Overnight Capital Costs: 06/2028				
Units	Nominal$	Nominal$	Nominal$	Nominal$	Nominal$
CONE Area	**EMAAC**	**SWMAAC**	**Rest of RTO**	**WMAAC**	**COMED**
Net Summer Capacity (MW)	*200*	*200*	*200*	*200*	*200*
Engineering, Procurement and Construction (EPC)	**$321**	**$306**	**$306**	**$312**	**$348**
BESS Equipment					
Batteries and Enclosures	$181	$181	$181	$181	$181
PCS and BOP Equipment	$51	$51	$51	$51	$51
Project Management	$13	$12	$12	$13	$13
Construction & Materials	$76	$61	$62	$67	$88
Sales Tax	$0	$0	$0	$0	$15
Non-EPC Costs	**$46**	**$45**	**$44**	**$45**	**$48**
Project Development	$16	$15	$15	$16	$17
Mobilization and Start-Up	$3	$3	$3	$3	$3
Owner's Contingency	$12	$12	$12	$12	$12
Land	$1	$1	$1	$1	$2
Electrical Interconnection	$12	$12	$12	$12	$12
Financing Fees	$2	$2	$2	$2	$2
Total Overnight Capital Costs	**$366**	**$351**	**$350**	**$357**	**$396**
Overnight Capital Costs ($/kW)	**$1,832**	**$1,753**	**$1,750**	**$1,784**	**$1,980**
Installed Cost ($/kW)	**$1,987**	**$1,901**	**$1,898**	**$1,935**	**$2,146**

The following capital costs were estimated for the BESS:

EPC COSTS

- Batteries and Enclosures: This is the largest share of plant costs at 52% of overnight costs. Cost estimates are derived from S&L's detailed data on numerous current projects under development and corroborated through interviews with battery developers and integrators to ensure that estimated costs are accurate and up-to-date.

  Batteries and enclosures are generally imported from China and are therefore subject to tariffs, but more limited domestic substitutes tend not to cost any less. The costs reported in this study assume a 48.4% total tariff comprised of a 25% Section 301 tariff, a 3.4% duty, and a 20% tariff from the current administration *before* the further increases ordered on April 2, 2025.[53] All estimates, even from earlier in 2025 when tariffs were lower are conformed to this level by applying tariff adjustment provisions in the vendor contracts in S&L's projects. Equation 1 could be used to extend our estimates to more recent and subsequent changes in tariffs.

EQUATION 1: FORMULA TO ADJUST CURRENT COSTS TO REFLECT FUTURE TARIFFS

Updated Overnight Batteries and Enclosures Cost = Anticipated Total Tariff x (Total Batteries and Enclosures Cost – Freight Cost – Medium-Voltage Transformer Cost – Reference Tariff Cost) + (Total Batteries and Enclosures Cost – Reference Tariff Cost)

WHERE:

Anticipated Total Tariff: The size of the expected future tariff in percentage terms

Total Batteries and Enclosures Cost: $181 Million in 2028$, from **Table 21**

Freight Cost: $9.5 million in 2028$, or the cost to transport the batteries from the port of entry to the site

Medium-Voltage Transformer Cost: $10.5 million in 2028$, or the cost of medium-voltage transformers which are not subject to tariffs

Reference Tariff Costs $52.5 million in 2028$, or the total tariff cost component of the current Batteries and Enclosures Cost

Despite the assumed 48.4% tariffs, overall overnight costs of batteries and enclosures have decreased 12% in real terms since the 2022 PJM CONE Study, from $980/kW to $858/kW in 2025 dollars.[54] This decrease is due to improved manufacturing, larger battery cell sizes and energy density, and economies of scale, and a current supply glut.

- PCS and BOP Equipment: Power Conversion System (PCS) and Balance of Plant (BOP) equipment costs are estimated by S&L using their proprietary cost database and experience with similar projects. PCS and BOP equipment costs have increased from $147/kW to $242/kW in 2025 dollars, or 65% in real terms, since the 2022 PJM CONE Study.[55]

[53] Office of the United States Trade Representative, Notice of Modification: China's Acts, Policies and Practices Related to Technology Transfer, Intellectual Property and Innovation, September 18, 2024; U.S. Customs and Border Protection, N312651: The tariff classification of lithium-ion battery packs from China, July 7, 2020; The White House, Further Amendment to Duties Addressing the Synthetic Opioid Supply Chain in The People's Republic of China, March 3, 2025.

[54] Based on costs in CONE Area 3. Current costs of $858/kW are pre-escalation and in 2025$. 2022 PJM CONE Affidavit batteries and enclosures costs of $1,011/kW in 2026$ were deflated from June 2026 to January 2025 years using the long-term inflation rate assumed in the 2022 PJM CONE Study.

[55] See footnote 54 above. 2022 PJM CONE Affidavit PCS and BOP Equipment costs are $151/kW in 2026$.

- Project Management: Estimated by S&L based on their proprietary project cost database and experience with similar projects.
- Construction & Materials: Calculated using the same method as for the CT described in Section IV.B.1. Construction and materials costs have increased from $251/kW to $289/kW in 2025 dollars, or 15% in real terms, since the 2022 PJM CONE Study.[56]

NON-EPC COSTS

- Project Development: Calculated at 5% of OFE and EPC costs, based on S&L's proprietary project cost database and experience with similar projects.
- Mobilization and Start-up: Calculated at 1% of OFE and EPC costs, based on S&L's proprietary project cost database and experience with similar projects.
- Owners Contingency: Calculated at 5% of BESS equipment costs, based on S&L's proprietary project cost database and experience with similar projects.
- Land: Similar to the CT, the cost of land was derived from current asking prices for vacant industrial land greater than 10 acres for sale in each county per CONE Area. 12 acres of land are required for the BESS. The land costs are escalated to the midpoint of the project development period to produce the land costs shown in Table 19. See Appendix A for more detail.
- Electrical Interconnection: Estimated using the same method as for the CT described in Section IV.B.2. Electrical interconnection costs have increased from $20/kW to $55/kW in 2025 dollars, 174% in real terms, since the 2022 PJM CONE Study.[57] More detail on this calculation is included in Appendix A.
- Financing Fees: Calculated at 4% of all other non-EPC costs, based on S&L's proprietary project cost database and experience with similar projects.

CAPITAL COST ESCALATION

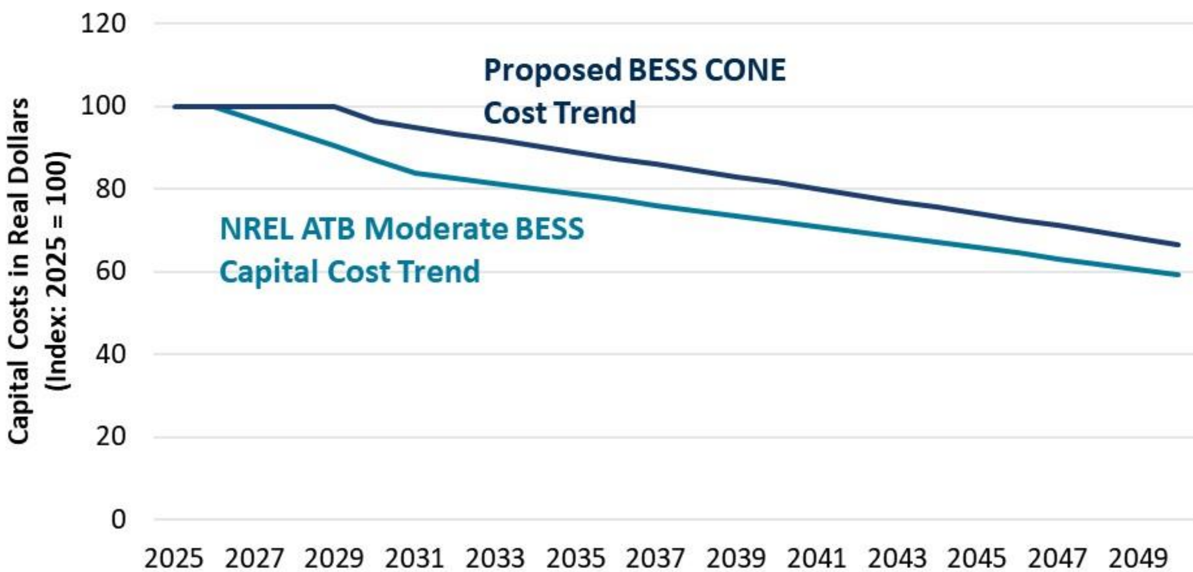
To estimate costs for a June 2028 COD, some escalation is required (and further escalation is required for assessing augmentation costs, in the next section). BESS equipment costs are assumed stay constant for five years in real terms, then follow the real cost decline trend from

[56] See footnote 54 above. 2022 PJM CONE Affidavit Construction and Materials costs are $259/kW in 2026$.

[57] See footnote 54 above. 2022 PJM CONE Affidavit Electrical Interconnection costs are $21/kW in 2026 dollars.

the NREL ATB as shown in Figure 12.[58] This assumption is based on discussions with S&L and battery developers, who believe that pricing trends are highly uncertain, but that continued cost declines from learning may be offset by increases in battery components that may currently be temporarily depressed due to a short-term supply glut. Eventually the overall cost decline should continue with improvements in technology, plant design, and construction.

FIGURE 12: PROJECTED BESS COST TRENDS (INDEXED TO REAL COSTS PER KW IN JANUARY 2025)



BESS capital costs were escalated to nominal dollars for a June 2028 online date using the same methods as for the CT and CC, which are described above in Section IV.B.3. S&L developed monthly capital drawdown schedules over the project development period of 20 months for the BESS. The tighter market for equipment and labor has lengthened the project duration by 4 months since the 2022 PJM CONE Study. This means that a BESS with a planned COD of June 1, 2028 will need to begin development on October 1, 2026. The Equipment Contract Lock-in Date, unlike with the CT and CC, is at month 4 of the project timeline, which would be August 1, 2027. All other capital costs are escalated to the Project Development Midpoint (August 2027) for the BESS using inflation. Escalations to the equipment price lock-in date and midpoint of project development are explained in further detail in Appendix A. The capital drawdown schedule is used to calculate debt and equity costs during development to arrive at a complete Installed Cost.

58 National Renewable Energy Laboratory, Electricity Annual Technology Baseline (ATB), July 23, 2024. 4-hour BESS, overnight capital costs, moderate case.

C. Operations and Maintenance Costs

Once the BESS plant enters commercial operation, the plant owners incur fixed O&M costs each year. While some O&M costs may vary with operation, these estimates were prepared with static operational assumptions and commensurate auxiliary loads, degradation, and augmentation profiles. Variable O&M costs are assumed to be zero. Table 20 summarizes the annual fixed O&M costs and augmentation costs for BESS with an online date of June 1, 2028. Comparisons to costs from the 2022 PJM CONE Study are expressed in 2025 dollars to align them with the basis of our initial cost estimates. All costs presented in this section are expressed in ICAP terms unless specified otherwise.

TABLE 20: FIRST-YEAR AND LEVELIZED FIXED COSTS FOR A BESS (NOMINAL$ FOR JUNE 2028 ONLINE YEAR)

O&M Costs	**Escalated O&M Costs: 06/2028**				
Units	Nominal$	Nominal$	Nominal$	Nominal$	Nominal$
	1	**2**	**3**	**4**	**5**
CONE Area	**EMAAC**	**SWMAAC**	**Rest of RTO**	**WMAAC**	**COMED**
Net Summer Capacity (MW)	*200*	*200*	*200*	*200*	*200*
Fixed O&M ($ million)					
O&M Contract Fixed Payments	$3.8	$3.8	$3.8	$3.8	$3.8
BOP and Substation O&M	$0.2	$0.2	$0.2	$0.2	$0.2
Station Load / Aux Load	$0.7	$0.7	$0.5	$0.6	$0.6
Miscellaneous Owner Costs	$0.5	$0.5	$0.4	$0.4	$0.5
Operating Insurance	$1.8	$1.8	$1.8	$1.8	$2.0
Property Taxes	$2.3	$4.5	$3.2	$2.6	$2.6
Interest on Working Capital	$0.1	$0.1	$0.1	$0.1	$0.1
First-Year Fixed O&M ($million/year)	**$9.5**	**$11.6**	**$9.9**	**$9.6**	**$9.8**
First-Year Fixed O&M ($/kW-yr)	**$47.4**	**$58.1**	**$49.4**	**$47.8**	**$49.0**
Levelized Fixed O&M ($/kW-yr)	**$56.7**	**$61.7**	**$55.4**	**$57.1**	**$58.6**
Augmentation Costs					
Levelized Augmentation Costs ($/kW-yr)	**$15.2**	**$14.3**	**$14.3**	**$14.6**	**$16.0**
Levelized O&M + Augmentation					
Total Levelized Fixed Costs ($/kW-yr)	**$71.8**	**$75.9**	**$69.7**	**$71.7**	**$74.5**

The following fixed O&M costs were estimated for the BESS:

- O&M Contract Fixed Payments: Estimated by S&L experience with recent LTSA terms and developers' financial models.
- BOP and Substation O&M: Same as above.
- Station Load / Aux Load: Same as above.
- Miscellaneous Owner Costs: Same as above.

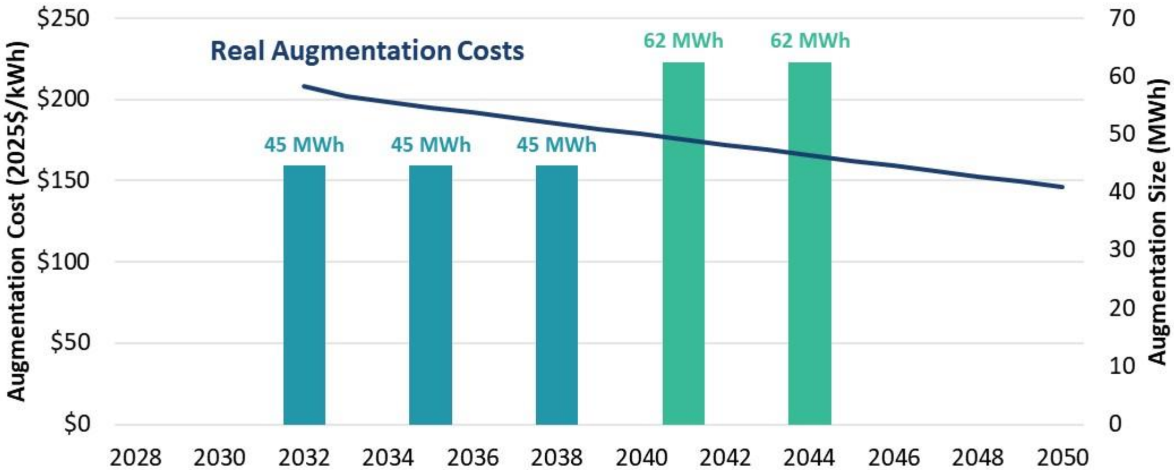
- Operating Insurance: Same as above. Insurance is typically 0.5% of overnight capital costs per year.
- Property Taxes: Calculated using the same method as for the CT described in Section IV.C.1 IV.C.1. Property Taxes costs have increased from $10/kW to $15/kW in 2025 dollars, or 45% in real terms, since the 2022 PJM CONE Study.[59] More detail on this calculation is included in Appendix A.
- Interest on Working Capital: Calculated using the same method as for the CT described in Section IV.C.1, assuming the working capital requirement is 0.5% of overnight capital costs and that the short-term debt rate is 5.8%.

The January 2025 fixed O&M cost estimates were escalated from 2025 to nominal dollars for a June 2028 online date by the same real escalation rates used to escalate the overnight capital costs in Section IV.B. O&M costs are escalated based on the expected inflation assumptions described in Appendix A and are inflated to the middle of each year of operation.

The levelized augmentation costs in Table 20 were calculated as the difference between the Gross CONE for a BESS with augmentation and the Gross CONE for a BESS without any augmentation. As discussed above in Section IV.A, the BESS will have five capacity augmentations over the course of its life to compensate for degradation and maintain rated capacity. S&L provided the total real cost of the first augmentation in each CONE Area in nominal dollars for January 2025, from which we derived a cost per-MWh. We then applied the modified NREL ATB cost trend in Figure 12 above to derive the real cost-per MWh in each subsequent year of augmentation. To calculate the cost of each augmentation, we multiplied our derived real cost per-MWh in each year by the size of the augmentation, then escalated the total cost to nominal dollars in the year it is incurred using the expected inflation assumptions described in Appendix A. Figure 13 shows how the augmentation schedule captures our assumed real cost declines over time.

[59] See footnote 54 above. 2022 PJM CONE Affidavit Property Taxes costs are $11/kW in 2026$. See 2022 PJM CONE Affidavit.

FIGURE 13: REAL AUGMENTATION COST (LEFT AXIS) AND AUGMENTATION SIZE (RIGHT AXIS) OVER BESS ECONOMIC LIFETIME (REST OF RTO, $/KWH, NOMINAL$ FOR JANUARY 2025)



D. BESS CONE Estimates

The Gross CONE values shown below represent the total annual net revenues that a new BESS resource would need to earn on average to recover its capital and fixed O&M costs, given reasonable expectations about future cost recovery over the plant's economic life. Table 21 summarizes the Gross CONE calculation, including capital costs, fixed O&M costs, levelized augmentation costs, and carrying costs in the form of the capital charge rate. The estimated level-nominal CONE for a BESS ranges from $652/MW-day ICAP in Rest of RTO to $726/MW-day ICAP in ComEd. All costs presented in this section are expressed in ICAP terms unless specified otherwise.

TABLE 21: CONE CALCULATION FOR A BESS
(NOMINAL$ FOR JUNE 2028 ONLINE YEAR IN ICAP TERMS)

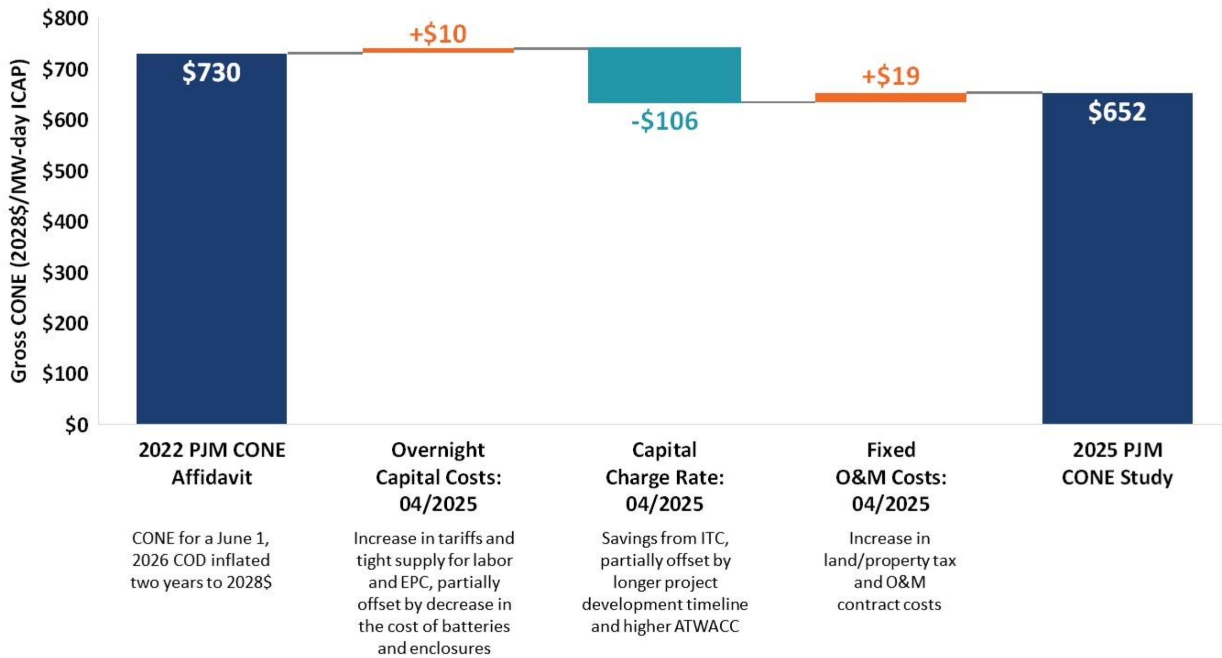
CONE Area				EMAAC	SWMAAC	Rest of RTO	WMAAC	COMED
Net Summer Capacity	MW	[1]		200	200	200	200	200
After-Tax WACC	%	[2]		9.5%	9.5%	9.5%	9.5%	9.5%
Capital Charge Rate	%	[3]		9.6%	9.6%	9.6%	9.6%	9.6%
Capital Costs								
Overnight Cost	Nominal $ million	[4]		$366	$351	$350	$357	$396
Overnight Cost	Nominal $/kW	[5]		$1,832	$1,753	$1,750	$1,784	$1,980
Installed Cost	Nominal $ million	[6]		$397	$380	$380	$387	$429
Installed Cost	Nominal $/kW	[7]	[6] x 1000 / [1]	$1,987	$1,901	$1,898	$1,935	$2,146
Levelized Capital Cost	Nominal $/kW-yr	[8]	[5] x [3]	$176	$169	$168	$172	$190
O&M Costs								
First Year FOM	Nominal $ million/yr	[9]		$10	$12	$10	$10	$10
Levelized FOM	Nominal $/kW-yr	[10]		$57	$62	$55	$57	$59
Levelized Augmentation	Nominal $/kW-yr	[11]		$15	$14	$14	$15	$16
Levelized CONE	**Nominal $/kW-yr**	**[12]**	**[8] + [10] + [11]**	**$248**	**$245**	**$238**	**$244**	**$265**
Levelized CONE	**Nominal $/MW-day**	**[13]**	**[12] x 1000 / 365**	**$680**	**$671**	**$652**	**$667**	**$726**

Sources and Notes: [3]: capital charge rate shown incorporates the 30% ITC.

The 2028/29 BESS CONE estimates for Rest of RTO are 11% lower in real terms comparing in 2028$ than those calculated in the 2022 PJM CONE Affidavit.[60] This is driven by the introduction of the 30% ITC for standalone storage and decreases in the cost of batteries and enclosures, partially offset by higher tariffs, higher costs of the PCS and BOP, construction labor and materials, and electrical interconnection, along with a higher ATWACC. Figure 14 below illustrates these drivers and the resulting changes in CONE. We present these in real terms by escalating the 2022 BESS CONE estimate from 2026 to 2028 dollars.

[60] Based on the 2022 Rest of RTO CONE of $699/MW-day for a plant with a June 2026 COD, escalated two years at the long-term inflation rate assumed in the 2022 PJM CONE Study. BESS CONE was calculated with the CONE model used in the 2022 PJM CONE Affidavit. See 2022 PJM CONE Affidavit.

FIGURE 14: DRIVERS OF DECREASED BESS CONE
(REST OF RTO, $/MW-DAY ICAP, NOMINAL$ FOR JUNE 2028 ONLINE YEAR)



These BESS CONE estimates and Net CONE estimates presented further below exceed the costs of gas-fired resources in most locations. Because this seemed to conflict with the prevalence of BESS projects in the interconnection queue, we scrutinized every element of the BESS costs estimates to make sure they were up-to-date and informed by sufficient data, and we discussed our estimates with equipment vendors and other sources. We are confident that our estimates reflect competitive costs for developing BESS plants with an online date of 2028, albeit before accounting for the effects of tariffs newly announced at the time of this report printing as discussed above.

Our explanation of the apparent dissonance between the queue data and the BESS cost estimates is that entering the queue is an easy way to create an option to develop projects if states or other parties offer incentives and/or costs drop more than expected, then rendering the overall economics viable. It appears that few or no standalone BESS developers have yet made a major financial commitment that might suggest they face lower costs relative to their market expectations. Hence there is no real contradiction.

VII. Review of E&AS Methodology

The E&AS offset represents the net revenues a resource expects to earn from the energy and ancillary service markets, to be deducted from CONE in order to estimate Net CONE.

For technology-specific Net CONE estimates, we recommend that PJM continue to calculate the E&AS on a forward basis using its existing methodology based on our prior recommendations, with only a few changes to parameters.[61] PJM calculates forward electricity prices used in the E&AS Offset estimation based on futures prices at liquid trading hubs, then derives basis differentials using long-term Financial Transmission Rights (FTR) auction results and current loss components of locational marginal prices (LMPs). These prices are assigned hourly day-ahead (DA) and real-time (RT) shapes using price shapes from the last three years. Similarly for hourly synchronized reserve prices, which are scaled to forward electricity prices, exploiting their correlation, lacking observable forward markets for ancillary services. Regulation is not included due to the thinness of that market. (And none of the candidate reference resources would be eligible for non-synchronous reserves.)

PJM then virtually dispatches the proxy plants against shaped forward prices using PJM's PLEXOS model, assuming the plant technical specifications from the relevant CONE Study and forward fuel prices. Natural gas prices are derived similarly to the electricity prices, from forward prices at liquid hubs assigned to each LDA and given a daily shape corresponding to the same three most recent historical years. The virtual dispatch for the BESS plant involves more judgement as discussed below.

After a holistic review of this method, the only changes we recommend are as follows:

- Plant Specifications: specifications should be updated to reflect the characteristics of the GE 7HA.03 as indicated in this CONE Study, including relevant updated Higher Heating Value (HHV) heat rate curves.
- Simulation of Plant's E&AS Offsets: The CT capacity factor should be limited to 40%, to comply with Section 111(b) of the Clean Air Act currently in place. BESS EAS offsets should include half of the incremental real-time value one could earn with perfect foresight in addition to the day-ahead-only value, to account for imperfect foresight as benchmarked in separate Brattle studies.

[61] PJM Interconnection, LLC. (2024), PJM Open Access Transmission Tariff, Effective January 1, 2024, Attachment DD, Section 5.10.a.v.; Samuel A. Newell, James A. Reid Jr., and Sang H. Gang, "Affidavit of Samuel A. Newell, James A. Read Jr., and Sang H. Gang on Behalf of PJM Interconnection, L.L.C.," filed before the Federal Energy Regulatory Commission September 30, 2022, Docket No. ER22-2984-000.

- RTO E&AS Offset: eliminate the virtual dispatch against a synthesized all-LDA average energy price and gas price; instead derive RTO Net CONE from the 33rd percentile of all LDAs, which turns out to be DEOK for our current assessment (see following Section).

A. Review of Forward Prices

We reviewed the construction and shaping of forward electricity and gas prices to evaluate if that they continue to represent reasonable representation of the market's expectations. We concluded that all of the elements are reasonable to continue:

- The current mapping of electricity and gas hubs to zones provide an accurate representation of market expectations, since those hubs remain liquid. We assessed current liquidity by reviewing open interest in futures contracts at each electric and gas hub. Open interest remained high across all the hubs, and thus futures prices at these hubs remain accurate indicators of market expectations.
- Long-term FTR prices continue to provide and accurate representation of the market's view of basis differentials. Participation in FTR auctions remains active. Forward prices have not been perfect predictors of realized congestion, but they should not be expected to any more than other forecasts.
- We recommend that PJM continue to incorporate the variable cost of procuring allowances from the RGGI carbon market when calculating the E&AS Offset for LDAs in Delaware, Maryland, and New Jersey. To most accurately represent expected RGGI costs in relevant states during the delivery year, PJM should use the prices of RGGI forwards to represent the cost of allowances. Pennsylvania is currently out of RGGI but a court case is pending that could reinstate its membership.[62] If we were conducting a private investment analysis for a generator in Pennsylvania, we might evaluate scenarios both with and without having to buy allowances and select a value in between. Yet in the context of defining parameters for RPM, it is difficult to see how to establish a solid basis for determining probability weights. It may be simplest to apply the current law and consider updating in future reviews.
- Ancillary service prices continue to be correlated with energy prices (especially for synchronized reserves), so it is reasonable to scale AS prices with energy prices informed by energy futures.

[62] Pennsylvania General Assembly, Senate Bill 186, 2025–2026 Regular Session, February 4, 2025.

- Finally, it remains reasonable and common practice to apply an hourly DA and RT shape to forward prices using hourly prices from the three latest historical years. Pricing shapes are likely to vary with weather conditions and to evolve over the long-run with changes in fundamentals, but not in ways that are straightforward to forecast.

B. Review of Virtual Dispatch Simulations

PJM's use of the PLEXOS virtual dispatch model to calculate E&AS offsets continues to be reasonable and commercially standard practice. PJM conducts a two-pass unit commitment and scheduling/dispatch optimization against the hourly DA and RT prices, given each unit's operating characteristics and costs; then it calculates net revenues corresponding to PJM's actual two-part settlement of day-ahead schedules and real-time deviations, and with make-whole payments as applicable.

For all technologies, real-time deviations from day-ahead schedules depend on each plant's commitment flexibility as well as foresight and look-ahead assumptions. For the CC, PJM's real-time simulation approach will always commit the proxy plant in hours in which it was day-ahead committed, but also allows the resource to extend its real-time operations beyond the day-ahead commitments. The real-time simulations may also turn on a resource if it is profitable to do so over the rolling optimization horizon, defined as the dispatch interval with an additional 2-hour look-ahead, subject to startup, minimum run time and minimum down time constraints. In each committed hour, the CC can operate between minimum load and maximum load with and without duct-firing, subject to economics and ramp limitations. All else equal, this might understate actual net revenues under a more flexible approach where the resource can de-commit. The simulation's Balancing Operating Reserve make-whole credit will ensure the resource is at least net revenue neutral over a simulated day, but non-economic hours in which the resource is constrained online because of its day-ahead commitment would reduce net profits.

To validate the reasonableness of the results, PJM staff benchmarked against actual units' historical performance. Staff ran the simulation model for several newer CCs using their plant characteristics and historical prices for 2021, 2022, and 2023. They calculated the total gross revenue for each CC resource within this group and compared to actual gross revenues from these resources observed over the same period. On average, the PJM simulation method overestimated the total gross revenues by 12%. This is not surprising given the lack of maintenance outages in the simulation model. Net revenues were not benchmarked due to complications in ascertaining units' actual costs. Yet we would expect that actual net revenues would differ from simulated net revenues by less than 12% difference in gross revenues, if the additional simulated generation is during maintenance periods when spark spreads tend to be low. This helped validate the reasonableness, even if not perfection, of the virtual dispatch approach used for calculating Net EAS for proxy resources.

For the CT, PJM's simulation approach similarly respects the DA commitment in real time. The proxy CT must run based on these commitments, but, based on real-time prices in a 3-hour look ahead window, it can extend these commitments and add new ones if they are profitable (but never de-commit relative to DA). It then operates between minimum and maximum load in each committed hour. In actual market operations, the look-ahead period is 2 hours, but the 3-hour simulated look-ahead captures the fact that participants can offer lower startup costs if they anticipate a longer payoff. PJM staff experimented with alternative simulations that treated the CT as a fast-start resource without having to honor DA commitments, but the differences in net revenues were not large enough to refine and adopt such an approach. In all cases, the CT is simulated with a 10% fuel cost adder as recommended in prior reviews and already practiced by PJM to account for challenging intra-day gas market conditions that CTs would be exposed to. One new change we and PJM staff agreed on and incorporated: the annual average capacity factor should be limited to 40% corresponding to Section 111(b) of the Clean Air Act.[63] Unfortunately, there are no comparable CTs in operation in PJM's market to provide a benchmark of the reasonableness of the virtual dispatch scheduling and net revenues, so PJM did not perform a benchmarking exercise as with the CC.

For the BESS simulations, the proxy resource optimizes its schedule based on a day-ahead prices, then re-optimizes in real time using a 16-hour look-ahead horizon with perfect foresight. This re-optimization adds approximately $30-$70/MW-day ICAP to the E&AS offsets, depending on the LDA. We recommend assuming that the proxy unit could attain *half* of these incremental revenues, given realistic forecasting and optimization abilities. This assumption is based on extensive benchmarking Brattle has done for clients operating BESS assets in markets with more substantial penetration of BESS. Our economic dispatch models for these clients have been calibrated to their actual value capture accounting for imperfect ability to forecast RT prices and to optimize their bids/offers/schedules. When we apply the calibrated model to PJM DA and RT energy and ancillary prices, the "realistic" net revenues are slightly more than halfway from the DA-only optimization to the RT-perfect foresight case.

[63] This limitation decreased the E&AS offset by $10-$40/MW-day ICAP in some areas but made no difference in most LDAs where the 40% capacity factor was not binding.

However, this level of total value capture is not currently possible in PJM, because (a) storage is not currently allowed to increase its offers in real time relative to day ahead, and (b) mitigated storage offers (in both day-ahead and real-time) must not exceed average charging costs (even though opportunity costs can be multiples higher); our model therefore assumes PJM reforms its rules.

Finally, we continue to recommend that regulation revenue be omitted from simulated ancillary service revenues because of its thin market with 500-800 MW of demand.[64] Synchronous reserves are a larger market with 2,800 MW of average demand, although even those prices could decline with substantial BESS entry. PJM could consider excluding a portion of them, although we fully included them in our Net CONE estimates for simplicity. Excluding them entirely would result in $70-$112/MW-day ICAP lower EAS net revenues for BESS, depending on the LDA, and very small differences for the CC and CT.

VIII. Net CONE Benchmarks and Proposed VRR Curve Reference Prices

The scope of our assignment includes estimating Gross CONE values and recommending changes to the E&AS approach but does not include estimating the E&AS Offsets. While we only calculate CONE values in this study for the five CONE Areas, the VRR curve requires a Reference Price that reflects the long-run marginal cost of supply, or Net CONE, at the RTO level as well as the LDA level. PJM calculates the E&AS Offset for each LDA based on the forward-looking E&AS approach discussed in the previous section close to the Base Residual Auction to capture the most up-to-date market expectations of future energy prices. Therefore, in this report we present Indicative Net CONE estimates based on the most recent E&AS Offset to inform the RTO and LDA Reference Prices. As discussed in this section, our recommended Reference Prices for the RTO and LDA VRR curves are informed by a range of benchmarks to arrive at a composite value that appears most likely to support the established VRR curve primary objectives of maintaining 1-in-10 loss of load expectation (LOLE) on a long-run average basis while limiting volatility such as extreme price spikes.

[64] Samuel A. Newell, James A. Reid Jr., and Sang H. Gang, "Affidavit of Samuel A. Newell, James A. Read Jr., and Sang H. Gang on Behalf of PJM Interconnection, L.L.C.," filed before the Federal Energy Regulatory Commission September 30, 2022, Docket No. ER22-2984-000.

A. Indicative Net CONE and Other Benchmarks

PJM provided forward E&AS offsets and ELCC values for the 2028/29 delivery year, which we incorporated with our current level-nominal CONE estimates to develop an Indicative Net CONE estimate for each technology type, as shown in Table 22. However, as discussed in previous sections, these current level-nominal CONE estimates are higher than one could expect in the long run because they embed the temporary premium pricing and extended project schedules, both of which can be expected to normalize once supply chains catch up to demand. This section explains how we developed additional benchmarks to estimate the long-run marginal cost of supply. We show the calculations first just for DEOK, which we take to be most representative of the marginal net cost of capacity for the RTO, as explained below; thereafter we present the corresponding results for all LDAs

TABLE 22: INDICATIVE 2028/29 NET CONE AND OTHER BENCHMARKS (RTO, NOMINAL$ FOR JUNE 2028 ONLINE YEAR)

Nominal$ for 2028 Online Year	Overnight Capital Cost [A] $/kW See notes	Capital Charge Rate [B] %/year See notes	Year 1 Capital Recovery [C] $/MW-day See notes	Levelized Fixed O&M [D] $/MW-day See notes	Gross CONE ICAP [E] $/MW-day [C] + [D]	E&AS Offset [F] $/MW-day See notes	Net CONE ICAP [G] $/MW-day [E] - [F]	ELCC [H] % See notes	Net CONE UCAP [I] $/MW-day [G] / [H]
Current Level-Nominal CONE with Forward EAS									
CT	$1,361	15.9%	$593	$69	**$663**	$241	$422	79%	**$534**
CC	$1,419	16.9%	$656	$157	**$813**	$506	$308	81%	**$380**
BESS 4-hr	$1,750	9.6%	$462	$191	**$652**	$244	$409	65%	**$629**
Other Benchmarks									
LTCT and Forward E&AS	$1,053	13.5%	$388	$69	**$457**	$241	$217	79%	**$274**
LTCC and Forward E&AS	$1,263	14.4%	$497	$157	**$655**	$506	$149	81%	**$184**
LTCT and 10-yr Avg. E&AS	$1,053	13.5%	$388	$69	**$457**	$207	$251	79%	**$317**
LTCC and 10-yr Avg. E&AS	$1,263	14.4%	$497	$157	**$655**	$374	$281	81%	**$346**
LTCC, 15-yr life and Forward E&AS	$1,263	16.2%	$560	$157	**$717**	$506	$212	81%	**$261**
CC, 15-yr life	$1,419	19.0%	$738	$154	**$892**	$506	$386	81%	**$477**
BESS 4-hr, Without 30% ITC	$1,750	13.0%	$621	$191	**$812**	$244	$569	65%	**$875**
Adjusted Empirical Net CONE 14/15 to 22/23	-	-	-	-	**-**	-	-	-	**$241**

Sources and Notes:

[A], [B], [D]: Outputs from CONE Model for CONE Area 3.

[C]: [A] x [B] x 1000/365.

[F]: Forward E&AS provided by PJM staff for DEOK LDA. 10-yr Avg. E&AS calculated from DEOK net revenues for delivery years 2017/2018 – 2023/24 from Monitoring Analytics, State of the Market Report for PJM, March 14, 2024, pp.399-400; Net revenues for delivery years 2024/25-2026/27 from PJM, Default New Entry MOPR Offer Prices, Accessed March 6, 2025.

[H]: Provided by PJM staff.

To derive an estimate of more normalized long-run marginal costs, we assumed several cost categories would revert to costs from the 2022 PJM CONE Study, which were estimated prior to the current turbine shortages and extended project timelines.[65] Since the CT in the 2022 PJM CONE Study was not a dual-fuel unit, first S&L provided estimates of the incremental capital costs for a dual-fuel CT for the same 2022-vintage costs per kW in the same January 2022 dollar-year estimates. We then adjusted the January 2022 *OFE and EPC costs* by inflation to arrive at a January 2025 estimate for those cost categories. Non-EPC and fixed O&M costs were assumed to stay the same as current estimates.[66] We then calculated a long-term level-nominal CONE assuming shorter 2022-vintage construction schedules and the current 9.5% ATWACC. The results are presented as "long-term CONE" for the CT ("LTCT") and the CT ("LTCC").

For indicative estimates of long-term *Net* CONE, we calculated one version for the CC and CT using the same forward E&AS values as above ("Forward E&AS") and, alternatively, another with a 10-year average of real E&AS revenues ("10-yr Average E&AS") from 2017/18 to 2026/27 using a combination of estimates of net E&AS revenues by the IMM and the most recent MOPR parameters.[67] See Appendix A for more details. Since the former is based on forward-looking values it reflects anticipated gas prices, congestion conditions, and Regional Greenhouse Gas Initiative allowance (RGGI) prices. However, the Forward E&AS is probably higher than long-run equilibrium conditions since this estimate reflects current tight capacity conditions—thereby understating long-term Net CONE. The 10-yr Average E&AS, on the other hand, is probably lower than long-run equilibrium since it reflects primarily past conditions of excess capacity in RPM, and it does not account for increasingly stringent environmental constraints or costs such as RGGI or Clean Air Act Section 111(b)—thereby overstating long-term Net CONE.

Another indicator of long-run Net CONE can be derived from clearing prices that sufficed to attract new generation in the past, often referred to as empirical Net CONE. For the delivery periods 2014/15 to 2022/23, when plentiful new generation (almost entirely CCs) entered, we derived a comparable estimate of empirical Net CONE by averaging the historical clearing prices, adjusting for inflation, adjusting for the effect of higher ATWACC now relative to past conditions, and adjusting for the effect of current accreditations (i.e., multiplied by old UCAP ratings divided by current ELCCs). See Appendix A for more details. The resulting "Adjusted Empirical Net CONE" was $241/MW-day in 2028 dollars. This imperfect measure does not necessarily incorporate

[65] Although those estimates were higher than in the 2018 PJM CONE Study in part due to elevated costs of materials.

[66] Specifically, Net Start-up Fuel, Gas and Electric Interconnection, Land, Working Capital, and Property Tax costs.

[67] Net revenues for delivery years 2017/2018 – 2023/24 from Monitoring Analytics, State of the Market Report for PJM, March 14, 2024, pp.399-400; Net revenues for delivery years 2024/25-2026/27 from PJM, Default New Entry MOPR Offer Prices, Accessed March 6, 2025.

prices consistent with earning an adequate return, nor does it account for many forward-looking conditions and plant designs, but it provides a useful benchmark among others.

In addition to the long-term CONE estimates, we developed additional benchmarks from the current level-nominal estimates. While we have not observed the same scarcity pricing and increases in project timeline for BESS, there is substantial uncertainty of future costs in the current policy environment. The most impactful being a potential repeal or reduction of the federal ITC, and tariff increases. To account for the possibility of ITC repeal, we calculated an estimate of BESS CONE without the ITC. For natural gas, there is a possibility that individual states could eventually pass more stringent environmental policy regulating greenhouse gas emissions. To account for this possibility, we also calculate an estimate for a CC under more stringent environmental policies, which we assume for simplicity could reduce the economic life to 15-years ("CC 15-yr"). We do not provide an equivalent benchmark for CTs since they generate at low capacity factors and would likely not be as impacted.

These same calculations can be performed for all of the LDAs. The calculations are presented below in three steps, in order to compactly convey the elements of Net CONE across so many LDAs and benchmarks. Table 23 shows the CONE values for all of the benchmarks across the 5 CONE Areas in ICAP terms; Table 24 shows the forward and 10-year average Net E&AS Offsets for each LDA and each benchmark, still in ICAP terms; and Table 25 shows the resulting Net CONE estimates, expressed in UCAP terms after applying the technology-specific ELCCs shown for the full DEOK calculations in Table 22 above.[68]

TABLE 23: GROSS CONE BENCHMARKS PER CONE AREA
($/MW-DAY ICAP, NOMINAL$ FOR JUNE 2028 ONLINE YEAR)

	Current Level-Nominal			Long-term Benchmarks with 2022 Capital Costs					Other Level-Nominal	
Technology	CT	CC	BESS	LT**CT**	LT**CC**	LT**CT**	LT**CC**	LT**CC** 15-yr	CC 15-yr	BESS w/o ITC
CONE Area 1, EMAAC	$670	$816	$680	$469	$685	$469	$685	$751	$901	$849
CONE Area 2, SWMAAC	$676	$819	$671	$446	$639	$446	$639	$700	$898	$831
CONE Area 3, Rest of RTO	$663	$813	$652	$457	$655	$457	$655	$717	$892	$812
CONE Area 4, WMAAC	$664	$814	$667	$467	$677	$467	$677	$742	$895	$830
CONE Area 5, COMED	$789	$953	$726	$648	$882	$648	$882	$892	$968	$909

[68] With the exception of the Adjusted Empirical Net CONE estimate which only is relevant for comparison at the RTO level.

TABLE 24: E&AS OFFSET PER LDA
($/MW-DAY ICAP, NOMINAL$ FOR JUNE 2028 ONLINE YEAR)

	Current Level-Nominal			**Long-term Benchmarks with 2022 Capital Costs**					**Other Level-Nominal**	
Technology **E&AS Type**	CT	CC Forward	BESS	LT**CT** Forward	LT**CC** Forward	LT**CT** 10-yr Avg	LT**CC** 10-yr Avg	LT**CC** 15-yr Forward	CC 15-yr Forward	BESS no ITC Forward
CONE Area 1, EMAAC										
AE	$58	$219	$235	$58	$219	$95	$198	$219	$219	$235
DPL	$142	$344	$328	$142	$344	$128	$209	$344	$344	$328
JCPL	$55	$223	$225	$55	$223	$96	$205	$223	$223	$225
PE	$90	$311	$241	$90	$311	$121	$232	$311	$311	$241
PSEG	$49	$208	$228	$49	$208	$111	$223	$208	$208	$228
RECO	$64	$252	$245	$64	$252	$112	$242	$252	$252	$245
CONE Area 2, SWMAAC										
BGE	$302	$608	$351	$302	$608	$241	$425	$608	$608	$351
PEPCO	$153	$425	$328	$153	$425	$143	$310	$425	$425	$328
CONE Area 3, Rest of RTO										
AEP	$279	$534	$238	$279	$534	$198	$368	$534	$534	$238
APS	$341	$604	$251	$341	$604	$187	$372	$604	$604	$251
ATSI	$215	$477	$236	$215	$477	$190	$355	$477	$477	$236
DAYTON	$260	$529	$246	$260	$529	$216	$390	$529	$529	$246
DEOK	$241	$506	$244	$241	$506	$207	$374	$506	$506	$244
DLCO	$201	$435	$239	$201	$435	$192	$347	$435	$435	$239
DOM	$276	$576	$338	$276	$576	$209	$373	$576	$576	$338
EKPC	$220	$481	$239	$220	$481	$163	$326	$481	$481	$239
OVEC	$251	$500	$234	$251	$500	$155	$396	$500	$500	$234
CONE Area 4, WMAAC										
METED	$158	$416	$251	$158	$416	$196	$336	$416	$416	$251
PENELEC	$311	$571	$240	$311	$571	$232	$324	$571	$571	$240
PPL	$105	$348	$228	$105	$348	$187	$325	$348	$348	$228
CONE Area 5, COMED										
COMED	$108	$327	$257	$108	$327	$112	$231	$327	$327	$257

TABLE 25: NET CONE PER LDA
($/MW-DAY UCAP, NOMINAL$ FOR JUNE 2028 ONLINE YEAR)

	Current Level-Nominal			Long-Term Benchmarks with 2022 Capital Costs					Other Level-Nominal	
Technology **E&AS Type**	CT	CC Forward	BESS	LT**CT** Forward	LT**CC** Forward	LT**CT** 10-yr Avg	LT**CC** 10-yr Avg	LT**CC** 15-yr Forward	CC 15-yr Forward	BESS no ITC Forward
CONE Area 1, EMAAC										
AE	$775	$738	$685	$520	$576	$473	$601	$658	$843	$944
DPL	$667	$583	$542	$413	$421	$431	$587	$503	$688	$801
JCPL	$778	$733	$700	$524	$571	$472	$592	$653	$838	$959
PE	$734	$624	$675	$479	$461	$440	$560	$543	$728	$934
PSEG	$785	$751	$695	$531	$589	$453	$570	$671	$856	$954
RECO	$767	$697	$670	$512	$535	$451	$547	$617	$802	$929
CONE Area 2, SWMAAC										
BGE	$473	$260	$493	$182	$38	$260	$265	$113	$358	$739
PEPCO	$662	$486	$528	$372	$264	$384	$407	$339	$584	$774
CONE Area 3, Rest of RTO										
AEP	$486	$345	$638	$226	$149	$328	$354	$226	$442	$884
APS	$408	$259	$618	$148	$63	$343	$349	$140	$356	$864
ATSI	$567	$415	$641	$307	$220	$338	$370	$297	$512	$887
DAYTON	$510	$351	$625	$250	$155	$306	$327	$232	$447	$871
DEOK	$534	$380	$629	$274	$184	$317	$346	$261	$477	$875
DLCO	$585	$468	$636	$325	$272	$336	$380	$349	$564	$882
DOM	$489	$293	$483	$230	$97	$314	$347	$174	$390	$729
EKPC	$561	$410	$636	$301	$214	$372	$406	$291	$507	$882
OVEC	$521	$387	$644	$261	$191	$383	$320	$268	$484	$890
CONE Area 4, WMAAC										
METED	$641	$491	$641	$391	$323	$343	$421	$403	$591	$891
PENELEC	$447	$300	$658	$197	$131	$297	$436	$212	$400	$908
PPL	$707	$575	$676	$458	$406	$355	$434	$486	$675	$926
CONE Area 5, COMED										
COMED	$862	$774	$720	$684	$685	$679	$803	$698	$791	$1,002

For the RTO Net CONE calculation, PJM currently calculates an unweighted average of the CONE Areas and subtracts an RTO E&AS Offset derived from a virtual dispatch of the proxy plant against a single set of synthetic of energy and gas prices. Synthetic energy and gas prices series are each constructed from a load-weighted average over all LDAs. Yet such averaging of inputs before exercising non-linear real options (i.e., the dispatch) can have unintended consequences; and even if it does represent some sort of average, that could overstate the cost of serving RTO needs, since one would not expect entry in areas with average economics, but in those with the best economics, with lower than average Net CONE.

Our recommendation is to instead conduct the CONE and E&AS analysis for each LDA as described above, then define the RTO Net CONE (for each of the different Net CONE benchmarks) as the 33rd percentile among LDA Net CONE values. In theory, the minimum might seem more appropriate, but that would threaten to understate the cost if the minimum is driven by estimation errors, if siting opportunities are limited in that area, or if the location of the minimum fluctuates from review to review. The latter could result in a lower overall Net CONE trajectory than any plant could receive if investing the in the single area with most favorable long-term average economics. Therefore, the 33rd percentile is more reasonable for the RTO.

Under the conditions considered in our selected benchmarks, DEOK's Net CONE is approximately at the 33rd percentile of all LDA Net CONEs. Accordingly, when reporting the individual Net CONE components as in Table 22, we show the values for CONE Area 3 and the DEOK E&AS Offset to approximate the RTO Net CONE.

C. Short-term Reservation Prices

One other benchmark that could inform the Reference Price is the price at which investors would be willing to enter under current market conditions, which we denote the "Short-term Reservation Price." Whereas under more steady state conditions, this short-term reservation price might be given by the level-nominal Net CONE, the reservation price for a one-year commitment might be much higher under very tight conditions that can support high prices temporarily then revert to lower prices. Revenues must be much more front-loaded under these conditions.

Our estimate of the Short-term Reservation price assumes investors consider how much higher than level-nominal CONE all-in market revenues would have to be for 1, 3, or 5 years of shortage conditions assuming revenues thereafter revert to a long-run equilibrium as shortage conditions moderate. For CCs and CTs, we assume that for the remainder of their 20-year economic lives beyond the short-term reservation price period they earn "long-run CONE" for their own technologies at the RTO level as shown in Table 22. For the BESS, we assume revenues thereafter earn a "long-run CONE" over the remainder of their 20-year economic lives based on the \$350/MW-day RTO Reference Price grossed up for the current forward RTO E&AS.[69] The result is impressively high under these assumptions, as summarized in Table 26 below.

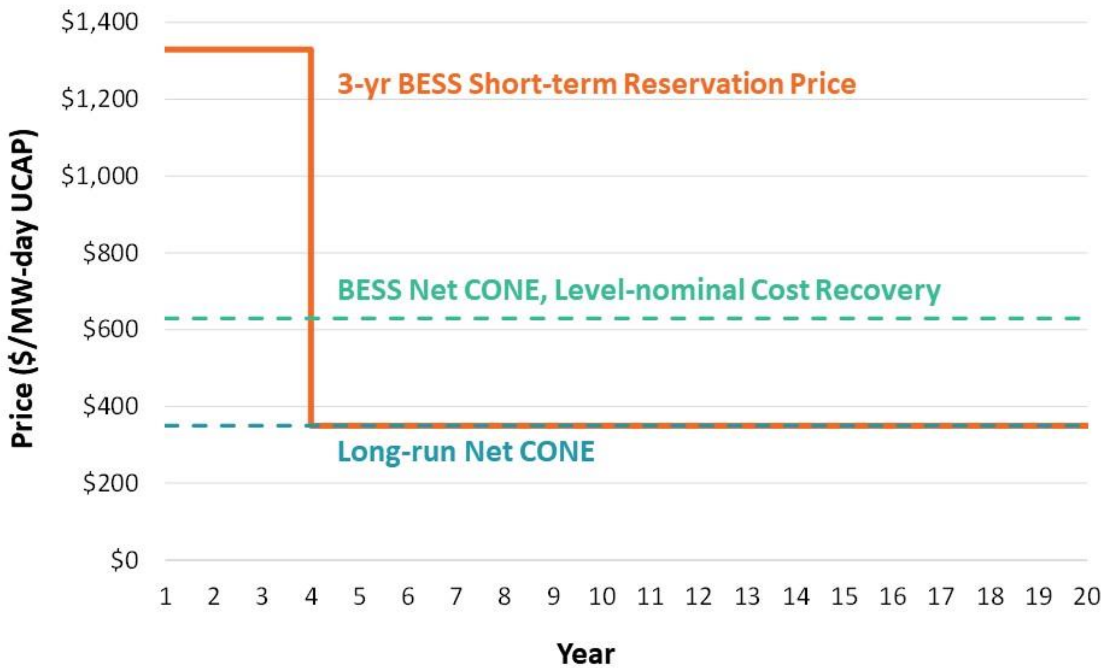
[69] This value is back-calculated from the \$350/MW-day UCAP RTO Reference Price using the Net CONE equation, where Net CONE = (CONE ICAP – E&AS ICAP) / ELCC as the following: \$471/MW-day CONE ICAP = (\$350/MW-day Net CONE UCAP × 65% ELCC) + \$244/MW-day ICAP Forward E&AS.

TABLE 26: SHORT-TERM RESERVATION PRICES
(RTO, $/MW-DAY, NOMINAL$ FOR JUNE 2028 ONLINE YEAR)

	Current Level-Nominal CONE (ICAP)	Long-run CONE (ICAP)	Front Loaded CONE (ICAP)			Forward E&AS (ICAP)	ELCC	Short-Term Reservation Price (UCAP)			Current Level-Nominal Net CONE (UCAP)
	[A] $/MW-day	[B] $/MW-day	[C] $/MW-day			[D] $/MW-day	[E] %	[F] $/MW-day			[G] $/MW-day
			1-yr	**3-yr**	**5-yr**			**1-yr**	**3-yr**	**5-yr**	
CT	$663	$457	$2,436	$1,178	$928	$241	79%	$2,779	$1,186	$870	$534
CC	$813	$655	$2,183	$1,211	$1,018	$506	81%	$2,070	$871	$633	$380
BESS	$652	$471	$2,219	$1,108	$887	$244	65%	$3,040	$1,329	$990	$629

Sources and Notes:
[A]: Current Level-Nominal CONE value from CONE model for RTO.
[B]: for CT and CC, long-run CONE from Table ES-2. For BESS, long-run CONE assumed to be back calculated from the $350/MW-day UCAP long-run Net CONE from Figure ES-1. $471 CONE ICAP = $350 Net CONE UCAP × 65% ELCC + $244 Forward E&AS ICAP for BESS.
[C]: Output from CONE model, reservation price analysis.
[D], [E]: Provided by PJM staff.
[F]: ([C] – [D]) / [E].
[G]: ([A] – [D]) / [E].

FIGURE 15: BESS 3-YR SHORT-TERM RESERVATION PRICE
(RTO, $/MW-DAY UCAP, NOMINAL$ FOR JUNE 2028 ONLINE YEAR)



These short-term reservation price estimates are highly uncertain but indicate the range of prices that investors might require in order to enter without any expectations of high prices continuing. These estimates suggest that, under current conditions, an extremely high-priced VRR curve might be needed to attract enough entry through RPM's single-year commitments. These estimates suggest that an extremely high-priced VRR curve might be needed to attract enough entry through RPM's single-year commitments. Assuming BESS will be the relevant marginal technology for the next few years while gas-fired generation additions are limited, the reference price might have to be $1,300/MW-day, assuming investors expect just 3 years of high prices which later normalize to long-run prices. Further, if the VRR curve price cap is 1.5 to 1.75 times that, the price could rise to nearly $2,300/MW-day in scarcity, or nearly 10 times what they were in the 2025/26 auction that transacted $14 billion.

B. Proposed Reference Prices for VRR Curves

We do not recommend the short-term reservation prices as a basis for the VRR curve Reference Price, since doing so would introduce the risks of excess price volatility; expose customers to the potential for extreme high costs in the event of price cap events; and because these short-term reservation prices substantially exceed the prices and price cap needed to attract supply over the long run. Even so, this exercise illustrates why there is a material risk that RPM prices available under one-year commitments may be insufficient to attract new entry in one or more of the upcoming auctions. In the companion 2025 PJM VRR Curve Report, we assess options for managing these conditions through either tolerating temporary reliability shortfalls or pursuing a backstop competitive procurement to fill the gap.

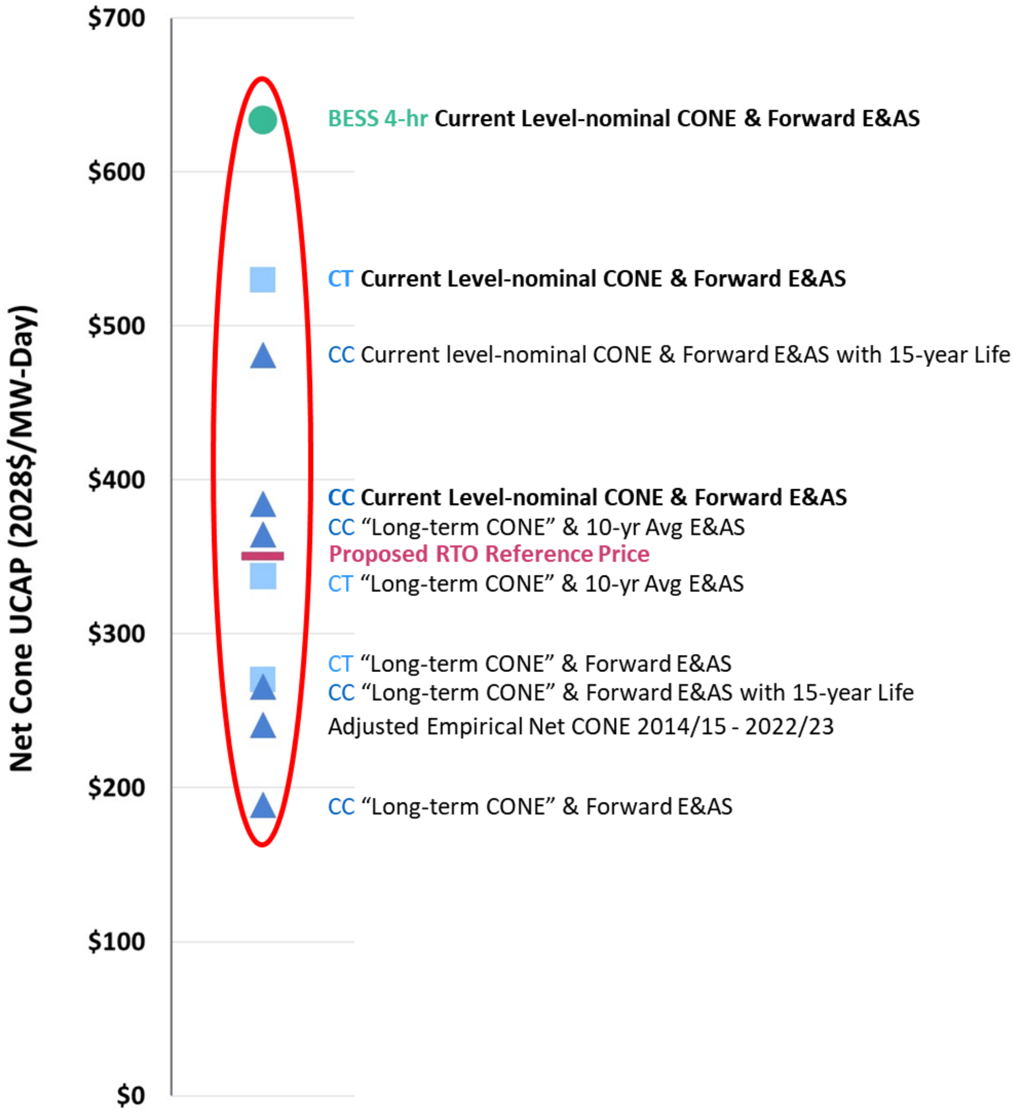
We recommend setting the Reference Price based on an estimate of the long-run marginal cost in order to support the established VRR curve primary objectives of maintaining 1-in-10 loss of load expectation (LOLE) on a long-run average basis while limiting volatility such as extreme price spikes. That might suggest deriving the Reference Price from only the long-term equilibrium estimates presented above. However, given the imperfect nature of those indicators and the need to elevate the curve a reasonable amount to address current conditions, we also consider the high Current Level-Nominal Net CONE. The full set of relevant benchmarks is presented graphically below.

PROPOSED REFERENCE PRICES FOR RTO

Consideration of that full set points to a central value at $350/MW-day UCAP, as shown in Figure ES-1.[70] This proposed RTO Reference Price is lower than current estimates of level-nominal technology costs that incorporate temporary cost premiums (Concept 1 above), and higher than the indictors of long-run marginal cost (Concept 2 above). This mid-point estimate of Reference Price is further informed by multiple technologies (primarily the CC and CT resources) and by a range of scenario analyses that may influence costs over the study period. Though the uncertainty range affecting the Reference Price is relatively large, we believe the uncertainties are approximately balanced.

[70] With the exception of the “BESS without ITC benchmark”, given that the ITC is still prevailing law at the time of publishing.

FIGURE ES-1 REPRODUCED: INDICATIVE NET CONE FOR CURRENT LEVEL-NOMINAL CONE ESTIMATES AND LONG-TERM BENCHMARKS (RTO, $/MW-DAY UCAP, NOMINAL$ FOR JUNE 2028 ONLINE YEAR)



Sources and Notes: "Long-term CONE" reflects escalated 2022 OFE/EPC costs with current Non-EPC costs and fixed O&M. Forward E&AS and 10-yr Avg E&AS from Appendix A.

This recommended value is clearly surrounded by judgment and uncertainty. Attaching a heavier weight to some reference points than others could change the value by plus or minus $100/MW-day or more, which is our estimate of the uncertainty range in Net CONE under present conditions. We incorporate this uncertainty range in Reference Prices in evaluating the robustness of alternative VRR Curve shapes and price caps in the 2025 PJM VRR Curve Report.

PROPOSED REFERENCE PRICES FOR LDAS

Reference prices for the LDAs can be derived using a comparable approach to the RTO. For each benchmark and each LDA, Net CONE is calculated; then for each benchmark and each CONE Area (EMAAC, SWMAAC, Rest of RTO, WMAAC, ComEd) and MAAC, calculate the 33rd percentile from all the constituent LDAs, for the same reasons this approach was applied to the RTO Reference Price, as explained above. For areas with few LDAs such as SWMAAC and WMAAC, the 33rd percentile concept does not correspond as closely to any individual LDA of the sample but is in between two LDAs. We derive the 33rd percentile in these cases based on the distance between the two LDAs closest to the 33rd percentile and the number of LDAs in the sample. For example, in a CONE Area with three LDAs representing the 0th, 50th, and 100th percentiles, since 33% / 50% - 0% = 2/3, the 33rd percentile would be 2/3 of the way from the 0th percentile LDA to the 50th percentile LDA. This proposed method is the same as that embedded in the "PERCENTILE.INC" formula in Microsoft Excel and is a sensible representation of the percentile concept applied to small samples.

Finally, for each CONE Area, the proposed reference price is the median from among all benchmarks (except for the BESS-without-ITC benchmark) rounded to the nearest $25/MW-day increment. If the resulting CONE Area Reference Price is at or above the RTO Reference Price, it receives the CONE Area Reference Price, otherwise the CONE Area receives the RTO Reference Price. The individual LDAs' reference prices are set equal to that of the immediate parent CONE Area, since variation within each CONE Area is relatively low in most cases. These calculations are shown in Table 27 below.

ComEd is unique since it is a single-LDA CONE Area and current environmental laws greatly impact the Net CONE estimates for gas-fired technologies due to the truncated economic lives. In each future year during the review period, economic lives for gas-fired resources would be further truncated which would cause their Net CONEs to be expected to remain above a BESS Net CONE, therefore we propose a $725/MW-day Reference Price for ComEd equivalent to the current level-nominal BESS Net CONE estimate for ComEd, rounded.

TABLE 27: NET CONE BY LDA
($/MW-DAY UCAP, NOMINAL$ FOR JUNE 2028 ONLINE YEAR)

	Current Level-Nominal			Long-Term Benchmarks with 2022 Capital Costs					Other Level-Nominal		Median
Technology	CT	CC	BESS	LT**CT**	LT**CC**	LT**CT**	LT**CC**	LT**CC** 15-yr	CC 15-yr	BESS no ITC	All except
E&AS Type		Forward		Forward	Forward	10-yr Avg	10-yr Avg	Forward	Forward	Forward	BESS no ITC
CONE Area 1, EMAAC											
AE	$775	$738	$685	$520	$576	$473	$601	$658	$843	$944	$658
DPL	$667	$583	$542	$413	$421	$431	$587	$503	$688	$801	$542
JCPL	$778	$733	$700	$524	$571	$472	$592	$653	$838	$959	$653
PE	$734	$624	$675	$479	$461	$440	$560	$543	$728	$934	$560
PSEG	$785	$751	$695	$531	$589	$453	$570	$671	$856	$954	$671
RECO	$767	$697	$670	$512	$535	$451	$547	$617	$802	$929	$617
EMAAC Average	$751	$688	$661	$497	$525	$453	$576	$607	$792	$920	$607
EMAAC 33rd percentile	$756	$673	$674	$501	$510	$447	$566	$592	$777	$933	**$592**
EMAAC Reference Price: $600/MW-day based on rounded median of all Net CONE 33rd percentile benchmarks except BESS w/o ITC.											
CONE Area 2, SWMAAC											
BGE	$473	$260	$493	$182	$38	$260	$265	$113	$358	$739	$260
PEPCO	$662	$486	$528	$372	$264	$384	$407	$339	$584	$774	$407
SWMAAC Average	$567	$373	$511	$277	$151	$322	$336	$226	$471	$757	$336
SWMAAC 33rd percentile	$536	$335	$505	$245	$114	$302	$312	$188	$433	$751	**$312**
SWMAAC Reference Price: $350/MW-day, same as RTO, no LDA premium (but could consider higher in PEPCO).											
CONE Area 3, Rest of RTO											
AEP	$486	$345	$638	$226	$149	$328	$354	$226	$442	$884	$345
APS	$408	$259	$618	$148	$63	$343	$349	$140	$356	$864	$343
ATSI	$567	$415	$641	$307	$220	$338	$370	$297	$512	$887	$370
DAYTON	$510	$351	$625	$250	$155	$306	$327	$232	$447	$871	$327
DEOK	$534	$380	$629	$274	$184	$317	$346	$261	$477	$875	$346
DLCO	$585	$468	$636	$325	$272	$336	$380	$349	$564	$882	$380
DOM	$489	$293	$483	$230	$97	$314	$347	$174	$390	$729	$314
EKPC	$561	$410	$636	$301	$214	$372	$406	$291	$507	$882	$406
OVEC	$521	$387	$644	$261	$191	$383	$320	$268	$484	$890	$383
Rest of RTO Average	$518	$367	$617	$258	$172	$338	$356	$249	$464	$862	$356
Rest of RTO 33rd percentile	$503	$349	$628	$243	$153	$324	$347	$230	$445	$873	**$347**
Rest of RTO Reference Price: $350/MW-day, same as RTO, no LDA premium.											
CONE Area 4, WMAAC											
METED	$641	$491	$641	$391	$323	$343	$421	$403	$591	$891	$421
PENELEC	$447	$300	$658	$197	$131	$297	$436	$212	$400	$908	$300
PPL	$707	$575	$676	$458	$406	$355	$434	$486	$675	$926	$486
WMAAC Average	$598	$456	$658	$349	$287	$332	$430	$367	$556	$908	$430
WMAAC 33rd percentile	$576	$428	$652	$327	$259	$328	$430	$339	$528	$903	**$428**
WMAAC Reference Price: $425/MW-day based on rounded median of 33rd percentile benchmarks (could consider higher in PPL and lower in PENELEC).											
MAAC 33rd percentile	$664	$519	$646	$399	$350	$365	$435	$431	$619	$897	**$435**
MAAC Reference Price: $425/MW-day based on rounded median of Net CONE 33rd percentile benchmarks except BESS w/o ITC.											
CONE Area 5, COMED											
COMED	$862	$774	$720	$684	$685	$679	$803	$698	$791	$1,002	**$720**
COMED Price: $725/MW-day based on current level-nominal BESS Net CONE, rounded.											

As indicated in Table 27 above, this results in proposed Reference Prices of:

- $600/MW-day for all LDAs in CONE Area 1 (EMAAC)
- $350/MW-day for all LDAs in CONE Area 2 (SWMAAC)
- $350/MW-day for all LDAs in CONE Area 3 (Rest of RTO)
- $425/MW-day for all LDAs in CONE Area 4 (WMAAC)
- $725/MW-day for CONE Area 5 (ComEd)
- $425/MW-day for MAAC.

Because CONE Area 2 exhibits divergence among the constituent LDAs, PJM could consider distinguishing a higher Reference Price of $400 for PEPCO. Similarly in CONE Area 4, PJM could consider a lower Reference Price of $350 for PENELEC and a higher Reference Price of $475 for PPL.

IX. Annual Updates

A. Updates for VRR Purposes

Setting the Reference Price for the VRR curve based on a single Reference Resource and updating its Net CONE annually based on changes in cost indexes and updated E&AS Offsets can cause large fluctuations in the VRR curve. This was demonstrated by the original parameters for the 2026/27 BRA which resulted in a very steep VRR curve due to the collapse of CC Net CONE to zero from high forward E&AS estimates. Some have concluded from this experience that the CC is exposed to too much variation in E&AS Offsets to be suitable as a Reference Resource, suggesting a CT instead. Yet a CT is not a perfect Reference Resource either since it has not been built in PJM in recent years and even a CT's Net CONE is exposed to changes in cost indexes, EAS offsets, and accreditation. A BESS Net CONE is also exposed to changes in those factors in addition to being highly affected by tax credits which may or may not continue in place.

As discussed above, we propose that the Reference Price reflect a long-term marginal cost of capacity informed by several relevant benchmarks across technologies and market conditions. In that case, the Reference Price does not express the net costs at a single point in time but over the long term, so it does not need to be updated annually for temporary changes in costs and revenues. We therefore propose to hold the Reference Price constant in real terms between Quadrennial Reviews. Maintaining a constant Reference Price will add stability to auctions that should help stabilize price signals, supporting investment and rate stability.

One annual adjustment that may be warranted is to scale for changes in accreditations (ELCC), since that amounts to a change in units rather than fluctuations in costs or value. Tracking accreditations of a single technology or fuel-type might re-introduce variability into the Reference Price, so we propose scaling based on fleet-wide average accreditation factors instead.

To hold the Reference Price otherwise constant in real terms, it can be updated using the Consumer Price Index (CPI) at the time auction parameters are set, relative to the time of this filing or prior update.[71] Selecting the CPI respects that the VRR curve is in some sense an expression of implied *value* of capacity—value that should not be fluctuating just because cost and revenue factors do. Scaling the Reference Price according to a Producer Price Index (PPI) may be less appropriate where the Reference Price has already been detached from current pricing and tied instead to indicators of long-run costs.

The Reference Price would still be reviewed in the subsequent Quadrennial Review, although, there too, if the standard is a long-term marginal cost of capacity rather than Net CONE under transient conditions, that should not change radically under most conditions.

B. Updates for MOPR Purposes

The PJM tariff specifies that, prior to each auction, PJM will escalate CONE for each year between the CONE studies during the RPM Quadrennial Review for Minimum Offer Price Rule (MOPR) purposes. The updates will account for changes in plant capital costs based on a composite of indexes for equipment, labor, materials, and other general costs. PJM can reasonably continue to update the CONE value and E&AS Offsets prior to each auction using this approach. These updates could be used to set price screens used as part of the MOPR even if the Reference Prices in the VRR curves escalate only based on inflation, as recommended above.

Based on experience with similar projects and market trends, S&L recommended the blend of indexes described below in Table 28 for updating MOPR thresholds.

71 Specifically, we propose the "Consumer Price Index for All Urban Consumers (CPI-U) for the U.S. City Average for All Items, 1982-84=100" as reported by the U.S. Bureau of Labor Statistics (BLS), since this is the broadest, most comprehensive CPI. See U.S. BLS, Consumer Price Index for All Urban Consumers (CPI-U).

TABLE 28: CONE ANNUAL UPDATE RECOMMENDED COMPOSITE INDEXES

Cost Component		Escalation Index	Interval	Index Weight by Technology: CT	CC	BESS
Overnight Capital Costs						
Construction Labor Costs	[1]	BLS Quarterly Census of Employment and Wages, [CONE Zone representative state], NAICS 2371 Utility System Construction, Private, All Establishment Sizes	Quarterly	15%	25%	17%
Materials and Other Equipment Costs	[2]	BLS Producer Price Index for Commodities, Not Seasonally Adjusted, Intermediate Demand by Commodity Type, Materials and Components for Construction	Monthly	10%	16%	19%
Gas and Steam Turbine Costs	[3]	BLS Producer Price Index for Commodities, Not Seasonally Adjusted, Machinery and Equipment, Turbines and Turbine Generator Sets	Monthly	46%	32%	-
Lithium Carbonate Price	[4]	Lithium Carbonate price, >99.5% Battery Grade from Shanghai Metals Market	Daily	-	-	5%
Battery Supply	[5]	See notes	-	-	-	42%
General Costs (GDP Deflator)	[6]	Bureau of Economic Analysis: Gross Domestic Product Implicit Price Deflator, Index 2017=100, Seasonally Adjusted	Quarterly	29%	27%	18%
Total	**[7]**	**SUM([1]:[6])**		**100%**	**100%**	**100%**
Fixed O&M Costs						
Thermal Power Labor Costs	[8]	BLS Quarterly Census of Employment and Wages, [CONE Zone representative state], NAICS 22111 Electric power generation, Private, All Establishment Sizes	Quarterly	37%	29%	-
Materials Costs	[9]	BLS Producer Price Index for Commodities, Not Seasonally Adjusted, Intermediate Demand by Commodity Type, Materials and Components for Construction	Monthly	17%	45%	40%
Asset Management / Administrative and General Costs	[10]	BLS Quarterly Census of Employment and Wages, [CONE Zone representative state], NAICS 561 Administrative and support services, Private, All Establishment Sizes	Quarterly	30%	19%	22%
Gas and Steam Turbine LTSA Costs	[11]	BLS Producer Price Index for Commodities, Not Seasonally Adjusted, Machinery and Equipment, Turbines and Turbine Generator Sets	Monthly	16%	7%	-
BESS Labor	[12]	BLS Quarterly Census of Employment and Wages, Northeast, NAICS 221114 - Solar Electric Power Generation	Quarterly	-	-	39%
Total	**[13]**	**SUM([8]:[12])**		**100%**	**100%**	**100%**

Sources and Notes:
[5]: S&L observed that there is no publicly accessible index that accurately reflects the costs of lithium-ion battery energy storage in terms of $/kWh with updates provided at reasonable intervals for effective annual CONE adjustments. Yet PJM could use a subscription service such as Bloomberg New Energy Futures (BNEF) to monitor cost fluctuations in this core technology, offering annual updates in their Battery Pack Price Index to adjust the BESS capital cost component between quadrennial reviews.

The application of these factors to the CONE calculation would follow the formula, CONE = overnight capital cost × capital charge rate + fixed O&M. The capital charge rate could be held constant at the same levels reported herein for plants coming online in 2028. We had considered also indexing the ATWACC underlying the capital charge rate to the risk-free rate, but that introduces more complexity and raises questions about other aspects of the capital charge rate, such as the assumed construction timeline. All of these factors could be considered more carefully by PJM and the IMM when reviewing actual offer submissions flagged by the price screen.

We also provide the calculations for an additional adjustment to CONE for CTs and CCs in ComEd. As noted in Section IV.A, Illinois requires all fossil-generating plants to reduce their carbon emissions to zero by January 1, 2045, so we assume these plants have an economic life of 16.5 years for the 2028 online year. However, for each subsequent auction before 2045, the economic life of these plants becomes one year shorter. To account for this, we calculated an Annual Real Adjustment Factor or "asset life factor" to adjust CONE and Net CONE for delivery years 2028/29 through 2031/32. To calculate the asset life factor, we started by recalculating CONE and Net CONE in each year by adjusting the capital charge rate to reflect the shorter timeline for the plant to recover its investment costs. We calculated Net CONE UCAP in each year using the 2028/29 ELCCs provided to us by PJM. The asset life factor then is the ratio of CONE for ComEd in each year to the CONE for ComEd in the 2028/29 delivery year as calculated in this report, with the same calculation for Net CONE. The ComEd CONE or Net CONE for each auction should be multiplied by the asset life factor to calculate the updated CONE/Net CONE for an asset with a shorter life. Table 29 below illustrates the asset life factor calculation for both CONE and Net CONE.

TABLE 29: COMED ASSET LIFE FACTOR CALCULATION, 2028/29 – 2031/32 DELIVERY YEARS (COMED, NOMINAL$ FOR JUNE 2028 ONLINE YEAR)

	Economic Life	Gross CONE ICAP	E&AS Offset ICAP	Net CONE ICAP	ELCC	Gross CONE UCAP	Net CONE UCAP	Annual Real Adjustment Factor (CONE)	Annual Real Adjustment Factor (Net CONE)
	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]
	years	$/MW-day	$/MW-day	$/MW-day	%	$/MW-day	$/MW-day	x	x
Nominal$ for 2028	See notes	See notes	See notes	[B] - [C]	See notes	[B] / [E]	[D] / [E]	See notes	See notes
CT									
COMED, 2028/29	16.5	**$789**	$108	$681	79%	$998	**$862**	**1**	**1**
COMED, 2029/30	15.5	**$804**	$108	$697	79%	$1,018	**$882**	**1.020**	**1.023**
COMED, 2030/31	14.5	**$829**	$108	$722	79%	$1,050	**$914**	**1.052**	**1.060**
COMED, 2031/32	13.5	**$846**	$108	$738	79%	$1,071	**$935**	**1.073**	**1.084**
CC									
COMED, 2028/29	16.5	**$953**	$327	$627	81%	$1,177	**$774**	**1**	**1**
COMED, 2029/30	15.5	**$973**	$327	$646	81%	$1,201	**$797**	**1.020**	**1.031**
COMED, 2030/31	14.5	**$1,000**	$327	$673	81%	$1,234	**$831**	**1.048**	**1.074**
COMED, 2031/32	13.5	**$1,022**	$327	$695	81%	$1,262	**$858**	**1.072**	**1.109**

Sources and Notes:
[B]: Output from CONE Model.
[C], [E]: Provided by PJM Staff.
[H]: [F] / [F] ComEd, 2028/29.
[I]: [G] / [G] ComEd, 2028/29.

Appendix A

A.1 Capital Drawdown Schedules

S&L provided capital drawdown schedules for each technology reflecting the percentage of the total nominal capital costs that are expended in each month of the project development period. Informed by S&L's experience, we assume that equipment prices will be locked in at an equipment contract lock-in date at 5 months into the project development period for the CT and CC, and 4 months into the project development period for the BESS.

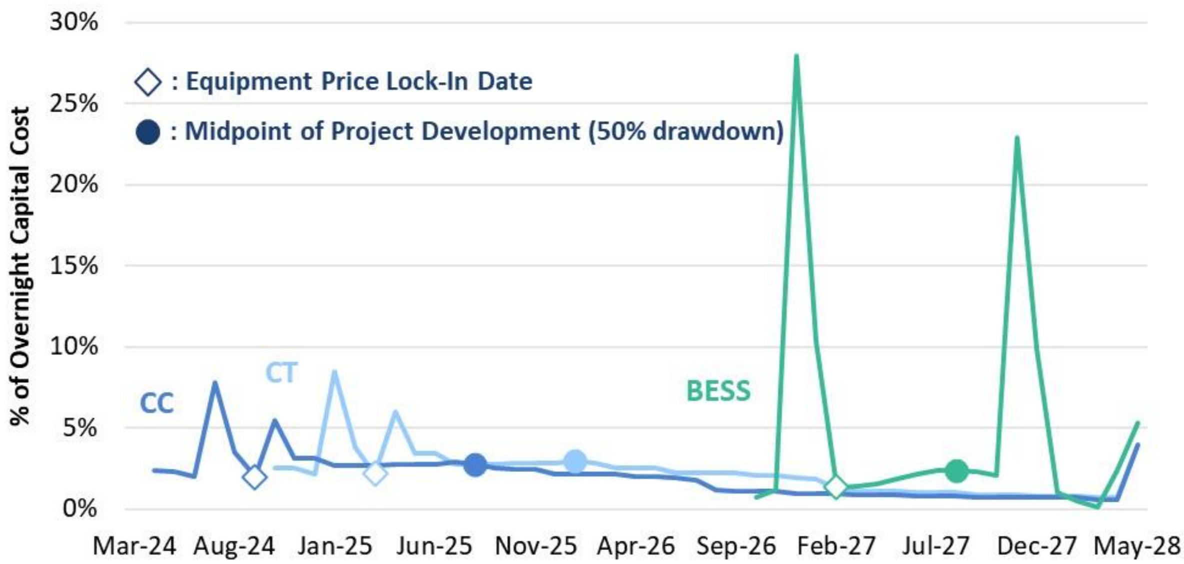
All CT equipment costs are adjusted from January 2025 to the equipment price lock-in date at month 5 of the 44-month project development period (i.e., escalated to March 2025 for a June 2028 COD). All other capital costs are escalated from January 2025 to the midpoint of project development at month 15 of the 44-month project development period (i.e., escalated to January 2026 for a June 2028 COD).

For CCs, the OFE, the condenser, and other EPC equipment are adjusted from January 2025 to the equipment price lock-in date at month 5 of the 50-month project development period (i.e., de-escalated to September 2024 for a June 2028 COD). We do not escalate net start-up fuel costs since they are incurred in the few months before operation and are based on energy and fuel futures prices for the months close to June 2028. All other capital costs are escalated from January 2025 to the midpoint of project development at month 16 of the 50-month project development period (i.e., escalated to August 2025 for a June 2028 COD).

BESS equipment costs are adjusted from January 2025 to the equipment price lock-in date at month 4 of the 20-month project development period (i.e., escalated to February 2027 for a June 2028 COD). All other capital costs are escalated from January 2025 to the midpoint of project development at month 10 of the 20-month project development period (i.e., escalated to August 2027 for a June 2028 COD).

Figure 16 below illustrates the capital drawdown schedules for the CT, CC, and BESS, including equipment price lock-in dates and the midpoint of each schedule.

FIGURE 16: VISUALIZATION OF CAPITAL DRAWDOWN SCHEDULES FOR CT, CC, AND BESS



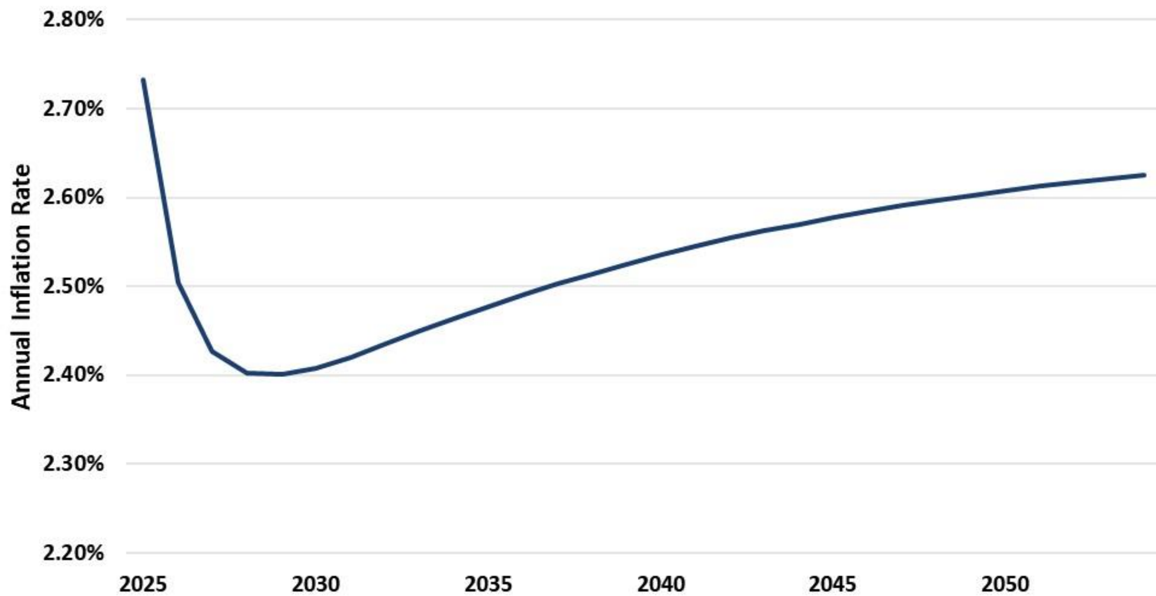
Notes and Sources: Capital drawdown schedules provided by S&L.

A.2 Inflation

We use 30-year inflation expectations reported by the Federal Reserve Bank of Cleveland.[72] That data, presented initially in the form of cumulative compound annual average expected inflation from February 2025 to each year from 2025-2054, is converted to annual year-on-year inflation rates shown in Figure 17. Project costs were escalated where applicable using this inflation curve.

72 Federal Reserve Bank of Cleveland, Inflation Expectations, February 12, 2025.

FIGURE 17: EXPECTED INFLATIONS, 2025–2055



Sources and Notes: Annual year-on-year inflation rate curve derived from 30-year forward-looking expected cumulative compound average annual inflation rates from Federal Reserve Bank of Cleveland, Inflation Expectations, February 12, 2025.

A.3 Net Start-Up Fuel Costs

To calculate the net costs a plant would incur during startup and testing, we used the following approach:

- Natural Gas: As in previous CONE studies, we used monthly natural gas forward prices for January-May 2028, assigning a pricing hub to each CONE Area. Transco Zone 6 (non-New York) is assigned to EMAAC, Transco Zone 5 to WMAAC, TCO to Rest of RTO, TGP Zone 4 300L to WMAAC, and Chicago to ComEd.
- Fuel Oil: We assumed an RTO-wide monthly fuel oil price from January-May 2028 based on forward prices. Fuel oil use is only relevant for the dual-fuel CT.
- Electric Energy: We estimated energy prices from April-May 2028 for each CONE Area using hourly hub-level forward prices. We assigned Western Hub to EMAAC, SWMAAC, and WMAAC, AEP-Dayton Hub to Rest of RTO, and Northern Illinois Hub to ComEd. We then averaged the on-peak and off-peak prices for each CONE Area to estimate the average price that the plant would receive for energy generated during testing.

S&L provided estimates of natural gas and fuel oil consumption, as well as energy production during testing. During testing plants are compensated for the electricity they generate therefore, net start-up costs are negative when the revenues a plant receives for the electricity it generates exceed the cost of the fuel used. Table 30 shows the elements of the net start-up cost calculation.

TABLE 30: STARTUP PRODUCTION AND FUEL CONSUMPTION DURING TESTING (NOMINAL$ FOR JUNE 2028 ONLINE YEAR)

	Natural Gas			Fuel Oil			Energy Production			Net
	Natural Gas Used MMBtu [A]	**Natural Gas Price** $/MMBtu [B]	**Natural Gas Cost** $millions [C] [A] x [B]	**Fuel Oil Used** MMBtu [D]	**Fuel Oil Price** $/MMBtu [E]	**Fuel Oil Cost** $millions [F] [D] x [E]	**Energy Produced** MWh [G]	**Energy Price** $/MWh [H]	**Energy Sales Credit** $millions [I] [G] x [H]	**Net Cost** $millions [J] [C] + [F] - [I]
Gas CT										
EMAAC	1,723,733	$4.2	$7.2	84,186	$14.6	$1.2	204,755	$47.0	$9.6	**-$1.1**
SWMAAC	1,734,771	$4.9	$8.5	84,696	$14.6	$1.2	206,106	$47.0	$9.7	**$0.0**
Rest of RTO	1,696,536	$3.3	$5.6	82,035	$14.6	$1.2	200,069	$42.3	$8.5	**-$1.7**
WMAAC	1,681,592	$3.2	$5.3	81,505	$14.6	$1.2	198,603	$47.0	$9.3	**-$2.8**
COMED	1,720,806	$4.0	$6.9	83,043	$14.6	$1.2	202,704	$34.7	$7.0	**$1.1**
Gas CC										
EMAAC	6,824,004	$4.2	$28.7				1,150,603	$47.0	$54.0	**-$25.4**
SWMAAC	6,862,754	$4.9	$33.5				1,157,481	$47.0	$54.4	**-$20.9**
Rest of RTO	6,727,054	$3.3	$22.1				1,125,556	$42.3	$47.6	**-$25.6**
WMAAC	6,666,820	$3.2	$21.0				1,117,679	$47.0	$52.5	**-$31.5**
COMED	6,821,085	$4.0	$27.5				1,139,616	$34.7	$39.5	**-$12.0**

Sources and Notes: Energy production and fuel consumption estimated by S&L. Estimated energy and fuel prices provided by PJM. Hub-level energy prices are an average of forward prices between 12/13/2024 and 01/15/2025.

A.4 Electric and Gas Interconnection Costs

We derived electrical interconnection costs from confidential, project-specific cost data for eight representative gas-fired projects provided by PJM. The total electrical interconnection costs were calculated by summing the cost of attachment facilities, necessary network upgrades, and passed-through PJM labor and overhead costs. For projects that chose to build their own attachment facilities, we estimated costs using the capacity-weighted average per-kW attachment cost from the other projects in the sample. All costs were then escalated to January 2025 dollars using the PPI for new industrial building construction. We set the per-kW electrical interconnection cost for all three resources using the capacity-weighted average total interconnection cost per-kW across all plants in the sample. An anonymized summary of these results is shown in Table 31.

TABLE 31: ELECTRICAL INTERCONNECTION COSTS (NOMINAL$ FOR JANUARY 2025)

Plant Size	Observations	Capacity-Weighted Average: Total Interconnection Cost	Capacity-Weighted Average: Interconnection Cost per kW
	count	2025$ millions	2025$/kW
< 500 MW	3	$7.3	$20.8
500 - 1,000 MW	2	$19.4	$23.0
> 1,000 MW	3	$91.2	$76.7
All Plants		**$60.3**	**$54.7**

Source and Notes: Confidential project-specific cost data provided by PJM.

Based on interviews with S&L, the IMM, and stakeholders, we have updated our approach for estimating gas interconnection costs from the 2022 PJM CONE Study. Previously we applied gas interconnection costs on a representative average per mile cost of pipeline laterals to both the CC and CT. Now we account for costs more explicitly based on pipeline diameter as well. From experience with similar projects, S&L advised us that the CT would need a 5-mile pipeline with a diameter between 12 and 16 inches, and the CC would need a 5-mile pipeline with a diameter between 20 and 24 inches.

As in the 2022 PJM CONE Study, we used the Energy Information Administration (EIA) Natural Gas Pipeline Projects dataset to examine costs for representative gas pipeline lateral projects.[73] We first filtered the data to lateral pipelines in the Northeast and Midwest that started operation in 2016 or later to capture the most relevant costs and account for regional cost differences. We then escalated each project's costs to 2025 dollars using the Bureau of Labor Statistics' (BLS) Producer Price Index (PPI) for new industrial building construction.[74]

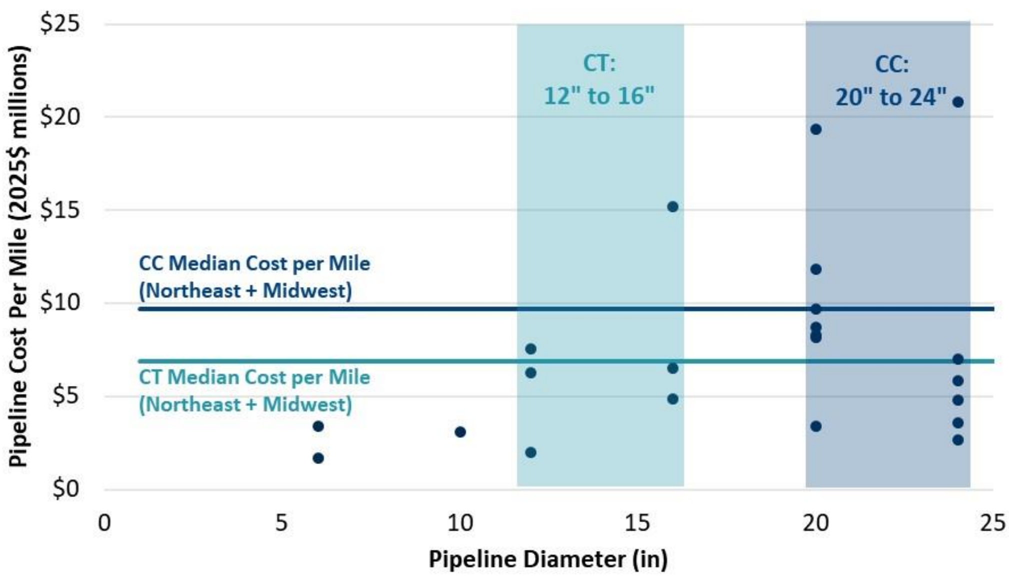
Project costs are highly situation-dependent and do not uniformly scale with pipeline diameter, as noted in the 2018 and 2022 PJM CONE Studies and confirmed with S&L. To minimize this effect, we calculated estimated gas interconnection cost per-mile as the median for two separate groups of pipelines, each with diameters corresponding to the ranges for a CT and a CC provided by S&L. This resulted in a gas interconnection cost of $6.9 million/mile and $34.5 million total for the CT and $9.7 million/mile and $48.4 million total for the CC in 2025 dollars. Figure 18 below shows a

[73] EIA, Natural Gas Pipeline Projects, January 2024.

[74] Bureau of Labor Statistics, PPI industry data for New industrial building construction, not seasonally adjusted, February 2025.

selection of pipelines from the EIA dataset along with the medians for the CT and the CC, and Table 32 shows the resulting gas interconnection costs calculation.

FIGURE 18: COST OF LATERAL PIPELINE PROJECTS, 2016 AND LATER (NOMINAL$ FOR JANUARY 2025)



Sources and Notes: EIA, Natural Gas Pipeline Projects, January 2024.

TABLE 32: GAS INTERCONNECTION COSTS CALCULATION (NOMINAL$ FOR JANUARY 2025)

Technology	Diameter	Observations	Median Pipeline Cost	Pipeline Length	Gas Interconnection Costs
	[A]	[B]	[C]	[D]	**[E]**
	in	count	2025$ millions/mi	mi	**2025$ millions**
					[C] x [D]
CT	12"-16"	4	$6.9	5	**$34.5**
CC	20"-24"	11	$9.7	5	**$48.4**

Sources and Notes: EIA, Natural Gas Pipeline Projects, January 2024. Median cost per mile of laterals built since 2016 in Northeast and Midwest regions.

A.5 Firm Transportation Service

To estimate the cost of firm transportation service for the CC, we utilized FT-1 and equivalent rate schedules for pipelines servicing each CONE Area. Next, using the plant's max summer capacity and max heat rate with duct firing, we determined the size of the firm gas reservation required for annual operations. Based on a review of hub liquidity and consultation with Brattle's experts in natural gas, we have updated SWMAAC's assigned pipeline to Transco Zone 4, and

WMAAC's assigned pipeline to Tennessee 300L from the 2022 PJM CONE Study. For CONE Areas with multiple pipelines, we calculated firm gas transportation cost as an average of the rate schedules for the pipelines in the zone. Finally, we multiplied the firm gas capacity cost by the required reservation size to calculate the total firm gas transportation cost and then escalated it to 2028 and later years using the approach described in Section V.C.

TABLE 33: FIRM GAS TRANSPORTATION SERVICE COSTS FOR CC ($ PER DTH/D PER MONTH, NOMINAL$ FOR JANUARY 2025)

CONE Area	Pipeline	Representative Firm Gas Capacity Cost 2025$ per Dth/d per month
1 EMAAC	Transco Zone 6 (non-NY)	$4.03
2 SWMAAC	Transco Zone 4	$7.63
3 Rest of RTO	Columbia-Appalachia TCO	$11.15
	Michcon	$12.88
	Transco Zone 5	$5.81
4 WMAAC	Tennessee 300L	$4.31
	TETCO M3	$9.98
5 COMED	Chicago	$3.21

Sources and Notes: Transcontinental Gas Pipe Line Company LLC, FERC Gas Tariff Fifth Revised Volume No 1., July 20, 2010, p. 15; TC Energy, FERC Gas Tariff Fourth Revised Volume No. 1, November 1, 2024, p. 13; DTE Gas Company, Operating Statement, November 21, 2024, p. 45; Tennessee Gas Pipeline Company LLC, FERC NGA Gas Tariff Sixth Revised Volume No.1, November 18, 2024, p. 15; Texas Eastern Transmission LP, Tariff Eighth Revised Volume No. 1, December 30, 2024, p. 30; Nicor Gas Company, Operating Statement, September 1, 2024, p. 35.

A.6 Land Costs

We estimated the cost of land by reviewing asking prices for vacant industrial land greater than 10 acres for a selection of counties in and around the reference location for each CONE Area.[75] The land price assumed for each CONE Area is the nominal acre-weighted average land price of all collected listings in that area as of November 2024.

[75] LoopNet, Accessed November 13, 2024; and LandSearch, Accessed November 13, 2024.

TABLE 34: CURRENT LAND ASKING PRICES
($/ACRE, NOMINAL$ FOR JANUARY 2025)

CONE Area	Observations	Range	Land Price
	count	2025$/acre	2025$/acre
1 EMAAC	5	$32,885 to $127,660	$106,417
2 SWMAAC	3	$93,174 to $127,500	$100,182
3 Rest of RTO	7	$2,943 to $125,294	$43,099
4 WMAAC	4	$55,000 to $124,409	$91,827
5 COMED	7	$27,518 to $283,902	$117,924

Sources and Notes: Land listings from LoopNet's Commercial Real Estate Listings and LandSearch.

TABLE 35: COST OF LAND PURCHASED FOR CT, CC, AND BESS
(NOMINAL$ FOR JANUARY 2025)

Technology		CT		CC		BESS	
CONE Area	Land Price	CT Plot Size	CT Land Cost	CC Plot Size	CC Land Cost	BESS Plot Size	BESS Land Cost
	[A]	[B]	[C]	[D]	[E]	[F]	[G]
	2025$/acre	acres	2025$	acres	2025$	acres	2025$
			[A] x [B]		[A] x [D]		[A] x [F]
1 EMAAC	$106,417	10	**$1,064,169**	60	**$6,385,011**	12	**$1,277,002**
2 SWMAAC	$100,182	10	**$1,001,817**	60	**$6,010,900**	12	**$1,202,180**
3 Rest of RTO	$43,099	10	**$430,989**	60	**$2,585,934**	12	**$517,187**
4 WMAAC	$91,827	10	**$918,266**	60	**$5,509,598**	12	**$1,101,920**
5 COMED	$117,924	10	**$1,179,242**	60	**$7,075,453**	12	**$1,415,091**

Sources and Notes:
[A]: Average land costs from Table 34.
[B], [D], [F]: Estimated by S&L.

A.7 Property Taxes

The property tax rates for each CONE Area are summarized in Table 36. We collected nominal tax rates, assessment ratios, and applicable depreciation schedules for the relevant counties of each CONE Area. We also reviewed any relevant tax code to confirm the applicability of real and personal property tax in each state. The effective property tax rate for each CONE Area is the product of the average nominal tax rate and the average assessment ratio. In Rest of RTO, the property tax liability is the average of the tax liability in Ohio and the tax liability in Pennsylvania.

TABLE 36: PROPERTY TAX RATE ESTIMATES BY CONE AREA

		Real Property Tax			Personal Property Tax				
		Nominal Tax Rate	Assessment Ratio	Effective Tax Rate	Nominal Tax Rate	Assessment Ratio	Effective Tax Rate	Depreciation Rate	Depreciation Floor
		[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]
		%	%	%	%	%	%	%/yr	%
EMAAC									
New Jersey	[1]	4.0%	75.4%	3.0%	n/a	n/a	n/a	n/a	n/a
SWMAAC									
Maryland	[2]	1.2%	100.0%	1.2%	2.7%	50.0%	1.3%	3.3%	25.0%
RTO									
Ohio	[3]	5.2%	35.0%	1.8%	5.2%	24.0%	1.2%	See notes	n/a
Pennsylvania	[4]	2.8%	100.0%	2.8%	n/a	n/a	n/a	n/a	n/a
WMAAC									
Pennsylvania	[5]	3.8%	100.0%	3.8%	n/a	n/a	n/a	n/a	n/a
COMED									
Illinois	[6]	8.4%	33.3%	2.8%	n/a	n/a	n/a	n/a	n/a

Sources and Notes:
[1] - [6]: State-level values are calculated as a simple average of included counties.
[C]: [A] x [B].
[F]: [D] x [E].
[1][A] - [1][B]: New Jersey rates estimated based on the average effective tax rates from Gloucester and Camden counties. See Gloucester County Board of Taxation & County Assessor's Office, Gloucester County Historical Rates and Ratios, October 11, 2024; Camden County Board of Taxation, 2024 Camden County Tax Rates.
[1][D]-[1][H]: No personal property tax is assessed on power plants in New Jersey. See New Jersey Legislature, NJ Rev Stat § 54:4-1, last amended 2004.
[2][A]-[2][C]: Maryland tax rates estimated based on 2024 average county tax rates in Charles County and Prince George's county. See Maryland Department of Assessments and Taxation, 2024-25 Tax Rates.
[2][E]: Maryland General Assembly, MD Tax-Prop Code § 7-237, 2016.
[2][G]: Maryland Division of State Documents, Maryland Code of Regulations 18.03.01.02 § C2.
[2][H]: Maryland Dept. of Assessments and Taxation, Instructions for Business Entity Annual Report (Form 1), 2024.
[3][A]: Ohio rates estimated based on the average effective tax rates in Trumbull and Carroll counties. See Trumbull County Treasurer, Trumbull County Tax Rates for 2024; Carroll County Auditor's Office, 2024 Tax District Report, January 6, 2025.
[3][B]: Ohio Legislative Service Commission, Ohio Revised Code 5715.01 § B, effective October 3, 2023.
[3][D]: In Ohio, utility tangible personal property is taxed at the same rate as real property. See Kuhns et al, Public Utility Personal Property Tax Basic Overview, May 2016.
[3][E]: All production plant for energy companies in Ohio is assessed at 24%. See Ohio Department of Taxation, Instructions and Valuation Procedures for Filing Ohio Public Utility Property Tax Reports, 2025.
[3][G]: Depreciation schedules for utility assets are found in: Ohio Department of Taxation, Form U-EN, SchC-Prod Tab. Merchant energy production plant is valued as Class C-30, see Ohio Department of Taxation, Instructions and Valuation Procedures for Filing Ohio Public Utility Property Tax Reports, pp. 14, 29.
[4][A]: Pennsylvania county tax rates for Rest of RTO based on 2025 rates in the county of Lawrence. See Lawrence County Board of Assessment, 2025 Millage Rate.
[4][B]: Pennsylvania publishes Common Level Ratios (CLRs) for each county to be used in assessment appeals. This model assumes that the property is assessed accurately, so CLRs greater than 100% were assumed to be 100%. See Pennsylvania Department of Revenue, Common Level Ratio (CLR) Real Estate Valuation Factors.
[4][D] - [4][H]: Only real estate tax is assessed by local governments. See Pennsylvania Local Government Commission, Pennsylvania Legislator's Municipal Deskbook 7th Edition, 2025, p.131.

[5][A]: Pennsylvania county tax rates for WMAAC based on average effective tax rate between Luzerne, Lycoming, and Bradford counties. See Luzerne County Assessment Office, 2024 Millages; Lycoming County Assessment Office, 2025 Millages, January 29, 2025; Bradford County Assessment Office, 2024 Mill Rates.
[6][A]: Will County Clerk, Tax Codes and Rates by Township, 2023.
[6][B]: Illinois General Assembly, 35 ILCS 200/9-145.
[6][D] - [6][H]: Illinois does not collect business personal property taxes. See Illinois General Assembly, 30 ILCS 115/12.

A.8 10-Year Average E&AS Offset

The 10-year historical average E&AS offset was derived from estimates of net revenues from the *2023 State of the Market Report* and from MOPR parameters for CTs and CCs.[76] For delivery years 2017/18 through 2023/24, the net revenues simulated by the IMM in the *2023 State of the Market Report* were inflated to 2025 dollars using the historical CPI. Net revenues for delivery years 2024/25 through 2026/27 were taken from published MOPR parameters by PJM. To match the inflation assumptions used in the 2022 PJM CONE Study to develop our long-run overnight costs, we deflated the net revenues from MOPR parameters to 2025 dollars. Historical E&AS offsets were then inflated to 2028 dollars. Table 37 and Table 38 below show ten years of CT and CC net revenues by LDA and the resulting average E&AS offsets in 2025 dollars and 2028 dollars.

[76] Net revenues for delivery years 2017/2018 – 2023/24 from Monitoring Analytics, State of the Market Report for PJM, March 14, 2024, pp.399-400; Net revenues for delivery years 2024/25-2026/27 from PJM, Default New Entry MOPR Offer Prices, Accessed March 6, 2025.

TABLE 37: CC 10 YEAR AVERAGE E&AS OFFSET BY LDA ($/MW-DAY ICAP, NOMINAL$ FOR JANUARY 2025)

	Net Revenues from IMM in 2025$							Net Revenues from MOPR in 2025$			Average Net Revenues	
Delivery Year	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2025$	2028$
CONE Area 1												
AE	$177	$231	$174	$100	$136	$208	$132	$139	$263	$258	**$182**	**$198**
DPL	$98	$164	$73	$59	$148	$300	$201	$193	$348	$340	**$192**	**$209**
JCPL	$188	$223	$175	$101	$145	$210	$141	$144	$281	$275	**$188**	**$205**
PE	$229	$254	$165	$150	$200	$329	$171	$135	$250	$244	**$213**	**$232**
PSEG	$255	$279	$182	$111	$160	$219	$141	$145	$284	$278	**$205**	**$223**
RECO	$196	$229	$182	$113	$193	$323	$165	$168	$328	$321	**$222**	**$242**
CONE Area 2												
BGE	$252	$337	$252	$226	$368	$568	$399	$307	$603	$590	**$390**	**$425**
PEPCO	$193	$289	$197	$131	$264	$439	$239	$225	$438	$429	**$284**	**$310**
CONE Area 3												
AEP	$210	$374	$253	$185	$307	$610	$294	$244	$456	$446	**$338**	**$368**
APS	$269	$402	$217	$181	$299	$493	$306	$268	$496	$485	**$342**	**$372**
ATSI	$215	$414	$256	$186	$309	$588	$280	$217	$403	$394	**$326**	**$355**
DAYTON	$216	$402	$275	$210	$363	$655	$313	$249	$454	$444	**$358**	**$390**
DEOK	$204	$419	$259	$194	$342	$626	$300	$233	$434	$425	**$344**	**$374**
DLCO	$229	$313	$195	$177	$280	$582	$349	$229	$420	$411	**$319**	**$347**
DOM	$215	$316	$229	$170	$328	$701	$318	$216	$473	$463	**$343**	**$373**
EKPC	$186	$313	$227	$171	$302	$564	$257	$203	$389	$380	**$299**	**$326**
OVEC								$227	$436	$427	**$363**	**$396**
CONE Area 4												
METED	$254	$269	$195	$181	$319	$564	$267	$202	$422	$413	**$309**	**$336**
PENELEC	$277	$406	$238	$210	$338	$1	$365	$242	$453	$443	**$297**	**$324**
PPL	$260	$373	$183	$164	$290	$628	$262	$159	$337	$330	**$299**	**$325**
CONE Area 5												
COMED	$135	$192	$152	$114	$192	$406	$204	$148	$292	$286	**$212**	**$231**

Notes and Sources: 2028 average net revenues are expressed in nominal$ for June 2028 online year. Net revenues for delivery years 2017/2018 – 2023/24 from Monitoring Analytics, State of the Market Report for PJM, March 14, 2024, pp.399-400; Net revenues for delivery years 2024/25-2026/27 from PJM, Default New Entry MOPR Offer Prices, Accessed March 6, 2025. CPI from Bureau of Labor Statistics, Consumer Price Index for All Urban Consumers (CPI-U), Accessed March 6, 2025.

TABLE 38: CC 10 YEAR AVERAGE E&AS OFFSET BY LDA ($/MW-DAY ICAP, NOMINAL$ FOR JANUARY 2025)

	Net Revenues from IMM in 2025$							Net Revenues from MOPR in 2025$			Average Net Revenues	
Delivery Year	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2025$	2028$
CONE Area 1												
AE	$177	$231	$174	$100	$136	$208	$132	$139	$263	$258	**$182**	**$198**
DPL	$98	$164	$73	$59	$148	$300	$201	$193	$348	$340	**$192**	**$209**
JCPL	$188	$223	$175	$101	$145	$210	$141	$144	$281	$275	**$188**	**$205**
PE	$229	$254	$165	$150	$200	$329	$171	$135	$250	$244	**$213**	**$232**
PSEG	$255	$279	$182	$111	$160	$219	$141	$145	$284	$278	**$205**	**$223**
RECO	$196	$229	$182	$113	$193	$323	$165	$168	$328	$321	**$222**	**$242**
CONE Area 2												
BGE	$252	$337	$252	$226	$368	$568	$399	$307	$603	$590	**$390**	**$425**
PEPCO	$193	$289	$197	$131	$264	$439	$239	$225	$438	$429	**$284**	**$310**
CONE Area 3												
AEP	$210	$374	$253	$185	$307	$610	$294	$244	$456	$446	**$338**	**$368**
APS	$269	$402	$217	$181	$299	$493	$306	$268	$496	$485	**$342**	**$372**
ATSI	$215	$414	$256	$186	$309	$588	$280	$217	$403	$394	**$326**	**$355**
DAYTON	$216	$402	$275	$210	$363	$655	$313	$249	$454	$444	**$358**	**$390**
DEOK	$204	$419	$259	$194	$342	$626	$300	$233	$434	$425	**$344**	**$374**
DLCO	$229	$313	$195	$177	$280	$582	$349	$229	$420	$411	**$319**	**$347**
DOM	$215	$316	$229	$170	$328	$701	$318	$216	$473	$463	**$343**	**$373**
EKPC	$186	$313	$227	$171	$302	$564	$257	$203	$389	$380	**$299**	**$326**
OVEC								$227	$436	$427	**$363**	**$396**
CONE Area 4												
METED	$254	$269	$195	$181	$319	$564	$267	$202	$422	$413	**$309**	**$336**
PENELEC	$277	$406	$238	$210	$338	$1	$365	$242	$453	$443	**$297**	**$324**
PPL	$260	$373	$183	$164	$290	$628	$262	$159	$337	$330	**$299**	**$325**
CONE Area 5												
COMED	$135	$192	$152	$114	$192	$406	$204	$148	$292	$286	**$212**	**$231**

Notes and Sources: 2028 average net revenues are expressed in nominal$ for June 2028 online year. Net revenues for delivery years 2017/2018 – 2023/24 from Monitoring Analytics, State of the Market Report for PJM, March 14, 2024, pp.399-400; Net revenues for delivery years 2024/25-2026/27 from PJM, Default New Entry MOPR Offer Prices, Accessed March 6, 2025. CPI from Bureau of Labor Statistics, Consumer Price Index for All Urban Consumers (CPI-U), Accessed March 6, 2025.

A.9 Adjusted Empirical Net CONE

We calculated the Adjusted Empirical Net CONE, one of our long-term benchmarks, as the average of BRA clearing prices in delivery years 2014/15 through 2022/23 (when many new resources entered, mostly CCs), with adjustments. First, each year's BRA clearing price was inflated to 2025 dollars using the historical CPI, then adjusted for updated ELCC values by multiplying by the ELCC in that year, then dividing by the current 81% ELCC.[77] These adjustments for inflation and an updated ELCC value resulted in a historical empirical Net CONE of $168/MW-day UCAP.

[77] Historical ELCCs calculated as Net CONE ICAP / Net CONE UCAP. See PJM, Default New Entry MOPR Offer Prices and Planning Parameters, Accessed April 8, 2025.

Next, the historical empirical Net CONE was adjusted to reflect a 1.5% higher ATWACC by backing out historical empirical Gross CONE using current ELCCs and E&AS offsets as of February 2024. Using the CONE model, we found the change in the CCR that resulted from an increase in the ATWACC from 8% to 9.5%, then used both the new CCR and the E&AS offset to calculate the ATWACC-adjusted empirical Net CONE of $241/MW-day UCAP.

X. List of Acronyms

ATWACC	After-Tax Weighted Average Cost of Capital
BESS	Battery Energy Storage System
BLS	Bureau of Labor Statistics
BOP	Balance of Plant
BRA	Base Residual Auction
CC	Combined Cycle
CCR	Capital Charge Rate
COD	Commercial Online Date
CoD	Cost of Debt
CoE	Cost of Equity
COMED	Commonwealth Edison
CONE	Cost of New Entry
CPI	Consumer Price Index
CT	Combustion Turbine
Dth	Dekatherm(s)
E&AS	Energy and Ancillary Services
EIA	Energy Information Administration
ELCC	Effective Load-Carrying Capability
EMAAC	Eastern Mid-Atlantic Area Council
FERC	Federal Energy Regulatory Commission
FTR	Financial Transmission Right(s)
GE	General Electric
GW	Gigawatt(s)
HRSG	Heat Recovery Steam Generator
ICAP	Installed Capacity
IMM	Independent Market Monitor
kW	Kilowatt(s)
LDA	Locational Deliverability Area
LMP	Locational Marginal Price
LTSA	Long-Term Service Agreement
MMBtu	One Million British Thermal Units
MOPR	Minimum Offer Price Rule
MW	Megawatt(s)
MWh	Megawatt-Hour(s)
NREL	National Renewable Energy Laboratory
O&M	Operations and Maintenance

PCS	Power Conversion System
PJM	PJM Interconnection, LLC
PPI	Producer Price Index
REC	Renewable Energy Certificate
RGGI	Regional Greenhouse Gas Initiative
RTO	Regional Transmission Organization
S&L	Sargent & Lundy
SCR	Selective Catalytic Reduction
SWMAAC	Southwestern Mid-Atlantic Area Council
TETCO	Texas Eastern Transmission Company
UCAP	Unforced Capacity
WMAAC	Western Mid-Atlantic Area Council

LEAD AUTHORS

Dr. Samuel Newell is a Principal at The Brattle Group and leads Brattle's Electricity Group of 60 consultants addressing economic questions in the industry's energy transition.

His 25 years of consulting experience centers on electricity wholesale markets, market design, transmission planning, resource planning and contracting, resource valuation, and policy analysis. He advises, conducts studies, and testifies in state and federal proceedings for a variety of clients, including ISOs, state energy agencies, infrastructure investors, and wholesale market participants.

Dr. Andrew W. Thompson is an Energy Associate at The Brattle Group with a background in electrical engineering and expertise in wholesale electricity market design, regulatory economics, and policy analysis of network industries, particularly in the energy sector.

His work focuses on wholesale electricity market design and reform, capacity market/auction design, integration of emerging energy technologies, energy market regulation, the hydrogen economy, energy finance, cost of capital estimation, utility rate cases, and economic damages assessments for renewable and battery storage assets.

Exhibit No. 3

August 2025 Gross CONE with Technology Cost and Depreciation Updates

Sixth Review of PJM's RPM VRR Curve Parameters

INTERIM UPDATE: GROSS CONE WITH TECHNOLOGY COST AND DEPRECIATION UPDATES

PREPARED BY

The Brattle Group

Sam Newell

Bin Zhou

Andrew W. Thompson

Nathan Felmus

Harsha Haribhaskar

Sargent & Lundy

Joshua Jungé

Hyojin Lee

PREPARED FOR

PJM Market Implementation Committee

AUGUST 18, 2025

Brattle

Summary of Updates

Physical Updates (CC and CT)

- With wet compression
- Updated specifications from GE including higher firing temperature
- Reduced inlet pressure drop

Financial Update (CC, CT, and BESS)

- 100% bonus depreciation returning with the OBBBA
- Bonus depreciation effect adjusted for reasonable estimate of typical present value capture for generators

Introduction

Our August 5 presentation incorporated 100% bonus depreciation per OBBBA, assuming gencos can take full advantage of it in year 1 of the project, as in our past reviews.

However, LS Power commented that our assumption was unrealistic because gencos tend to have limited taxable income to absorb 100% bonus depreciation in year 1 and pointed to its testimony in 2018.

After a fresh look given current circumstances, we agree with some of LS Power's conclusions:

- PJM's proposed reference resource is now a 1,393 MW CC with a $2.4 billion installed cost (in Area 3) vs. a $270 million CT that PJM used in the 2018 CONE study. This single-plant cost is more than a typical IPP's taxable income, such that the typical IPP cannot take full advantage of the bonus depreciation in year 1. (A 437 MW CT is $670 million and 200 MW BESS is $380 million installed cost).
- Taxable incomes may rise but so will investors' capital spend programs with load growth, not just in PJM but nationally. This will quickly "use up" taxable income.
- Since 100% bonus depreciation was allowed between 2018 and 2022 under TCJA, there has been essentially no market for depreciation-only investment structures with partner entities, such as tax equity flips or sales-and-leasebacks, to monetize the benefits.
- Moreover, the choice of tax strategies depends not only on the taxable income, but also on the companies' financial leverage, tax consolidation, existing NOLs, and other factors.

Analysis of Tax Appetite of Different Market Participants

Publicly-traded IPPs: an analysis of their taxable incomes suggests they, as representative developers, may not be sufficient to take full advantage of the 100% bonus deprecation in year 1.

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.

Private Developers: less information and smaller than publicly-traded IPPs. Even if they can pass the tax benefits up to their corporate parents, some parents could potentially take full advantage of the year-1 100% bonus depreciation, but some parents could not as they are pass-through entities with some of the ultimate investors being tax-exempt.

Hyperscalers: some with high taxable incomes could invest in some projects, but we do not consider them typical or "marginal" for setting reference prices for the rest of the market.

Market Transfers: based on the TCJA experience, we do not believe the benefits can be readily captured through structured arrangements such as flips and sales-and-leasebacks.

Our Updated Tax Deprecation Assumptions

The key question is how quickly the "marginal" genco in PJM can depreciate the installed cost from its taxable income; faster realization of the same nominal depreciation has a higher present value.

We assume that the marginal genco 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:

- Full year-1 realization of 100% bonus depreciation (giving rise to the "Min" CONEs); and
- The original MACRS of 20 years for CC, 15 years for CT, and 7 years for BESS (giving rise to the "Max" CONEs).

Because the current taxable incomes of publicly-traded IPPs are smaller than the cost of even a single CC plant, we believe something closer to MACRS is more reasonable. We represent this with the following assumptions: 10-year straight-line depreciation for CC, 7-year straight-line depreciation for CT, and 3-year straight-line depreciation for BESS.

- These result in CONE values that are equivalent to weighted averages between **Min** (100% bonus depreciation in year 1) and **Max** (applicable MACRS) of 25/75 for CC, and 40/60 for CT and BESS.
- Due to lumpiness, the larger plants have a longer schedule to capture all of the NOLs.

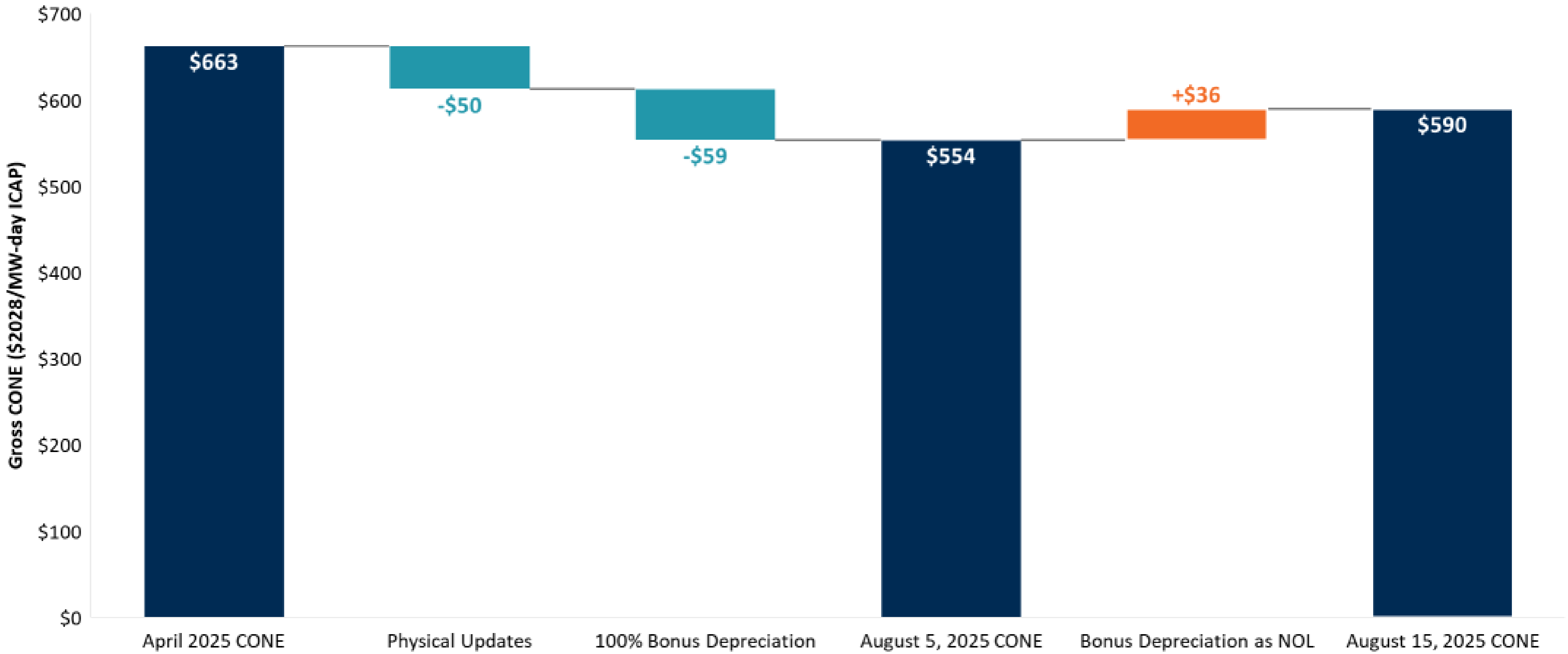
We believe these assumptions are reasonable, while recognizing that the present value of depreciation is a less precise component of the CONE analysis than many others. This is inevitable since we lack relevant data and are not able to rigorously identify the relevant investors and predict their taxable incomes, capital expenditures, and tax strategies.

Updated Results by Technology and CONE Area

CONE Area	Technology	Overnight Capital Cost [A]	Capital Charge Rate [B]	Year 1 Capital Recovery [C]	Levelized Fixed O&M [D]	Gross CONE ICAP [E]
Nominal$ for 2028 Online Year		$/kW	%/year	$/MW-day	$/MW-day	$/MW-day
1. EMAAC	Gas CT	$1,278	15.3%	$535	$61	**$596**
	Gas CC	$1,449	16.3%	$645	$106	**$752**
	BESS 4-hr	$1,832	9.4%	$470	$197	**$667**
2. SWMAAC	Gas CT	$1,235	15.3%	$516	$91	**$608**
	Gas CC	$1,354	16.2%	$601	$159	**$761**
	BESS 4-hr	$1,753	9.4%	$450	$208	**$658**
3. Rest of RTO	Gas CT	$1,247	15.2%	$521	$69	**$590**
	Gas CC	$1,363	16.2%	$605	$152	**$757**
	BESS 4-hr	$1,750	9.4%	$449	$191	**$640**
4. WMAAC	Gas CT	$1,274	15.2%	$532	$60	**$592**
	Gas CC	$1,415	16.2%	$628	$127	**$754**
	BESS 4-hr	$1,784	9.4%	$458	$196	**$655**
5. COMED	Gas CT	$1,369	16.5%	$619	$60	**$679**
	Gas CC	$1,579	17.6%	$760	$100	**$860**
	BESS 4-hr	$1,980	9.3%	$507	$204	**$711**

Updates to CT CONE

CONE Area 3, Rest of RTO, $2028/MW-day ICAP



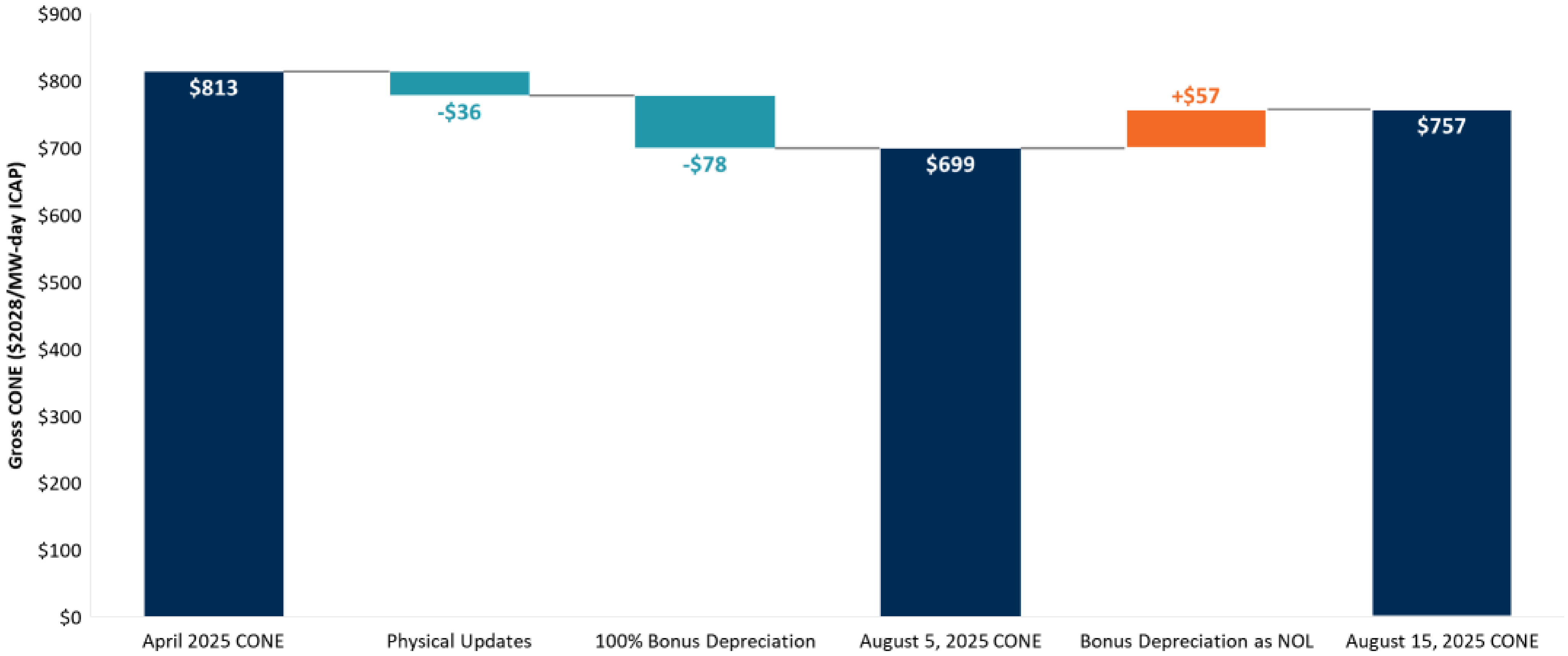
Physical Updates: Wet compression, higher firing temperature, and reduced inlet pressure drop together increase ICAP by 9% to 437 MW (summer), while overnight cost increases 4.8%, so $/kW overnight cost ends up 4% lower

100% Bonus Depreciation: Full recognition of potential present value (corresponds to very high taxable income)

Bonus Depreciation as NOL: Adjust for more reasonable estimate of typical generator present value capture given limited taxable income, now represented as creating NOL carried forward linearly over 7 years

Updates to CC CONE

CONE Area 3, Rest of RTO, $2028/MW-day ICAP



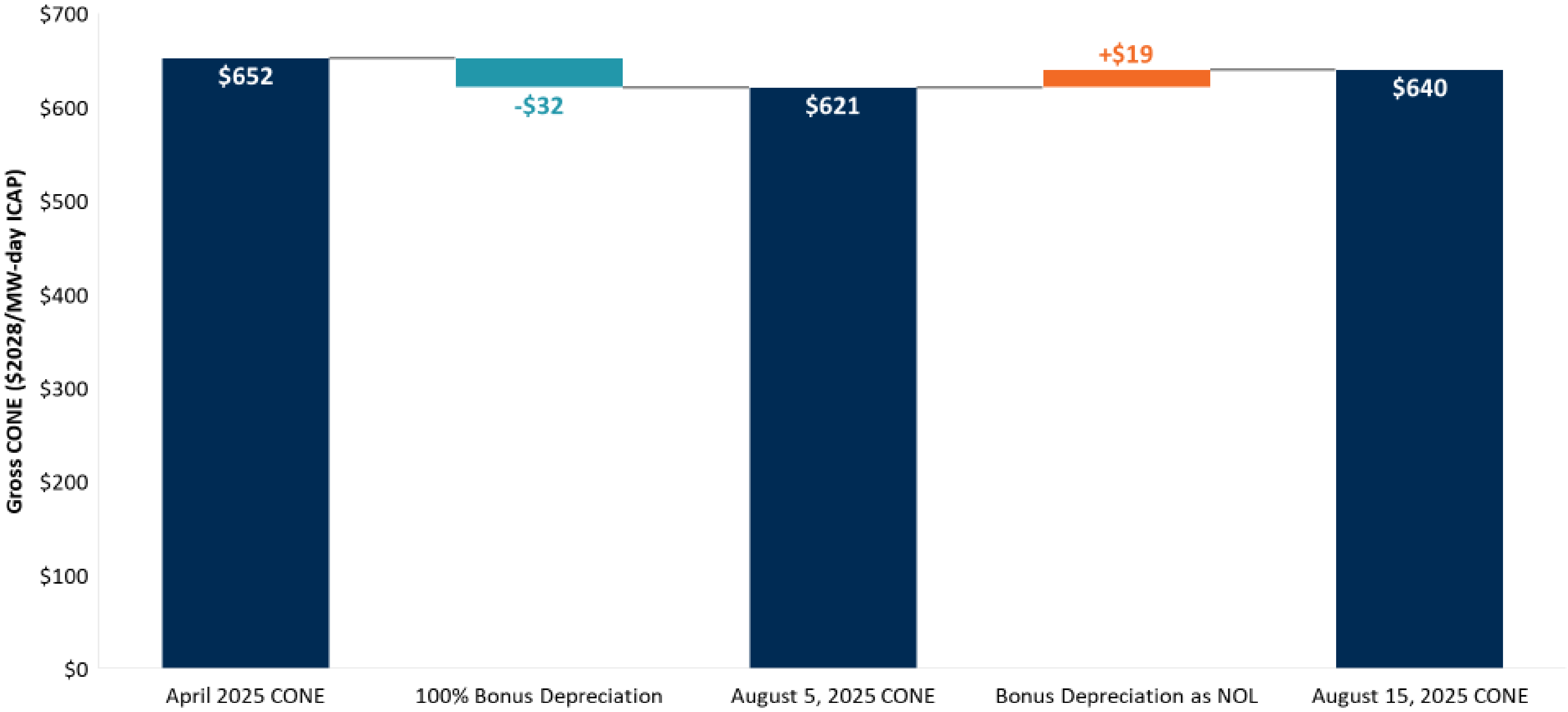
Physical Updates: Wet compression, higher firing temperature, and reduced inlet pressure drop together increase ICAP by 9% to 1,393 MW (summer), while overnight cost increases 4.8%, so $/kW overnight cost ends up 4% lower

100% Bonus Depreciation: Full recognition of potential present value (corresponds to very high taxable income)

Bonus Depreciation as NOL: Adjust for more reasonable estimate of typical generator present value capture given limited taxable income, now represented as creating NOL carried forward linearly over 10 years

Updates to BESS CONE

CONE Area 3, Rest of RTO, $2028/MW-day ICAP



Full recognition of potential present value (corresponds to very high taxable income)

Adjust for more reasonable estimate of typical generator present value capture given limited taxable income, now represented as creating NOL carried forward as 3-year straight-line depreciation

Contact Information

Dr. Sam Newell

PRINCIPAL | BOSTON

Sam.Newell@brattle.com

+1 (781) 801-2652

Dr. Bin Zhou

PRINCIPAL | BOSTON

Bin.Zhou@brattle.com

+1 (617) 234-5677

Dr. Andrew W. Thompson

ENERGY ASSOCIATE | BOSTON/MADRID

Andrew.Thompson@brattle.com

+34 666 639 197