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Holding the Line: U.S. Natural Gas Performance During Winter Storm Fern

Prepared for:

NATURAL GAS COUNCIL

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Executive Summary

Winter Storm Fern was an approximately two-week Arctic outbreak affecting an estimated 230 million people across North America, with core impacts running from January 23 to February 1, 2026. What distinguished Fern from prior major cold weather events was not peak temperature severity but duration: sustained below-normal temperatures over more than 10 consecutive days drove natural gas demand across the Central and Eastern United States to near-record single-day levels. Electricity across the Central & Eastern U.S. surpassed 450 GW on numerous occasions, peaking at over 500 GW on January 27, with natural gas serving as the primary fuel resource in almost every affected power market.

A key finding of this report is that the natural gas system performed well in terms of sustained flowing production, transportation and storage, and record sustained deliveries during the long-duration weather event. Additionally, market-driven efforts to winterize natural gas production yielded significant dividends. Appalachian output, the largest contributor to Eastern gas supply, held within 10% of recent production highs throughout the storm despite temperatures comparable to those during Winter Storm Elliott, when production fell by nearly 30%. South Central production losses were smaller and shorter in duration than during any prior benchmark event. Lower-48 production recovered to within 5% of pre-storm highs within three days of the peak, compared to five days during Elliott and more than eight days during Winter Storm Uri. These results directly reflect the weatherization investments made by producers and midstream operators since 2021.

Lower-48 natural gas demand peaked at 167 Bcf/d on January 24, the fifth-highest single-day level on record, with 12 of the top 25 all-time demand days occurring during the storm window. Record storage withdrawals, peaking at approximately 63 Bcf/d and reaching a weekly record of 360 Bcf for the week ending January 30, provided essential supplemental supply as intended. Liquefied natural gas (LNG) export terminals demonstrated operational flexibility by reducing feedgas intake by approximately 44% at the height of the event, effectively redirecting volumes to domestic markets.

Across the Lower-48, natural gas local distribution companies entered the 2025–2026 winter heating season prepared for major cold events, drawing on lessons learned from prior winters and historical precedent. For natural gas utilities, there were no known losses of service to customers due to Winter Storm Fern's impact on production. Natural gas utilities using a portfolio of supply options, including storage, met their obligation to serve firm customers and provide essential services to homes and businesses despite the high energy demand during Winter Storm Fern.

Natural gas spot prices across the Northeast and Mid-Atlantic, as well as parts of the Midwest and South Central, reached unprecedented levels, with the highest spot prices recorded at Iroquois Zone 2 when prices exceeded $175/MMBtu at the peak on January 28,[1] driven primarily by the market charging a risk premium tied to anticipated Appalachian production losses rather than by an actual supply-demand imbalance. Once production data confirmed that output had been maintained, prices corrected rapidly.

The Northeast basis spike exposed a structural issue: insufficient pipeline capacity in the region amplified an otherwise modest supply disruption into an extreme pricing event. Due to high demand, pipeline operators deployed Operational Flow Orders (OFOs) and capacity-constraint notices across all major northeastern systems for the full two-week window, which allowed them to serve all primary firm transportation customers throughout the winter event. The OFOs notified customers that conditions rendered secondary firm service and interruptible transportation unavailable at numerous delivery points, and interruptible storage withdrawals were entirely unavailable at several northern storage facilities. These actions preserved pipeline integrity when demand greatly exceeded supply, ensured customers with firm contracts received their contracted supply, but limited customers' ability to obtain lower-priority pipeline capacity that they did not contract for. Modeling of four delayed or canceled Northeast pipeline projects (Access Northeast, Transco Northeast Supply Enhancement, PennEast, and Constitution Pipeline) showed monthly average price reductions of 10–20% at key

[1] https://www.ice.com/products/21592921/Iroquois-Z2-Swing-Platts-Future

market hubs (with greater reductions on a daily basis during peak demand days), had those pipelines been constructed and in service today.

Winter Storm Fern affirmed material progress in cold-weather resilience since Winter Storms Uri and Elliott. However, it also revealed persistent issues: working gas storage capacity in market areas has remained effectively flat over the last decade while supply and demand have grown by more than 35 Bcf/d, constrained Northeast pipeline infrastructure continues to amplify regional price volatility, and gas-electric interdependency risks persist in some key regions. Meeting growing energy demand under similar conditions will require investment in storage deliverability and pipeline capacity, as well as increased industry efforts on gas-electric coordination frameworks.

Based on the findings of this analysis, the following actions are recommended:

- Policymakers and regulators should prioritize expedited review and permitting of natural gas pipeline and storage projects, particularly where infrastructure constraints most directly translate into consumer price volatility and regional reliability risk.
- Federal and state policymakers should consider implementing frameworks to protect critical natural gas infrastructure from load shedding to ensure that critical natural gas infrastructure cannot be curtailed during electric emergencies.
- Electric market design reforms should encourage electric generators to contract for firm pipeline and storage capacity or tailored pipeline and storage services commensurate with their fuel security obligations, rather than relying on interruptible contracts. Reforms should also support long-term investment in pipeline capacity and storage to meet power demand during storms and support demand growth.
- Storage capacity expansion, with associated transportation capabilities, particularly in market areas close to demand centers in the Mid-Atlantic and Northeast, should be treated as a reliability investment alongside pipeline expansion.
- The industry should continue to bolster weatherization investment programs in South Central producing regions, recognizing that the full stress test of post-Uri improvements has not yet occurred under Uri-level temperature conditions, including working with state officials to ensure roads are promptly cleared to ensure passable conditions.

Winter Storm Fern demonstrated meaningful resilience in the natural gas system. However, the gap between current infrastructure and the capacity needed to continue to reliably serve growing energy demand under Winter Storm Fern-like or more severe conditions is real and addressable, but only through timely, targeted investment and permitting of infrastructure.

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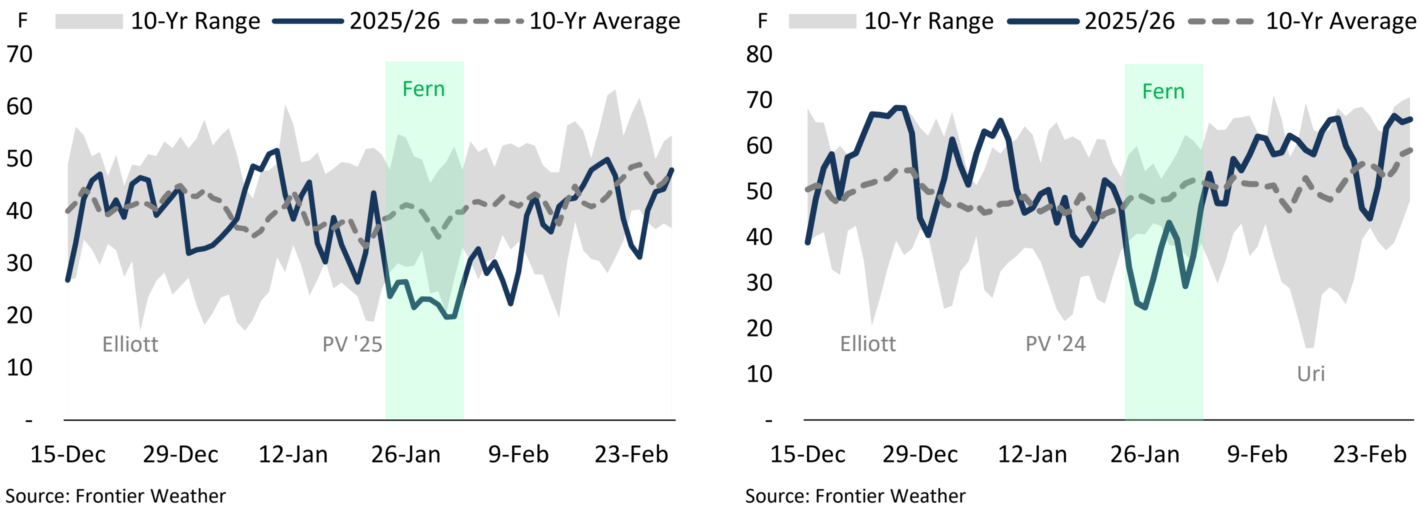
1. Overview of Winter Storm Fern

Winter Storm Fern was an approximately two-week North American weather event, with core impacts from January 23 to February 1, 2026, bringing sustained Arctic cold, ice, and snow from Northern Mexico through the Southern United States into the Northeast and parts of Canada. At peak impact, the storm affected an estimated 230 million people and caused more than 1 million customers to experience power outages across multiple regions. Winter Storm Fern delivered several consecutive days of below-normal temperatures, creating prolonged stress across both the electric power system and the natural gas supply chain.

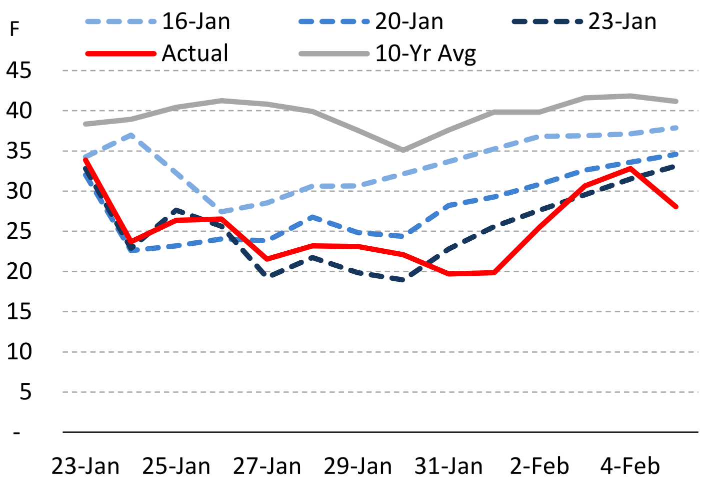
What distinguished Winter Storm Fern from prior events, such as the January 2025 Polar Vortex and Winter Storm Elliott, was duration rather than single-day peak temperature. Actual temperatures during Winter Storm Fern were not the coldest single day observed in the past decade; the Polar Vortex and Winter Storm Elliott produced lower readings in the East, and Winter Storm Uri produced far lower readings in the South Central region. By contrast, during Winter Storm Fern, temperatures in the East remained below ten-year averages until approximately February 10, underscoring the prolonged nature of the event.

EXHIBIT 1 - AVERAGE DAILY TEMPERATURE (POP.-WEIGHTED) - EAST (LEFT) & SOUTH CENTRAL (RIGHT) REGIONS

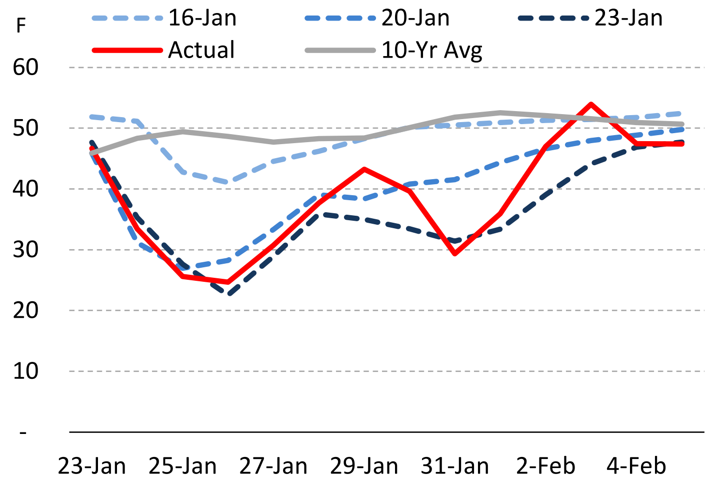


Weather models over the Martin Luther King, Jr. holiday weekend first indicated Winter Storm Fern's potential. As a result, financial markets recorded one of the largest single-day prompt-month futures price swings in Henry Hub history on Tuesday, January 20. Temperature forecasts continued to trend colder in the East throughout the pre-storm period but were relatively stable for South Central, correctly anticipating the lowest temperatures around January 26 before a trend back toward the respective regional ten-year averages by early February.

EXHIBIT 2 - AVG. DAILY TEMPERATURE FORECAST BY FORECAST DATE - EAST (LEFT) & SOUTH CENTRAL (RIGHT)



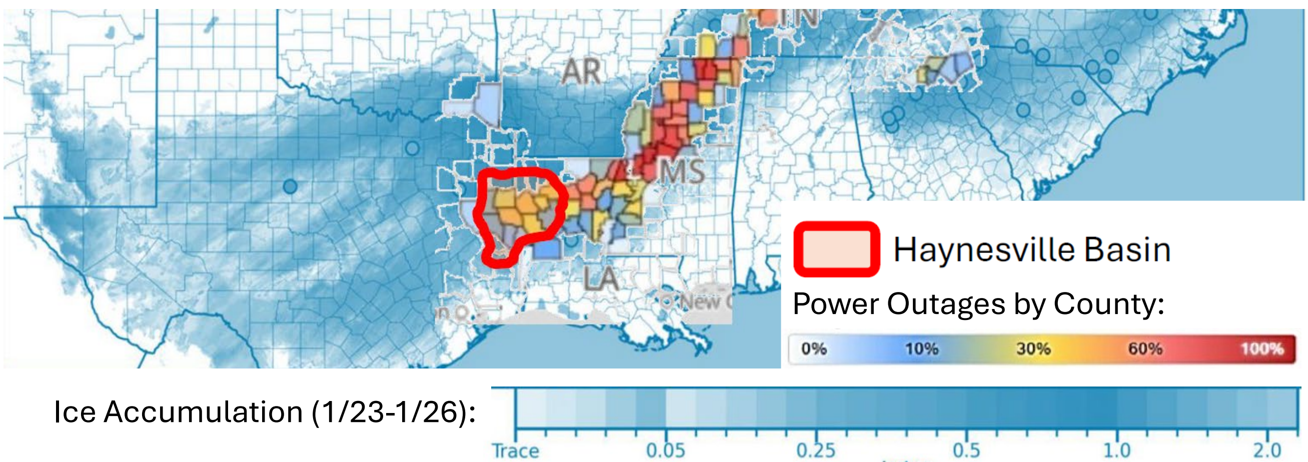
Source: Frontier Weather



Source: Frontier Weather

In addition to prolonged extreme cold, Winter Storm Fern brought a significant amount of freezing rain and ice to key natural gas production areas. For example, the Haynesville Basin, located in Northern Louisiana, Southern Arkansas, and Eastern Texas, and accounting for about 15% of U.S. natural gas production, saw nearly 1 inch of ice accumulation, resulting in widespread power outages across the region. The ice accumulation not only caused widespread power outages across the region but also made roads and bridges impassable, affecting the ability to haul water from production sites and to get key personnel to worksites.

EXHIBIT 3 - ICE ACCUMULATION & POWER OUTAGES DURING WINTER STORM FERN



Source: American Exploration & Production Council

2. Industry Practices and Preparations Before the Storm

In the years following Winter Storms Uri (2021) and Elliott (2022), the U.S. natural gas industry undertook a broad reassessment of its cold-weather operations and made substantial market-driven investments to improve reliability. Those efforts produced measurable results: the 2025 Joint Federal Energy Regulatory Commission (FERC)/North American Electric Reliability Corporation (NERC) Staff Report[2] concluded that natural gas infrastructure performed effectively during the January 2025 Arctic events, meeting record demand across wellheads, gathering systems, processing facilities, pipeline transportation, and local distribution networks.

Producers and midstream operators expanded and formalized investment programs tailored to each facility's and formation's specific characteristics ahead of the 2025–26 winter season. Physical hardening measures now commonly include permanent heated enclosures, heat tracing, pipe insulation with built-in heating cables, windbreaks, and portable heating equipment. Chemical injection of methanol and similar freeze-depressants has been deployed more systematically to prevent hydrate formation and pipeline blockages. Some operators have begun running compressors in advance of storms or relocating compressors and related machinery to enclosed or underground installations to reduce exposure to cold air. These physical investments have been supported by pre-winter customer meetings, more robust staffing and communication protocols during storms, specifying primary and secondary contact chains, and pre-event coordination with state and local emergency operations centers.

The industry has also taken steps to address interdependencies between the gas and electric industries, highlighted by Winter Storm Uri. A substantial portion of natural gas infrastructure—including many compressors, processing plants, and control systems throughout the supply chain—depends on grid electricity to operate. An outage that curtails electricity deliveries to natural gas infrastructure could reduce the production, processing, and delivery of natural gas to generators, leading to additional electric outages. Following Storm Uri, FERC and NERC recommended that balancing authorities and transmission operators act to protect critical natural gas infrastructure by avoiding manual and automatic load shedding that could adversely affect Bulk Electric System Reliability.[3] Natural gas infrastructure operators have worked with the relevant segments of the electric industry to identify critical infrastructure and protect it from load shedding. Some areas, such as Texas, have adopted rules to safeguard critical gas facilities from utility load shedding during rolling blackouts. While load shedding was not an issue during Winter Storm Fern, protecting critical infrastructure from it remains a valuable precaution.

System infrastructure expansions were another key investment in improving winter reliability. Since 2021, natural gas industry stakeholders have supported 39 pipeline projects adding approximately 65.87 Bcf/d of deliverability across the U.S. Gulf Coast producing region, with 25.74 Bcf/d already in service before the 2025–26 winter season. On the storage side, public company and regulatory disclosures support roughly 50 Bcf of U.S. underground natural gas storage additions in 2024–25. These investments directly address the supply-area vulnerabilities exposed during Winter Storm Uri, where upstream production declines combined with limited storage access contributed to cascading outages. New infrastructure substantially mitigated the impact of supply shortfalls on market deliveries during Winter Storm Fern.

Despite this progress, several structural issues remained unresolved as the 2025–26 winter season began. Permitting roadblocks continue to delay or hinder the building of essential pipeline and market-based storage projects. Many generators, particularly in organized wholesale electric markets, continue to rely on options such as interruptible pipeline capacity, non-primary firm transportation capacity, and capacity release rather than firm transportation and gas supply, leaving them vulnerable during peak demand periods when firm customers are utilizing their contract rights. This

[2] https://www.ferc.gov/media/report-january-2025-arctic-events-system-performance-review-ferc-nerc-and-its-regional

[3] *See, e.g.*, FERC, NERC, and Regional Entity Staff, *The February 2021 Cold Weather Outages in Texas and the South Central United States* at 208-210 (Nov. 2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and (discussing Key Recommendations 1i-1j)

contracting pattern also reduces the incentive for pipeline and storage developers to build new market-based capacity, which requires long-term investment in the form of firm commitments. Pipeline capacity constraints remain a persistent concern in many areas, including in the Mid-Atlantic and Northeast. Storage located close to demand centers remains the most effective tool for managing peak-hour reliability in constrained regions.

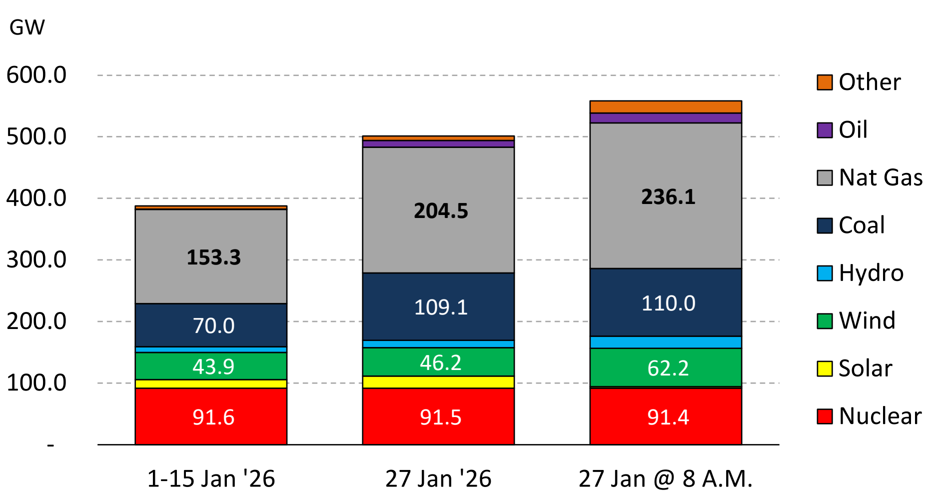
3. Impacts and System Operations During the Storm

3.1 Electric Power Sector Performance

Winter Storm Fern drove electricity demand to near-record or record winter levels across major power markets, including PJM and the broader Northeast. Aggregate electricity demand across impacted regions peaked at roughly 500.6 GW on January 27, January 31, and again on February 1, reflecting both the severity and the persistence of the event. Demand averaged above 450 GW from January 21 through February 2, compared to roughly 385 GW during the first half of January.

Natural gas was the single largest source of incremental electricity supply across every affected region during Winter Storm Fern. At the aggregate level, gas output increased by approximately 33% on the peak demand day relative to the early-January average of 153 GW. At the peak demand hour (8:00 AM on January 27), natural gas consumption ramped to approximately 236 GW, a 54% increase above the early-January average and 15% higher than the peak day. Gas and oil capacity factors rose from about 35% in early January to nearly 49% systemwide during the storm, reflecting the depth and breadth of the thermal dispatch call across the affected footprint.

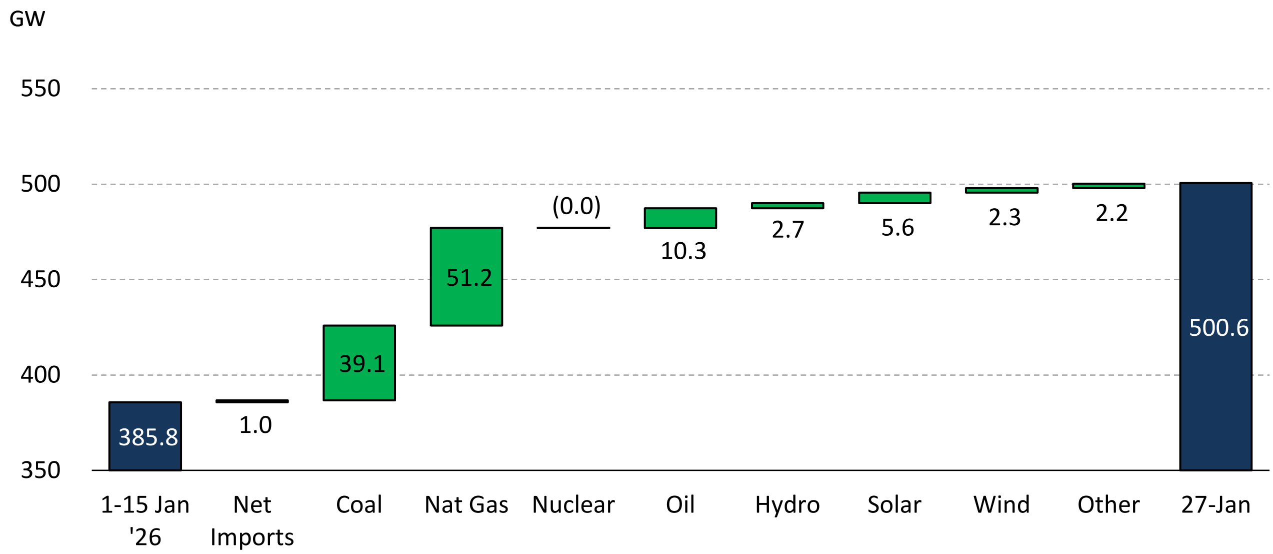
EXHIBIT 4 – CENTRAL & EASTERN U.S. GENERATION MIX DURING THE FIRST HALF OF JAN '26 VS. PEAK DEMAND DAY AND HOUR[4]



Source: EIA Hourly Grid Monitor

[4] "Central & Eastern U.S." in the electric power sector performance section includes all balancing authorities located in the Eastern and Texas Interconnects. The Western Interconnect was excluded due to lack of impact of Winter Storm Fern.

EXHIBIT 5 - CENTRAL & EASTERN U.S – INCREMENTAL GENERATION ON PEAK DEMAND DAY VS. FIRST HALF OF JAN '26



Source: EIA Hourly Grid Monitor

3.1.1 Regional Performance

Regional performance during Winter Storm Fern showed a consistent pattern: when demand surged and wind or solar output weakened, natural gas provided the primary dispatchable response. A map of the power markets described in this section is included in the **Appendix**.

In the **Southwest Power Pool (SPP),** this pattern was especially pronounced. Natural gas generation more than doubled at the peak demand hour as wind output fell 34%, declining from an average of 14.4 GW in early January to 9.5 GW during peak conditions.

In **ERCOT**, natural gas bore the heaviest operational burden of any region. On the peak-demand day (January 25), gas-fired generation accounted for more than 80% of the roughly 21 GW increase in electricity demand. Overall, gas output rose by around 23 GW relative to early-January levels, reflecting not only the rise in load but also the need to offset declining renewable output from wind and solar. At the peak hour, natural gas supplied approximately 40.6 GW at a capacity factor of roughly 75%, with coal providing secondary support at 10.6 GW. Wind output decreased by 7.4 GW compared to early-January averages. ERCOT had also added nearly 25 GW of solar capacity since Winter Storm Uri, much of it located between the Dallas and Austin metro areas, which were directly in the storm's path. Reduced solar output on the peak day required gas generation to increase to levels that exceeded Winter Storm Uri. Thanks largely to weatherization improvements and somewhat less extreme temperatures, ERCOT observed fewer power plant outages during Winter Storm Fern than during Winter Storm Uri and met peak demand without issuing Emergency Electric Alerts.

In **Mid-Continent ISO (MISO),** both natural gas and coal played major balancing roles. On the peak demand day, each increased by approximately 7 GW, with wind output ranging from about 14 GW in the morning to 23 GW in the evening, requiring coal and gas units to absorb significant intra-day swings. Natural gas capacity factors rose from around 39% in early January to 50% during the storm.

In **PJM**, the most severe conditions arrived on January 30, when natural gas increased by approximately 19 GW relative to early-January averages and combined natural gas capacity factors rose from about 45% to roughly 61%. Market outcomes also reflected the uncertainty surrounding the event; earlier PJM forecasts had projected a new winter peak on January 27, driving day-ahead power prices to an all-time high of approximately $2,314/MWh. In real time, however, warmer-than-forecast temperatures and widespread government and school closures pushed prices to approximately $700/MWh.

In **New York ISO (NYISO)**, natural gas supplied nearly the entire incremental load, increasing by about 4.7 GW during the peak demand hour and providing roughly 60% of total generation. Natural gas capacity factors rose from around 37% in early January to 50% during Winter Storm Fern.

ISO-New England (ISO-NE) presented the most structurally constrained natural gas supply environment: pipeline capacity and storage withdrawal limits prevented consumers from accessing gas supply, leading to a decrease of about 2.4 GW in gas-fired generation on the peak demand day, despite significantly higher electricity demand. Dual-fuel units adapted by switching to on-site oil storage, with oil-fired generation rising from approximately 2% of the fuel mix to approximately 39–40% on the peak day, and oil-fired generation rising by roughly 7.6 GW at the peak demand hour.

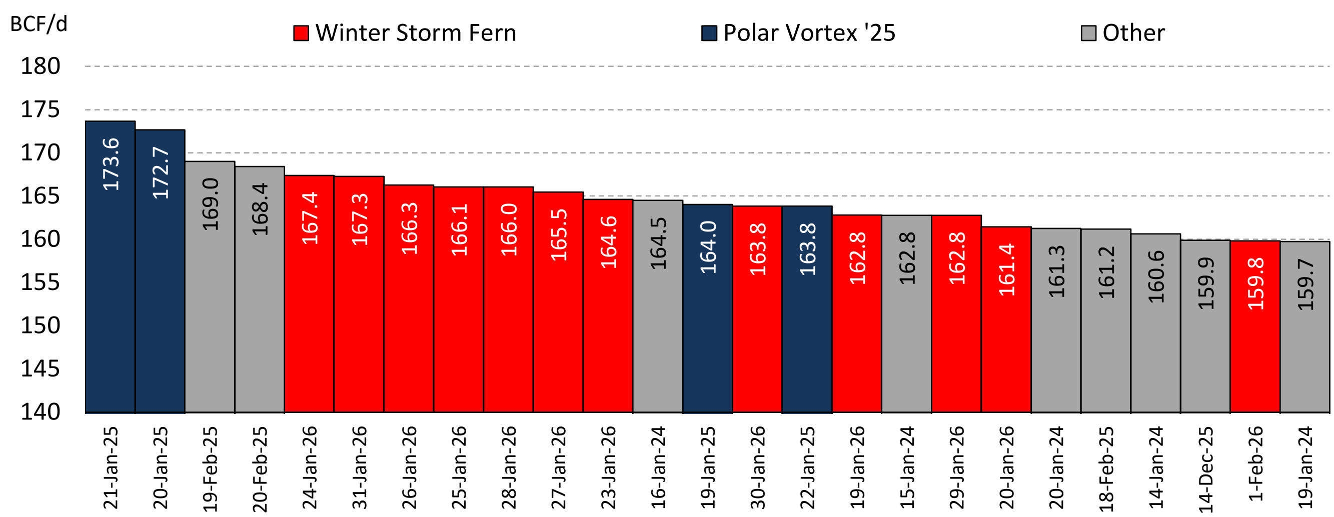
In the **Southeast**, the storm pushed the region to a new all-time demand record, with hourly load approaching 171 GW on February 2. Natural gas generation increased by 45.9 GW at the peak hour, more than doubling to reach 87.6 GW.

3.2 Natural Gas Demand

U.S. Lower-48 natural gas demand averaged 132 Bcf/d during the first half of January before climbing to an average of 161 Bcf/d between January 23 and February 5, an increase of approximately 29 Bcf/d, or nearly 22%. Peak natural gas demand occurred on January 24 at 167.4 Bcf/d, the fifth-highest level on record. Notably, 12 of the top 25 natural gas demand days in the Lower-48 on record occurred during the Winter Storm Fern window, underscoring the prolonged system stress the storm imposed.

Lower-48 demand growth was concentrated in the residential and commercial ("ResComm") and power sectors. ResComm demand increased by 13.9 Bcf/d, or 33%, compared to the first half of January. Power sector demand rose by 8.9 Bcf/d, or 38%. LNG feedgas demand declined by more than 2.3 Bcf/d, or 12% on average, as terminals reduced intake in response to domestic price signals, falling from an early-January average of 19 Bcf/d to less than 17 Bcf/d during the two storm weeks. Pipeline exports to Mexico eased modestly by approximately 4%, or 0.3 Bcf/d.

EXHIBIT 6 – LOWER-48 - TOP 25 NATURAL GAS DEMAND DAYS



Notably, the majority of Winter Storm Fern's impacts were observed in the Eastern part of the country. **Central & Eastern U.S.**[5] natural gas demand averaged 115 Bcf/d during the first half of January before climbing to an average of 144 Bcf/d

[5] Central & Eastern U.S. is defined as the combination of the East, Midwest, and South Central EIA storage regions. The Mountain and Pacific storage regions were excluded due to the lack of impact on their respective natural gas systems during Winter Storm Fern. A map of EIA storage regions is included in the **Appendix**.

between January 23 and February 5, an increase of approximately 28.5 Bcf/d, or nearly 25%. Peak demand of 151 Bcf/d occurred on January 31, the third-highest recorded volume in the Central & Eastern U.S. Again, emphasizing the prolonged system stress that the storm imposed, 12 of the top 25 natural gas demand days in the Central & Eastern U.S. on record occurred during Winter Storm Fern.

Central & Eastern U.S. demand growth was concentrated in the ResComm and power sectors. ResComm demand increased by 13.4 Bcf/d, or 39%, compared to the first half of January. Power sector demand rose by 9.0 Bcf/d, or 33%.

EXHIBIT 7 – CENTRAL & EASTERN U.S. - TOP 25 NATURAL GAS DEMAND DAYS

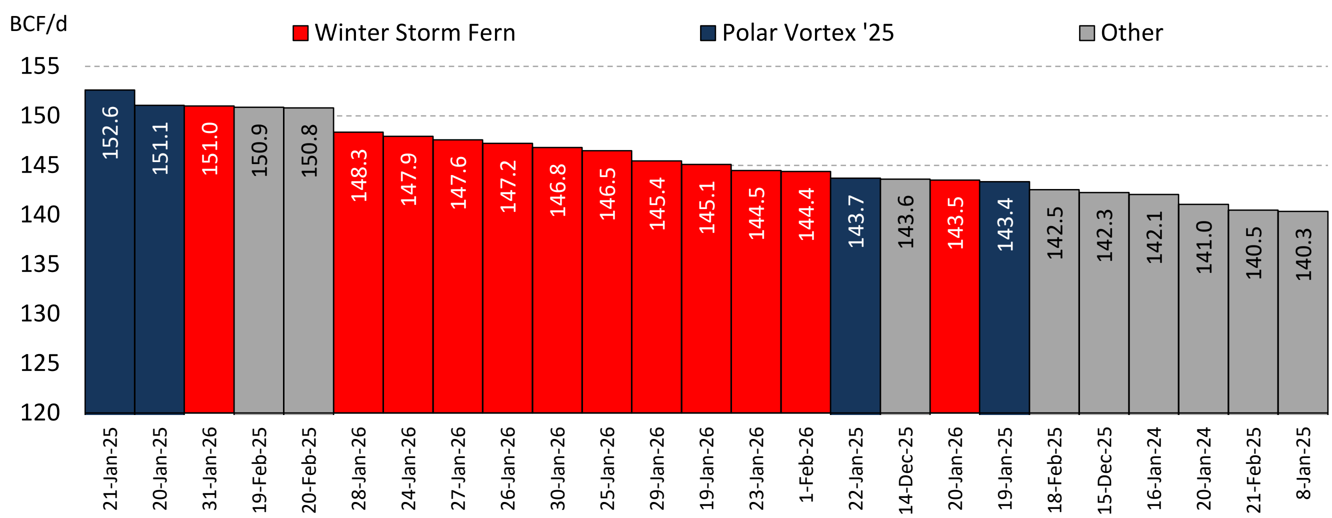
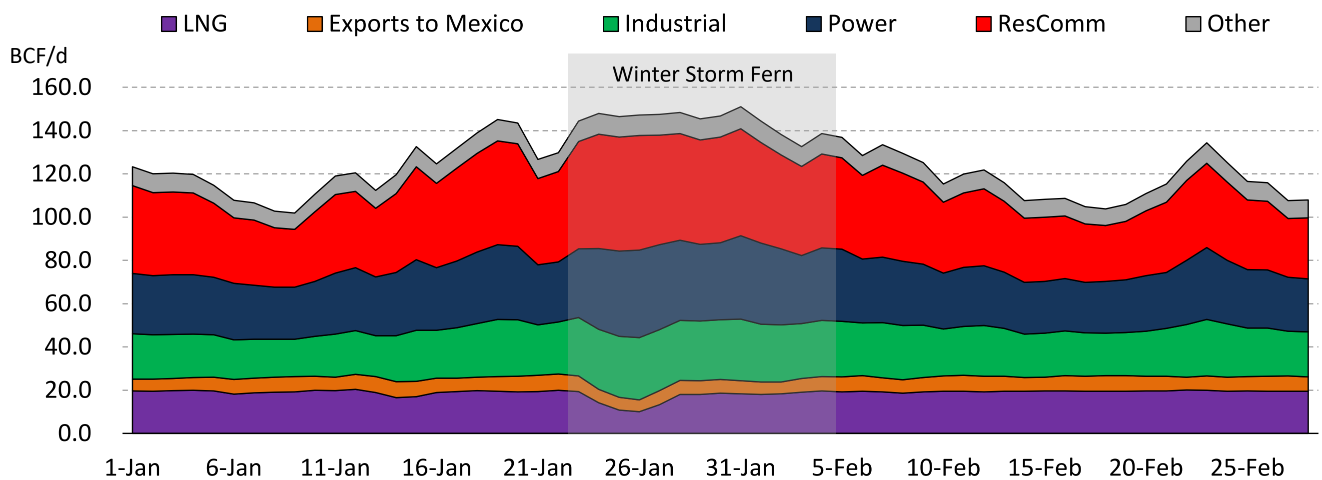


EXHIBIT 8 - CENTRAL & EASTERN U.S. - NATURAL GAS DEMAND BY SECTOR

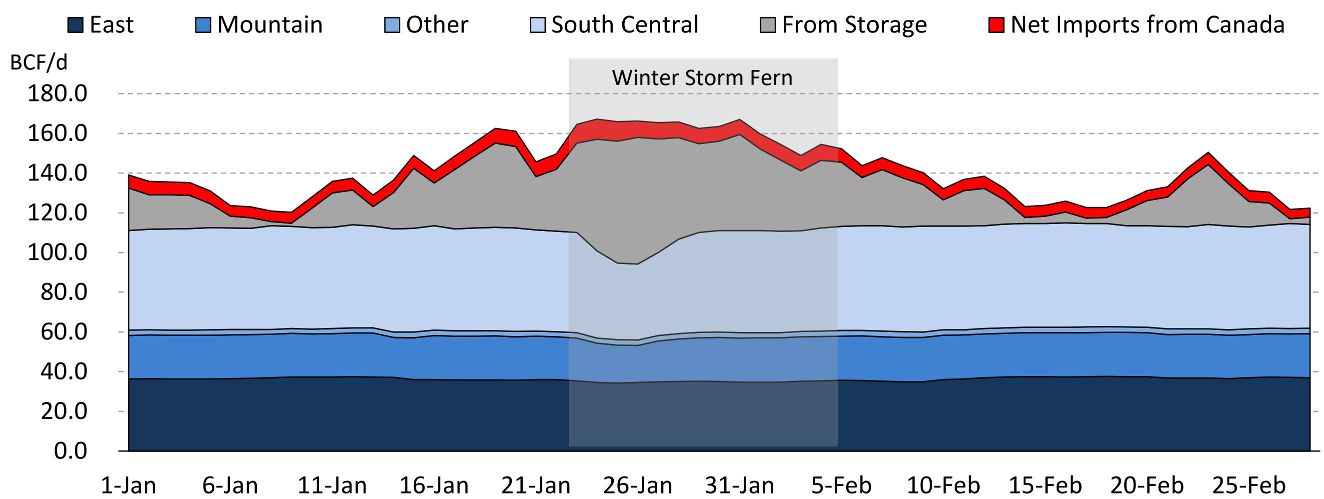


Source: S&P Global Platts

3.3 Natural Gas Production Performance

The largest operational challenge during Winter Storms Uri and Elliott was the loss of natural gas production at the moment of peak demand, resulting in fuel supply shortfalls and contributing to prolonged power outages and residential heating emergencies.[6] The primary production regions supplying Central & Eastern U.S. consumption are Appalachia and, in the South Central region, the Haynesville, Permian, and Eagle Ford plays. During the height of South Central production losses on January 26, total Lower-48 natural gas production dropped below 95 Bcf/d, and estimated storage withdrawals peaked at over 63 Bcf/d, accounting for nearly 40% of natural gas supply on that day. Imports from Canada also played an important role, increasing by an average of 2 Bcf/d between January 23 and February 5, and peaking at around 10 Bcf/d on January 24 and 25.

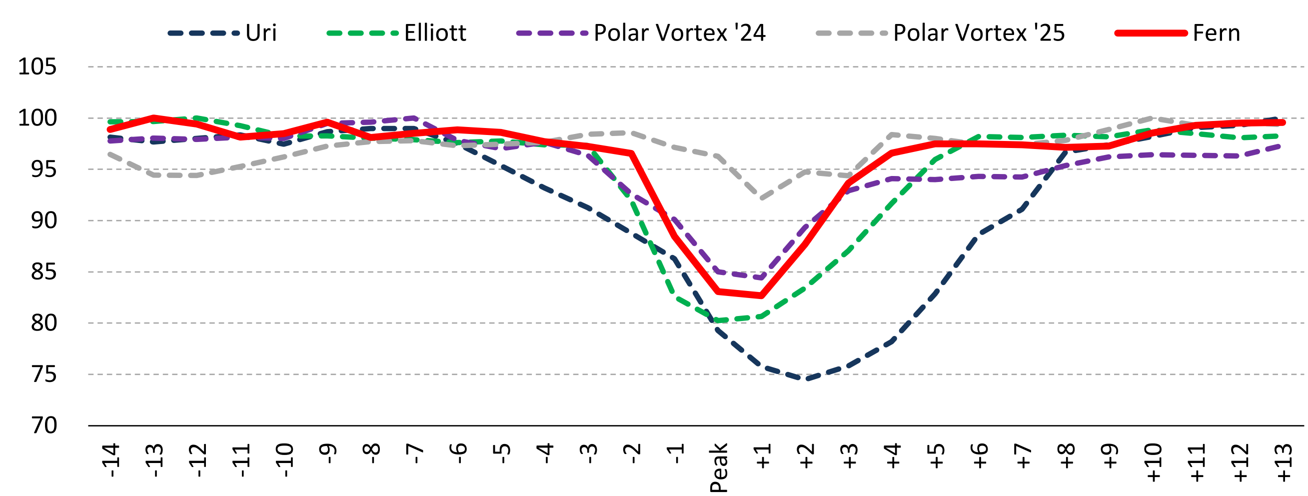
EXHIBIT 9 - LOWER-48 NATURAL GAS SUPPLY



Source: S&P Global Platts

Lower-48 natural gas production declined by approximately 17% during the storm's peak from recent production highs achieved outside the Winter Storm Fern period and recovered to within 5% of pre-storm highs within just three days. By contrast, during Winter Storm Elliott, production dropped by 20% and required more than five days to return to near-normal levels; and during Winter Storm Uri, production fell by 25% and took more than eight days to recover.

EXHIBIT 10 - NORMALIZED LOWER-48 NATURAL GAS PRODUCTION DURING FERN VS PREVIOUS COLD WEATHER EVENTS

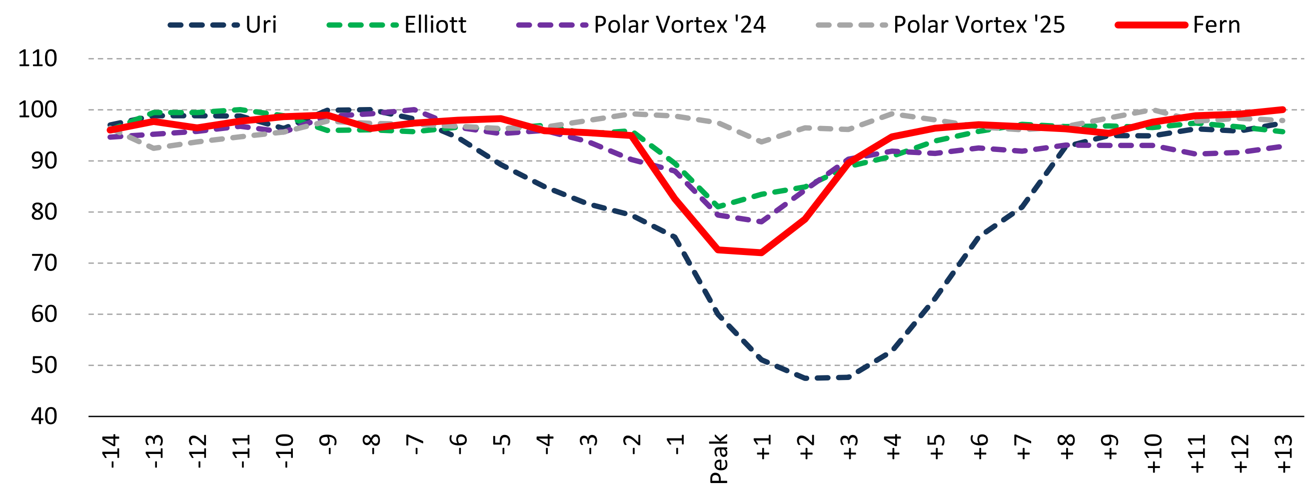


Source: U.S. DOE EIA and S&P Global Platts data

[6] Notably, the FERC-NERC reports on those storms found that these production losses were due to a myriad of issues including impassable roads, power loss, downstream issues associated with processing that contributed to freeze-offs. (p. 115) https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022

In the South Central region, production declined by less than 30% during Winter Storm Fern from recent pre-storm highs and held below 90% of that high for just four days, materially better than during Uri, when production dropped by more than 50% and remained below 90% for nearly two weeks.

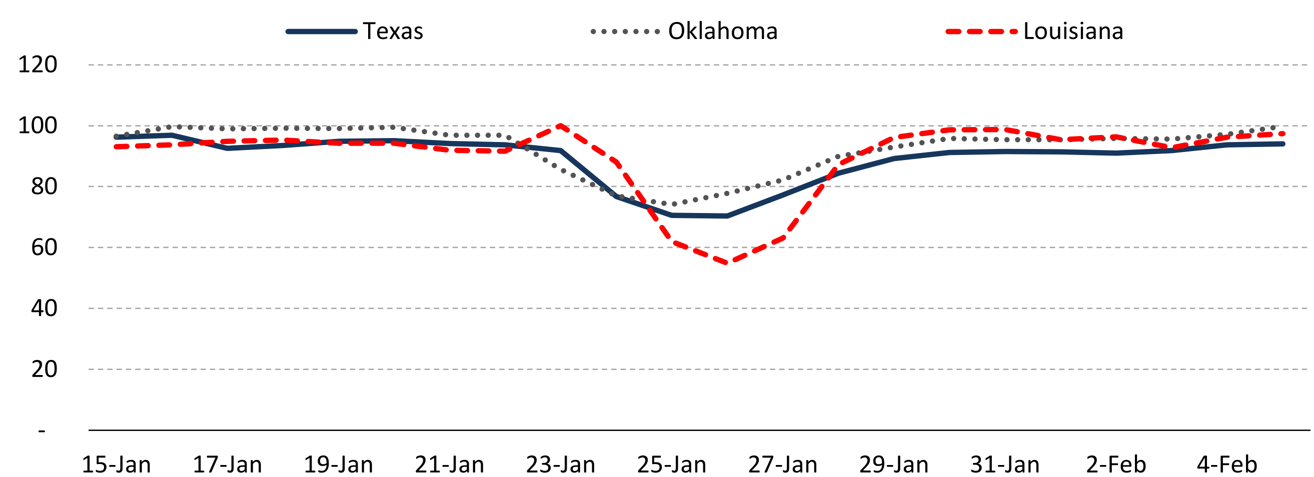
EXHIBIT 11 - NORMALIZED SOUTH CENTRAL NATURAL GAS PRODUCTION DURING FERN VS PREVIOUS COLD WEATHER EVENTS



Source: U.S. DOE EIA and S&P Global Platts data

Notably, natural gas production across Louisiana declined by more than 40% from pre-storm highs achieved on January 23, as cold temperatures and substantial ice and freezing rain accumulation led to widespread power outages, affecting production sites and rendering many access roads impassable for work crews and critical water removal. Other production areas across Western Texas and Oklahoma, which experienced similar extreme cold to the Haynesville production area in Louisiana, saw significantly smaller declines in production rates because they lacked ice and freezing rain accumulation and power outages. Therefore, protecting critical natural gas facilities from load shed and ensuring prompt road maintenance during similar extreme weather events are also key to maintaining natural gas production, in addition to the continuation of weatherization improvements to protect natural gas supply chain equipment.

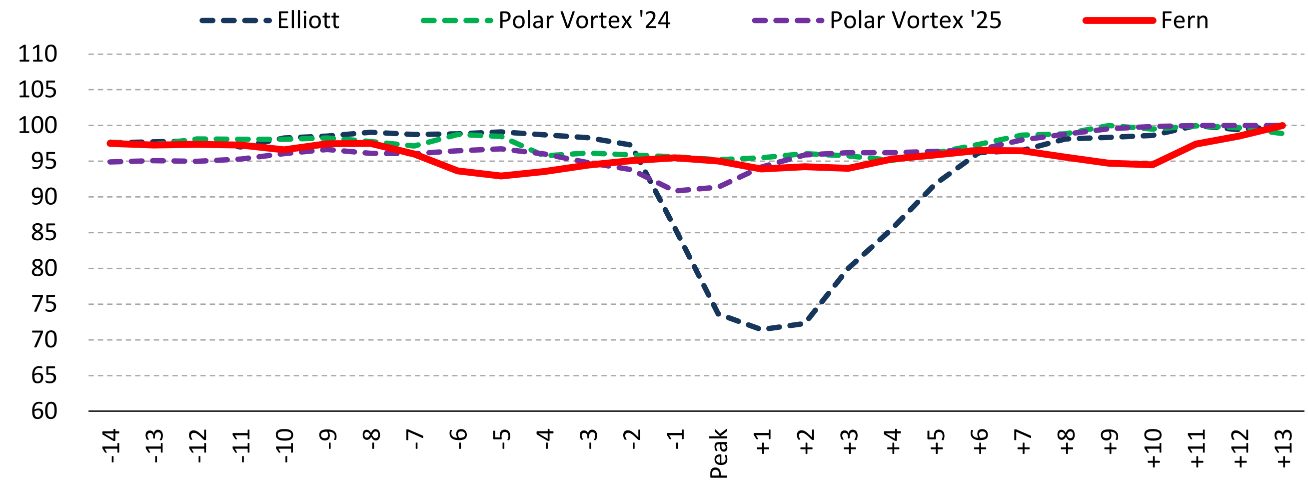
EXHIBIT 12 - NORMALIZED SOUTH CENTRAL PRODUCTION BY STATE DURING WINTER STORM FERN



Source: S&P Global Platts

During Winter Storm Elliott, Appalachian natural gas output dropped by nearly 30% from pre-storm levels and required close to a week to recover to pre-storm levels. Comparably, during Winter Storm Fern, Appalachian production remained within 10% of recent highs achieved before the storm for virtually the entire duration of the storm. Extensive market-driven winterization investments have been made across the Appalachian basin since Winter Storm Elliott, and in addition to the regular robust planning, the use of natural gas storage and the reliability efforts of the gas value chain promoted resilience and helped avoid disruptions comparable to those seen during Winter Storm Elliott and Winter Storm Uri.

EXHIBIT 13 - NORMALIZED APPALACHIAN NATURAL GAS PRODUCTION DURING FERN VS PREVIOUS COLD WEATHER EVENTS



Source: U.S. DOE EIA and S&P Global Platts data

3.4 *Pipeline Operations*

3.4.1 Operational Framework and Pre-Storm Actions

Interstate pipelines manage system integrity by prioritizing service based on contract type as outlined in their respective tariffs. Primary firm service, for which customers pay a fixed reservation charge to hold capacity regardless of use, is protected first and was maintained across all affected systems throughout the Winter Storm Fern event. Secondary firm nominations, which use capacity beyond a shipper's primary delivery point(s) or contracted path, are typically not scheduled when capacity is tight since the pipeline's primary firm transportation shippers are using their capacity at those points. Interruptible service, which carries no capacity reservation charge, has the lowest scheduling priority and is typically unavailable during peak demand periods.

These contractual priorities shape how pipelines respond operationally when systems tighten, with critical notices serving as the mechanisms for enforcing contractual agreements in practice. Pipelines have two primary operational tools: OFOs, which are formal directives requiring shippers to align physical flows with scheduled nominations (non-compliance carries financial penalties typically equal to two to three times prevailing spot gas prices and are returned to "non-offending shippers"); and capacity constraint notices, which communicate where physical limits have been reached on the pipeline and lower-priority services will be unavailable or reduced. Both were deployed extensively and continuously during Winter Storm Fern.

3.4.2 Pipeline Operations During the Event

Due to extreme cold weather, physical capacity constraints at non-primary delivery points were in place on all major affected systems for effectively the full two-week window. Tennessee Gas Pipeline escalated to a higher-tier OFO than typical on multiple days and eliminated secondary firm service at numerous delivery locations systemwide and at key Northeast delivery points beginning in mid-January and persisting into early February. Iroquois Gas Transmission maintained capacity constraint notices at three key system locations for all 14 gas days during Winter Storm Fern. There was no available pipeline capacity on Iroquois above what was contracted to primary firm transportation customers.

Transco issued a single constraint notice on January 24 that remained in effect through February 5, covering 12 consecutive gas days and identifying zero available non-firm capacity at multiple Mid-Atlantic delivery points. Transco did not restrict any firm transportation capacity or limit any specific receipt or delivery points on its system. Rather, the constraint notice informed customers of the quantity of available gas capacity for the full 12-day period, indicating compounding pressures from both market-area delivery limits and upstream supply constraints simultaneously. The constraints implemented by Transco were consistent with actions taken by Tennessee and Iroquois on their respective systems, ensuring it did not schedule capacity above its capability in order to meet its firm transportation commitments.

Columbia Gas Transmission ran a restrictive simultaneous constraint posture for the full window, with storage, transport, and supply-side OFO restrictions all active concurrently to protect system-wide integrity. Shipper balancing tools were suspended in all operating areas, and despite an unexpected equipment issue at a Virginia compressor station, adding a physical infrastructure element from January 23–27, no commercial impacts were seen.

Based on available pipeline operational data, primary firm service to local gas distribution companies was maintained across all analyzed systems throughout the Winter Storm Fern event. Pipeline capacity constraint notices and OFOs affecting secondary and interruptible service categories were extensive due to firm shippers using their contracted entitlements, but there were no disruptions to primary firm service. The maintenance of residential and commercial supply and services during Winter Storm Fern reflects the priority contractual protection afforded to firm service under interstate pipeline tariffs, and the robust planning and supply options used by natural gas utilities.

3.4.3 The Pipeline Transport Constraint on Storage Withdrawals

During cold-weather events, storage inventory held near consuming markets can deliver incremental volumes to market in response to demand and provide a reliable backstop against other supply shortfalls. Winter Storm Fern illustrated, however, an important operational limit to this backstop. A storage field's effective contribution to meeting peak demand requires not only sufficient physical withdrawal capability and firm storage capacity contracting, but also sufficient available pipeline take-away capacity connecting the storage to end-use markets. Insufficient pipeline capacity can limit storage withdrawal rates independent of what the fields themselves could physically deliver. For example, Columbia Gas Transmission met its customers' contracted needs but suspended excess storage withdrawal capacity in specific market areas because it lacked pipeline transport capacity to move additional storage gas to those destinations. Storage inventory levels alone do not fully capture a region's weather resilience; available pipeline capacity to move that gas when needed is an equally important variable. Still, storage, along with associated transport, remains a critical tool for customers to manage and mitigate price exposure during periods of elevated market prices.

3.5 Natural Gas Storage Performance

Natural gas storage is a critical component of the U.S. energy infrastructure, providing system reliability, stabilizing market prices, and enhancing resiliency during high-demand periods and unexpected disruptions. However, market-based natural gas underground storage capacity has not expanded meaningfully over the last decade, holding steady at approximately 4.8 trillion cubic feet (Tcf) of working gas storage capacity. Over the same period, natural gas supply and demand have both increased by more than 35 Bcf/d, or approximately 45%. This divergence means that smaller absolute changes in demand or supply can produce more pronounced inventory pressure than in earlier periods, and that limited pipeline linepack and local production swings have increasingly been used to manage near-term demand fluctuations, reducing stress on storage withdrawals during peak demand periods. Storage withdrawals also face physical limitations that determine the maximum volume of working gas that can be withdrawn from a facility over a given period, depending on factors such as reservoir pressure and field type (e.g., salt caverns, aquifers, and depleted oil and gas wells all have different operating characteristics). In addition, any future expansion of storage capacity would also require commensurate pipeline takeaway capacity to allow additional gas supply to reach demand centers.

Underground storage assets played a critical role in meeting regional natural gas demand during Winter Storm Fern. In the Central & Eastern U.S., withdrawals increased significantly in the lead-up to and during Winter Storm Fern, peaking at just under 59 Bcf/d on January 26, supplying approximately 40% of total Central & Eastern U.S. demand. During Winter Storm Fern, natural gas storage withdrawals accounted for about 30% of total natural gas demand in the Central & Eastern U.S.

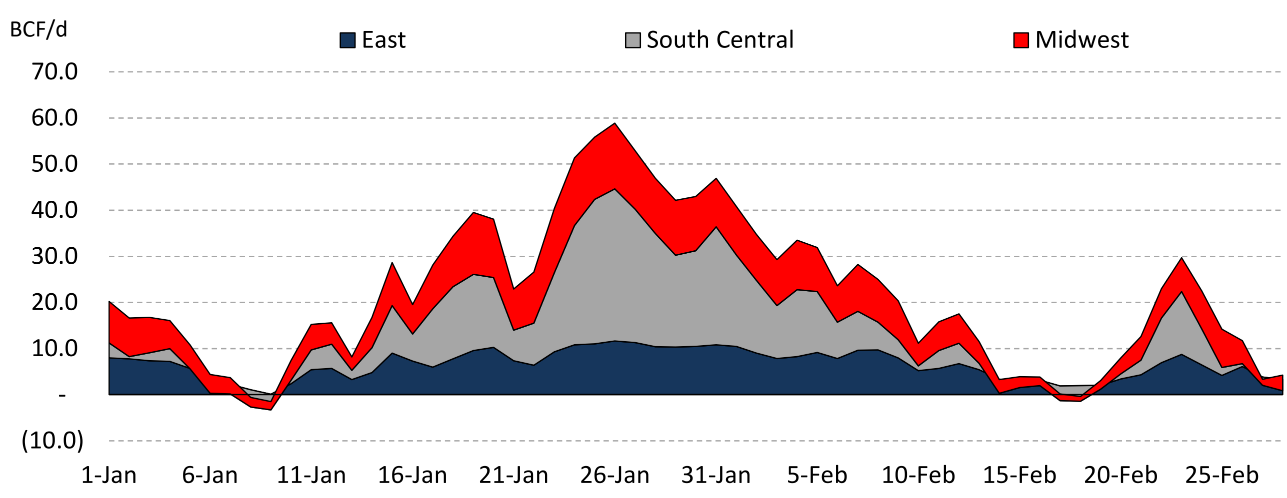
January 25 and 26 marked the two largest single-day storage withdrawals in South Central over the past decade, at approximately 31 and 33 Bcf/d, respectively, with January 26 also ranking among the top ten for single-day withdrawals in the combined East and Midwest EIA storage regions. The weekly withdrawal for the gas week ending January 30 set a new record at 360 Bcf, or 51.4 Bcf/d, reducing overall inventory levels by nearly 13% in a single week. These withdrawals were essential for the reliability of the energy system as underground storage served up to 37% of demand nationally on January 26 and roughly 30% of the total U.S. gas demand over a 10-day period.

EXHIBIT 14 - LOWER-48 WORKING NATURAL GAS STORAGE CAPACITY BY REGION AND TYPE

Region	Aquifer	Depleted Field	Salt Dome	Total	*% of Total*
East	1	1,035	5	**1,041**	*22%*
Midwest	369	850	2	**1,221**	*26%*
Mountain	2	494	-	**495**	*11%*
Pacific	25	345	-	**369**	*8%*
South Central	-	1,095	471	**1,566**	*33%*
Total	**396**	**3,818**	**479**	**4,693**	
% of Total	*8%*	*81%*	*10%*		

Source: EIA-191 data from January 2026

EXHIBIT 15 - CENTRAL & EASTERN U.S. DAY-OVER-DAY ESTIMATED CHANGE IN STORAGE



Source: S&P Global Platts

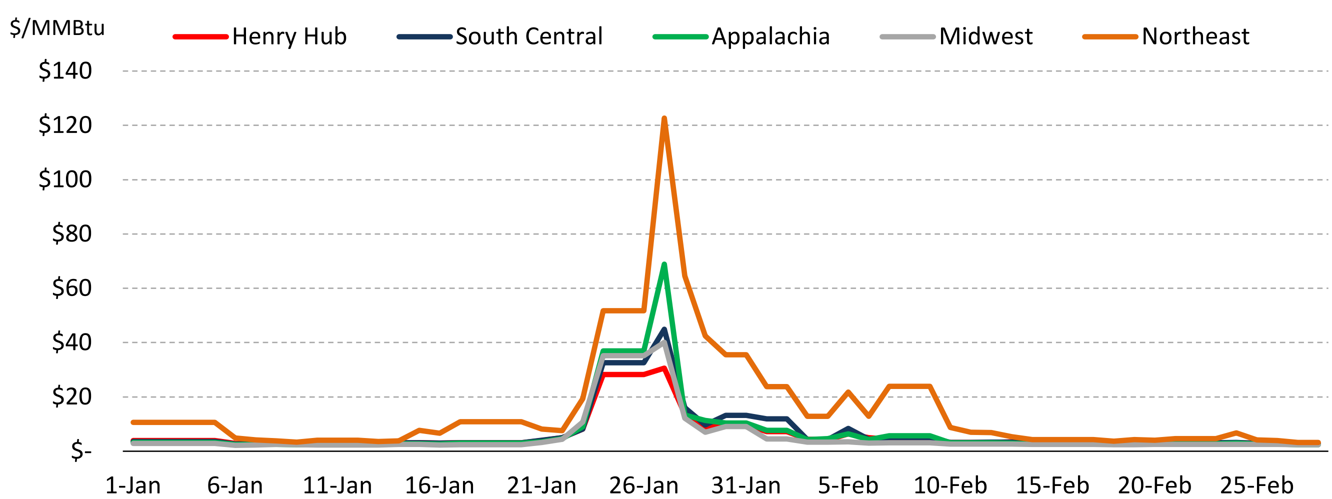
3.6 Natural Gas Prices

Natural gas spot and futures prices began trending higher following the Martin Luther King, Jr. holiday weekend as updated weather models showed elevated heating demand for the latter half of January. Average regional spot natural gas prices peaked on January 27 in anticipation of near-record demand, constrained pipeline transportation, and record storage withdrawal needs, among other factors. Iroquois Zone 2 prices exceeded $175/MMBtu, among the highest spot prices ever recorded on a major U.S. pipeline system. Other price points in the Northeast, such as Transco Zone 6 New York ($143/MMBtu) or Algonquin Citygate ($122/MMBtu), reached similar levels. Northeast prices remained elevated around $20/MMBtu until approximately February 9, as the region's extreme cold lingered, driving continued high demand and persistent pipeline capacity constraints.

The subsequent price correction was equally striking. For example, as Appalachian production data confirmed a smaller-than-expected decline and swift supply recovery, market participants who had been pricing in a severe supply-loss scenario began unwinding those positions. Northeast spot prices corrected rapidly, not because the demand event ended, but because the market repriced, given that production was not impacted as much as in past winter events.

The Northeast price spike during Winter Storm Fern underscores a structural market issue and a lesson for other areas in the country as demand increases, e.g., a lack of pipeline capacity in the region amplified an otherwise modest supply disruption into a more extreme pricing event, with direct consequences for natural gas consumers, electric generators, and industrial users across the most densely populated corridor in the country. Additional pipeline infrastructure would materially reduce congestion and could temper the magnitude of future winter price spikes, as shown below, that the highest prices were in the Northeast, where natural gas infrastructure is the most constrained. This is explained in more detail below in the section titled "Modeling Alternative Pipeline Scenarios."

EXHIBIT 16 - AVERAGE DAY-AHEAD NATURAL GAS PRICES BY REGION



Source: S&P Global Platts

3.7 Gas Utility Performance

Natural gas utilities use a portfolio of tools to ensure customers receive service during peak demand. During the winter heating season, temperature variability, especially during winter storms, presents the greatest risk to natural gas utilities. To help ensure customers receive safe and reliable service during periods of elevated demand, utilities rely on design-day planning strategies, diversified supply portfolios, and targeted price-risk management. Across the Lower-48, natural gas local distribution companies entered the 2025–2026 winter heating season prepared for major cold events, drawing on lessons learned from prior winters and historical precedent.

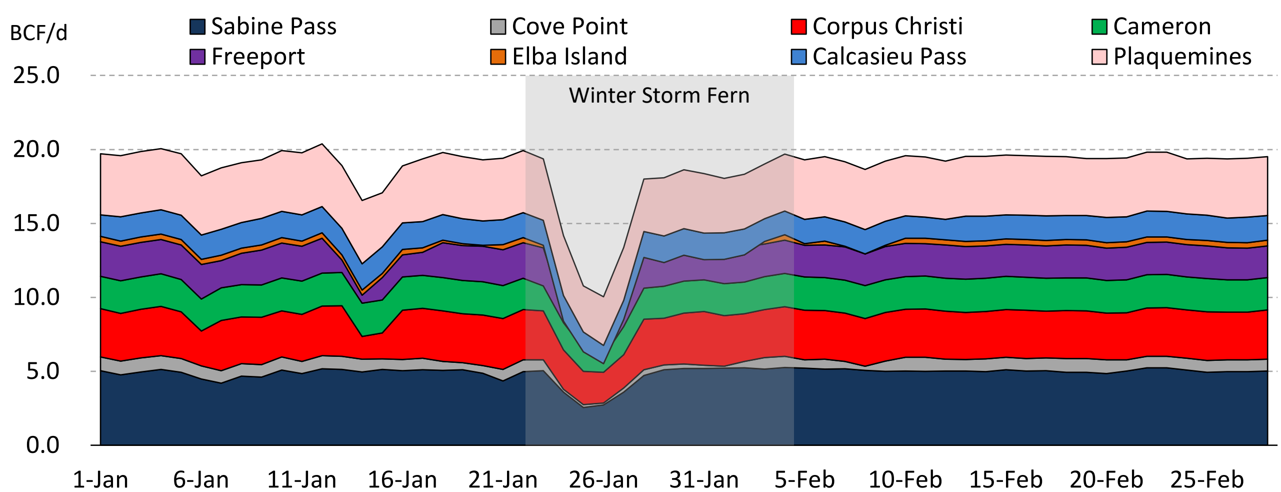
During Winter Storm Fern, planning and preparation were put to the test. Where pipeline data indicated extremely tight conditions, natural gas utilities with access to multiple pipelines and storage, as well as supplemental on-site peaking resources (including propane-air mixing), LNG vaporization, and compressed natural gas were positioned to provide margin against supply variability. For natural gas utilities, there were no known losses of service to customers due to Winter Storm Fern's impact on production.

Storage was also essential to maintain the reliability of the system during Winter Storm Fern. Over the storm period, natural gas storage withdrawals hit a record high for the week ending January 30, 2026, as discussed above. Natural gas storage is a critical component of the natural gas utility planning portfolio and U.S. energy infrastructure, as it provides system reliability, stabilizes market prices, and enhances resiliency during high-demand periods and unexpected disruptions. Overall, natural gas reliability for natural gas utilities depends on sustained infrastructure development and maintenance, operational preparedness, and multiple supply and balancing tools working together during weather events. Natural gas utilities met their obligation to serve firm customers and provided essential services to homes and businesses despite the high energy demand during Winter Storm Fern.

3.8 LNG Operations

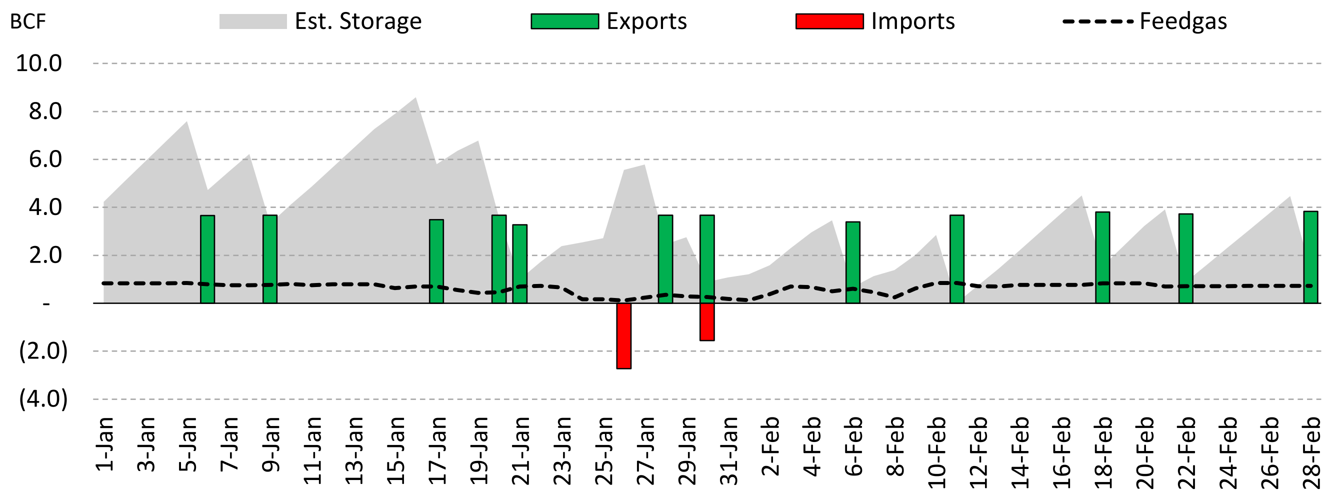
Across the eight operating export terminals, U.S. LNG feedgas demand reached a new monthly record of over 19 Bcf/d during December 2025. LNG feedgas continued to average over 19 Bcf/d during the first two weeks of January, before falling approximately 44% during the height of Winter Storm Fern. This decline to 10.6 Bcf/d from January 20 to 23 served as a balancing mechanism for the domestic market, flexibly redirecting flows to meet peak heating demand. Specific terminal operations illustrated the breadth of available flexibility. Virtually all LNG export facilities along the Gulf Coast reduced their feedgas flows during the peak of the storm, declining as much as 67% at Freeport LNG compared to the first half of January 2026. Elba Island in Georgia shifted from feedgas intake to LNG imports, providing approximately 0.7 Bcf/d of natural gas supply to the regional market between January 24 and February 2 from on-site storage and the import of one LNG vessel from Trinidad and Tobago, which arrived on January 28. Cove Point in Maryland reduced net feedgas flows to near zero by January 24, averaging only 0.2 Bcf/d between January 24 and February 1 compared to 0.9 Bcf/d in early January, while importing two LNG vessels from Trinidad and Tobago and maintaining its export obligations on January 28 and 30.

EXHIBIT 17 - LNG FEEDGAS FLOWS BY EXPORT TERMINAL



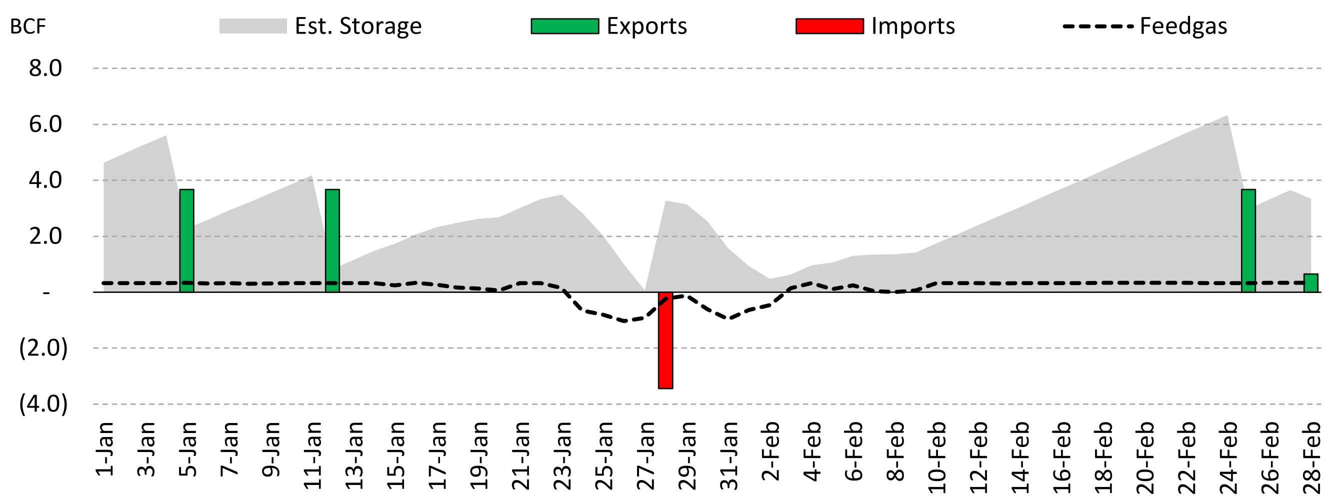
Source: S&P Global Platts

EXHIBIT 18 - COVE POINT FEEDGAS FLOWS & LNG EXPORTS/IMPORTS BY VESSEL



Source: S&P Global Platts & KPLER

EXHIBIT 19 - ELBA ISLAND FEEDGAS FLOWS & LNG EXPORTS/IMPORTS BY VESSEL



Source: S&P Global Platts & KPLER

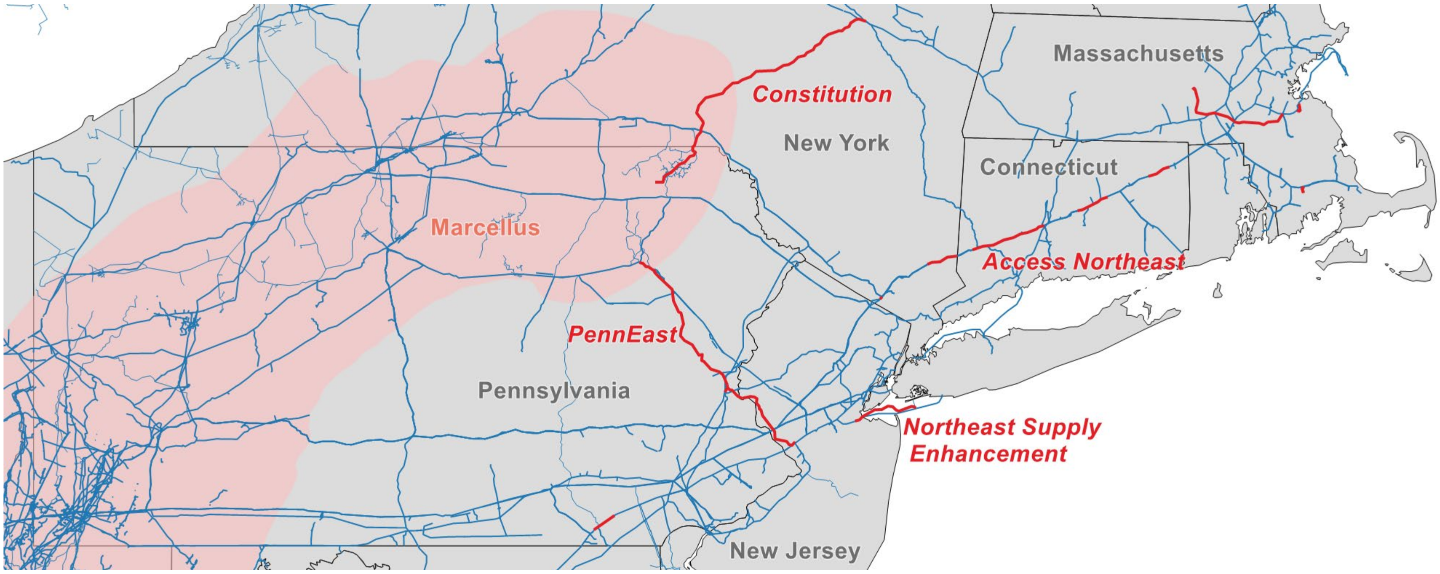
The eight active U.S. LNG projects have a combined on-site LNG storage capacity of approximately 107 Bcf of re-gasified natural gas. This on-site inventory allows terminals to continue export operations during feedgas supply disruptions or reductions, and as demonstrated during Winter Storm Fern, to reverse flows or reduce intake to support domestic markets under certain market-driven conditions.

4. Modeling of Alternative Pipeline Scenario

To quantify the potential price impact of constrained gas infrastructure during winter events, EVA assessed the value of delayed or canceled pipeline infrastructure in the Northeast and Mid-Atlantic regions and modeled an alternative pipeline scenario using its supply-demand balance model calibrated to January 2026 conditions. The base case includes the actual demand and supply conditions observed during Winter Storm Fern. The alternative scenario retains identical demand and supply assumptions but incorporates four pipeline projects that are currently either delayed or canceled: Access

Northeast,[7] Northeast Supply Enhancement,[8] PennEast,[9] and Constitution Pipeline.[10] Collectively, these projects are some of the most consequential unbuilt pipeline capacity projects in the Northeast. Additional background information on each project is available in the **Appendix**.

EXHIBIT 20 - MAP OF PIPELINE PROJECTS INCLUDED IN THE ALTERNATIVE SCENARIO



In this alternative scenario, utilization modeling underscores the structural need for additional pipeline capacity. Except for Access Northeast, which modeled at 62% utilization, all four projects showed utilization rates above 99% for the entire month of January, indicating that the market would fully absorb the available capacity under actual demand conditions.

Modeling results showed meaningful reductions in system stress on the most constrained pipeline systems. The Constitution Pipeline, by routing additional Appalachian supply toward the New York City metro area via the Iroquois system, materially reduced the need for Canadian imports and alleviated the basis differentials that caused the extreme price spike at the Iroquois Zone 2 price point. The PennEast project similarly alleviated supply constraints along Transco and Texas Eastern Transmission, facilitating additional Appalachian gas supply into the Philadelphia and New York metro areas. The Northeast Supply Enhancement and Access Northeast projects primarily enhanced supply flows along existing major pipeline infrastructure, including Transco and Algonquin, relieving key constraints along the most congested trunk lines.

The largest monthly average price decreases in the model were observed at Transco Zone 6 NY (down approximately 20%), Iroquois Zone 1 (down approximately 11%), Algonquin city-gates (down approximately 11%), and Tennessee Zone 6 (down approximately 10%). Given the model's monthly granularity, peak-day price reductions cannot be directly quantified, but they are likely significantly higher than reductions in monthly average prices due to greater constraints across the entire Northeast pipeline system compared to the monthly average system stress. Notably, the delivery points with the greatest modeled cost reductions were also the locations where prices reached the most extreme levels during Winter Storm Fern.

The analysis also highlights an environmental co-benefit of additional pipeline capacity. Many ISO-NE power plants with dual-fuel capability switched to on-site fuel oil during Winter Storm Fern due to limited natural gas supply availability. Projects such as Access Northeast, which increase the availability and lower the price of natural gas during extreme cold

[7] https://ecori.org/wp-content/uploads/2022/02/AccessNortheastFactsheet1pager.pdf
[8] https://www.williams.com/wp-content/uploads/sites/8/2025/05/NESE-Project-Fact-Sheet.pdf
[9] https://www.pa.gov/agencies/dep/programs-and-services/permitting-coordination/pennsylvania-pipeline-portal/penneast
[10] https://www.williams.com/expansion-project/constitution-pipeline/

events, would enable greater use of gas-fired generation in place of fuel oil, directly supporting New England states' emission-reduction goals.

5. Conclusion and Recommendations

Winter Storm Fern was a major cold-weather event that, while not reaching the peak temperature extremes of Winter Storm Uri or the Polar Vortex of 2025, posed a distinct and, in some respects, more demanding challenge to the natural gas system throughout its duration. Sustained below-normal temperatures over more than ten consecutive days drove demand to near-record levels, required record storage withdrawals, and tested the operational limits of natural gas infrastructure across the Northeast and Mid-Atlantic for an extended period. The natural gas system met that challenge and continued to reliably serve natural gas customers without any significant disruption. Infrastructure investments and industry preparedness efforts since 2021 have made this outcome possible.

Winter Storm Fern illustrated the resilience of the natural gas system, and one driver of improved performance compared to past events was the natural gas production sector, particularly in Appalachia. The region experienced far less production loss than during Winter Storm Elliott under comparable temperature conditions, reflecting the cumulative impact of market-driven investments, including investments in production-area storage and pipeline capacity, enhanced operational protections, improved field operations protocols, and other industry efforts. South Central production performance also improved materially.

Against that backdrop, Winter Storm Fern also highlighted issues that could become increasingly consequential as demand increases, including the need for additional natural gas infrastructure. Working gas storage capacity and deliverability in market areas have effectively stagnated for at least a decade, while supply and demand have grown by nearly 50%, leaving a smaller buffer against sustained demand surges. The record weekly withdrawal during Winter Storm Fern accounted for approximately 13% of the total working gas inventory. Northeast pipeline infrastructure remains chronically undersupplied relative to peak demand.

Based on the findings of this analysis, the following actions are recommended:

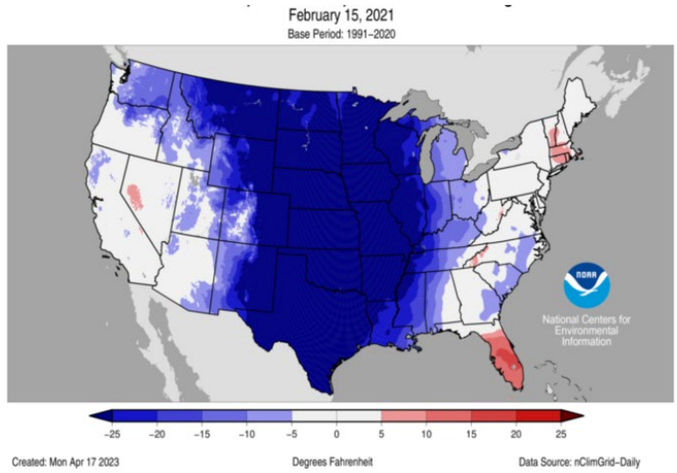
- Policymakers and regulators should prioritize expedited review and permitting of natural gas pipeline and storage projects where infrastructure constraints most directly translate into consumer price volatility and regional reliability risk.
- Federal and state policymakers should consider implementing frameworks to protect critical natural gas infrastructure from load shedding to ensure that natural gas infrastructure cannot be curtailed during electric emergencies.
- Electric market design reforms should encourage electric generators to contract for firm pipeline and storage capacity or tailored pipeline and storage services commensurate with their fuel security obligations, rather than relying on interruptible contracts. Reforms should also support long-term investment in pipeline capacity and storage to meet power demand during storms and to support demand growth.
- Storage capacity expansion, with associated transportation capabilities, particularly in market areas close to demand centers in the Mid-Atlantic and Northeast, should be treated as a reliability investment alongside pipeline expansion.
- The industry should continue to bolster weatherization investment programs in South Central producing regions, recognizing that the full stress test of post-Uri improvements has not yet occurred under Uri-level temperature conditions, including working with state officials to ensure roads are promptly cleared to ensure passable conditions.

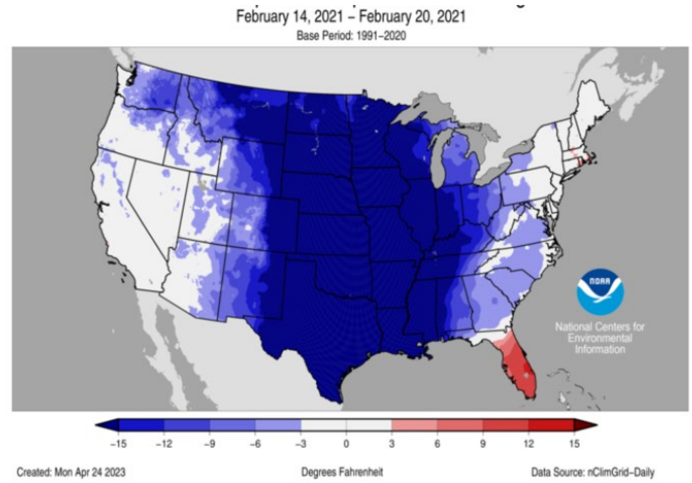
Winter Storm Fern demonstrated meaningful resilience in the natural gas system. However, the gap between current infrastructure and the capacity needed to reliably serve growing energy demand under Winter Storm Fern-like or more severe conditions is real and addressable, but only through timely, targeted investment and permitting of infrastructure.

Appendix

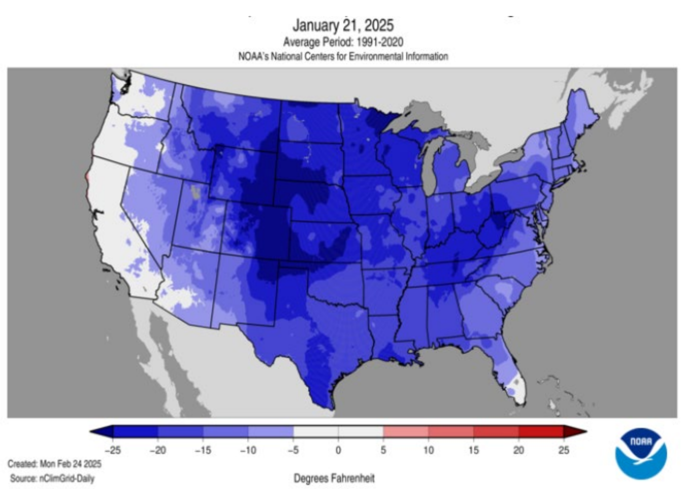
Weather Maps – Mean Temperature Departures from Average

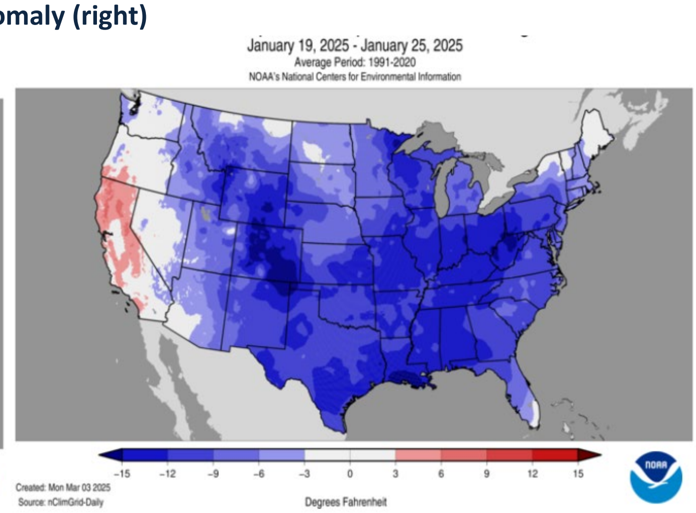
Winter Storm Uri 2021 – Daily Anomaly (left) and weekly anomaly (right)



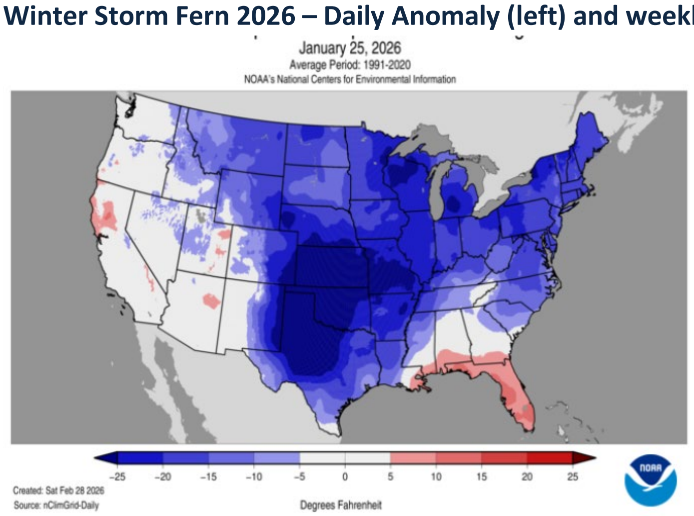


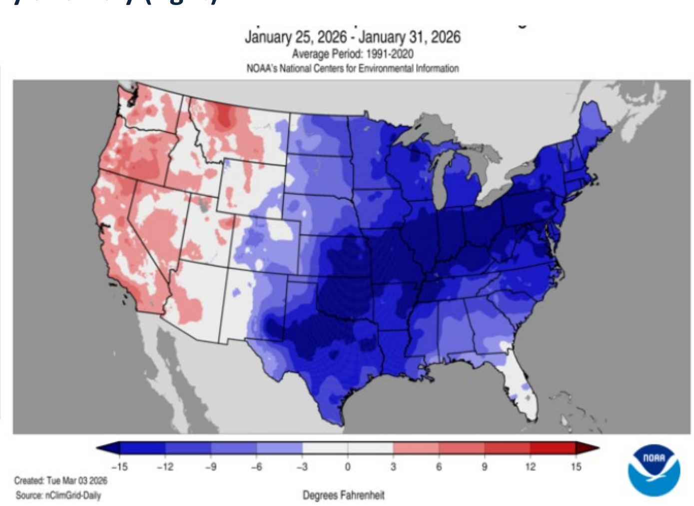
Polar Vortex 2025 – Daily Anomaly (left) and weekly anomaly (right)



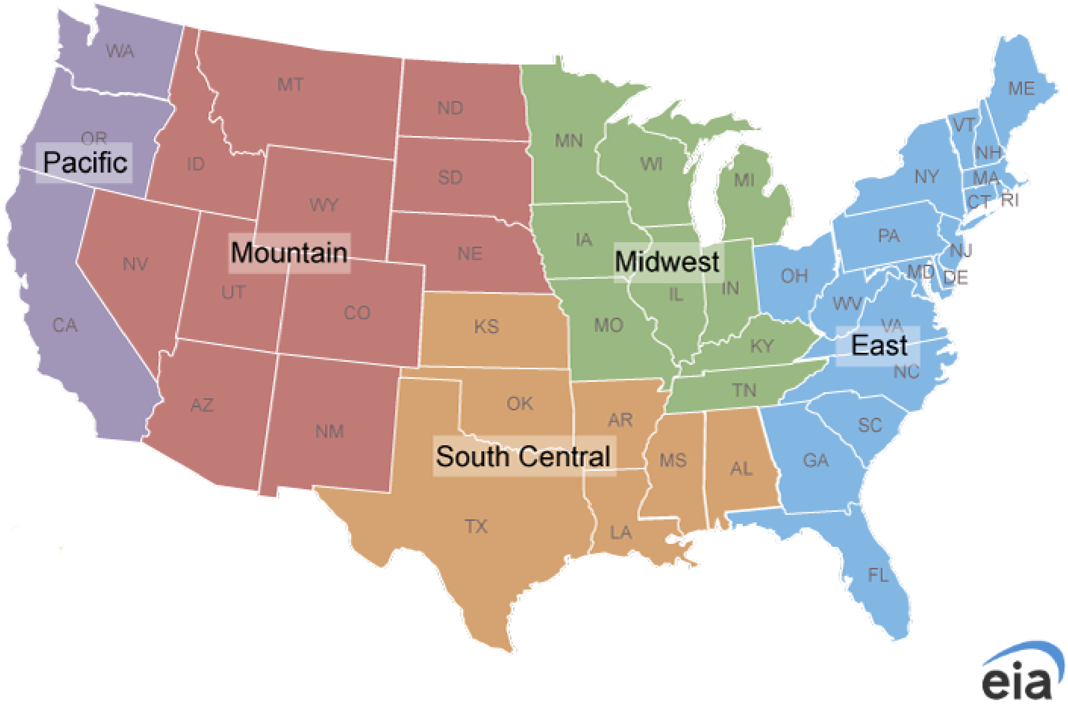


Winter Storm Fern 2026 – Daily Anomaly (left) and weekly anomaly (right)

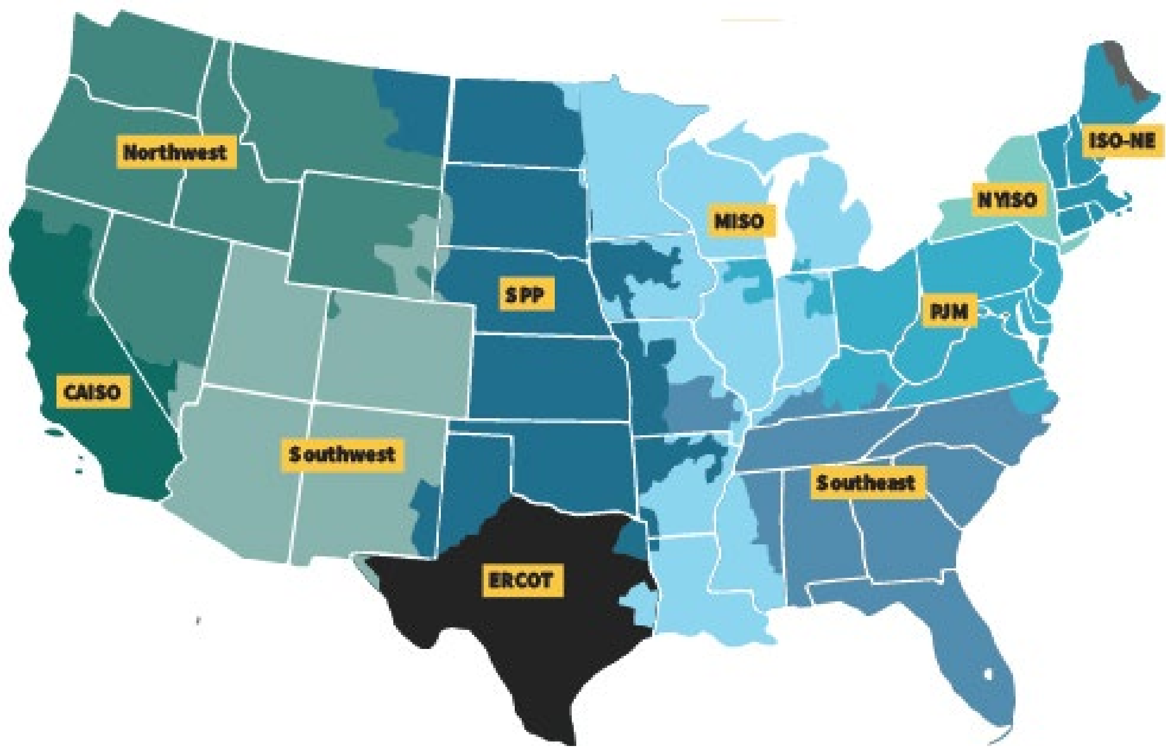




EIA Natural Gas Storage Regions



U.S. Power Market Regions[11]



[11] https://www.ferc.gov/electric-power-markets

Background Information on the Pipeline Projects Included in the Alternative Pipeline Scenario

Three of the four projects included in the alternative scenario share a common history: they received federal approval from FERC but were ultimately blocked or abandoned after state-level environmental regulators denied required authorizations.

The **Constitution Pipeline**, a 124-mile, 650 MMcf/d project designed to connect Marcellus Shale supply in northeastern Pennsylvania to downstream interconnections with Tennessee Gas Pipeline and Iroquois Gas Transmission in New York, received its FERC certificate in 2014 and was originally slated for service in 2015. Notably, in early 2025, Williams filed with FERC to revive the Constitution Pipeline under President Trump's national energy emergency declaration, and as of early 2026, the project is again working through permitting processes.

The **Northeast Supply Enhancement** project, a Transco expansion that would have added approximately 400,000 Dth/d to serve National Grid customers in Brooklyn, Queens, and Long Island, followed a similar trajectory. FERC approved the project in 2019. Williams Transco allowed the FERC certificate to expire on May 3, 2024, but the project has since been revived: FERC reissued a certificate of public convenience and necessity on August 28, 2025. Williams is currently targeting a construction start in Q3 2026 and an in-service date of Q4 2027.

The **PennEast** Pipeline, a 116-mile, approximately 1 Bcf/d project proposed by a consortium of five energy companies to move Marcellus gas from Luzerne County, Pennsylvania, to Mercer County, New Jersey, received FERC approval in 2018.

Additionally, **Access Northeast** was a $3 billion project, developed jointly by Spectra Energy (now Enbridge), Eversource, and National Grid, and was designed to expand the existing Algonquin Gas Transmission system by approximately 900,000 Dth/d across southern New England and was intended to solve chronic winter reliability and price constraints in the ISO-NE region. The project did not move forward due to legal and financial issues.