U.S. Winter Market Update Webinar
Q&A

Compiled: Sept. 30, 2024

The following are answers to the questions our presenters received from participants during the U.S. Winter Market Update webinar on Sept. 25, 2024

Weather

How cold of a winter do you think it will be as compared to the last couple of winters?

This winter is almost certainly going to be colder than last winter, which was the warmest on record since 1950. With models indicating La Niña conditions, there is more risk for weather volatility. Some other details to keep in mind:

- Since 2000, winters on average have decreased in the number of heating degree days by almost 14 and the top six warmest winters have all occurred since 2011.
- Seven of the last nine La Niña winters have been colder and decreased by less than 14 heating degree days.

How will the tropics (Pacific equator) impact winter in the U.S.?

The western Pacific has been active late this summer and early fall. If this active period extends into the late fall months, a strong enough typhoon could cause a cascading effect toward early season cold (i.e. November/December) if it follows the traditional recurving typhoon. There are no indications that this will happen, but this is a scenario in which weather patterns in the tropics would impact winter in the U.S.

How much influence does Siberian snow cover have on winter temperatures in North America?

The theory is that increased early season snow cover across Siberia can help support building early season cold in North America. The problem with that theory is two-fold:

- The correlations have shown to be weaker than originally theorized, with some recent early-season high Siberian snows not resulting in cold air intrusions.
- Even if there is early-season snowfall and cold across Siberia, there would need to be a mechanism to transport the cold air to North America. We usually get that from a polar vortex split resulting in cross-polar flow. In a case like that, it becomes a chicken or egg situation: *was it cold because the polar vortex split itself or was it from the Siberian snow cover?*

NRG's meteorology team looks at Siberian snow cover to see where it is at heading into a winter, but only uses it as supporting evidence, rather than a key part of the forecast.

Pricing

Why are natural gas forwards continuing to trend lower while power forwards are bullish?

Near-term power prices continue to clear relatively low versus historical trends as a result of lower demand and cheap natural gas prices. When comparing longer-term power versus gas price trends, there is a weakening correlation due to tightening supply-demand fundamentals that are driving overall uncertainty in the market. These fundamentals—all of which have the potential to create a supply-demand imbalance—include generation retirements, delayed new generation coming online, interconnection queue issues (PJM), and significant demand growth projections—especially in PJM and ERCOT.

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Why did the July 2024 PJM Base Residual Auction (BRA) prices settle so high?

The rates for the PJM BRA, held on July 17, 2024, settled more than 9x higher than the 2024/25 BRA (increase of $241/MW-day) for most of the RTO. Dominion-VA settled more than 15x higher (an increase of $415.34/MW-day), and Baltimore Gas & Electric settled more than 6x higher (an increase of $393.35/MW-day). Other load delivery areas (LDAs) across the RTO saw smaller increases, while Delmarva saw a decrease of $156.25/MW-day. These rates are for capacity for the 25/26 delivery year, which runs June 1, 2025-May 31, 2026.

According to PJM, the significant increases can be attributed to:

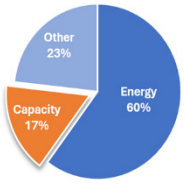
- Decreased supply offers into the auction due mainly to generator retirements
- An increase in projected peak load
- Implementation of FERC-approved market reforms, such as improved reliability risk modeling for extreme weather and accreditation that more accurately values each resource's contribution to reliability

Learn more about the July BRA results in our report.

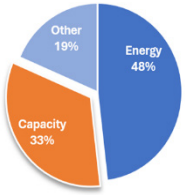
What is the impact of the PJM BRA outcome on energy supply costs?

It's important to note that capacity costs impact all PJM consumers, regardless of who supplies their power. Once these cost increases take effect (June 1, 2025), capacity will comprise a larger chunk of energy costs. As an example, for a customer priced before the BRA, capacity would've comprised about 17% of their total price. For customers priced after the auction for terms that include June 1, 2025 forward, capacity costs will now comprise about 33% of their total price. With the increased influence of capacity on a customer's overall energy costs, it is now more important than ever to consider the ways in which you can manage down costs.

Energy price pre-PJM BRA results



Energy price post-PJM BRA results



There are two ways (within your control) to lower or offset rising capacity costs:

- Because your capacity costs are based both on rates *and* your peak demand during PJM's five peak days (May 1 to Sept. 30), you may wish to **consider** peak load management. This approach involves lowering your consumption when peak load days (i.e. "coincident peak days") are likely so that you can lower your peak demand (i.e. peak load contribution or "PLC") and help lower capacity costs, which are calculated as: **capacity rate x your PLC = charges**
- Demand response (DR) resources that are able to commit to lowering their consumption during grid peaks are also being compensated more (in line with the higher capacity rates). There is no better time to explore your organization's **ability to** participate in DR because payments for your commitment to curtail when called upon can help offset the significantly higher capacity rates. See next page for earning examples.

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DEMAND RESPONSE PAYMENT EXAMPLES	
2024/25 Delivery Year	2025/26 Delivery Year
Customer in RTO zone commits 1 MW reduction **$8,444** earned for DR	Customer in RTO zone commits 1 MW reduction **$59,900** earned for DR

Earnings shown above are for capacity payments; energy payments are separate and in addition to capacity payments. Payments behind BGE & Dominion are substantially higher than what's shown above.

How we can help with these efforts: With peak load management, we provide alerts on days when peak demand is expected, so that you know when to lower or curtail consumption. We can also help you determine how to achieve reductions based on your operations. With demand response, we'll provide free metering equipment/installation, in-advance curtailment alerts, and help with an individualized reduction action plan, so that you can maximize your participation and earning potential. You'll also have access to our real-time energy management dashboard, Active Management Platform (AMP). With near real-time consumption data, AMP helps you better understand how your business consumes energy, including your load reduction activities, and allows you to act and report on it with customized alerts and personalized reporting.

What kind of financial costs or penalties would a customer enrolled in demand response be subject to if they did not perform during an emergency event?
Customers enrolled in an NRG Demand Response program are paid for performance and **would not be subject to penalties**. For example, if a customer was able to curtail 75% of their enrolled amount, then they would be paid at 75%. If a customer doesn't perform at all during an emergency event, then they would not be paid, but they would not be responsible for out-of-pocket expenses or penalties.

With the 2026/27 PJM BRA on the horizon, what are the expectations for those results given the high clears in July?

The implementation of FERC-approved market reforms for the 2025/26 auction (held in July) resulted in a tightening of the supply/demand balance. As quantified by PJM in their 2025/2026 Base Residual Auction Results presentation, the amount of load that generators were qualified to offer under the new rules was less. Other factors include:

- Peak load increased from 150,640 MW in the 24/25 BRA to 153,883 MW in 25/26. This increase is generally attributable to data centers, industrial growth, and electrification.
- Annual unforced capacity (UCAP) offered in the auction (cleared and uncleared) in excess of the reliability requirement went from over 16 GW (24/25 BRA) to less than 1 GW (25/26).
- The installed reserve margin (IRM) increased from 14.7% in 24/25 to 17.8% in 25/26, with the most significant contributor to this being increased load uncertainty under extreme conditions.

According to PJM, the load forecast and IRM for 26/27 are both increasing relative to 25/26. While no one can say for sure how the results will shake out in December, the same factors weighing into the 25/26 auction will be in play for the 26/27 auction.

How will LNG exports impact natural gas prices over the next 2-4 years?

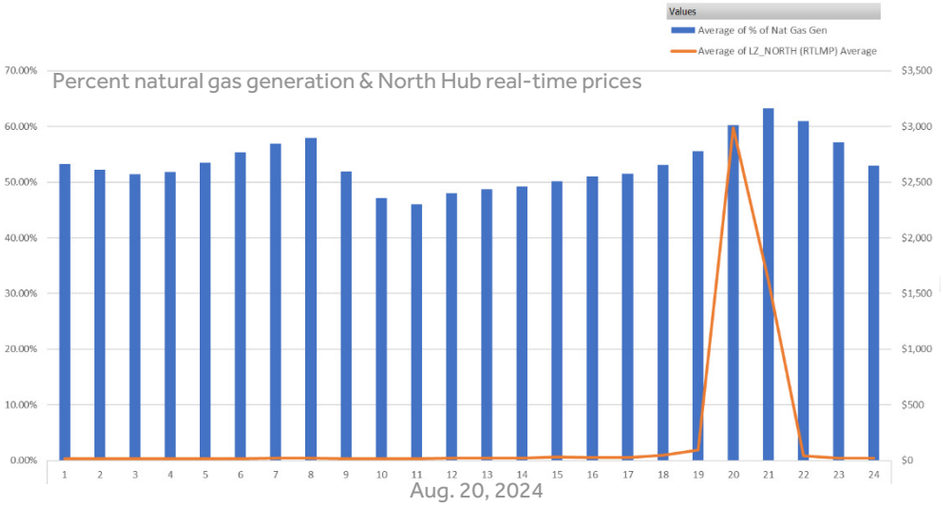
LNG export capacity is planned to rise by ~5 Bcf/day by the start of 2026, with some forecasts calling for capacity growth up to about 30 Bcf/day by 2028 onward. If natural gas production does not increase at the same pace as LNG export demand, this could be bullish for domestic prices.

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What role does natural gas play in ERCOT power prices now that the generation stack is evolving?

Natural gas remains a *significant* piece of the ERCOT supply stack. In times of tight grid conditions, natural gas generation is often crucial in maintaining grid stability. ERCOT forward prices however have seen a disconnect from natural gas prices as a result of increased volatility risk due to the growing amount of intermittent, renewable resources.

The following chart shows the percent of natural gas generation on Aug. 20, 2024—which was around 60%-65% of the total fuel mix—when prices were over $3,000/MWh. Gas prices will continue to have some weight in forward power price composition, since it can be the marginal unit during dispatch that sets the price.



Politics

Please explain how each presidential candidate would affect future energy rates.

Policies implemented from any given administration may be part of the reason for trends over time, but factors that could be more impactful include the overall supply-demand economics, market design (such as the PJM interconnection queue), and local/state policy.

Strategy

Would you recommend a fixed or index natural gas strategy this winter?

Since natural gas pricing is primarily comprised of commodity (NYMEX price) and (regional) basis, it's particularly important to consider how you want to handle (fix or float) these key cost components. Given current fundamentals, choosing a flexible purchasing strategy—rather than fixing or floating all of your contract volume—could help you better weather the winter weather risk. In the webinar we discussed:

- **Commodity:** since Spring 2023, NYMEX monthly settlements have continued to clear low and are close to the lowest we've seen over the last two years. Calendar strips 2025-2028 are trading near two-year lows when compared to the last 24 months of their trading history, however the market is in contango, with longer-term prices higher than near-term. This is due to bullish fundamentals ahead, like producer cut-backs, increased demand, and increased LNG exports.
- **Basis:** prices, volatility, and swings between highs and lows can vary quite a bit depending on the region.

Given these factors, you could consider managing your commodity and basis costs separately, rather than wrapping them all in at contract start, by choosing a hybrid product structure that provides more flexibility in your purchasing strategy. Some flexible purchasing strategies include:

- Locking in your basis but executing commodity purchases over time through layered hedges, with some volume settled at market rates.
- Floating your basis until a market opportunity makes it worth locking in—regardless of whether you're fixing your commodity price, floating at market rates or executing layered commodity purchases.
- Locking in a percentage of your volume at a fixed price, while setting lower-bound price triggers to quickly hedge for additional volumes if the market hits your strike price. Given the contango market, this would also allow for more time to watch the market for dips in those outer years.