PJM Capacity Market—
2025/2026 BRA results & outlook for upcoming auctions

September 2024

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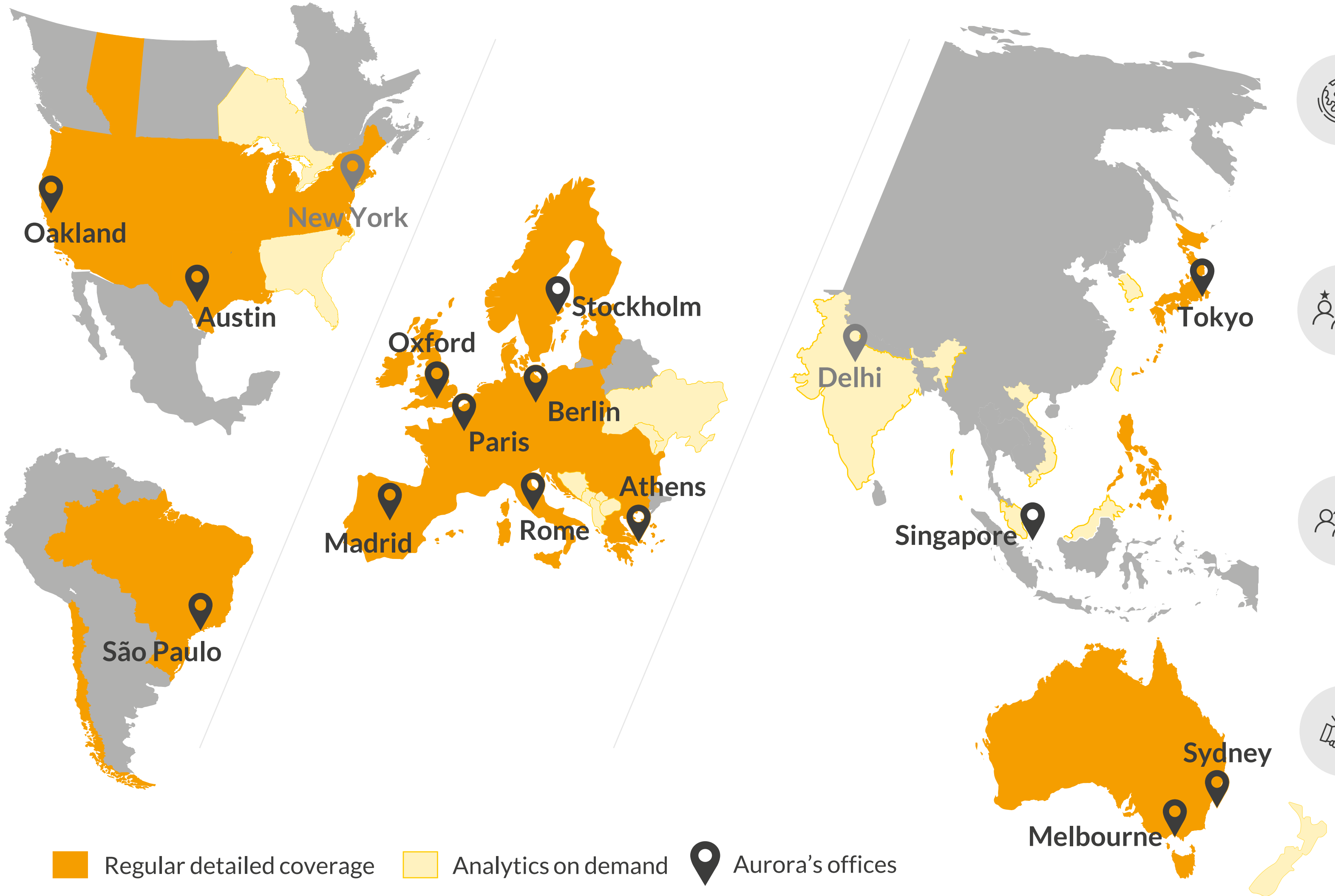

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Source: Aurora Energy Research

Unique, proprietary, in-house modelling capabilities underpin Aurora's superior analysis

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5 Integrated Models

- Global Commodities (AER-GLO)
- Hydrogen (AER-HY)
- Gas (AER-GAS)
- Power markets (AER-ES)
- Nodal/network model (AER-EN)

INPUTS

- Technology
- Policy
- Demand
- Commodity prices[1]
- Weather patterns

Dispatch model

- ½ hourly or hourly
- Iterative modelling
- Dynamic dispatch of plant
- Endogenous interconnector flows

Continuous iteration until an equilibrium is reached

Investment decisions module

- Capacity market modelling
- Capacity build / exit / mothballing
- IRR / NPV driven
- Detailed technology assessments

OUTPUTS

- Capacity mix
- Generation mix
- Wholesale & imbalance prices
- Capacity market prices
- Profit / Loss and NPV
- Electric vehicle charging

ADDITIONAL INPUTS

- Network snapshot - existing & future
- Nodal load map
- Nodal generation map

OUTPUTS

- Power flows & losses
- Nodal prices / loss factors

Up to 70 specifications modelled for each plant

c. 85k investment hours on modelling capabilities

~15k model runs per week

50+ strength of modelling team globally

Quarterly updates through subscription research

1) Gas, coal, oil and carbon prices fundamentally modelled in-house with fully integrated commodities and gas market model

Source: Aurora Energy Research

Aurora is the market leader in complex transaction support involving flexible and renewable assets accessing multiple revenue streams

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Non-comprehensive project examples

Battery generation

- Buy-side advisor for Engie's successful acquisition of Broad Reach Power
- Sell-side advisor for Black Mountain on ~1.5 GW asset sales to UBS Asset Management, Cypress Creek Renewables, Brookfield Renewable, & East Point Energy
- Siting strategy analysis for battery developer to inform build locations and project valuation
- Buy-side advisor on multiple equity transactions for over 1.5 GW of battery storage projects across ERCOT and CAISO, including nodal modelling, ancillary service price forecasts, and solar/wind + storage co-location analysis

Strategic

- Debt case scenario analysis for large pension fund to inform investing and lending decisions
- Downside scenario modelling for international bank to inform debt sizing
- Pricing and PPA analysis for publicly listed data center company

Renewable generation

- Buy-side advisor for Boralex's acquisition of 840 MW of onshore wind from Blackrock, including nodal pricing, basis risk, and curtailment
- Buy-side financing for 470 MW solar project in ERCOT by SocGen
- Asset-specific valuation of two wind and solar projects totalling 540 MW for infrastructure fund including nodal forecasting and curtailment
- Asset valuation for a large pumped hydro plant participating in the CAISO wholesale and ancillary markets

Thermal generation

- Modelling of proposed ERCOT market reforms (e.g. dispatchable energy credits) for project developer
- Asset valuation for lender for two existing CCGT projects in ERCOT and WECC
- Sell-side advisory for 400 MW OCGT peaking plant in West Texas for large utility
- Analysis of Biden's Clean Electricity Standard design for one of US largest utilities, to engage with White House on the role of gas CCS in the energy transition

Source: Aurora Energy Research

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Reach out for any follow-up questions or to continue the conversation!

Executive Summary

- PJM's **2025/26 BRA** took place in July 2024 and cleared at historically high levels: **$270/MW-day** for the RTO and MAAC; the auction cap for BGE (**$466/MW-day**) and Dominion (**$444/MW-day**)—which rejoined the capacity market after four delivery years as an FRR region, and was modeled as an LDA for the first time.
- These high prices were driven by:
  - Higher demand: +8GW ICAP[1] reliability requirement (compared to the 2024/25 BRA)
  - Lower supply: -4GW ICAP[1] offered (compared to the 2024/25 BRA)
  - PJM's CIFP reforms, implemented for the first time, which raised individual bids by lowering capacity accreditation
- For the **2026/27 BRA**, taking place in December 2024, Aurora considers the outcome highly uncertain: from $100/MW-day (low case) to $696/MW-day (high case), with ~$250/MW-day a p50 expectation. Key factors impacting the 2026/27 BRA relative to the previous auction include:
  - A significantly steeper VRR curve, causing sharply increased price sensitivity compared to previous auctions, raising outcome uncertainty.
  - Higher demand: +3GW UCAP reliability requirement, which could cause a $696/MW-day clearing price (barring supply increases).
  - A strong incentive for increased supply, due to (i) expected higher clearing prices and (ii) effectively removed capacity performance penalties in >50% of PJM, due to a $0/MW-day Net CONE. The extent of supply increases is highly uncertain, but could come from withheld capacity in the 2025/26 BRA (~6GW), DR additions, bidders switching from seasonal to annual bids, or new capacity.

1) Installed capacity. Structural changes between the 2024/25 and 2025/26 BRAs make a comparison in GW UCAP (unforced capacity)—the market's native unit—meaningless.

Sources: Aurora Energy Research, PJM

Agenda

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I. 2025/26 BRA: results & drivers

II. CIFP capacity market reforms

III. 2026/27 BRA: parameters, drivers, & expectations

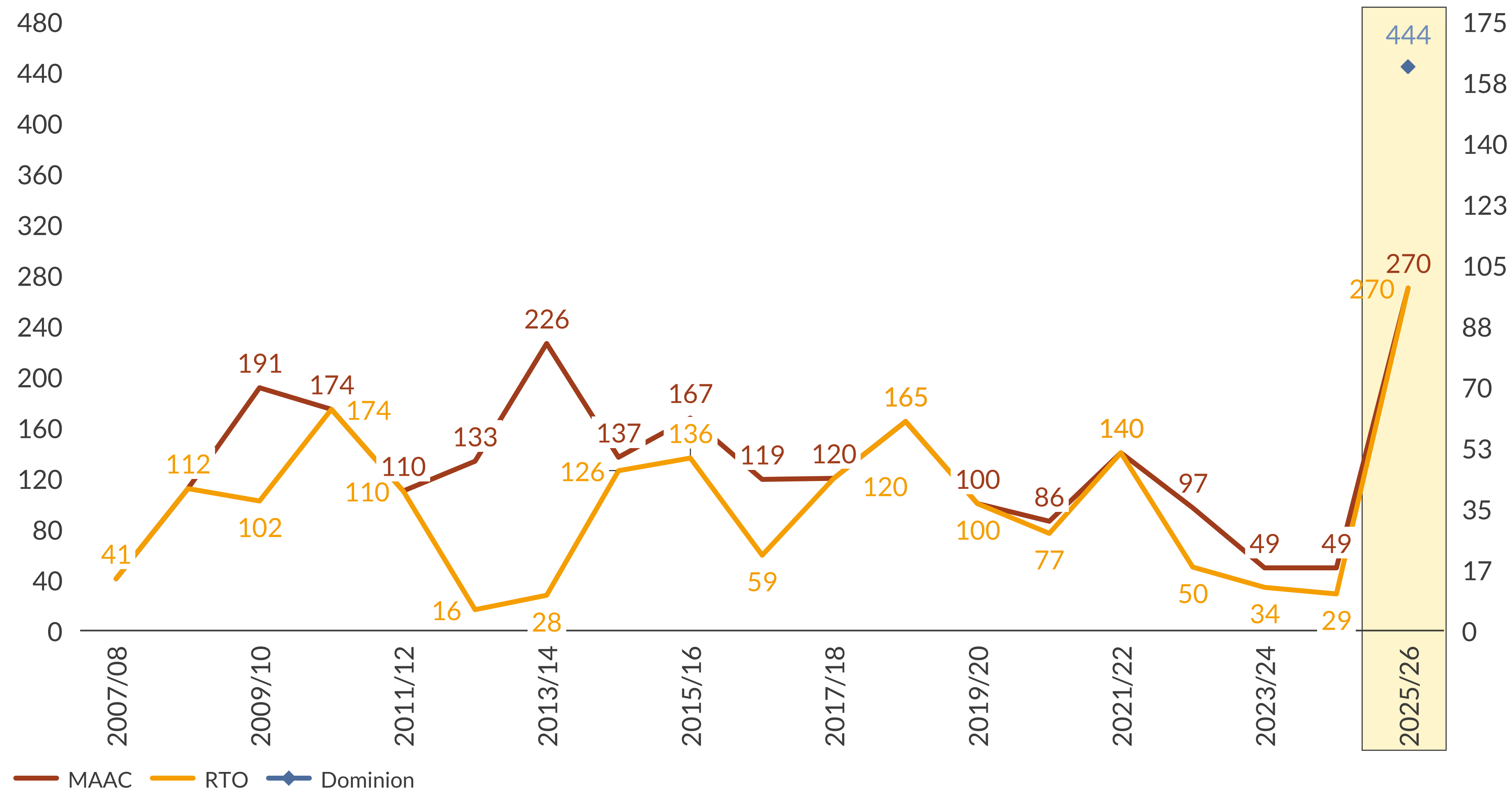
IV. Long-term forecast

Results | The 2025/26 BRA cleared at $270/MW-day, a record for PJM's capacity market, with Dom clearing at its $444 price cap

PJM Base Residual Auction (BRA) clearing price for RTO and selected LDAs

$/MW-day (nominal)

$/kW-year (nominal)



RTO

- The Base Residual Auction (BRA) for the 2025/26 delivery year cleared RTO-wide at **$269.92/MW-day**, the highest in the 19-year history of PJM's capacity market. [1]

Dominion

- Dominion, which re-entered the capacity market for the 2025/26 BRA, is one of the two constrained Locational Deliverability Areas (LDAs) in the 2025/26 BRA, clearing well above the RTO at **$444.26/MW-day.**
- LDAs account for transmission constraints across PJM and have individual procurement targets.[2]

MAAC

- MAAC, which has historically been a constrained LDA, cleared at the same level as the rest of the RTO in the 2025/26 BRA.

1) The first delivery year for which PJM held a capacity auction was 2007/08. 2) LDA auction target capacities take existing capacity and capacity transfer objectives (CETO) into account.

Sources: Aurora Energy Research, PJM

Results | Nearly all of PJM-RTO cleared at $270/MW-day—10x the last BRA's price—with BGE rising to $466 and Dominion to $444/MW-day

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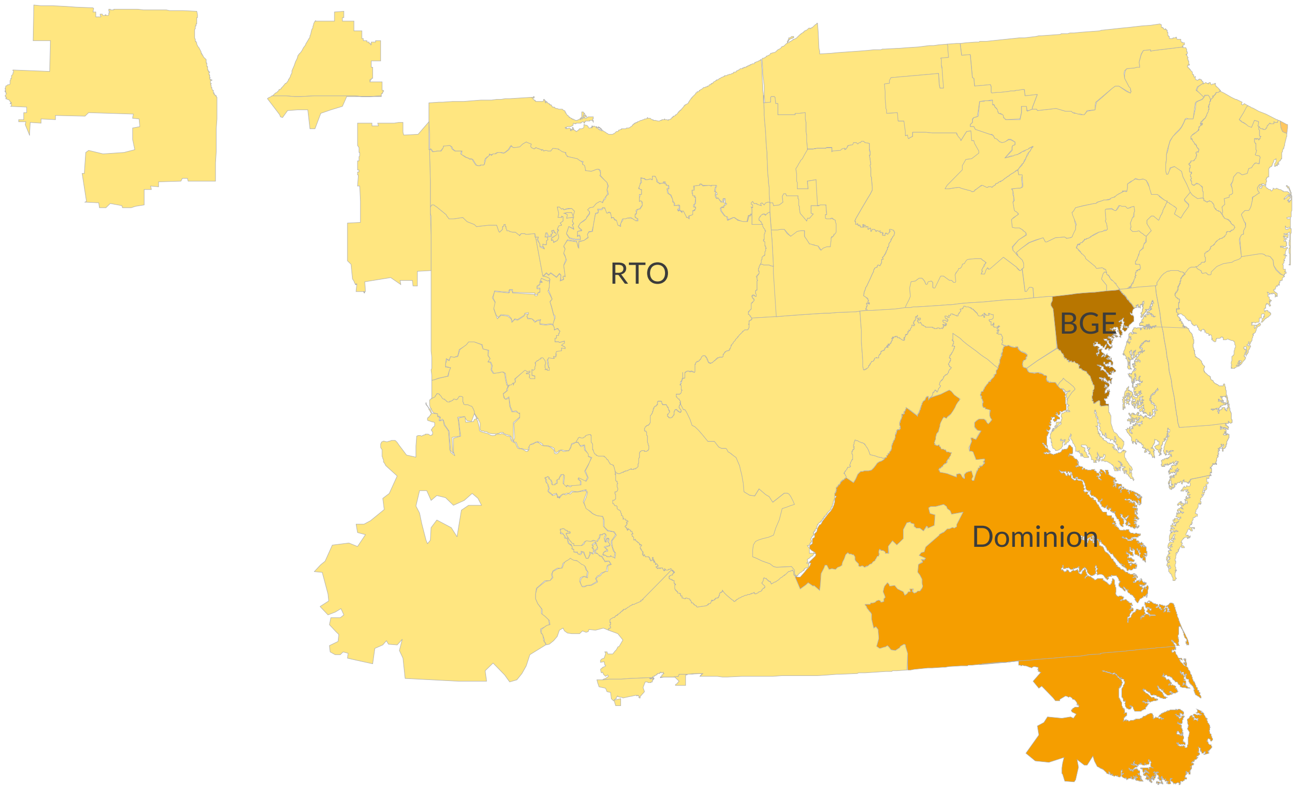
2025/26 BRA clearing prices and constrained LDAs



2025/26 BRA clearing price $/MW-day ($/kW-year)	RTO	Above RTO (constrained LDA)	
	269.92 (98.87)	444.26 (162.15)	466.35 (170.21)

Parent-child LDA relationship[2]

Clearing price for RTO and all constrained LDAs[1]

$/MW-day

	2024/25 BRA	2025/26 BRA
Rest of RTO	$28.92	$269.92
DEOK	$96.24	$269.92
Dominion	-	$444.26
MAAC	$49.49	$269.92
EMAAC	$54.95	$269.92
BGE	$73.00	$466.35
DPL-South	$90.64	$269.92
Total cost	$2.2bn	$14.7bn

- The RTO clearing price was ~10x higher in the 2025/26 BRA than the 2024/25 BRA.
- 2 LDAs, Dominion and BGE, were constrained in this BRA, down from 5 in the previous auction. Although MAAC cleared at the same price as the rest of RTO, it still cleared at a substantially higher price than in the last BRA.
- Total cost increased by ~$12.5bn from the last auction, primarily due to the significant increase in RTO clearing price.

1) Constrained LDAs are those with a price above their immediate region parent. For example, BGE was constrained in the 2025/26 BRA because it cleared above the RTO price. 2) Shown for each constrained LDA is the (grand)parent region responsible for all intermediate regions' prices.

Sources: Aurora Energy Research, PJM

Drivers | Supply decreases, load growth, Dominion's capacity market re-entry, and CIFP rule changes all contributed to record-high clearing prices

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Factors contributing to the 2025/26 BRA's high clearing prices

		Impact on Clearing Prices
Supply decreases	▪ Due to retirements and modestly lower Demand Response participation, supply eligible to offer into the capacity market declined by 6.5GW[1] from the 2024/25 BRA to the 2025/26 BRA. ▪ Extremely limited new generation is expected to come online prior to the start of the 2025/26 delivery year, particularly for resource types with higher ELCCs, such as dispatchable generation and offshore wind. In total, only 110MW of unforced capacity (UCAP) from new generation cleared the 2025/26 BRA.	↑↑
Demand growth	▪ Driven by data center demand, PJM forecasted peak load increased by 2.2% from 2024/25 to 2025/26, from 150.6GW to 153.9GW.	↑
Dominion rejoining the capacity market	▪ Prior to the 2025/26 BRA, the Dominion LDA primarily satisfied its capacity obligation through an FRR[2] plan outside of the PJM capacity market. Its entry into the capacity market for the 2025/26 delivery year added ~22GW to the RTO UCAP reliability requirement.[3] ▪ However, the generation resources previously used to satisfy Dominion's FRR obligations contributed only ~17GW UCAP of supply, 5 GW below the amount added to the reliability requirement.[3] With Dominion back in the capacity market, this imbalance contributed to the RTO-level supply-demand tightness.	↑
CIFP rule changes	▪ The introduction of a marginal capacity accreditation methodology decreased ELCCs[4] for most resource classes, and therefore UCAP supply. However, the impact of this change was partially offset by a corresponding reduction in the UCAP reliability requirement. ▪ Updates to PJM's approach to modeling reliability risk contributed to an increase in the Installed Reserve Margin (IRM) from 14.7% in the 2024/25 BRA to 17.8% in the 2025/26 BRA.	↓/↑

1) Measured in ICAP (Installed Capacity) terms. 2) Fixed Resource Requirement. 3) Aurora estimate based on data released by PJM. 4) Effective Load Carrying Capability.

Sources: Aurora Energy Research, PJM

Supply-demand | 2025/26 BRA conditions were much tighter than the previous auction: excess supply offered fell from 16 to 3GW ICAP

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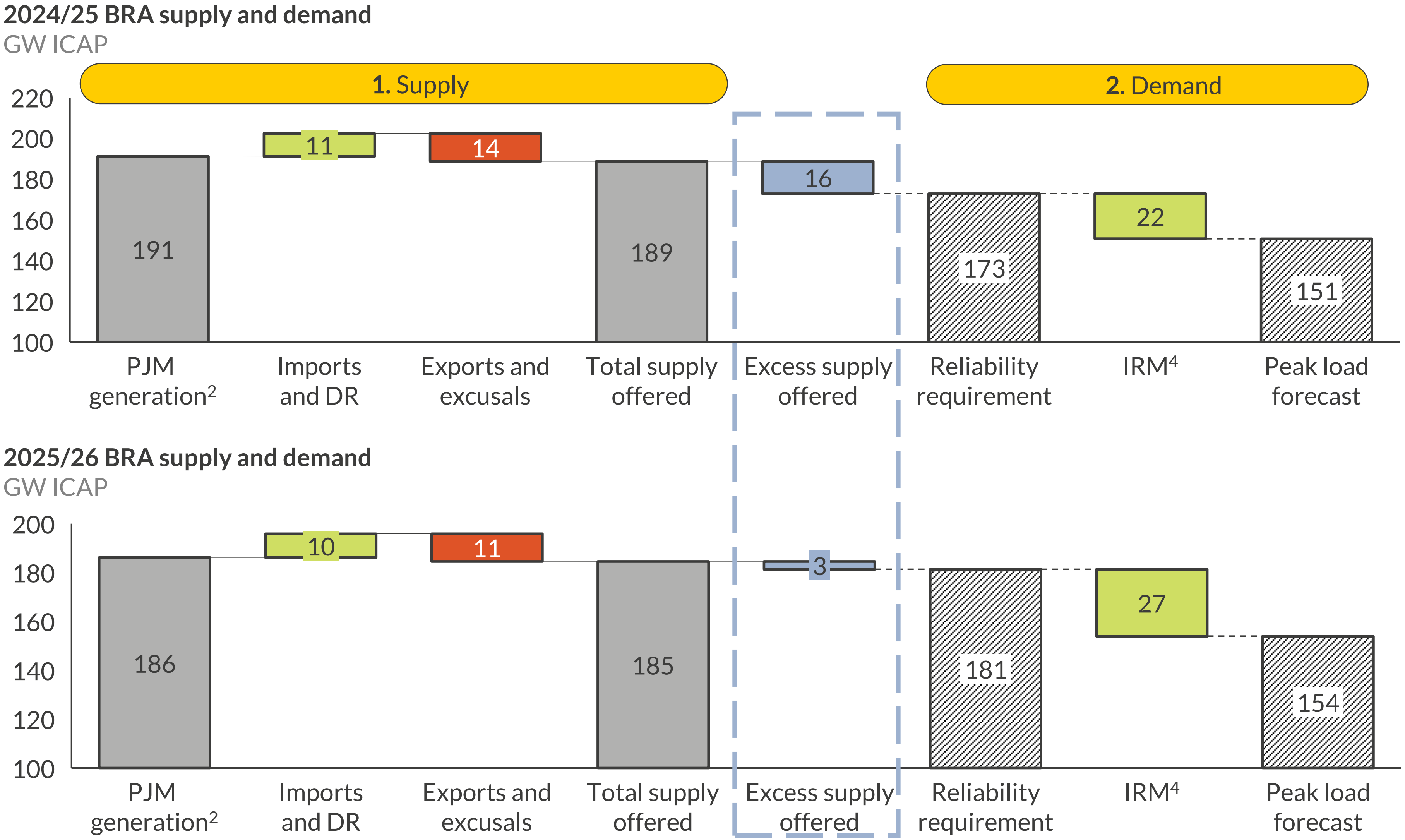

- Given the dramatic change in calculation of UCAP between the 2024/25 and 2025/26 BRA, ICAP[1] values provide the most apt comparison between supply and demand conditions between auctions.

1 Total supply offered into the BRA (or committed via an FRR plan) declined from 189GW to 185GW, driven by retirements and modestly lower DR[3] participation.

2 Total demand, as reflected by the reliability requirement, increased from 173GW to 181GW, due to:

- Peak load growth from 151GW to 154GW, driven primarily by data center demand.
- IRM[4] increase from 14.7% to 17.8%, driven primarily by changes to PJM's reliability risk modeling.

1) Installed capacity. While PJM's capacity market procures Unforced Capacity (UCAP), results are presented in ICAP terms due to substantial changes in PJM's computation of UCAP between the 2024/25 and 2025/26 auctions. 2) Including Fixed Resource Requirement (FRR) capacity. 3) Demand response. 4) Installed Reserve Margin.

Sources: Aurora Energy Research, PJM

Supply-demand | All offered thermal, nuclear, demand response and solar capacity cleared the 2025/26 BRA

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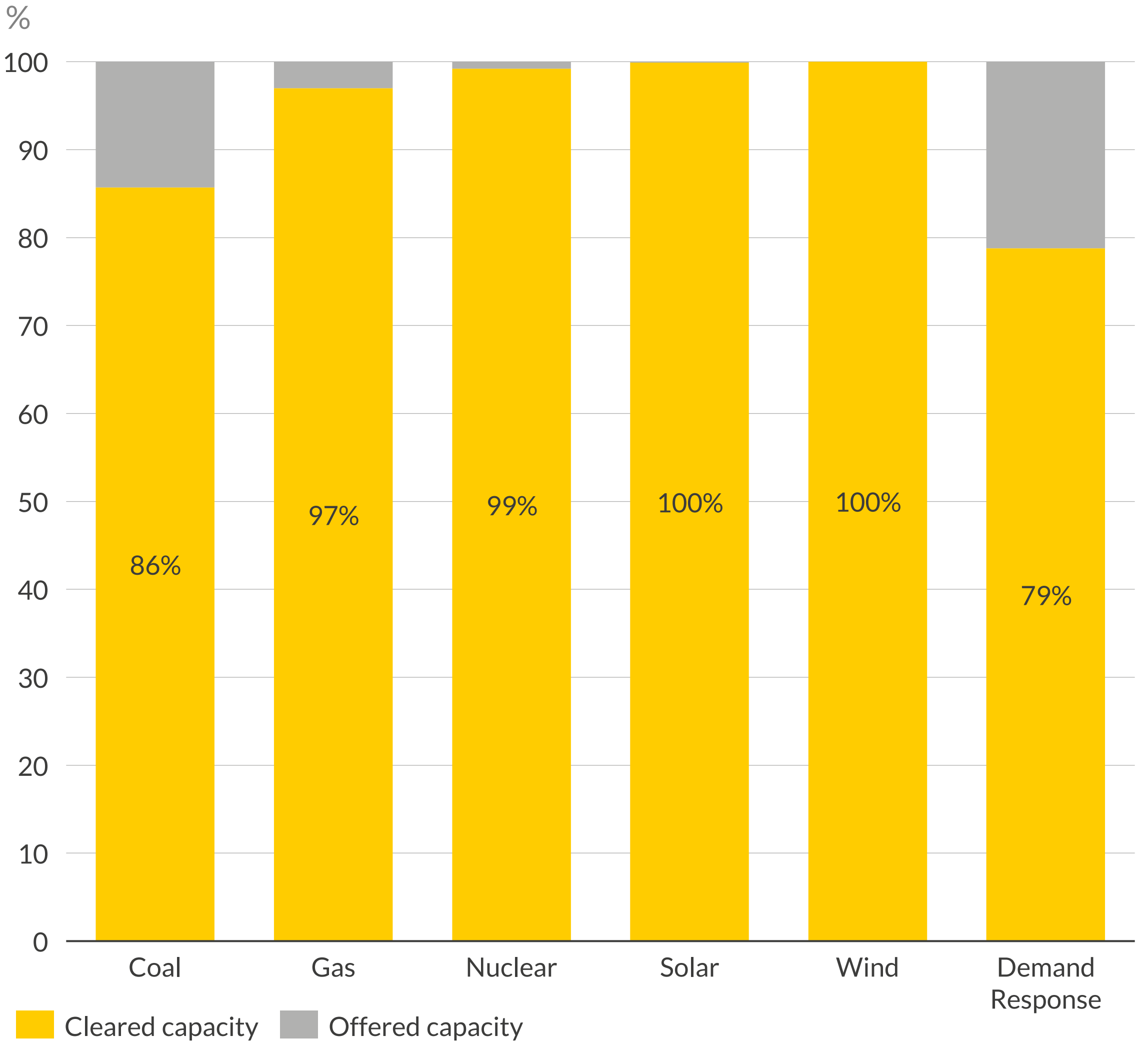
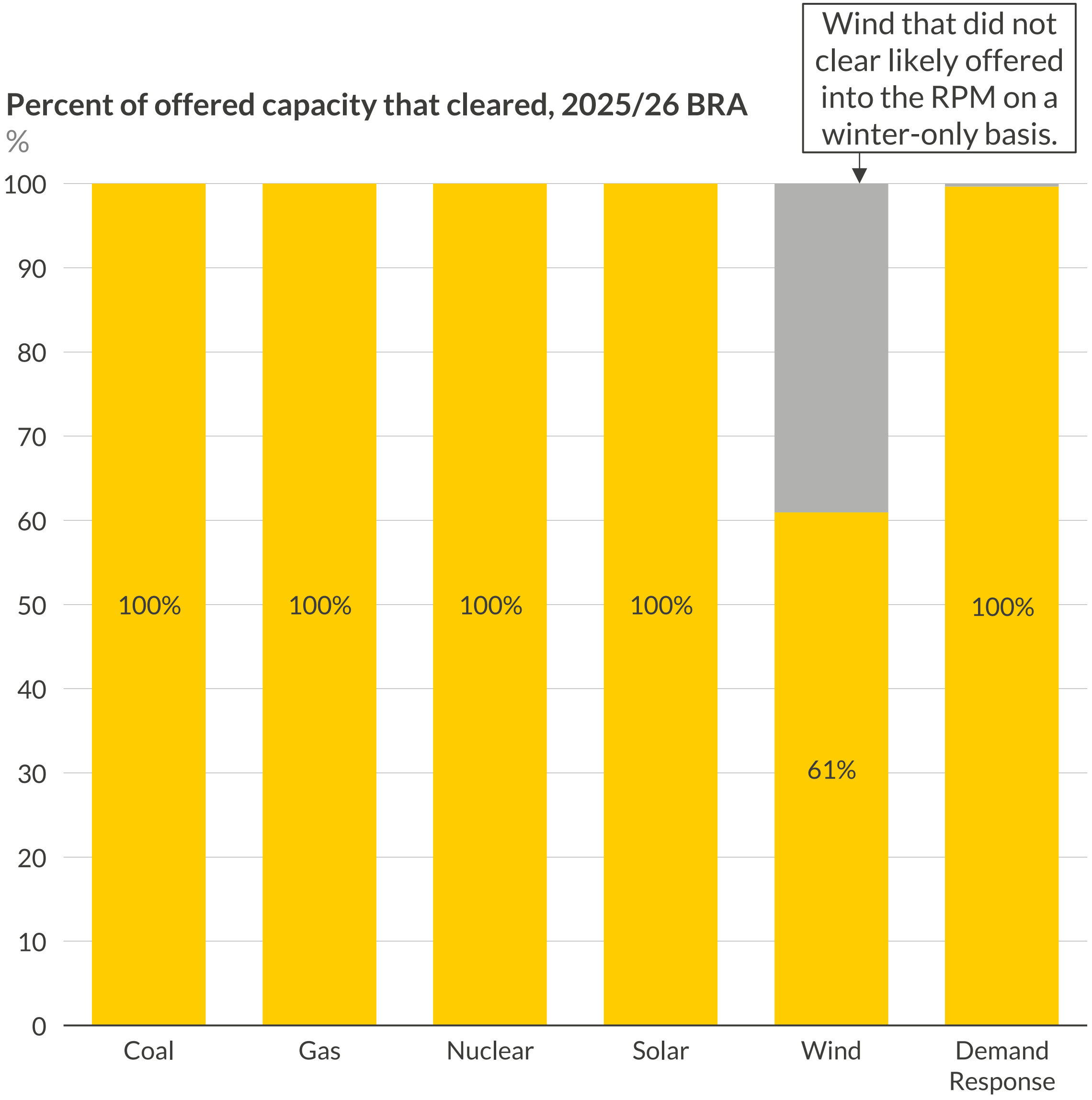
Percent of offered capacity that cleared, 2024/25 BRA



Percent of offered capacity that cleared, 2025/26 BRA



Sources: PJM, Aurora Energy Research

Supply | PJM reported 9.8GW ICAP as “excused” from the 25/26 BRA, comprising categorically exempt resources and retiring thermal plants

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Resources “excused” from 2025/26 BRA

	Total ICAP GW	Associated plants MW ICAP	Likelihood of re-entering capacity market
Reliability must run (RMR) plants	2.4	Brandon Shores (1,282); Wagner units 3-4 (702); Indian River (412)	**Very unlikely:** these plants have already confirmed retirement dates and secured revenue through retirement via the RMR agreements.
Other thermal deactivation requests	1.5	Eddystone (760); Sayreville (217); Vienna (167); Carlls Corner (75); Mickleton (57); Perryman 6 Unit 1 (55); Wagner units 1, CT 1 (139)	**Unlikely:** Withdrawn deactivation requests are precedented, but rare. Certain of these plants (Carlls Corner, Mickleton, and Sayreville) formally retired in June 2024.
Categorically exempt resources	~6	Not available, but the IMM reported that 3.9GW ICAP of intermittent resources and 1.3GW ICAP of storage resources elected not to offer into the 2024/25 BRA.	**Unclear; moderately likely that a portion will re-enter:** ▪ Information on why these resources did not participate is not publicly available, but avoiding of capacity performance penalties is likely a key factor. ▪ High clearing prices and a lack of CP penalties in much of the RTO for the 2026/27 delivery year (due to $0 net CONE) may incentivize capacity to return.

- **Methodology note:** PJM does not publish the data shown here explicitly, except for total excused capacity. The capacities and generators listed are the result of Aurora’s analysis, based on the best available data.
- **Almost all resource classes are subject to capacity market must-offer requirement**, and PJM only grants exemptions under specific circumstances:
  - If the resource has submitted a deactivation request to PJM.
  - If the resource has “significant physical operational restrictions” or is “under major repair.”
  - If the resource has committed to provide capacity to a region outside PJM.
- Intermittent, Demand Response, and storage (including hydroelectric pumped storage) resources are **categorically exempt** from the capacity market must-offer requirement.

Sources: Aurora Energy Research, PJM

Supply | Thermal plants that did not participate in the 2025/26 BRA due to planned retirements are concentrated in Eastern PJM, particularly BGE

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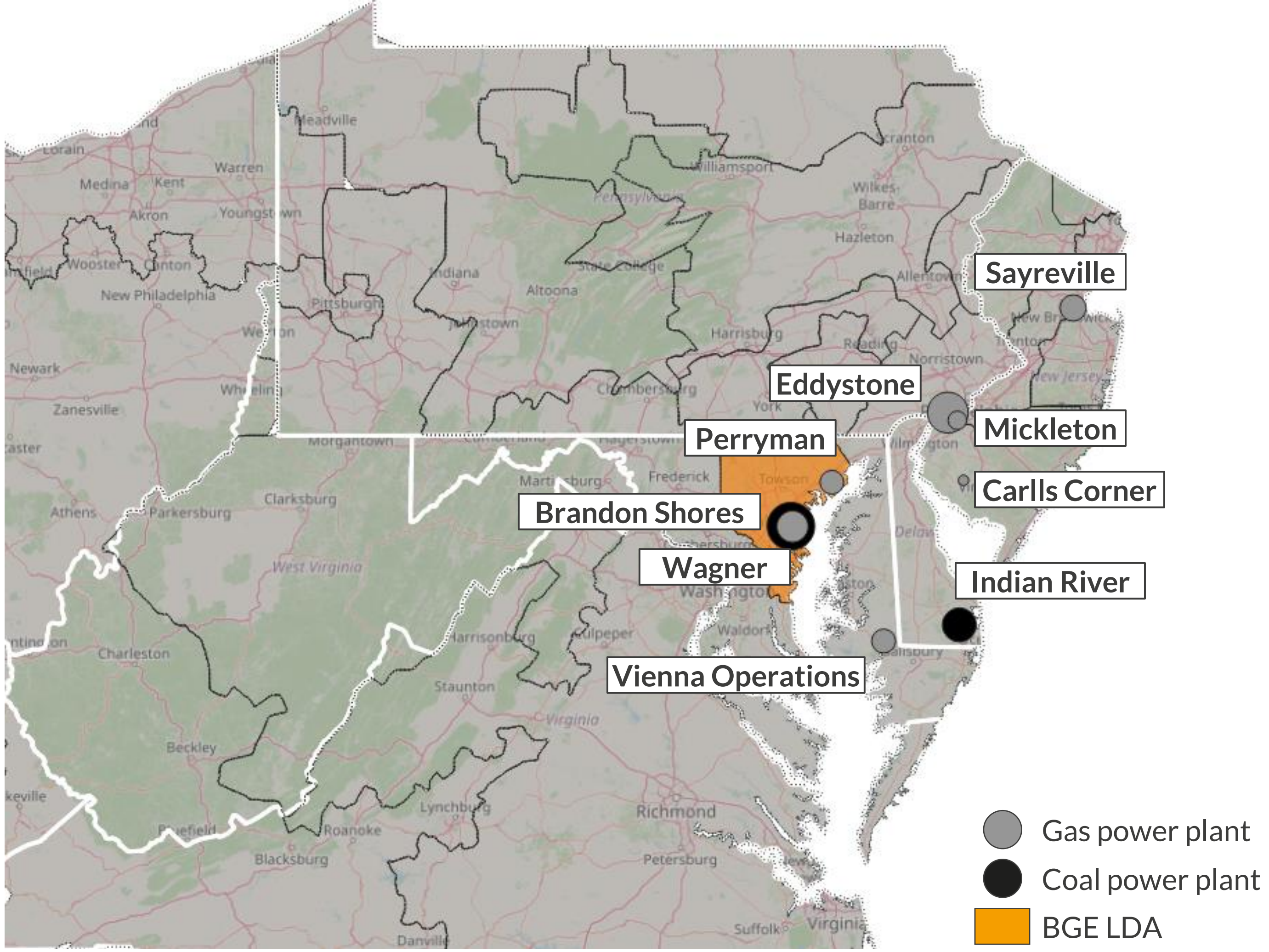
Resources "excused" from 2025/26 BRA due to planned deactivation



The retiring thermal plants that PJM excused from the 2025/26 BRA were concentrated in the eastern portion of PJM, particularly in the Baltimore Gas & Electric (BGE) LDA in Maryland.

- The 1.3GW ICAP Brandon Shores plant and 0.7GW ICAP Wagner plant, both of which are operating through 2028 on Reliability-Must-Run (RMR) contracts, did not participate in the 2025/26 BRA.
- The loss of these plants from the 2025/26 BRA left BGE with only 0.6GW UCAP of internal capacity, resulting in the BGE LDA clearing at its price cap of $444.26/MW-day.
- Prompted by concerns over the impact of capacity market prices on consumer energy bills, ratepayer advocates in several PJM states (including Maryland) have urged PJM to account for the RMR units in the capacity market, even if that requires delaying the 2026/27 BRA.

Methodology note: PJM does not publish the plants shown here explicitly, except for total excused capacity. The power plants listed are the result of Aurora's analysis, based on the best available data.

Sources: Aurora Energy Research, PJM, UtilityDive

Demand | 2025/26 BRA demand rose sharply compared to previous auctions primarily due to PJM's 2024 peak load forecast increase

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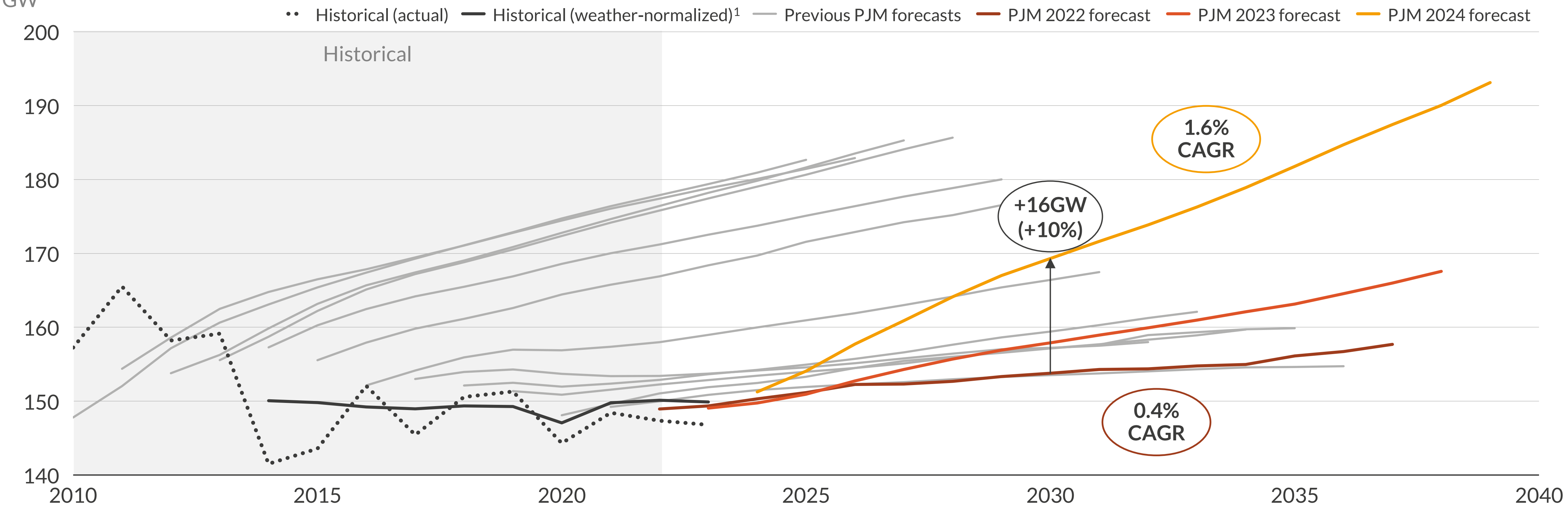
Historical and forecasted RTO coincident peak load

GW



- PJM has consistently overpredicted peak and total annual load, repeatedly shifting its forecast back year-on-year during the last decade.
- Despite PJM's expectations of load growth, peak load in PJM has generally decreased since 2010, primarily due to efficiency improvements.
- Between its 2022 and 2024 load forecasts, PJM raised its 2030 expectations for coincident peak load by 16GW (10%), primarily due to increased expectations of data center and EV growth.

1) As reported by PJM.

Sources: Aurora Energy Research, PJM

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CIFP reform | On Jan 30th, 2024, FERC approved one of PJM's CIFP capacity market reform filings, rejecting the other on Feb 6th

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On Jan 30, 2024, FERC conditionally accepted PJM's proposal to reform risk modeling and capacity accreditation within its capacity market, based on PJM's "CIFP"[1] fast-track process.

The 2025/26 BRA was the first auction held under PJM's CFP reform rules.

PJM CIFP capacity market reform timeline

Feb 2023

Feb 24: **PJM's board initiated the Critical Issue Fast Path ("CIFP")** stakeholder process to "address resource adequacy challenges" in the capacity market.

Aug 2023

Aug 23: In final stakeholder vote on CIFP Capacity Market reform proposals, no proposal passed sector-weighted endorsement threshold. The non-binding vote left the final decision to PJM's board. Stakeholders' favored option would only reduce CP[3] penalties, with PJM's annual CIFP proposal coming in second.

Oct 13: **PJM submitted its "CIFP" capacity market reform proposals** to FERC,[2] significantly reducing capacity accreditation, imposing stricter reliability testing, and increasing MSOC[4] to include CPQR[5] costs.

Nov 17: FERC issued deficiency notices for PJM's CIFP capacity market reform filings.

Dec 1, Dec 8: PJM filed replies to FERC's deficiency notices, resetting FERC's 60-day window to issue a ruling.

Jan 2024

Jan 30, Feb 6: **FERC conditionally approved PJM's filing ER24-99** (updating PJM's risk modeling & capacity accreditation), pending another compliance filing; **and rejected filing ER24-98** (to reform MSOC), citing insufficient detail and explanation.

Feb 16: PJM submitted FERC's requested compliance filing.

Feb 26: FERC granted PJM's request to delay the 2025/26 BRA[6] by 35 days, to Jul 17, along with associated pre-auction deadlines.

Apr 2024

Apr 25: FERC accepted PJM's compliance filing, officially finalizing approval for PJM's reforms.

Jul 2024

Jul 23: The auction window closed for the 2025/26 BRA—the first auction running under PJM's CIFP reform rules. PJM published results on **Jul 30**.

1) Critical Issue Fast Path 2) Federal Energy Regulatory Commission 3) Capacity Performance. 4) Market Seller Offer Cap, a bid cap in PJM's capacity market. 5) Capacity Performance Quantifiable Risk. 6) Base Residual Auction.

Sources: Aurora Energy Research, PJM

CIFP reform | The 25/26 BRA is the first to reflect PJM's updates to risk modeling and capacity accreditation through its CIFP process

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PJM's filed capacity market reforms following its CIFP stakeholder process

	Docket No. ER24-98 Rejected by FERC (but PJM may still refile)	Docket No. ER24-99 Implemented in 2025/26 BRA	Expected BRA Impact: Resource accred.	Expected BRA Impact: Amount procured	Expected BRA Impact: Bids	Expected BRA Impact: Clear. Price
Capacity Accreditation		▪ Move all resources (incl. demand) to **marginal ELCC**[1] ▪ Include separate **"dual-fuel" class categories** for natural gas resources	↓	↓/↑[2]	↑	↑
Risk modelling		▪ Adopt **Expected Unserved Energy (EUE) as key metric** (replacing current LOLE[3]) ▪ Model risk on hourly level with more weather years				
Market Seller Offer Cap (MSOC)	▪ **Include Capacity Performance Quantifiable Risk (CPQR) cost in MSOC** (PJM's bid cap) ▪ Clarify CPQR definition		-	(↓)	↑	↑
Capacity Performance	▪ Performance payments only for cleared resources ▪ Exclude resources excused from non-performance charges from Balancing Ratio calculation	▪ **Reduce penalty cap** ("stop-loss limit") ▪ Capacity testing required in summer & winter ▪ Add generation operational testing	-	-	↓/↑	↓/↑
E&AS offset	▪ **Forward-looking Energy & Ancillary Services (E&AS) offset** for MSOC, MOPR		-	-	-	-
FRR[4] alignment	▪ Apply Capacity Performance incentive revisions to FRR rules	▪ Align FRR rules with capacity market, e.g. capacity shortfall charges	-	-	-	-
Participation rules		▪ Require **binding notice of participation intent** from planned generation resources ▪ Revisions to sell offer requirements	-	-	-	-

1) Effective Load Carrying Capacity (ELCC) is a measure of a resource's contribution to reliability. 2) Reduced ELCCs indirectly increase procurement targets. However, PJM modeling determines that under stricter ELCC derating, less UCAP is required to meet reliability targets. 3) Loss of load expected. 4) The Fixed Resource Requirement (FRR) alternative is an option for load-serving entities to meet resource adequacy requirements outside the capacity market, e.g. via internal resource planning.

Sources: Aurora Energy Research, PJM

CIFP reform | Lower capacity accreditation is driven by a shift of all asset types to marginal ELCCs[1] and a focus on winter risk

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Drivers of the CIFP reforms' decrease in capacity accreditation

	Driver	Impact
Thermal to ELCC[1]	**All resource types moved to using ELCC for conversion to UCAP[2].** ▪ Thermal resources previously used "EFORd[3]" metric, defined by historical probability of a forced outage, uncorrelated to system risk. ELCC does capture such risk correlation and is thus typically lower. ▪ Renewable, intermittent, and duration-limited (e.g. storage) resources already used ELCC.	**Higher thermal bids, raising clearing prices because thermal usually price-setting.** ▪ As bids are per MW UCAP, assets must raise bids when capacity accreditation falls, to keep their effective bid per MW nameplate constant.
Marginal ELCC	**Move from "average ELCCs" to "marginal ELCCs", which are typically lower.** ▪ Average ELCCs measure the average contribution of any MW within a class to system reliability. ▪ Marginal ELCCs measure the contribution of an additional MW to reliability, which is typically below the average due to correlated outage risks and cannibalization within a technology type.	**Renewables, batteries, and natural gas ELCCs most affected.** ▪ These technologies have stronger correlations (between assets of same type) in their ability to reduce system risk than some others (coal, nuclear). E.g. solar assets typically generate at roughly the same time; natural gas outages are often caused by regional fuel deliverability issues. The technologies' ability to contribute to system reliability thus saturates as more MW are built, lowering marginal ELCCs.
Winter risk	**Shift in focus from primarily summer risk to primarily winter risk, resulting from updated risk modelling methodology.** ▪ Capacity market previously focused on summer risk, when peak load occurs. ▪ A key driver in this shift has been the move to Expected Unserved Energy ("EUE", in MWh) as the metric for outages, rather than Loss of Load Expected ("LOLE", in event-days per year). ▪ PJM has also increased the granularity of its risk modelling and extended it to more historical years.	**Lower ELCCs for assets with lower reliability contribution during winter risk, and vice versa for assets with higher winter reliability.** ▪ Solar and battery reliability contributions lower, because winter system stress events are generally longer than summer events. ▪ Gas ELCCs lower due to risk of weather-driven mechanical failure and correlation between winter storms and natural gas deliverability issues. ▪ Wind ELCCs higher, as wind typically generates more in winter.

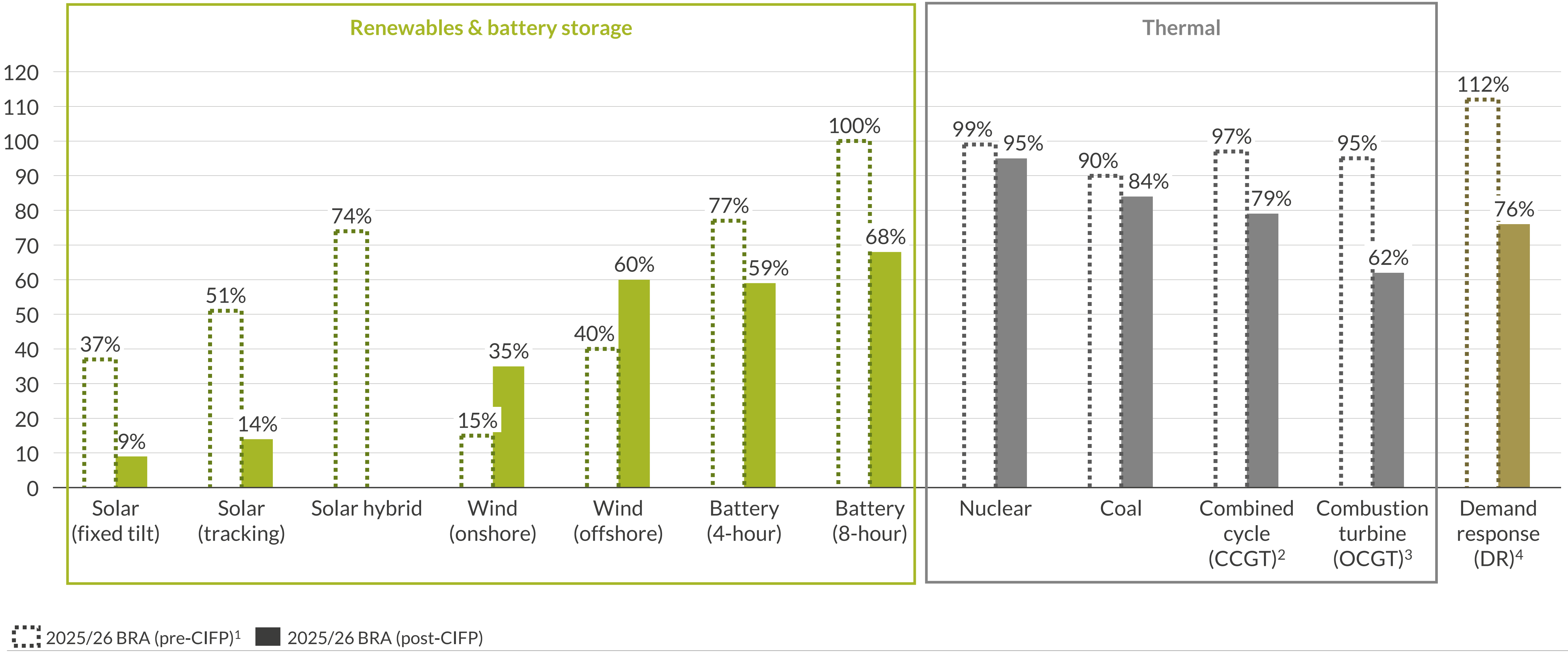
1) Effective Load Carrying Capability. 2) Unforced Capacity—i.e., capacity after accreditation adjustment. PJM's capacity market uses MW UCAP as its native unit for capacity. 3) Equivalent Demand Forced Outage Rate.

Sources: Aurora Energy Research, PJM

CIFP reform | Capacity accreditation decreased for most technologies in the 2025/26 BRA, with solar, batteries, gas, and DR most affected

ELCC values by technology for the 2025/26 BRA[1]

%

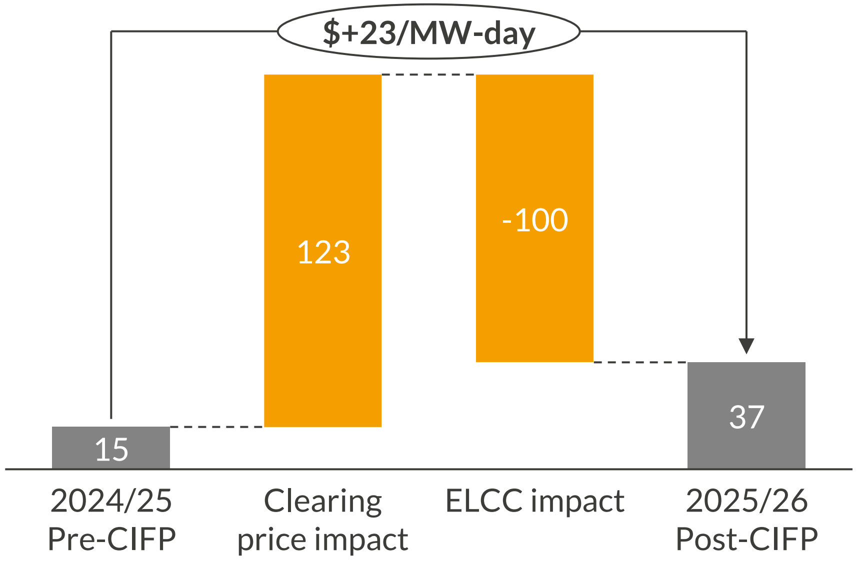


1)"Pre-CIFP" values for thermal plants reflect historical average of [1 - EFORd] per technology class. 2) Combined cycle gas turbine. 3) Open cycle gas turbine.
4) Before CIFP, Demand Response resources were effectively awarded a value equal to the Forecast Pool Requirement (FPR), which PJM recommended be set at 1.1171 for the 2025/26 delivery year in its October 2023 Reserve Requirement Study.
Sources: Aurora Energy Research, PJM

Revenues | Solar PV and onshore wind see opposite ELCC impacts from CIFP reform, but capacity revenues increase for both due to a high clearing price

Capacity revenue change from 2024/25 to 2025/26 BRA (RTO-level clearing price)
$/MW-day

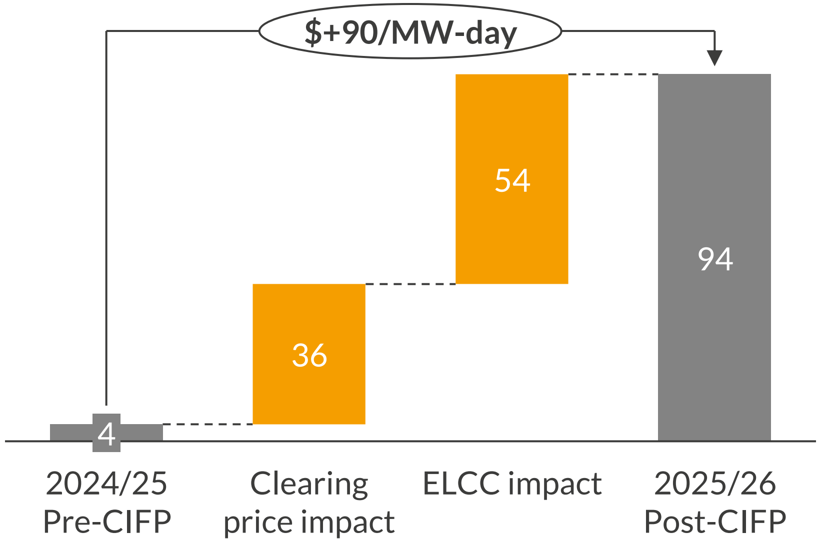
Solar PV (single-axis tracking)



- Capacity revenues for tracking solar PV see a $23/MW-day increase between the 2024/25 and 2025/26 BRAs due to a rise in clearing price.
- The impact of the large reduction in tracking solar's ELCCs —down from 51% pre-CIFP to just 14% post-CIFP—is mitigated by the $123/MW-day impact due to the change in clearing price.

Total Impact

Onshore wind



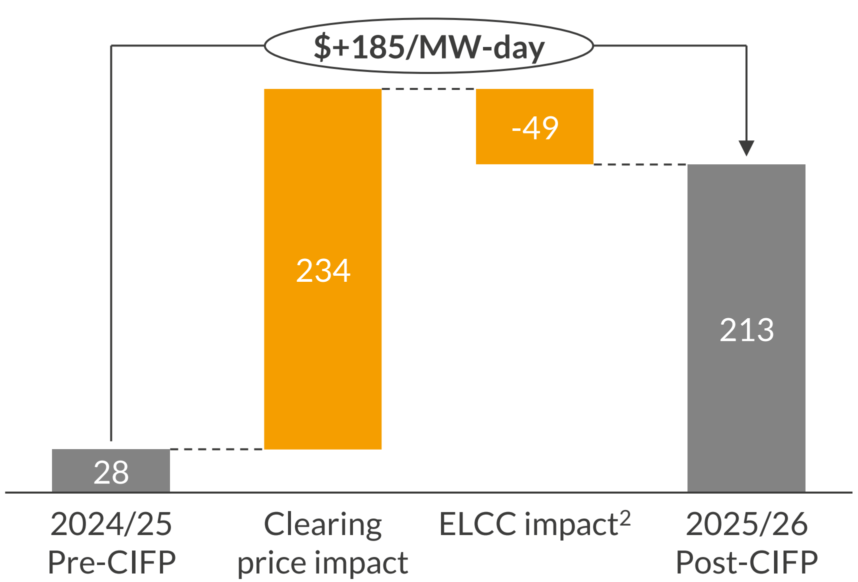
- Post CIFP reform, onshore wind capacity revenues increased by ~$90/MW-day, with the increased ELCC values—15% to 35%—contributing $54/MW-day. Onshore wind ELCCs were adjusted in May 2023 after PJM's ELCC methodology update capping modeled output at CIR.
- Wind's higher ELCCs are due to PJM's risk modeling improvements shifting significant perceived reliability risk to winter months, when wind output is generally higher and more stable.

Source: Aurora Energy Research

Revenues | Natural gas assets can expect an overall increase in capacity revenues, despite lower ELCCs

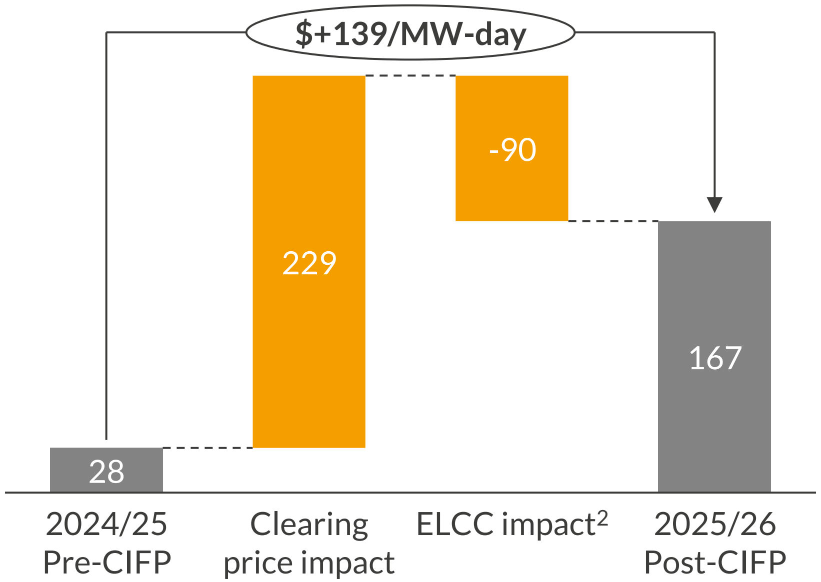
Capacity revenue change from 2024/25 to 2025/26 BRA (RTO-level clearing price)
$/MW-day

Natural gas CC (CCGT)



- Capacity revenues for a CCGT in PJM could rise by $185/MW-day due to clearing price impact, despite its capacity accreditation falling from 97% to 79%.[1]
- $234/MW-day impact due to the price mitigates all the $49/MW-day downside from the accreditation decrease.

Natural gas CT (OCGT)



- Combustion turbines take a stronger hit to capacity accreditation due to CIFP—falling from 95% to 62%[1]—which results in a higher decrease in capacity revenues of $90/MW-day.
- However, this decrease is once again mitigated by the $229/MW-day impact of the rising clearing price.

Total | Impact

1) Based on Aurora estimate of "status quo" EFORd values and CIFP ELCC values published by PJM.

Source: Aurora Energy Research

Agenda

I. 2025/26 BRA: results & drivers

II. CIFP capacity market reforms

III. 2026/27 BRA: parameters, drivers, & expectations

IV. Long-term forecast

Timeline | The 2026/27 BRA will take place 18 months before the delivery year, with a return to 36 months planned for the 2029/30 BRA

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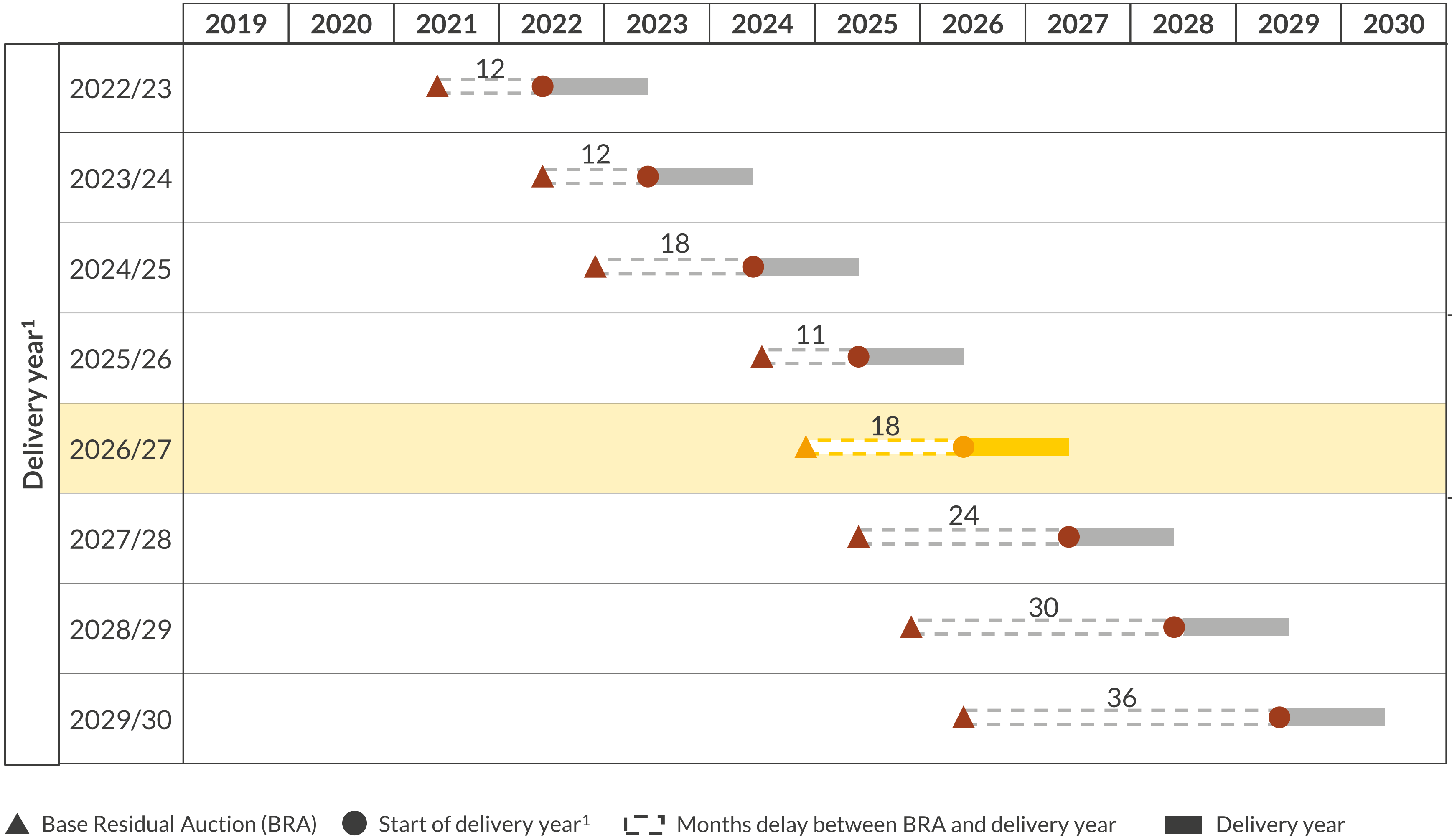
PJM's Base Residual Auction (BRA) schedule



The BRA schedule—typically 36 months ahead of each delivery year—was significantly delayed for the 2022/23 delivery year, due to several FERC rulings and related stakeholder management and counterproposals by PJM, most importantly concerning changes to PJM's Minimum Offer Price Rule (MOPR)

PJM also delayed the 2025/26 BRA, due to its CIFP capacity market reforms and changes to the capacity performance construct, reducing the auction lead time to 11 months.

PJM has published a schedule for incrementally increasing the time between BRA and delivery year starts, returning to their original schedule by the 2029/30 BRA, with 2028/29 BRA having a shorter 30-month lead time.

1) Delivery years run from June 1 through May 31.

Sources: Aurora Energy Research, PJM

Drivers | Demand has risen by 3GW compared to the previous BRA, while changes in supply are highly uncertain—with >3GW additions feasible

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	Factor	Key changes from 25/26 BRA, GW UCAP	Price impact	Explanation
Supply	New entrants	+ 0.8-5.5	↓	▪ Trumbull CC (0.8GW UCAP) expected to participate for first time. ▪ Additional capacity possible due to new batteries, renewables, DR, and imports; incentivized by high expected clearing prices and low capacity performance penalties (due to the $0 Net CONE in many regions, yielding a $0 penalty rate).
	Re-entry of exempt resources	+ 0-2.0	↓	▪ Up to ~6GW ICAP available that withheld from 2025/26 BRA. ▪ Incentivized by abovementioned high clearing prices and low capacity performance penalties, but unclear how much will re-enter, if any.
	ELCC changes	- 1.2	↑	▪ Lower ELCCs for renewables and batteries will reduce effective supply (partially offset by higher ELCCs for combustion turbines).
	Retirements	- 0-1.5	↑	▪ New retirements possible despite expected high capacity prices, e.g. due to environmental regulations.
Demand	Reliability requirement	RTO: +2.8 DOM: +0.9	RTO: ↑ DOM: ↑	▪ Strong increase in forecasted RTO-wide and Dominion peak load driven primarily by data center additions, raising reliability requirements.
	VRR curve shape	*Significantly steeper*	↑/↓	▪ Caused by updated VRR parameters and a switch to a gas CC as PJM's reference generator, significantly raising Gross CONE (which sets the VRR's upper bound) and lowering Net CONE (to $0/MW-day for much of the RTO).
LDAs	CETL	EMAAC: -1.1 SWMAAC: -1.2 DOM: +1.5	EMAAC: ↑ SWMAAC: ↑ DOM: ↓	▪ Significantly lower CETL in EMAAC and SWMAAC may constrain capacity imports, potentially causing price separation in these LDAs. ▪ Dominion's CETL increase more than offsets its higher reliability requirement, potentially lowering its clearing price compared to the 2025/26 BRA.

Sources: Aurora Energy Research, PJM

Supply | 2026/27 BRA prices could range from $100 to $700/MW-day, depending on supply—with a $200-$300 Central expectation

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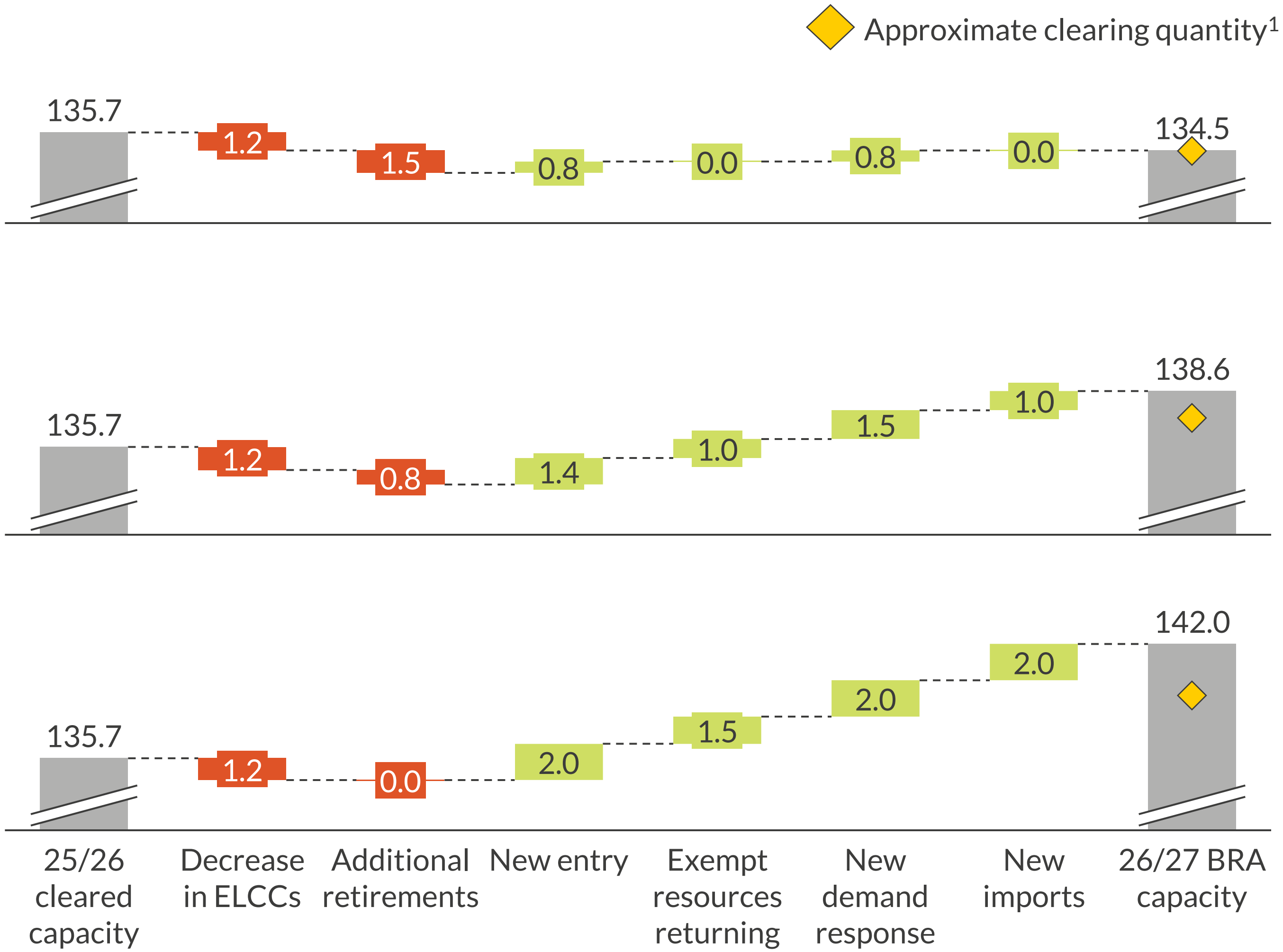
Sources of capacity supply shifts for 2026/2027 BRA, GW UCAP

High case
- Clearing price: **$696/MW-day**
- Price setter: RPM price limit

Central case
- Clearing price: **$200-300/MW-day**
- Price setter: New unit or higher-cost DR[2]

Low case
- Clearing price: **~$100/MW-day**
- Price setter: Existing unit or lower-cost DR



1) 2026/27 BRA capacity reflects total capacity offering into the auction. The quantity of cleared capacity depends on the amount of offered capacity, bid levels, and the shape of the VRR curve. 2) Demand response.

Sources: Aurora Energy Research, PJM

- The amount of supply anticipated to participate in the 2026/27 BRA ranges from 134.5 to 142.0GW UCAP.
  - Supply decreases, relative to the 2025/26 BRA, range from 1.2GW UCAP to 2.7GW UCAP, depending on additional retirements.
  - Supply increases range from 1.6GW to 7.5GW UCAP, depending on new entry, exempt resources re-entering the capacity market, and incremental demand response and import participation.
- Small changes in supply could drive large differences in clearing prices—the “Low supply” case would result in clearing at the price cap, while the “High supply” case would likely see a clearing price set by an existing unit or lower-cost demand response resource.

Supply | 2026/27 ELCCs increased by 6p.p. for combustion turbines but decreased slightly for most renewables and batteries, relative to 2025/26

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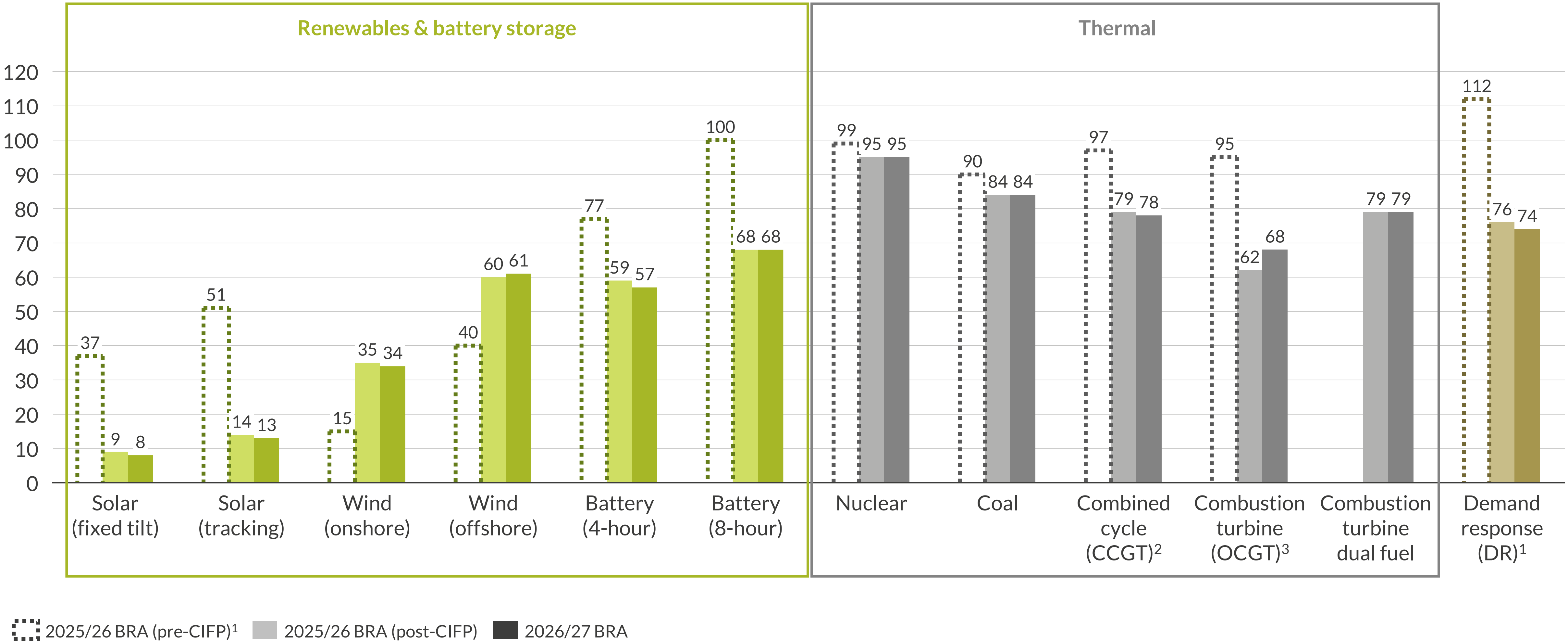
Capacity accreditation by technology[1]
%



1)"Pre-CIFP" values for thermal plants reflect historical average of [1 - EFORd] per technology class; for DR, "pre-CIFP" values are effective, as implied by PJM's parameters through the 2025/26 BRA's FPR. All other values are ELCCs. 2) Combined cycle gas turbine. 3) Open cycle gas turbine.
Sources: Aurora Energy Research, PJM

Supply | Much of PJM has $0 Net CONE for 2026/27, removing Capacity Performance penalty risk and potentially incentivizing more supply

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Many areas of PJM will have effectively no capacity performance penalty for the 2026/27 delivery year, due to their Net CONE[1] dropping to $0/MW-day.

- **This could incentivize additional supply to (re-)enter the capacity market that previously may have withheld due to penalty risk**—e.g. renewables, which are exempt from must-offer obligations and susceptible to penalty risk, having little control over output during system stress events.
- Because the capacity performance penalty rate for each 5-minute interval is proportional to Net CONE, performance penalties are null when Net CONE falls to $0:

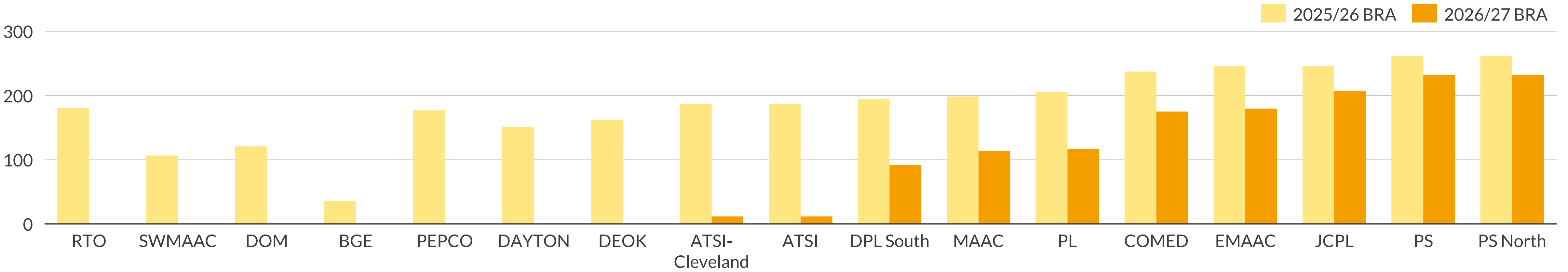
$$Charge\ Rate_{LDA} = \frac{Net\ CONE\ (ICAP)\ _{LDA}}{360}$$

Risks:

- Even with a $0 Net CONE, capacity generators will be subject to capability testing and penalties for test failure. Intermittent resources are exempt from such tests, however.
- This may increase penalty risk for LDAs with a non-zero Net CONE, as (i) much of the RTO has little incentive to perform, potentially triggering drawn-out PAIs[2] and (ii) the total penalty cap is proportional to the BRA clearing price, which could be as high as $700/MW-day.
- Although it has not stated any plans to do so, PJM could reform its capacity performance penalties to ensure a non-zero penalty rate.

Net CONE for PJM RTO and LDAs

$/MW-day ICAP



1) Net cost of new entry—an annualized estimate of the revenue required to cover fixed and capital costs, net of margins earned from energy and ancillary services. 2) Performance Assessment Intervals.

Sources: Aurora Energy Research, PJM

Demand | The 2026/27 BRA's VRR curve is much steeper than previously, making price outcomes significantly more volatile

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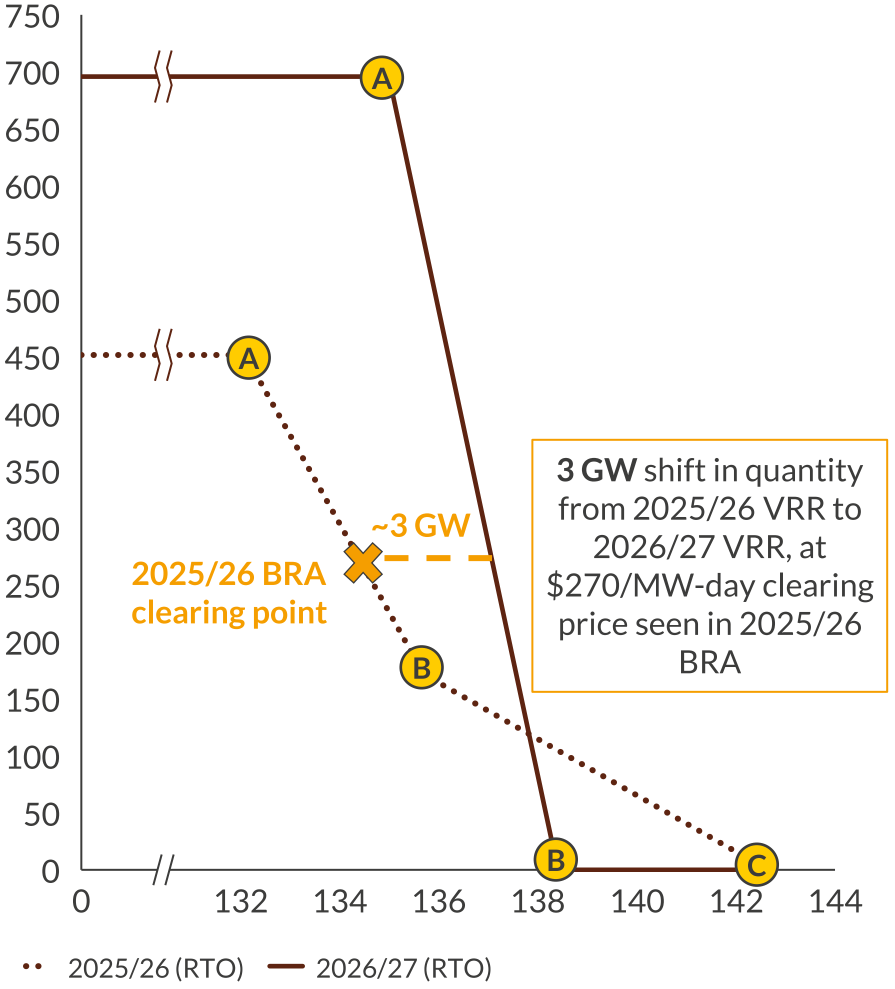
RTO-wide VRR curve[1], incl. point definitions
$/MW-day (nominal), GW UCAP



Key impacts of VRR curve changes

1. The steeper shape of the 2026/27 VRR curve—resulting from changes to the parameters underlying the VRR—increases clearing price uncertainty and volatility.
2. The outward shift of the 2026/27 VRR curve—resulting from increases to PJM's Reliability Requirement—implies that at least 3GW of additional supply is necessary to maintain a clearing price at or below the $270/MW-day seen in the 2025/26 BRA.

Key parameter changes for the 2025/26 BRA relative to the previous auction

Parameter	2025/26 BRA (prev. auction)	2026/27 BRA (next auction)	Driver(s)
Reliability Requirement	144,450MW	147,246MW	▪ Increase in forecasted RTO peak load of 3.3GW
Gross CONE (determines point A)	$451.6/MW-day UCAP	$695.8/MW-day UCAP	▪ Shift in the VRR reference resource from a combustion turbine to a combined cycle, which is both more capital intensive (increasing Gross CONE) and more lucrative in energy and ancillary services markets (decreasing Net CONE).
Net CONE (determines point B)	$228.8/MW-day UCAP	$0/MW-day UCAP	

1) Variable Resource Requirement—PJM's capacity demand curve, defined by 3 points. 2) VRR curves are net of FRR demand. As PJM has not yet released FRR designations for the 2026/27 BRA, the values here assume identical FRR participation from the 2025/26 BRA.
Sources: Aurora Energy Research, PJM

LDAs | SWMAAC, JCPL, DPL South, BGE, & EMAAC all have higher likelihood of price separation, due to tighter CETO:CETL ratios

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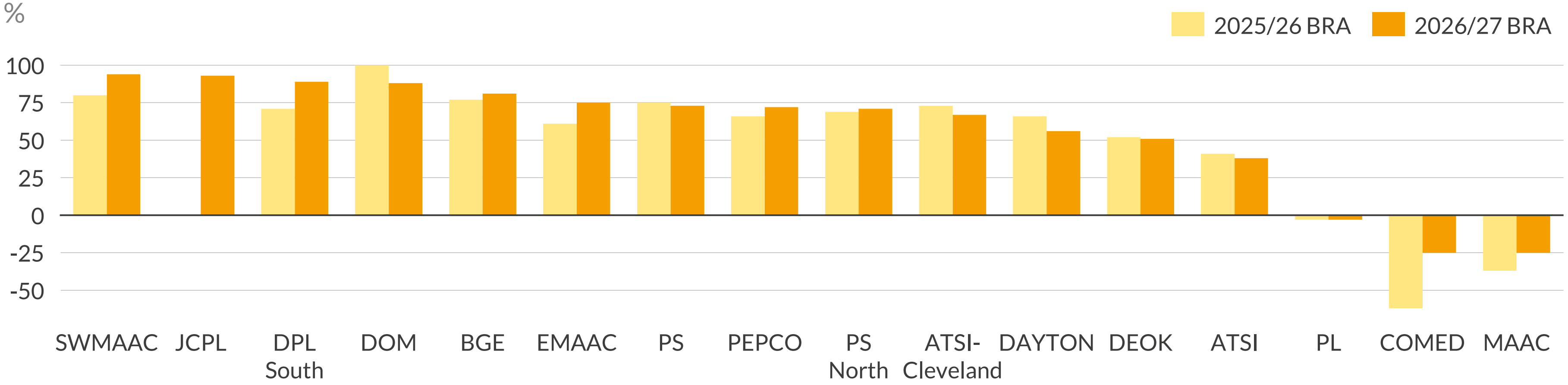
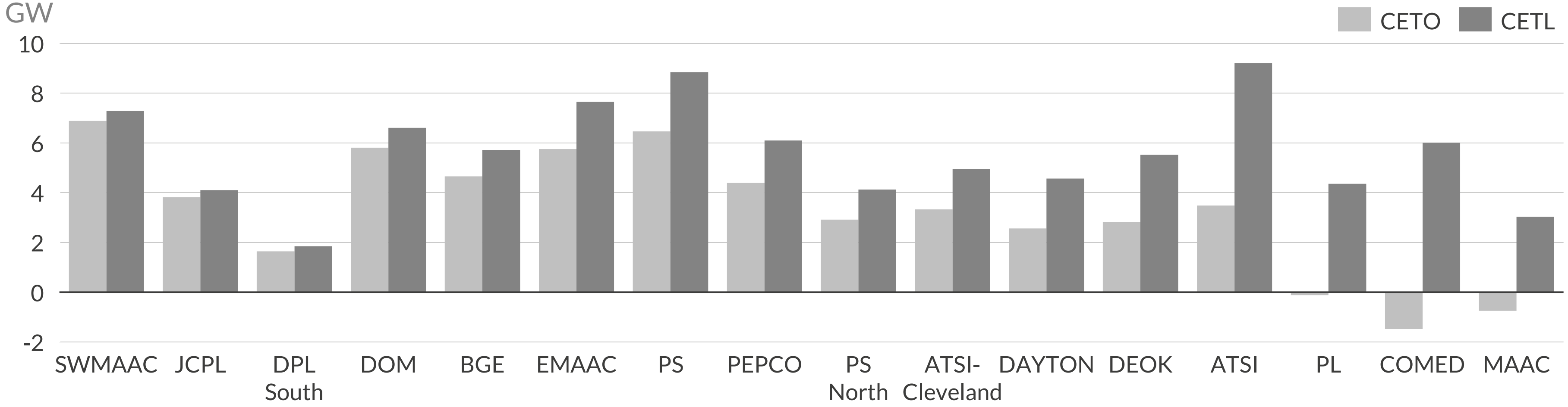
CETO:CETL ratio by LDA



*← **Higher ratio:** more likely to clear above parent region*

*← **Lower ratio:** less likely to clear above parent region →*

CETO and CETL by LDA (2026/27 BRA)



Sources: Aurora Energy Research, PJM

- **Capacity Emergency Transfer Limits** (CETLs) determine how much capacity can be imported into an LDA during peak system stress moments, thus acting as constraints on PJM's cost optimization of the BRA.
- An LDA's **Capacity Emergency Transfer Objective** (CETO) is PJM's estimate of the capacity import necessary to satisfy loss of load expectation requirements.
- The closer CETO is to CETL, generally the more likely that LDA will clear above its parent price ("price separation").
- SWMAAC, JCPL, DPL South, Dominion, BGE, and EMAAC all have a relatively high likelihood of price separation, due to tight CETO:CETL ratios (≥75%).
- Of the above LDAs, only Dominion's CETO:CETL ratio is lower than the previous BRA.

LDAs | Dominion's large CETL increase could bring its clearing price as low as $198/MW-day, although $695 is still feasible

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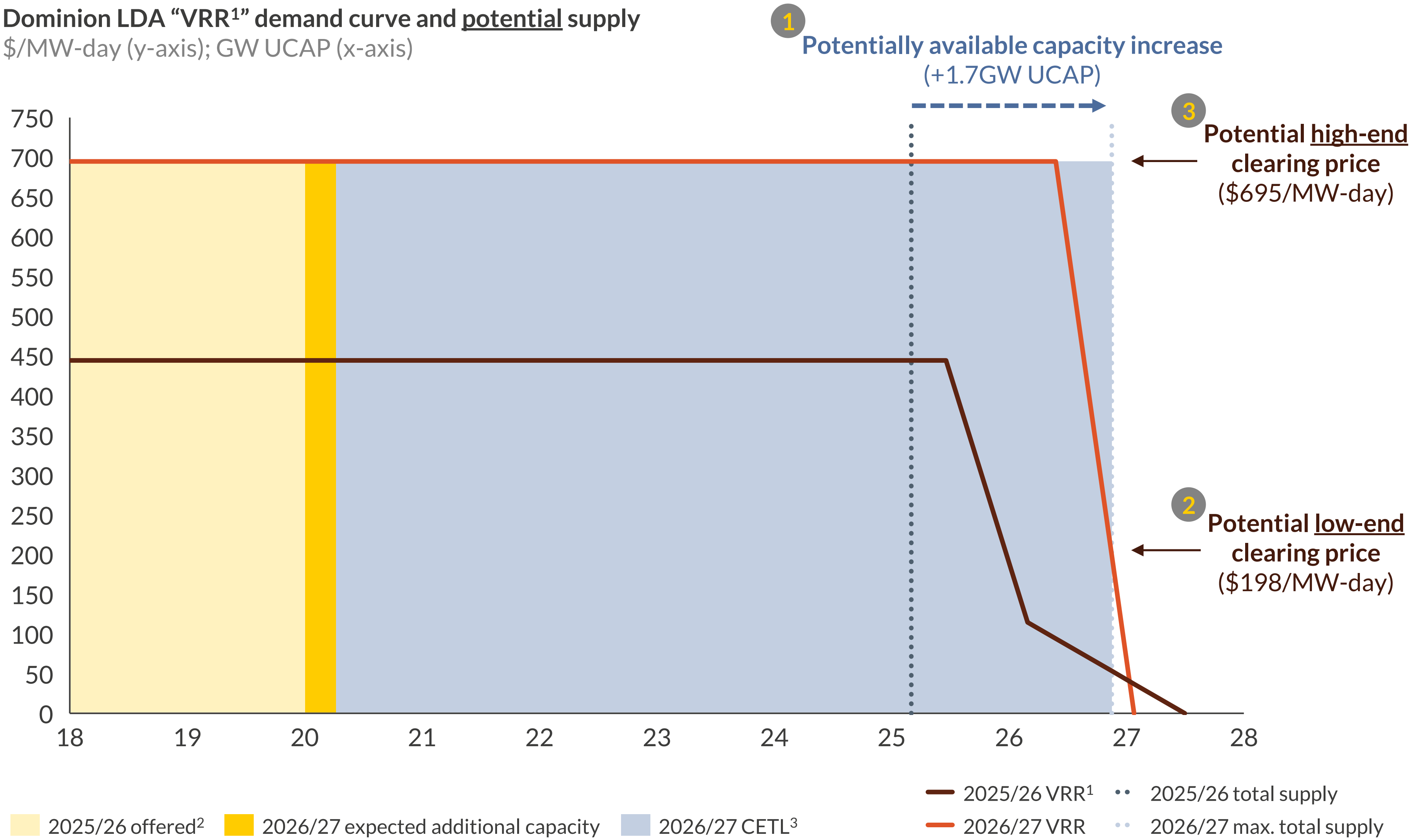
Dominion LDA "VRR[1]" demand curve and potential supply
$/MW-day (y-axis); GW UCAP (x-axis)



1) Variable Resource Requirement. 2) Excl. (estimated) capacity offered as winter-only but not cleared because no summer-only counterpart available. 3) Capacity Emergency Transfer Limit/ Objective. 4) Estimated from BRA parameters via [reliability requirement] - [CETO]. 4) Also assuming RTO does not clear >$198/MW-day; but in that case CETL would likely not be fully utilized.
Sources: Aurora Energy Research, PJM

1. The total available capacity in Dominion—as indicated by PJM's auction parameters—has risen by 1.7GW compared the last auction, primarily due to its 1.4GW CETL[3] increase.
   - PJM expects net additional 0.3GW UCAP of capacity bidding within the LDA.
2. As a result, Dominion's price could clear as low as $198/MW-day, if the entire extent of the LDA's CETL is utilized and no participants bid above that level.[4]
3. However, neither of the abovementioned criteria are guaranteed—as underscored by CETO[3]<CETL, i.e. PJM's expectation that not all of CETL will be used—and Dominion could still feasibly clear at its auction cap of $695/MW-day if supply falls ≥0.5GW short of the 26.9GW available.

Agenda

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I. 2025/26 BRA: results & drivers

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Outlook | Aurora's Central case expects clearing prices at $XX/MW-day levels

5-year rolling average clearing prices for PJM's Base Residual Auction (BRA)
$/MW-day (real 2023)

Redacted

2026-2030

Prices around the $XX/MW-day level, as tight supply-demand conditions are expected to persist:

- PJM forecasts continued short-term peak load growth.
- Additional thermal resources (particularly coal plants) have announced retirements before 2030.

2031-2050

Sustained prices of $XX/MW-day, as newbuild is required almost every year:

- Retirements from gas plants built in the ~20s reaching end of life, new capacity needed.
- Gas capacity factors driven down by continued renewables growth and flexible demand (e.g., EVs); higher CM revenue needed.

Sources: Aurora Energy Research, PJM

Drivers | Peak load growth and retirements will persist until at least 2030, partially offset by potential new build, DR, and imports

Drivers of capacity price developments through 2029

	Factor	Expected change from 25/26 to 29/30 BRA GW UCAP	Price impact	Explanation
Supply	**New entrants**	+11	↓	▪ New resources primarily comprise solar, wind, and battery storage resources in the interconnection queue, with a small amount of additional thermal capacity possible.
	Other new sources of capacity	Imports: +4 Demand response: +4	↓	▪ The 2025/26 BRA saw low demand response and capacity import participation by historical standards. Higher RPM clearing prices will likely incentivize further participation from these resources.
	Retirements	-10	↑	▪ Coal plants totaling 7GW UCAP have announced retirements by 2029.[1] Some additional peaking capacity may also retire; though higher RPM clearing prices will incentivize these units to remain online.
Demand	**Peak load**	+12	↑	▪ PJM's 2024 load forecast sees peak load rising from **153.5GW** in 2025 to **165.7GW** in 2029. Because PJM uses its own forecasting to assess peak load for the RPM, this forecast provides a basis for near-term auctions.
	VRR curve shape	*Uncertain*	↑/↓	▪ PJM refreshes the parameters underlying the VRR curve annually. An increase in the Net CONE parameter above the $0/MW-day used for the 2026/27 BRA would result in a less steep VRR curve.

1) Rockport, Kincaid, Miami Fort, Keystone, Conemaugh.

Sources: Aurora Energy Research, PJM

Risks | Structural changes to PJM's capacity market or state policy could lower the price outlook, but most have low probability of occurring

Potential measures PJM or its member states may take that could reduce capacity market prices

Measure	Relevant areas	Estimated likelihood	Explanation
Interconnection queue fast-track process	PJM		▪ PJM is considering implementing a process that would allow "shovel-ready projects" to fast-track their interconnection and construction process, to benefit system reliability.[1] ▪ PJM's planning committee is also considering ways for new projects to bypass the interconnection queue by taking over retiring resources' capacity interconnection rights and physical locations.
Policy hindering impact of data centers on power grid	OH, VA		▪ Legislators in both OH and VA proposed multiple bills in 2023 and 2024 to regulate data centers' impacts on power costs, environment, and local land use. If successful, such bills could slow data center additions or oblige operators to source and pay for power in ways that minimizes impacts on PJM rates.
State subsidies for new generation	MD, PA		▪ State Delegates of MD—the state containing BGE, which cleared at $466/MW-day in the 2025/26 BRA—have announced potential plans to introduce bills to (i) add energy storage to the state's distribution grid and (ii) provide additional REC support to advanced-stage solar projects. ▪ PA Sen. Gene Yaw (R) has announced plans to introduce bills to (i) create a fund to support power plant construction (akin to the Texas Energy Fund) and (ii) increase certainty within the state's permitting process.
Include RMR plants in capacity auction	DE, DC, IL, MD, NJ, OH		▪ Ratepayer advocates from 6 states urged PJM in an August 30 open letter to include RMR units in the capacity auction. ▪ However, PJM uses RMR primarily to guarantee transmission security (rather than resource adequacy), and their inclusion in the capacity auction could distort the necessary price signals to replace the retiring plants.
State or LSE exit as FRR region to lower costs	-		▪ Although no states or utilities have announced intentions to opt out of PJM's capacity market, multiple entities including MD, NJ, and Dominion VA threatened to do so (with Dominion following through) around 2020 when PJM expanded its bid floor ("MOPR") to apply to subsidized renewables. ▪ Such exits could provide feasible pathways for states and utilities to lower costs to ratepayers, should PJM see continued high capacity clearing prices.

1) According to PJM executive vice president for market services and strategy Stu Bresler.

Sources: Aurora Energy Research, UtilityDive

Agenda

I. Appendix

2025/26 BRA | 2 LDAs cleared above their parent price, down from 5 in the previous auction

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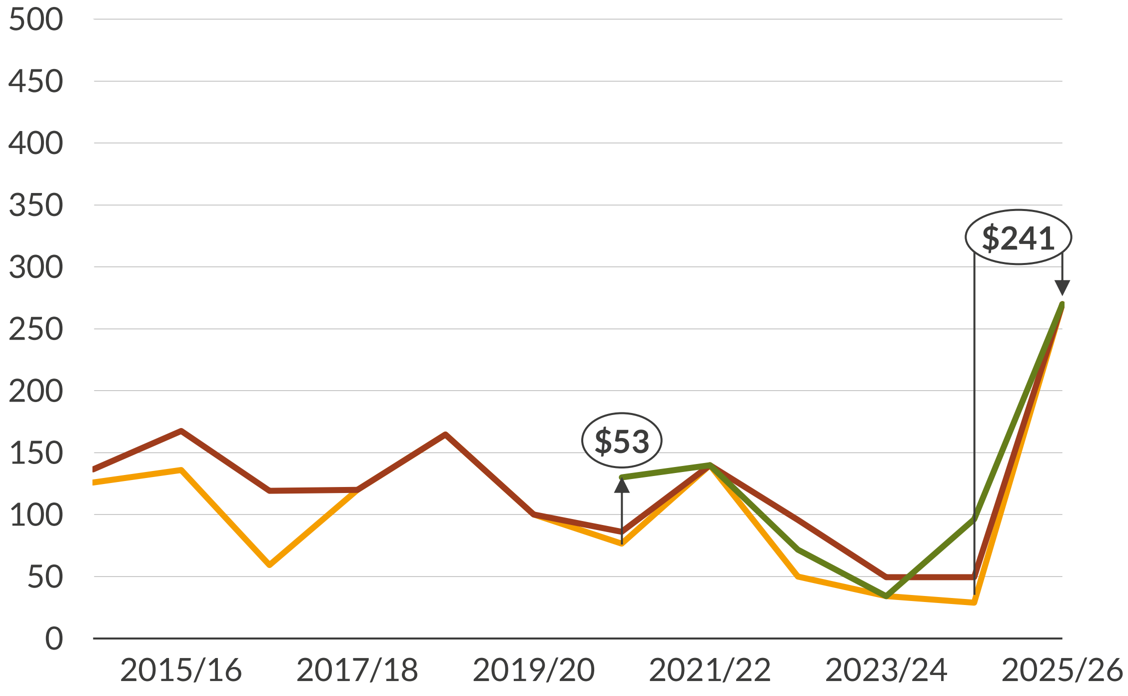
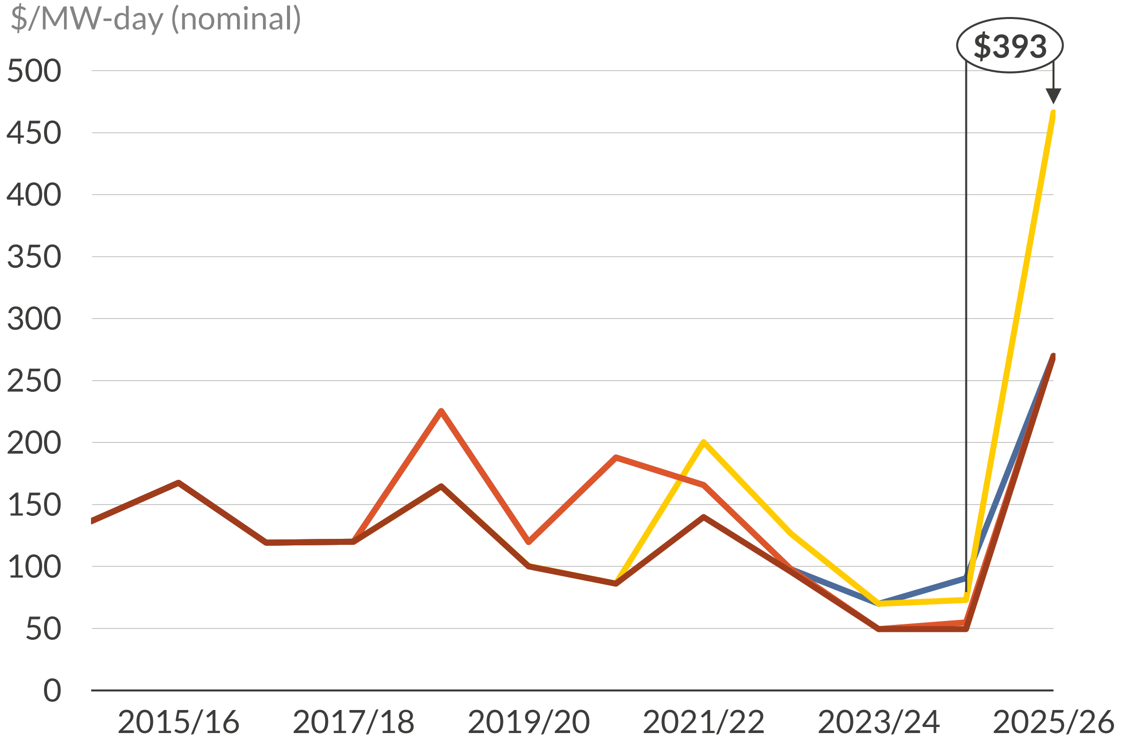
Clearing prices within RTO (for selected LDAs in 2025/26 BRA)
$/MW-day (nominal)



- The 2025/26 BRA saw the largest delta between consecutive RTO clearing prices to date, at $241/MW-day.
- DEOK—modelled as an LDA since the 2020/21 BRA—has cleared above RTO level in 3 out of the 5 prior auctions; however, both DEOK and MAAC cleared at the same level as RTO this time, largely due to RTO's high clearing price.

Clearing prices within MAAC for 2025/26 BRA
$/MW-day (nominal)

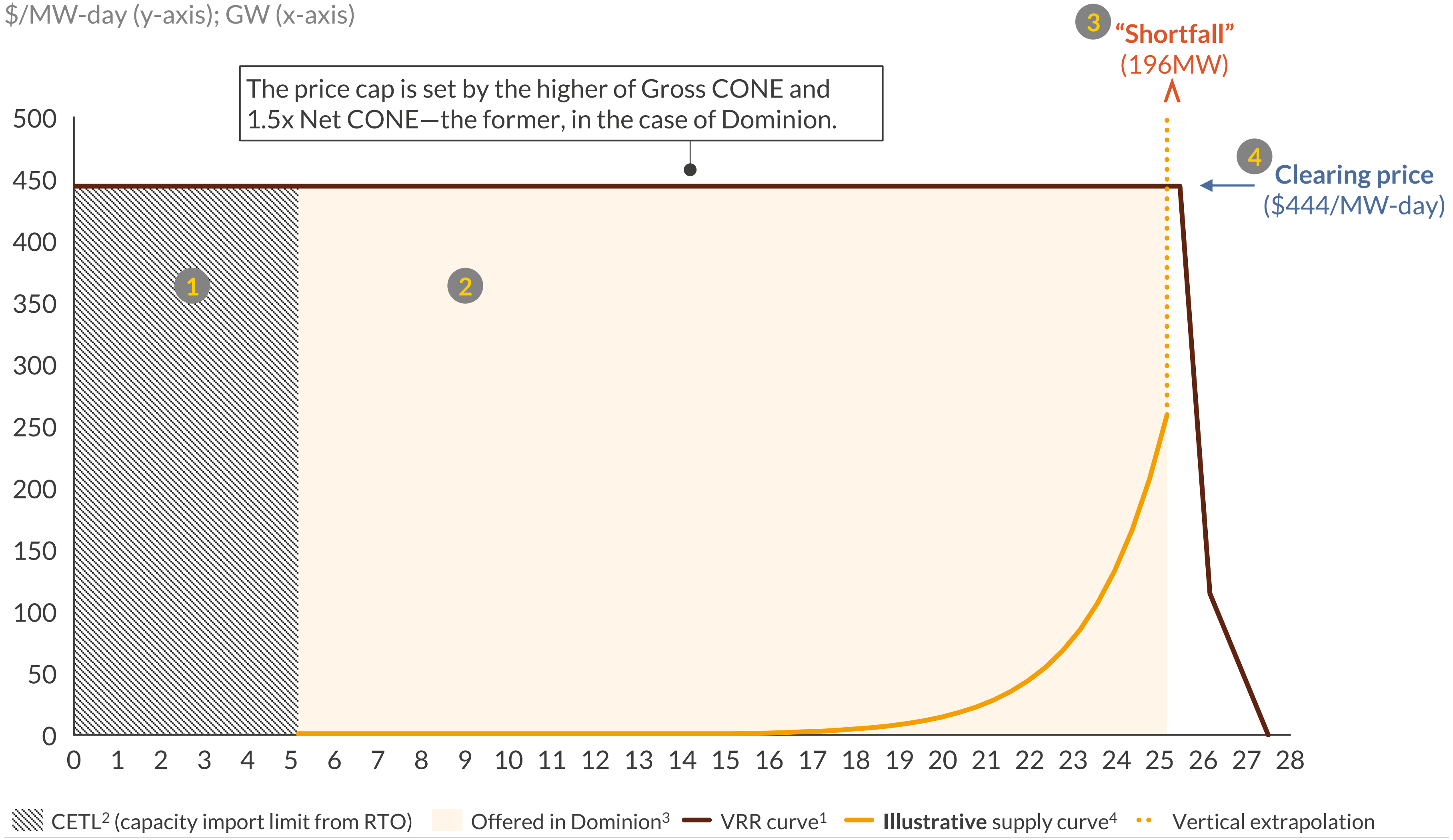


- BGE cleared above the MAAC level in the past 5 auctions, and the trend continued in the 2025/26 BRA too, with BGE clearing $393/MW-day higher than its previous clearing price and $196/MW-day higher than the MAAC clearing price.

2025/26 BRA | Dominion and BGE cleared at their price cap, with total available capacity below any point on the sloped demand curve

Dominion LDA "VRR[1]" demand curve and representative supply stack

$/MW-day (y-axis); GW (x-axis)



- Available capacity in Dominion LDA can come from two sources:
  1. Capacity imported from elsewhere in the RTO, limited by CETL;
  2. Capacity offered within Dominion (including DR and non-PJM imports).

3. The total available capacity (25,167MW) fell nearly 300MW short of the highest point on the sloped portion of the LDA's demand curve, point A (25,463MW).

4. As a result, the LDA's price automatically cleared at the LDA's price cap, at $444/MW-day.

- BGE showed analogous shortfall, clearing at its LDA price cap of $466/MW-day.

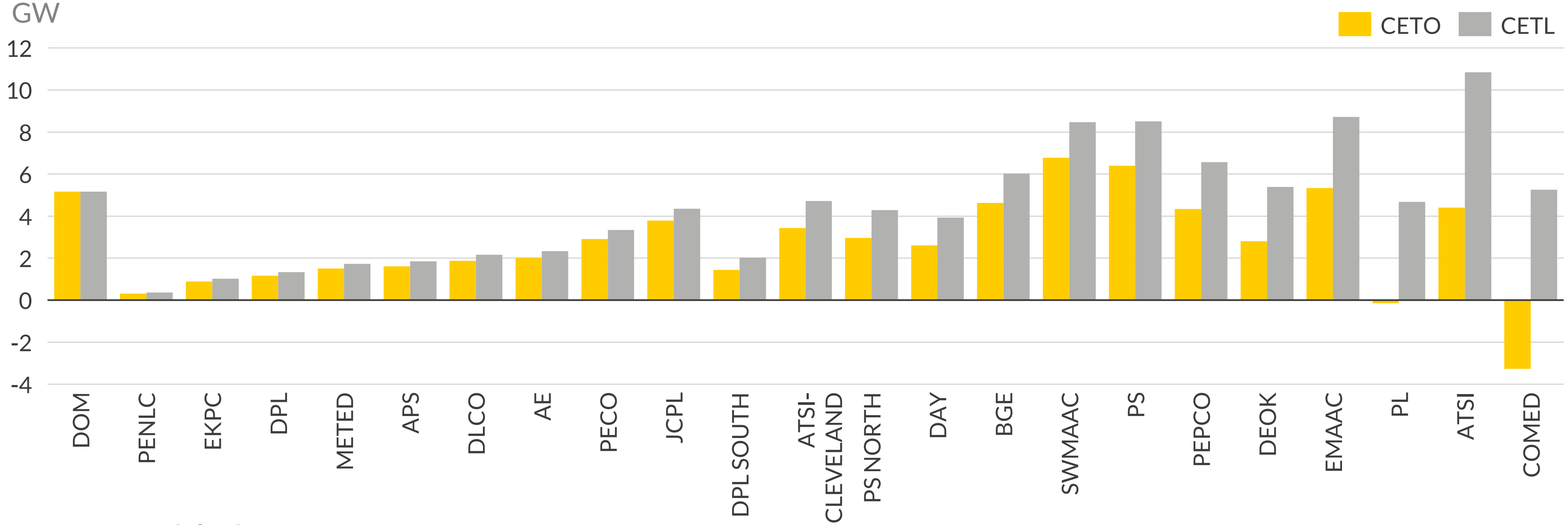
1) Variable Resource Requirement: PJM's capacity demand curve. 2) Capacity Emergency Transfer Limit. 3) Excluding estimated capacity offered but unavailable to clear because offered as winter-only and no summer-only capacity counterpart was available. 4) X-extent is true to auction results; rest of curve is illustrative, as PJM does not publish bid levels or individual bidder info.

Sources: Aurora Energy Research, PJM

2025/26 BRA | PJM expected Dominion LDA to be highly constrained, assigning it a CETO value nearly identical to its CETL

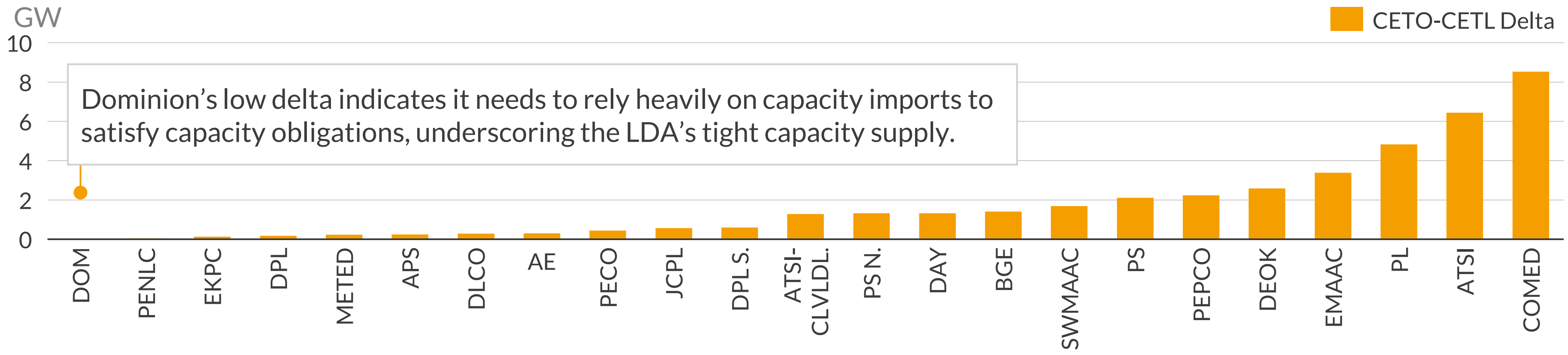
CETL and CETO by LDA

GW



CETL-CETO delta by LDA

GW



Sources: Aurora Energy Research, PJM

- Capacity Emergency Transfer Limits (CETLs) determine how much capacity can be imported into an LDA during peak system stress moments, thus acting as constraints on PJM's cost optimization of the BRA outcome
- An LDA's Capacity Emergency Transfer Objective (CETO) represents the capacity import amount necessary to satisfy loss of load expectation requirements, according to PJM's studies
- Dominion's CETO was nearly identical to its CETL, indicating the LDA's tight capacity supply and resulting need for capacity imports.

Demand deep-dive | VRR shifted out & more vertical; roughly 3 GW UCAP more demand at 2025/26 BRA's $270/MW-day price point

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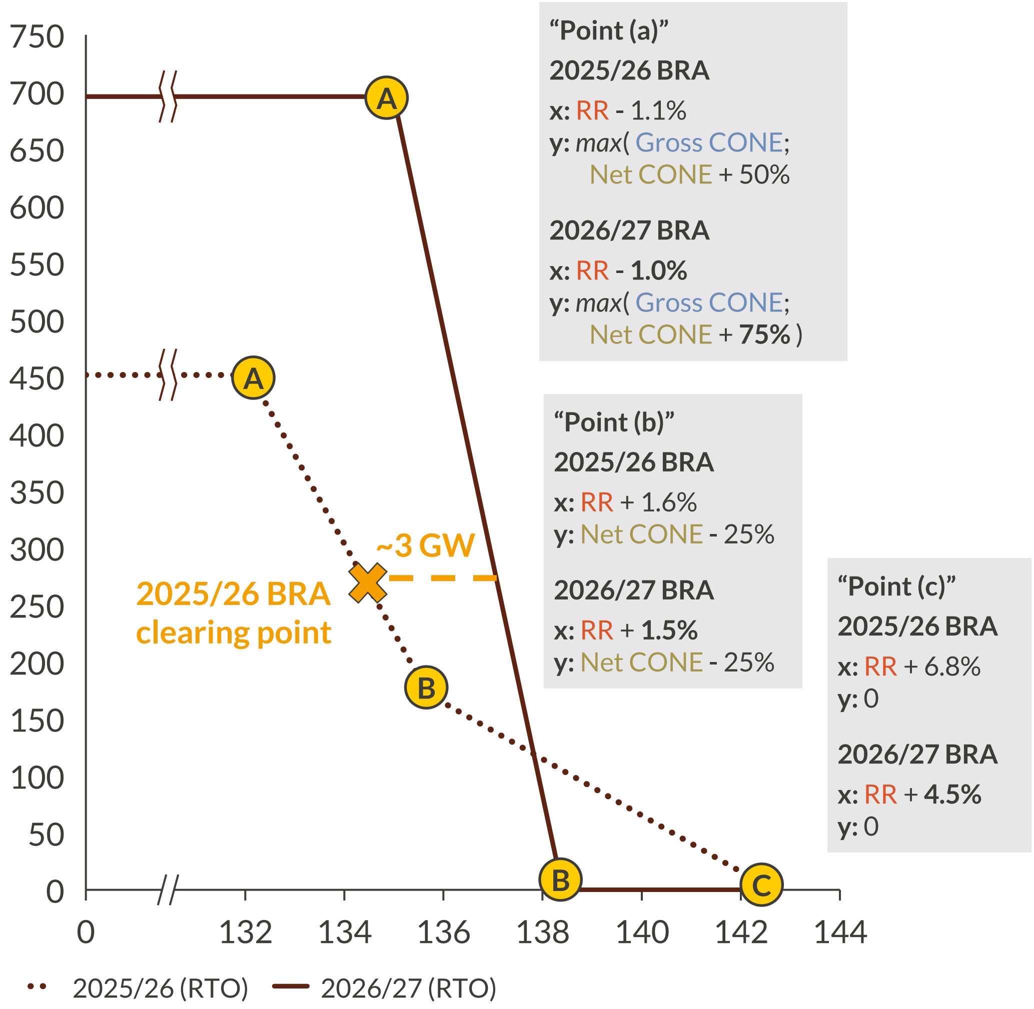
RTO-wide VRR curve[1], incl. point definitions
$/MW-day (nominal), GW UCAP



Key parameter changes for the 2025/26 BRA relative to the previous auction

Parameter	2025/26 BRA (prev. auction)	2026/27 BRA (next auction)	Driver(s)
Reliability Requirement (RR)[2]	144,450MW (133,564MW excl. FRR)	147,246MW (136,360MW excl. FRR)	▪ Increase in forecasted RTO peak load of 3.3GW ▪ Increase in Installed Reserve Margin (IRM) from 17.8% to 18.6%.
Gross CONE	$451.6/MW-day UCAP	$695.8/MW-day UCAP	▪ Shift in the VRR reference resource from combustion turbine to combined cycle. Relative to combustion turbines, combined cycle units are both more capital intensive (increasing Gross CONE) and more lucrative in energy and ancillary services markets (decreasing Net CONE).
Net CONE	$228.8/MW-day UCAP[9]	$0/MW-day UCAP	

1) Variable Resource Requirement—PJM's capacity demand curve, defined by 3 points.

Sources: Aurora Energy Research, PJM

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