

Market Commentary

WEEK ENDING 10.02.26



Contracted MWs, not speculative ones, now drive PJM planning.



Mountaineer Xpress outage sparks a natural gas rally.



September finishes as **2nd warmest nationally** since 1950.

SUMMARY

PJM's load forecasts continue to climb, and so does the scrutiny behind them. Utilities across PJM requested roughly 14.5 gigawatts (GW) of additional demand for 2027 alone, with growth spreading beyond Dominion's Virginia territory into Ohio, Illinois, Pennsylvania, and other PJM states. Utilities that had little to no data center exposure until recently are now forecasting GWs of future load. After several years of load projection concern, many utilities are now working harder to prove those forecasts are real, counting only load backed by signed agreements rather than speculative megawatts (MW).

The forward market is already pricing in a tighter future: The 2027 around-the-clock power price at PJM West Hub hit a 3-year high of \$76.18 per megawatt-hour (MWh) in late September. Wholesale electricity costs rose 42.5% during January to August 2026 from the same time period in 2025, while capacity-related costs more than doubled, according to PJM's Independent Market Monitor. Many of these pressures look likely to last for years, not months.

Natural gas traded in a predictable \$2.75-\$3 per million British thermal units (MMBtu) range until a

force majeure event on the Mountaineer Xpress pipeline cut about 1.8 billion cubic feet per day (Bcf/d) of capacity out of the Appalachian Basin. The October contract rallied to \$3.31/MMBtu before settling at \$3/MMBtu. Supply remains comfortable overall: Storage stands at 3.415 trillion cubic feet (Tcf), 79 Bcf above the 5-year average, though South-Central inventories trail last year. Despite near-record heat, power plants burned about the same amount of gas as in recent summers, as battery storage, solar, and wind carried more of the peak load.

Only 2019 had a warmer September nationally since 1950, based on power-weighted cooling degree days (CDDs). October forecasts favor well-above-normal temperatures in the West, with the East near normal. El Niño is now present and strengthening: Sea surface temperatures in the ENSO 3.4 region (the area of the Pacific Ocean used to track El Niño) sit 2.2 degrees Celsius above normal, and some models point to 3-3.5 degrees by early winter. That signal continues to drive forecasts for a warmer-than-normal winter.

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SUMMARY

Looking Ahead

Based on the insights in this month's Market Commentary, we recommend a few key things for our customers to consider:

- **Plan around a higher power price baseline:** PJM forward prices are at a 3-year high, and the drivers behind them (demand growth, generator retirements, and slow-to-build new supply) are likely to persist. But markets rarely move in a straight line. If your agreement renews in the next year or two, now is a good time to review your strategy. [A Load Following approach](#), for example, can fix a percentage of your load to guard against further increases while letting the rest follow the market, so you can benefit if prices ease.
- **Know how capacity shows up in your costs:** Now is a good time to reconnect with your IGS Energy Account Representative to

understand how your capacity charges are being handled, and to avoid any surprise charges on your invoice.

- **Don't mistake a well-supplied gas market for a risk-free one:** Storage is comfortable and El Niño points to a milder winter, but the Mountaineer Xpress outage showed how quickly a single disruption can move prices. Layering in forward purchases over time can help protect your budget if winter doesn't go as forecast.

To learn more about how this impacts your business, reach out to your IGS Energy rep or email EnergyAdvisor@igs.com

POWER MARKET

For years, PJM's power supply has stayed comfortably ahead of demand. That era is ending. This month, that transition shows up in three places: utility forecasts, forward prices, and the latest wholesale cost data.

Forecasts continue to climb, but so does the scrutiny

Utilities across PJM requested approximately 14.5 GW of additional demand for the 2027 forecast year alone, with long-term projections ranging from roughly 78 GW to more than 120 GW by the mid-2040s.

Dominion remains at the center of the conversation, but significant growth is now spreading across Ohio, Illinois, Pennsylvania, and other PJM states. Utilities that had little or no data center exposure only a few years ago are now forecasting GWs of future load.

What stood out most was not the sheer size of the forecasts, but how much effort utilities are putting into proving those forecasts are real.

After several years of concerns that load projections were getting ahead of actual development activity, utilities have considerably tightened their methods. Many are now limiting forecast adjustments to projects backed by signed service agreements, transmission commitments, or [take-or-pay contracts](#), which commit customers to pay for a minimum share of their contracted demand whether or not they use it.

That discipline matters because only firm commitments ultimately flow into PJM's resource adequacy calculations and planning assumptions. As a result, the conversation is shifting away from speculative MWs and toward contracted MWs.

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POWER MARKET

The challenge for PJM is twofold: If forecasts overstate growth, customers may pay for infrastructure that isn't needed. If they understate growth, reliability risks increase, and future supply shortages become more likely.

The forward market is pricing the forecasts

While stakeholder conversations focus heavily on forecasts and market reforms, the **forward market** is focused on something else: What those changes are likely to mean for future power prices.

Over the last 3 years, PJM forward energy prices have steadily moved higher as market participants have incorporated stronger demand growth, tighter **reserve margins**, generator retirements, transmission investment requirements, and slower-than-expected resource additions. As Fig. 3-2 shows, the 2027 around-the-clock power price at PJM West Hub has risen from about \$48/MWh in fall 2023 to a 3-year high of \$76.18/MWh as of September 29.

What's notable is not simply the move higher, but the persistence of the trend.

Unlike short-term price spikes driven by weather or fuel volatility, **today's forward curve reflects a growing belief that PJM is entering a structurally tighter market.** Demand growth is accelerating while the process of adding generation, transmission, storage, and supporting infrastructure remains slow and capital intensive.

The market is effectively signaling that higher prices will likely be required to attract the investment needed to maintain reliability.

That doesn't mean prices will move higher every year. Commodity markets rarely follow a straight line. But it does suggest that the long-term pricing baseline for PJM may be shifting upward as the region transitions from an era of excess capacity to one increasingly defined by resource adequacy concerns.

The data supports the structural shift

The September update from PJM's Independent Market Monitor reinforces the notion that this is more than a temporary market cycle.

Through the first 8 months of 2026 compared to the first 8 months of 2025:

- Total PJM wholesale electricity costs increased 42.5% year over year.
- Energy market costs increased 45% year over year.
- **Capacity**-related costs increased 101.8% year over year.
- Data center-driven load growth contributed approximately \$10.10/MWh to wholesale market costs, representing roughly 9% of total wholesale costs.

Individually, these numbers are noteworthy. Collectively, they point toward a market undergoing structural change.

PJM is simultaneously managing accelerating demand growth, aging infrastructure, generation retirements, transmission expansion needs, and the challenge of integrating new resources quickly enough to maintain reliability. The implication is straightforward: Many of the factors supporting higher forward prices today appear likely to remain in place for years rather than months.

POWER MARKET COMMODITY CHANGES (c/kWh)						
ISO & Index Point	PJM AD Hub	PJM NI Hub	MISO Illinois Hub	PJM West Hub	ISONE Mass Hub	ERCOT Houston Hub
Markets Served	OH	IL (ComEd)	IL (Ameren)	PA/MD/NJ	MA	TX
12-Month Strip on 8/28/2026	5.590	4.062	4.771	6.920	8.180	3.973
12-Month Strip on 9/30/2026	6.197	4.538	5.490	7.696	7.743	4.150
Monthly \$ Change	0.608	0.476	0.718	0.776	-0.437	0.176
Monthly % Change	10.9%	11.7%	15.1%	11.2%	-5.3%	4.4%

Fig. 3-1

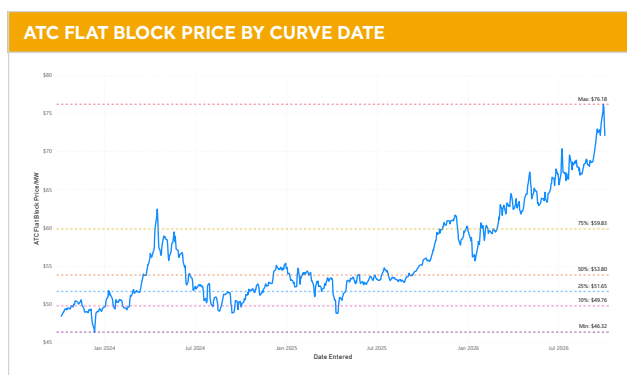


Fig. 3-2

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NATURAL GAS MARKET

The natural gas market has recently shown renewed signs of strength, though it ultimately took a significant supply disruption to generate meaningful price volatility. Prior to the force majeure event on the Mountaineer Xpress pipeline, which temporarily removed approximately 1.8 Bcf/d of takeaway capacity from the Appalachian Basin, [NYMEX](#) futures had been trading within a relatively predictable range of \$2.75 to \$3/MMBtu. Following the outage, the October 2026 contract rallied sharply, reaching a high of \$3.31/MMBtu before finally settling at \$3/MMBtu.

Cash market fundamentals remain constructive, particularly across the South and Southeast, where next-day pricing continues to be well supported by warmer-than-normal temperatures. [Storage inventories](#) in the South-Central region also remain materially below year-ago levels, providing additional support to regional pricing and reinforcing concerns around winter preparedness.

As of late September, total working gas in storage stands at 3.415 Tcf, 138 Bcf below last year's levels but 79 Bcf above the 5-year average. Looking ahead, due to the extended warmth, analysts have lowered their end-of-season storage projections from 3.92 Tcf a month ago to 3.88 Tcf, a level still widely viewed as comfortable and sufficient to meet typical winter demand.

The power sector's natural gas demand has been one of the more notable developments this summer. While temperatures, as measured by power-weighted CDDs, ranked among the highest observed in the past 76 years, natural gas-fired generation did not reach the record peaks seen in recent summers. Total gas burn from June through September 2026 came in at approximately 5.53 Tcf, compared to 5.47 Tcf

LAST MONTH ON THE NYMEX				
	Prompt-Month (Nov. '26)	12-Month Strip	36-Month Strip	Winter Strip '26-'27
Settlements on 8/28/2026	2.888	3.167	3.498	3.402
Settlements on 9/25/2026	3.196	3.175	3.524	3.406
Monthly \$ Change	0.308	0.008	0.026	0.004
Monthly % Change	10.7%	0.3%	0.7%	0.1%

Fig. 4-2

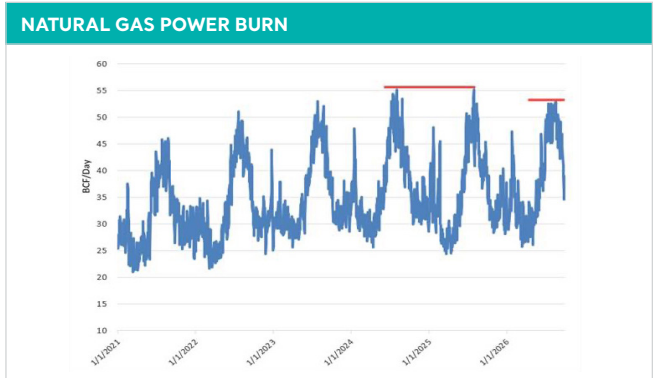


Fig. 4-3

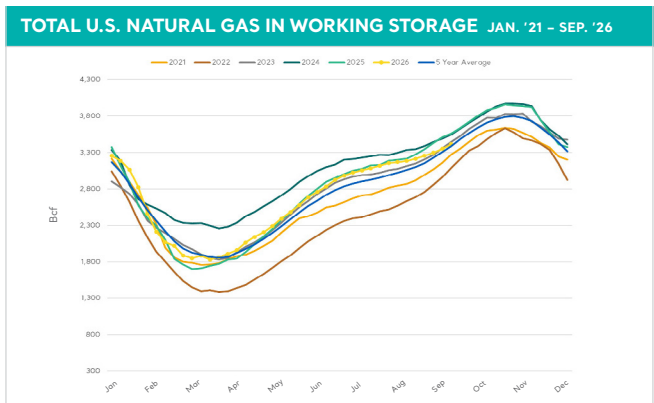


Fig. 4-4

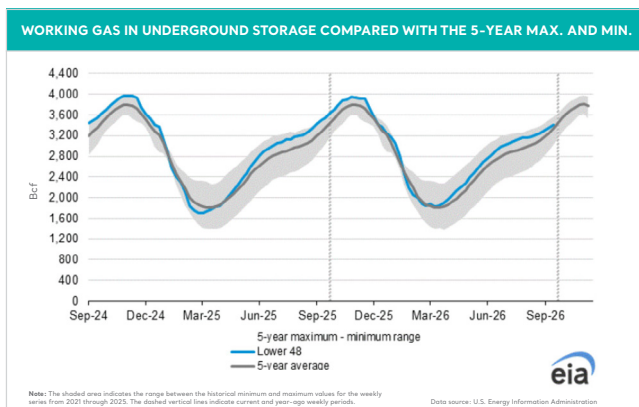


Fig. 4-1

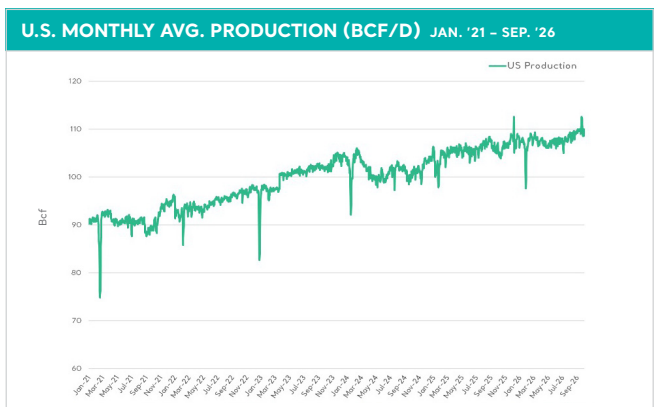


Fig. 4-5

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NATURAL GAS MARKET

during the same period in 2024. The apparent disconnect between record warmth and relatively flat gas demand highlights the ongoing evolution of the power grid.

A key driver of this trend has been the continued growth of battery storage and renewable generation. Expanded battery deployment has helped smooth peak demand by storing power when it's plentiful and releasing it during the highest-demand periods, while growing solar and wind output continues to displace natural gas generation within the power stack. As a result, even periods of exceptional heat did not translate into proportionately higher natural gas power burns. However, power demand is expected to grow at an accelerated rate which could keep natural gas generation at the forefront of price volatility, depending on the generation mix.

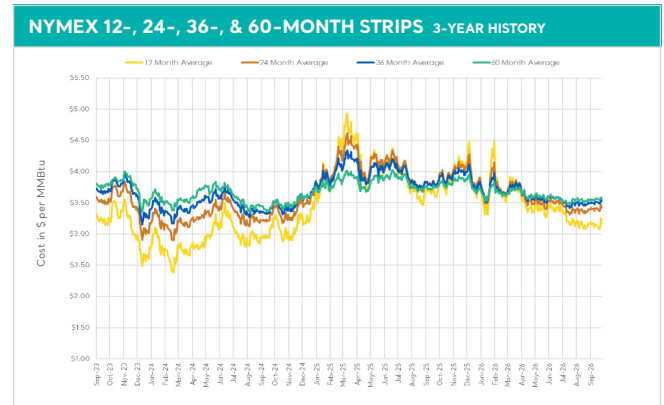


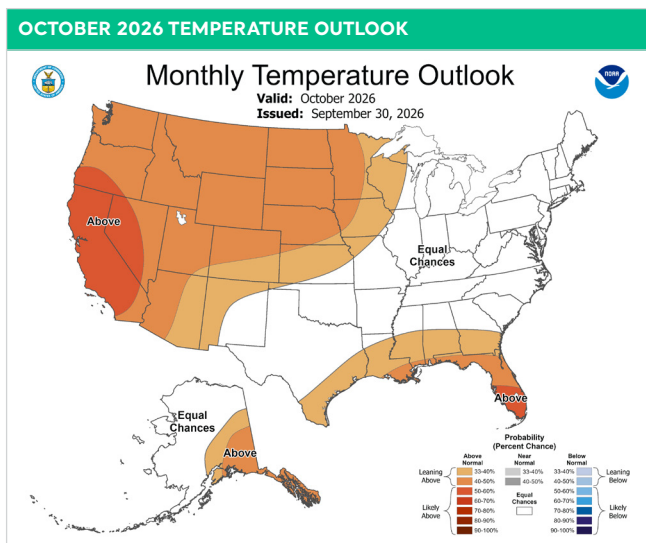
Fig. 5-1

WEATHER

- September finished as the second-warmest September nationally since 1950 based on power-weighted CDDs — only 2019 came in warmer. Seven of the top 10 warmest Septembers have occurred since 2015, and only three have come in cooler than the 30-year normal nationally since 2010.
- October forecasts highlight the western half of the country to be well above normal temperatures while the East averages near the 30-year normal. Medium-range weather models are fairly consistent with this pattern through about mid-month, with some

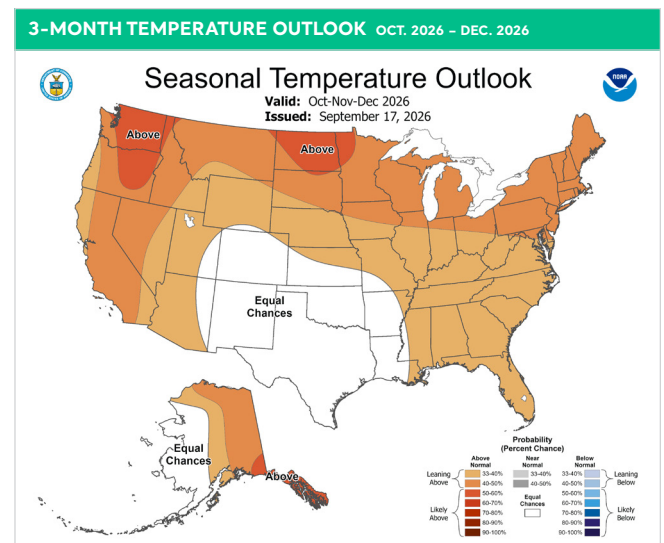
longer-range models extending the pattern through the end of the month.

- El Niño is now present and continues to strengthen as we approach winter. Current sea surface temperature anomalies in the ENSO 3.4 region are 2.2 degrees Celsius above normal, with some models indicating those readings could jump to 3 to 3.5 degrees in early winter, well into strong El Niño territory. Warmer winter forecasts continue to lean heavily on this single large-scale weather pattern.



Source

Fig. 5-2



Source

Fig. 5-3