PJM Market Update Webinar
Q&A

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The following are answers to the questions our presenters received from participants during the PJM Market Update webinar on Jan. 31, 2024.

Pricing

What is the outlook in terms of energy rates for the next month going forward? Will they be lower than last year?

Near-term pricing is almost always a weather bet. Mild winters and summers will usually result in cheap power and gas, like the low index pricing we experienced last year. PJM 2023 index pricing returned to pre-Covid levels, which was an unexpected, pleasant surprise. What's more:

- Throughout 2023, PJM index pricing consistently delivered below the forward market. Forward prices will be impacted by both recent low index prices, as well as the very high index pricing seen in 2022.
- Elevated power prices in the outer years are being supported by higher NYMEX forwards driven by new LNG facilities coming online, and the expected shrinking generation reserves in PJM.
- If index pricing continues to be a discount to the forwards, the expectation would be that forward prices for the balance of this year could see some relief, which would result in a potential buying opportunity.
- There are factors that can come out of nowhere—such as extreme weather and geopolitical events (like wars)—that could materially push up both gas and power.

Buying considerations for a market contango scenario: this is the perfect environment for buyers to consider a layering or index strategy. This could take some risk off the table right now while still giving you the ability to capitalize on a market dip if weather remains mild and pricing trends back to 2023 levels.

36-month layered purchasing example: You could execute a 36-month adder agreement where you determine which adder components you'd like to lock in, then throughout the term of the contract, you would have the flexibility to buy energy layers for any percentage/any timeframe within the contract term. Right now, locking in some or all your requirements for the first year may provide value since the market is in contango.

How will Offshore Wind Renewable Energy Credits (ORECs) affect pricing?

Theoretically, more renewable generation should put downward pressure on the market because there is no fuel cost for those generators. If the grid is operating with a high percentage of no-cost or low-cost generators, index pricing should be relatively low. The concern in the market is the intermittency risk of renewables. As renewable generation become a higher percentage of the generation mix, there could be reliability issues on days when the sun isn't shining, or the wind isn't blowing. Reliability issues will require the highest-cost generators to run to meet demand, which could result in extremely high index pricing. This risk of a few very high-priced hours could be keeping forward prices overvalued as well.

The shift to more renewables could also—and maybe more so—impact the capacity market. Fossil-fuel generators are not expected to be eliminated completely any time soon. Those generators may shift from being baseload assets that run every day, to only running periodically, when necessary, to maintain reliability. These generators will not be profitable by only receiving limited energy payments, so they will need higher capacity revenues to ensure they remain economically viable, and they will need to bid into the capacity market at higher prices, therefore causing capacity rates to rise.

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Pricing impacts of ORECs/RECs (con't)

What REC pricing will directly impact is the Renewable Portfolio Standard (RPS) component of energy supply pricing. REC pricing is driven by simple supply and demand and state compliance requirements. REC demand has been increasing, and customers in states with an RPS requirement will see higher costs as REC pricing increases. One option to mitigate cost increases is to sign a long-term power contract that fixes the RPS cost component.

Will there be natural gas price impacts as a result of the recent decision to pause pending and future permits to export LNG?

The recent decision to pause LNG permits is expected to have a very minimal impact on pricing. The decision does not impact permits that have already been approved and the pause. In addition, this is only temporary and expected to be lifted after the upcoming presidential election. When the news broke, there was almost no reaction in the market. If the pause would be extended for any reason, it is likely that there could be some downward pressure on pricing, since more of our domestic supply would remain at home. But the pause would likely have to last well into 2025 or 2026 to see any material impact on pricing.

Supply/Demand

With so much generation in the interconnection queue, how much can we expect will be built?

One thing is certain: Not every resource that enters the interconnection queue is going to be built. Naturally, many factors influence the decision to move forward with a project, including the cost of the facility, the cost to interconnect to the electric grid, the timeliness of doing so, and—for many investors—the ability to contract their output. Using history as our guide, less than 15% of the projects that enter the queue come to fruition. While this sounds like a small number, keep in mind that PJM has added 35,000 MWs in the last 10 years. If that percentage were to hold true with the current queue, another 30,000 MWs could be on the way.

January saw the first significant cold weather in the PJM region since Winter Storm Elliott. How did the system do compared to the Elliott event?

You may remember in late December 2022, Winter Storm Elliott raced across the PJM footprint, impacting electric generation and natural gas supplies in the region. While no firm load was shed, PJM did enter emergency operations over a 48-hour period and relied on all the tools in their toolbox to maintain reliability. Earlier this month we saw the first deep and sustained freeze in the region since Elliott. Fortunately, both the gas and electric systems performed well. No major emergencies were reported, energy prices were steady, and there were no demand response events called.

PJM Interconnection Queue by the numbers:

Overall queue: over 3,000 active generation interconnection projects at various stages of study with a total energy value of nearly 100 GW greater than PJM's peak load.

2024: PJM's reformed interconnection process is expected to clear about 300 new generation projects totaling 26,000 MW.

2025: PJM anticipates another 46,000 MW in projects that should clear PJM's study process and be ready for construction by mid-2025.

2026: by the end of the year, an additional 100,000 MW of projects is expected to be cleared.

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Capacity & Transmission

How will the capacity market changes impact market outcomes in PJM?

During the webinar we discussed many of the changes PJM is seeking to implement to its capacity market. If approved, these changes will seek to 1) better identify the periods of reliability risk, and 2) how many MWs a resource may sell and the prices at which those MWs may be offered. Given these dynamics, it's tricky to predict results. We'll get our first insight into supply and demand dynamics in February when PJM publishes what is referred to as "Planning Period Parameters." These parameters outline the expected load for the footprint and the regions inside PJM. It will also provide insight into the dynamics of changes to the demand curve, which is utilized to determine prices and expected energy market revenues that impact supply offers.

What is the expectation for the 2025-26 PJM capacity auction? When will it happen and when will PJM move back to normal auction cycle?

PJM's "steady state" involved holding a capacity auction three years in advance of delivery. This timeline was set up to permit new entry or reinvestment, allow informed and timely retirement decisions, and better inform PJM's transmission planning process. Due to a variety of different regulatory and litigation matters, the timeline has been much shorter for the last several auctions.

The next auction will be June 2024 for capacity commitments that commence in summer 2025. Preparations for what we call the "2025/2026 Base Residual Auction" are underway, with the next major milestone being the publication of "Planning Period Parameters," which will indicate the target load for procurement in the auction.

PJM is expected to continue with these auctions every six months or so for each subsequent delivery year. PJM will conduct their Base Residual Auction for the 2029-2030 delivery year in May 2026. That means that PJM will conduct five Base Residual Auctions over the course of 24 months to catch up to the "classic" schedule.

What is the biggest risk factor to the upside or downside for capacity markets? Are any specific regions within PJM that are especially vulnerable?

Although there are shifting dynamics with PJM changing their capacity market design, supply and demand remain the key drivers for capacity market outcomes. Even in the absence of the proposed changes, we know that supply is becoming tighter in the near-term as additional resources retire, and we've seen an increase in reliability concerns concentrated in the eastern portion of PJM's footprint. While there are many resources in the interconnection queue, it isn't certain that retiring units will be replaced megawatt-for-megawatt. Lastly, PJM is seeing the rate of load growth increase significantly for the first time in many years. We'll know more about specific risks as FERC takes action on PJM's proposed changes and we approach the auction cycle for the delivery year beginning June 2025.

If PJM is forecasting power demand increases from data centers and other consumers, do you foresee PJM selectively increasing capacity payments as incentive to build additional generation?

Capacity market outcomes are driven by two primary factors: forecast load and supply offers. The interaction of demand and supply and the capacity market prices they produce should drive the incentive for resources to build, reinvest, or retire.

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What's the best way to reduce the cost impact of capacity and transmission charges?

First, consider a capacity and transmission pass-through product. This will allow a buyer to avoid paying the risk premium associated with fixing those components for the term and have the opportunity to impact their capacity/transmission obligation by lowering consumption during peak hours.

On average in PJM, transmission management is almost 7Xs the value of capacity management

Total Transmission Costs ($/MW-Year)

	2019	2020	2021	2022	2023	2024
PJM Max (PSEG)	$110,307	$144,011	$152,926	$140,894	$148,511	$164,691
PJM Average	**$46,718**	**$50,771**	**$57,564**	**$61,635**	**$63,787**	**$68,310**
PJM Min (APS)	$31,891	$33,495	$35,238	$37,941	$33,629	$36,022

Capacity Costs ($/MW-Year)

	2019/2020	2020/2021	2021/2022	2022/2023	2023/2024	2024/2025
PJM-RTO	$36,500	$27,933	$51,100	$18,250	$12,457	$10,556

Capacity rates are very low in most zones through May 2025, which is making capacity only a small percentage of overall costs at this point. The same cannot be said for transmission.

The aging transmission infrastructure is causing network integration transmission service (NITS) costs, one of the transmission components, to continuously trend up in almost all PJM utilities—with no relief in sight. Currently, transmission costs are outpacing capacity costs in all zones, with some utilities having transmission costs nearly 10x capacity costs.

Transmission costs comprise 7% to 25% of a retail customer's cost.

- Transmission rates have been trending up over the past several years due to the aging grid infrastructure.
- Transmission cost adjustments can be announced by a utility at any time.
- Suppliers have no insight into a utility's future transmission rates.

NRG provides notifications to assist customers with identifying ISO and utility/zone potential peak hours, during which time it could benefit a business to curtail or shed load in an effort to reduce capacity and transmission obligations (aka cap and trans tags). It is in a business' best interest to have a curtailment plan in place so that decisive actions can be taken when a notification is received. Even curtailing during only one peak demand day can result in a material cost reduction. In addition, customers on a capacity/transmission pass-through product should be enrolled in demand response, and vice-versa, to ensure that potential savings and earnings can be realized.

Renewables

How will clean energy mandates affect PJM's supply mix?

A review of PJM's generation interconnection queue demonstrates that the bulk of new projects involve solar, battery, and wind resources. Much of this is driven by public and private goals for incremental new renewable and/or carbon-free technologies to provide electricity. It is reasonable to expect the grid operator—whether in PJM or other regions experiencing similar changes to their system—to maintain a close eye on impacts to reliability and resiliency and react accordingly should concerns arise.

What are the impacts to customers now that Dominion's green tariff is in place?

Under Dominion Rider TRG, customers in Dominion's Virginia service terrritory with peak load less than 5 MW may only receive a 100% renewable energy service from Dominion. This limitation does not apply to customers with peak load greater than 5 MW—these larger customers may still purchase renewable products from their preferred supplier.